PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) (1) *Financial Statements*

See “Index to the Consolidated Financial Statements” set forth on Page F-1.

(2) *Financial Statement Schedules*

All schedules are omitted because they are either not applicable or the required information is shown in the consolidated financial statements or notes thereto.

(3) *Exhibits*

3.1	—	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 27, 2001).
3.2	—	Amendment No. 1 dated April 15, 2004 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	—	Amendment No. 2 dated November 15, 2006 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed November 21, 2006).
3.4	—	Amendment No. 3 dated August 16, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 22, 2007).
3.5	—	Amendment No. 4 effective as of January 1, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed April 15, 2008).
3.6	—	Amendment No. 5 dated May 28, 2008 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed May 30, 2008).
3.7	—	Amendment No. 6 dated September 3, 2009 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed September 3, 2009).
3.8	—	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.9†	—	Amendment No. 1 dated December 31, 2010 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P.
3.10†	—	Amendment No. 2 dated January 1, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P.
3.11	—	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.12	—	Fifth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated December 23, 2010 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed December 30, 2010).
3.13	—	Sixth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated December 23, 2010 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed December 30, 2010).

3.14	—	Certificate of Incorporation of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.15	—	Bylaws of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.16	—	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K filed January 4, 2008).
4.1	—	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	—	First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.3	—	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003).
4.4	—	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168).
4.5	—	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).
4.6	—	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 12, 2006).
4.7	—	Seventh Supplemental Indenture dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed May 12, 2006).
4.8	—	Eighth Supplemental Indenture dated August 25, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed August 25, 2006).
4.9	—	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006).
4.10	—	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to

		Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006).
4.11	—	Eleventh Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed November 21, 2006).
4.12	—	Twelfth Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.21 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.13	—	Thirteenth Supplemental Indenture (Series A and Series B 6.5% Senior Notes due 2018) dated April 23, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 23, 2008).
4.14	—	Fourteenth Supplemental Indenture dated July 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.15 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).
4.15	—	Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 20, 2009).
4.16	—	Sixteenth Supplemental Indenture (4.25% Senior Notes due 2012) dated July 23, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 23, 2009).
4.17	—	Seventeenth Supplemental Indenture (5.75% Senior Notes due 2020) dated September 4, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed September 4, 2009).
4.18	—	Eighteenth Supplemental Indenture (3.95% Senior Notes due 2015) dated July 14, 2010 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 13, 2010).
4.19	—	Nineteenth Supplemental Indenture (5.00% Senior Notes due 2021) dated January 14, 2011 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed January 11, 2011).
4.20	—	Registration Rights Agreement dated September 3, 2009 by and between Plains All American Pipeline, L.P. and Vulcan Gas Storage LLC (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-3, File No. 333-162477).
10.1	—	Second Amended and Restated Credit Agreement dated as of July 31, 2006 by and among Plains All American Pipeline, L.P., as US Borrower; PMC (Nova Scotia) Company and Plains Marketing Canada, L.P., as Canadian Borrowers; Bank of America, N.A., as Administrative Agent; Bank of America, N.A., acting through its Canada Branch, as Canadian Administrative Agent; Wachovia Bank, National Association and J. P. Morgan Chase Bank, N.A., as Co-Syndication Agents; Fortis Capital Corp., Citibank, N.A., BNP Paribas, UBS Securities LLC, SunTrust Bank, and The Bank of Nova Scotia, as Co-Documentation Agents; the Lenders party thereto; and Banc of America Securities LLC

		and Wachovia Capital Markets, LLC, as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 4, 2006).
10.2	—	Amended and Restated Crude Oil Marketing Agreement dated as of July 23, 2004, among Plains Resources Inc., Calumet Florida Inc. and Plains Marketing, L.P. (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
10.3	—	Amended and Restated Omnibus Agreement dated as of July 23, 2004, among Plains Resources Inc., Plains All American Pipeline, L.P., Plains Marketing, L.P., Plains Pipeline, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
10.4	—	Contribution, Assignment and Amendment Agreement dated as of June 27, 2001, among Plains All American Pipeline, L.P., Plains Marketing, L.P., All American Pipeline, L.P., Plains AAP, L.P., Plains All American GP LLC and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 27, 2001).
10.5	—	Contribution, Assignment and Amendment Agreement dated as of June 8, 2001, among Plains All American Inc., Plains AAP, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 11, 2001).
10.6	—	Separation Agreement dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc., Plains All American GP LLC, Plains AAP, L.P. and Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed June 11, 2001).
10.7**	—	Pension and Employee Benefits Assumption and Transition Agreement dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed June 11, 2001).
10.8**	—	Plains All American GP LLC 2005 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 26, 2005).
10.9**	—	Plains All American GP LLC 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to Registration Statement on Form S-8, File No. 333-74920) as amended June 27, 2003 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003).
10.10**	—	Plains All American 2001 Performance Option Plan (incorporated by reference to Exhibit 99.2 to the Registration Statement on Form S-8 filed December 11, 2001, File No. 333-74920).
10.11**	—	Amended and Restated Employment Agreement between Plains All American GP LLC and Greg L. Armstrong dated as of June 30, 2001 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.12**	—	Amended and Restated Employment Agreement between Plains All American GP LLC and Harry N. Pefanis dated as of June 30, 2001 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.13	—	Asset Purchase and Sale Agreement dated February 28, 2001 between Murphy Oil Company Ltd. and Plains Marketing Canada, L.P. (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed May 10, 2001).
10.14	—	Transportation Agreement dated July 30, 1993, between All American Pipeline Company and Exxon Company, U.S.A. (incorporated by reference to Exhibit 10.9 to the Registration Statement on Form S-1 filed September 23, 1998, File No. 333-64107).
10.15	—	Transportation Agreement dated August 2, 1993, among All American Pipeline Company, Texaco Trading and Transportation Inc., Chevron U.S.A. and Sun Operating Limited Partnership (incorporated by reference to Exhibit 10.10 to the Registration Statement on Form S-1 filed September 23, 1998, File

No. 333-64107).

10.16	—	First Amendment to Contribution, Conveyance and Assumption Agreement dated as of December 15, 1998 (incorporated by reference to Exhibit 10.13 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.17	—	Agreement for Purchase and Sale of Membership Interest in Scurlock Permian LLC between Marathon Ashland LLC and Plains Marketing, L.P. dated as of March 17, 1999 (incorporated by reference to Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.18**	—	Plains All American Inc. 1998 Management Incentive Plan (incorporated by reference to Exhibit 10.5 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.19**	—	PMC (Nova Scotia) Company Bonus Program (incorporated by reference to Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2004).
10.20**	—	Quarterly Bonus Program Summary (incorporated by reference to Exhibit 10.21 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.21**†	—	Directors' Compensation Summary.
10.22	—	Master Railcar Leasing Agreement dated as of May 25, 1998 (effective June 1, 1998), between Pivotal Enterprises Corporation and CANPET Energy Group, Inc., (incorporated by reference to Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 2001).
10.23**	—	Form of LTIP Grant Letter (Armstrong/Pefanis) (incorporated by reference to Exhibit 10.24 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.24**	—	Form of LTIP Grant Letter (executive officers) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed April 1, 2005).
10.25**	—	Form of LTIP Grant Letter (independent directors) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed February 23, 2005).
10.26**	—	Form of LTIP Grant Letter (designated directors) (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed February 23, 2005).
10.27**	—	Form of LTIP Grant Letter (payment to entity) (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K filed February 23, 2005).
10.28**	—	Form of Performance Option Grant Letter (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed April 1, 2005).
10.29	—	Administrative Services Agreement between Plains All American GP LLC and Vulcan Energy Corporation dated October 14, 2005 (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed October 19, 2005).
10.30	—	Membership Interest Purchase Agreement by and between Sempra Energy Trading Corp. and PAA/Vulcan Gas Storage, LLC dated August 19, 2005 (incorporated by reference to Exhibit 1.2 to the Current Report on Form 8-K filed September 19, 2005).
10.31**†	—	Waiver Agreement dated as of December 23, 2010 between Plains All American GP LLC and Greg L. Armstrong.
10.32**†	—	Waiver Agreement dated as of December 23, 2010 between Plains All American GP LLC and Harry N. Pefanis.

10.33	—	Excess Voting Rights Agreement dated as of August 12, 2005 between Vulcan Energy GP Holdings Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed August 16, 2005).
10.34	—	Excess Voting Rights Agreement dated as of August 12, 2005 between Lynx Holdings I, LLC and Plains All American GP LLC (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed August 16, 2005).
10.35**	—	Form of LTIP Grant Letter (executive officers) (incorporated by reference to Exhibit 10.39 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.36**	—	Employment Agreement between Plains All American GP LLC and John P. vonBerg dated December 18, 2001 (incorporated by reference to Exhibit 10.40 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.37**	—	Form of LTIP Grant Letter (audit committee members) (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 23, 2006).
10.38**	—	Plains All American PPX Successor Long-Term Incentive Plan (incorporated by reference to Exhibit 10.45 to the Annual Report on Form 10-K for the year ended December 31, 2006).
10.39**	—	Forms of LTIP Grant Letters dated February 22, 2007 (Named Executive Officers) (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2007).
10.40	—	First Amendment dated July 31, 2007 to the Second Amended and Restated Credit Agreement [US/Canada Facilities] by and between Plains All American Pipeline, L.P., PMC (Nova Scotia) Company, Plains Marketing Canada, L.P., Rangeland Pipeline Company, Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 6, 2007).
10.41**	—	Separation and Release Agreement dated August 21, 2007 between Plains All American GP LLC and George R. Coiner (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2007).
10.42**	—	Form of Plains AAP, L.P. Class B Restricted Units Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 4, 2008).
10.43	—	Second Restated Credit Agreement dated as of November 6, 2008 by among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party there to (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed November 7, 2008).
10.44	—	Second Amendment to Second Restated Credit Agreement dated as of October 25, 2010, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed October 28, 2010).
10.45	—	Restated Guaranty Agreement dated November 6, 2008 by Plains All American Pipeline, L.P. in favor of Bank of America, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed November 7, 2008).
10.46	—	Contribution and Assumption Agreement dated December 28, 2007, by and between Plains AAP, L.P. and PAA GP LLC (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed January 4, 2008).
10.47	—	Assumption, Ratification and Confirmation Agreement dated January 1, 2008 by Plains Midstream Canada ULC in favor of the Lenders party to the Second Amended and Restated Credit Agreement [US/Canada Facilities], as amended (incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K for the year ended December 31, 2007).
10.48†	—	Assumption, Ratification and Confirmation Agreement dated January 1, 2011 by Plains Midstream

Canada ULC in favor of the Lenders party to the Second Amended and Restated Credit Agreement [US/Canada Facilities], as amended.

10.49**	—	First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Greg L. Armstrong (incorporated by reference to Exhibit 10.49 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.50**	—	First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Harry N. Pefanis (incorporated by reference to Exhibit 10.50 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.51**	—	First Amendment to Plains All American GP LLC 2005 Long-Term Incentive Plan dated December 4, 2008 (incorporated by reference to Exhibit 10.51 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.52**	—	Second Amendment to Plains All American GP LLC 1998 Long-Term Incentive Plan dated December 4, 2008 (incorporated by reference to Exhibit 10.52 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.53**	—	Form of Amendment to LTIP grant letters (executive officers) (incorporated by reference to Exhibit 10.53 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.54**	—	Form of Amendment to LTIP grant letters (directors) (incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.55	—	Contribution Agreement dated as of April 29, 2010 by and among PAA Natural Gas Storage, L.P., PNGS GP LLC, Plains All American Pipeline, L.P., PAA Natural Gas Storage, LLC, PAA/Vulcan Gas Storage, LLC, Plains Marketing, L.P. and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to PNG's Current Report on Form 8-K filed May 4, 2010).
10.56	—	Omnibus Agreement dated May 5, 2010 by and among Plains All American GP LLC, Plains All American Pipeline, L.P., PNGS GP LLC and PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 10.1 to PNG's Current Report on Form 8-K filed May 11, 2010).
10.57**	—	Form of Transaction Grant Agreement (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2010).
10.58**†	—	Form of 2010 LTIP Grant Letters.
10.59**†	—	Employment Agreement between Plains All American GP LLC and John R. Rutherford dated September 27, 2010.
10.60	—	364-Day Credit Agreement dated January 3, 2011 among Plains All American Pipeline, L.P., as Borrower; Bank of America, N.A., as Administrative Agent; DnB NOR Bank ASA and JPMorgan Chase Bank NA, as Co-Syndication Agents; SunTrust Bank and Wells Fargo Bank, National Association, as Co-Documentation Agents; the Lenders party thereto; and Merrill Lynch, Pierce, Fenner & Smith Incorporated, DnB NOR Markets, Inc. and J.P. Morgan Securities LLC, as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 7, 2011).
12.1†	—	Computation of Ratio of Earnings to Fixed Charges
21.1†	—	List of Subsidiaries of Plains All American Pipeline, L.P.
23.1†	—	Consent of PricewaterhouseCoopers LLP.
31.1†	—	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2†	—	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1†	—	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350

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32.2†	—	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350
101†	—	The following financial information from the annual report on Form 10-K of Plains All American Pipeline, L.P. for the year ended December 31, 2010, formatted in XBRL (extensible Business Reporting Language): (i) Consolidated Statements of Operations, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) Consolidated Statements of Changes in Partners' Capital, (v) Consolidated Statements of Comprehensive Income, (vi) Consolidated Statements of Changes in Accumulated Other Comprehensive Income and (vii) Notes to the Consolidated Financial Statements.

† Filed herewith

** Management compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto 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

By: /s/ GREG L. ARMSTRONG
Greg L. Armstrong,
Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)

February 25, 2011

By: /s/ AL SWANSON
Al Swanson,
Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)

February 25, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Name	Title	Date
/s/ GREG L. ARMSTRONG Greg L. Armstrong	Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)	February 25, 2011
/s/ HARRY N. PEFANIS Harry N. Pefanis	President and Chief Operating Officer of Plains All American GP LLC	February 25, 2011
/s/ AL SWANSON Al Swanson	Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)	February 25, 2011
/s/ CHRIS HERBOLD Chris Herbold	Vice President—Accounting and Chief Accounting Officer of Plains All American GP LLC (Principal Accounting Officer)	February 25, 2011
/s/ EVERARDO GOYANES Everardo Goyanes	Director of Plains All American GP LLC	February 25, 2011
/s/ GARY R. PETERSEN Gary R. Petersen	Director of Plains All American GP LLC	February 25, 2011
/s/ JOHN T. RAYMOND John T. Raymond	Director of Plains All American GP LLC	February 25, 2011
/s/ ROBERT V. SINNOTT Robert V. Sinnott	Director of Plains All American GP LLC	February 25, 2011
/s/ VICKY SUTIL Vicky Sutil	Director of Plains All American GP LLC	February 25, 2011
/s/ J. TAFT SYMONDS J. Taft Symonds	Director of Plains All American GP LLC	February 25, 2011
/s/ CHRISTOPHER M. TEMPLE Christopher M. Temple	Director of Plains All American GP LLC	February 25, 2011

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Plains All American Pipeline, L.P.'s management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Management has used the framework set forth in the report entitled "Internal Control—Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") to evaluate the effectiveness of the Partnership's internal control over financial reporting. Based on that evaluation, management has concluded that the Partnership's internal control over financial reporting was effective as of December 31, 2010.

The effectiveness of the Partnership's internal control over financial reporting as of December 31, 2010 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on Page F-3.

/s/ GREG L. ARMSTRONG

Greg L. Armstrong
Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC
(Principal Executive Officer)

/s/ AL SWANSON

Al Swanson
Executive Vice President and Chief Financial Officer of Plains All American GP LLC
(Principal Financial Officer)

February 25, 2011

Report of Independent Registered Public Accounting Firm

To the Board of Directors of the General Partner and Unitholders of
Plains All American Pipeline, L.P.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of cash flows, of changes in partners' capital, of comprehensive income, and of changes in accumulated other comprehensive income, present fairly, in all material respects, the financial position of Plains All American Pipeline, L.P. and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Houston, Texas
February 25, 2011

PricewaterhouseCoopers LLP

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions, except units)

	December 31, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 36	$ 25
Restricted cash	20	—
Trade accounts receivable and other receivables, net	2,746	2,253
Inventory	1,491	1,157
Other current assets	88	223
Total current assets	4,381	3,658
PROPERTY AND EQUIPMENT	7,814	7,240
Accumulated depreciation	(1,123)	(900)
	6,691	6,340
OTHER ASSETS		
Goodwill	1,376	1,287
Linefill and base gas	519	501
Long-term inventory	154	121
Investments in unconsolidated entities	200	82
Other, net	382	369
Total assets	$ 13,703	$ 12,358
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 2,738	$ 2,295
Short-term debt	1,326	1,074
Other current liabilities	151	413
Total current liabilities	4,215	3,782
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discount of $12 and $14, respectively	4,363	4,136
Long-term debt under credit facilities and other	268	6
Other long-term liabilities and deferred credits	284	275
Total long-term liabilities	4,915	4,417
COMMITMENTS AND CONTINGENCIES (NOTE 11)		
PARTNERS' CAPITAL		
Common unitholders (141,199,175 and 136,135,988 units outstanding, respectively)	4,234	4,002
General partner	108	94
Total partners' capital excluding noncontrolling interests	4,342	4,096
Noncontrolling interests	231	63
Total partners' capital	4,573	4,159
Total liabilities and partners' capital	$ 13,703	$ 12,358

The accompanying notes are an integral part of these consolidated financial statements.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per unit data)

	Year Ended December 31,		
	2010	2009	2008
REVENUES			
Supply & Logistics segment revenues	$ 24,989	$ 17,757	$ 29,348
Transportation segment revenues	565	536	556
Facilities segment revenues	339	227	157
Total revenues	25,893	18,520	30,061
COSTS AND EXPENSES			
Purchases and related costs	23,921	16,656	28,479
Field operating costs	689	638	617
General and administrative expenses	260	211	160
Depreciation and amortization	256	236	211
Total costs and expenses	25,126	17,741	29,467
OPERATING INCOME	767	779	594
OTHER INCOME/(EXPENSE)			
Equity earnings in unconsolidated entities	3	15	14
Interest expense (net of capitalized interest of $16, $15 and $17, respectively)	(248)	(224)	(196)
Other income/(expense), net	(9)	16	33
INCOME BEFORE TAX	513	586	445
Current income tax (expense)/benefit	1	(15)	(9)
Deferred income tax benefit	—	9	1
NET INCOME	514	580	437
Less: Net income attributable to noncontrolling interests	(9)	(1)	—
NET INCOME ATTRIBUTABLE TO PLAINS	$ 505	$ 579	$ 437
NET INCOME ATTRIBUTABLE TO PLAINS:			
LIMITED PARTNERS	$ 338	$ 443	$ 325
GENERAL PARTNER	$ 167	$ 136	$ 112
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 2.41	$ 3.34	$ 2.66
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 2.40	$ 3.32	$ 2.64
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	137	130	120
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	138	131	121

The accompanying notes are an integral part of these consolidated financial statements.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 514	$ 580	$ 437
Reconciliation of net income to net cash provided by operating activities:			
Depreciation and amortization	256	236	211
Equity compensation expense	98	68	24
Inventory valulation adjustments	3	—	168
Gain on sale of linefill	(21)	(4)	(3)
Gain on sale of investment assets	—	—	(12)
Deferred income tax benefit	—	(9)	(1)
(Gain)/loss on foreign currency revaluation	(2)	(13)	22
Equity earnings in unconsolidated entities, net of distributions	6	(8)	(4)
Net cash received/(paid) for terminated interest rate and foreign currency hedging instruments	—	(9)	15
Net gain on purchase of remaining 50% interest in PAA/Vulcan	—	(9)	—
Other	10	(6)	2
Changes in assets and liabilities, net of acquisitions:			
Trade accounts receivable and other	(59)	(744)	668
Inventory	(336)	(319)	(120)
Accounts payable and other current liabilities	(210)	602	(550)
Net cash provided by operating activities	259	365	857
CASH FLOWS FROM INVESTING ACTIVITIES			
Cash paid in connection with acquisitions, net of cash acquired (Note 3)	(407)	(219)	(709)
Restricted cash in escrow for acquisitions	(20)	—	—
Additions to property, equipment and other	(451)	(460)	(589)
Investment in unconsolidated entities	—	(4)	(37)
Net cash received/(paid) for sales and purchases of linefill and base gas	25	(9)	(55)
Cash received for sale of noncontrolling interest in a subsidiary	268	26	—
Proceeds from sales of assets and other investing activities	2	6	51
Net cash used in investing activities	(583)	(660)	(1,339)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings/(repayments) on PAA's revolving credit facility	49	(19)	286
Net borrowings on PNG's revolving credit facility	260	—	—
Net borrowings/(repayments) on PAA's hedged inventory facility	200	20	(196)
Repayment of PNGS debt	—	(446)	—
Proceeds from the issuance of senior notes	400	1,346	597
Repayments of senior notes	(175)	(430)	—
Net proceeds from the issuance of common units (Note 5)	296	458	315
Distributions paid to common unitholders (Note 5)	(512)	(468)	(418)
Distributions paid to general partner (Note 5)	(170)	(137)	(114)
Distributions to noncontrolling interests (Note 5)	(10)	(2)	—
Other financing activities	(2)	(10)	(6)
Net cash provided by financing activities	336	312	464
Effect of translation adjustment on cash	(1)	(3)	5
Net increase/(decrease) in cash and cash equivalents	11	14	(13)
Cash and cash equivalents, beginning of period	25	11	24
Cash and cash equivalents, end of period	$ 36	$ 25	$ 11
Cash paid for interest, net of amounts capitalized	$ 253	$ 214	$ 206
Cash paid for income taxes, net of amounts refunded	$ 21	$ (5)	$ 15

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL
(in millions)

	Common Units		General	Partners' Capital Excluding Noncontrolling	Noncontrolling	Partners'
	Units	Amount	Partner	Interests	Interests	Capital
Balance at December 31, 2007	**116**	**$ 3,343**	**$ 81**	**$ 3,424**	**$ —**	**$ 3,424**
Net income	—	325	112	437	—	437
Distributions	—	(418)	(114)	(532)	—	(532)
Issuance of common units	7	309	6	315	—	315
Issuance of common units under Long Term Incentive Plans ("LTIP")	—	1	—	1	—	1
Class B Units of Plains AAP, L.P. (Note 10)	—	12	—	12	—	12
Other comprehensive loss	—	(103)	(2)	(105)	—	(105)
Balance at December 31, 2008	**123**	**$ 3,469**	**$ 83**	**$ 3,552**	**$ —**	**$ 3,552**
Sale of noncontrolling interest in a subsidiary	—	(37)	(1)	(38)	64	26
Net income	—	443	136	579	1	580
Distributions	—	(468)	(137)	(605)	(2)	(607)
Issuance of common units	11	447	9	456	—	456
Issuance of common units in connection with the PNGS Acquisition	2	91	2	93	—	93
Issuance of common units under LTIP	—	12	—	12	—	12
Class B Units of Plains AAP, L.P. (Note 10)	—	2	3	5	—	5
Other comprehensive income	—	46	2	48	—	48
Other	—	(3)	(3)	(6)	—	(6)
Balance at December 31, 2009	**136**	**$ 4,002**	**$ 94**	**$ 4,096**	**$ 63**	**$ 4,159**
Sale of noncontrolling interest in a subsidiary	—	99	2	101	167	268
Net income	—	338	167	505	9	514
Distributions	—	(512)	(170)	(682)	(10)	(692)
Issuance of common units	5	290	6	296	—	296
Issuance of common units under LTIP	—	16	—	16	—	16
Equity compensation expense under LTIP	—	4	—	4	3	7
Class B Units of Plains AAP, L.P. (Note 10)	—	—	9	9	—	9
Other comprehensive loss	—	(5)	—	(5)	—	(5)
Other	—	2	—	2	(1)	1
Balance at December 31, 2010	**141**	**$ 4,234**	**$ 108**	**$ 4,342**	**$ 231**	**$ 4,573**

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions)

	Year Ended December 31, 2010	2009	2008
Net income	$ 514	$ 580	$ 437
Other comprehensive income/(loss)	(5)	48	(105)
Comprehensive income	509	628	332
Less: Comprehensive income attributable to noncontrolling interests	(9)	(1)	—
Comprehensive income attributable to Plains	$ 500	$ 627	$ 332

CONSOLIDATED STATEMENTS OF CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME
(in millions)

	Derivative Instruments	Translation Adjustments	Other	Total
Balance at December 31, 2007	$ 4	$ 176	$ —	$ 180
Reclassification adjustments	46	—	—	46
Net deferred gain on cash flow hedges	111	—	—	111
Currency translation adjustment	—	(262)	—	(262)
2008 Activity	157	(262)	—	(105)
Balance at December 31, 2008	$ 161	$ (86)	$ —	$ 75
Reclassification adjustments	8	—	—	8
Net deferred loss on cash flow hedges	(151)	—	—	(151)
Currency translation adjustment	—	192	—	192
Proportionate share of our unconsolidated entities' other comprehensive loss	—	—	(1)	(1)
2009 Activity	(143)	192	(1)	48
Balance at December 31, 2009	$ 18	$ 106	$ (1)	$ 123
Reclassification adjustments	(24)	—	—	(24)
Deferred loss on cash flow hedges, net of tax benefit	(73)	—	—	(73)
Currency translation adjustment	—	92	—	92
2010 Activity	(97)	92	—	(5)
Balance at December 31, 2010	$ (79)	$ 198	$ (1)	$ 118

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Organization and Basis of Presentation

Organization

Plains All American Pipeline, L.P. is a Delaware limited partnership formed in 1998. Our operations are conducted directly and indirectly through our primary operating subsidiaries. As used in this Form 10-K, the terms "Partnership," "Plains," "PAA," "we," "us," "our," "ours" and similar terms refer to Plains All American Pipeline, L.P. and its subsidiaries, unless the context indicates otherwise.

We engage in the transportation, storage, terminalling and marketing of crude oil, refined products and LPG. Through our general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P. (NYSE: PNG), we also engage in the development and operation of natural gas storage facilities. Our business activities are conducted through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. See Note 15 for further discussion of our three operating segments.

Our 2% general partner interest is held by PAA GP LLC, a Delaware limited liability company, whose sole member is Plains AAP, L.P., a Delaware limited partnership. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P.'s general partner. Plains All American GP LLC manages our operations and activities and employs our domestic officers and personnel. Our Canadian officers and personnel are employed by our subsidiary Plains Midstream Canada ULC. References to our "general partner," as the context requires, include any or all of PAA GP LLC, Plains AAP, L.P. and Plains All American GP LLC. Plains AAP, L.P. and Plains All American GP LLC are essentially held by 18 owners with interests ranging from approximately 35% to less than 1%.

Definitions

The following additional defined terms are used in this Part IV and shall have the meanings indicated below:

AOCI	=	Accumulated other comprehensive income
Bcf	=	Billion cubic feet
Btu	=	British thermal unit
CAD	=	Canadian dollar
CERCLA	=	Federal Comprehensive Environmental Response, Compensation and Liability Act, as amended
DERs	=	Distribution equivalent rights
EBITDA	=	Earnings before interest taxes depreciation and amortization
FASB	=	Financial Accounting Standards Board
FERC	=	Federal Energy Regulatory Commission
GAAP	=	Generally accepted accounting principles in the United States
GATX	=	GATX Corporation
HEP	=	Holly Energy Partners-Operating, L.P.
ICE	=	IntercontinentalExchange
IPO	=	Initial public offering
LIBOR	=	London Interbank Offered Rate
Link	=	Link Energy LLC
LPG	=	Liquefied petroleum gas and other natural gas-related petroleum products
LTIP	=	Long-term incentive plan
Mcf	=	Thousand cubic feet

MLP	=	Master limited partnership
MTBE	=	Methyl tertiary-butyl ether
MQD	=	Minimum quarterly distribution
Nexen	=	Nexen Holdings U.S.A. Inc.
NJDEP	=	New Jersey Department of Environmental Protection
NPNS	=	Normal purchase normal sale
NYMEX	=	New York Mercantile Exchange
PAA/Vulcan	=	PAA/Vulcan Gas Storage, LLC
Pacific	=	Pacific Energy Partners, L.P.
PLA	=	Pipeline loss allowance
PNG	=	PAA Natural Gas Storage, L.P.
PNGS	=	PAA Natural Gas Storage, LLC
PPT	=	Plains Products Terminals LLC (formerly known as Pacific Atlantic Terminals LLC)
Rainbow	=	Rainbow Pipe Line Company, Ltd.
RCRA	=	Federal Resource Conservation and Recovery Act, as amended
RMPS	=	Rocky Mountain Pipeline System
SG Resources	=	SG Resources Mississippi, LLC
SLC Pipeline	=	SLC Pipeline LLC
SOP	=	Shell Oil Products
TNM	=	Texas New Mexico
USD	=	United States dollar
VIE	=	Variable interest entity
White Cliffs	=	White Cliffs Pipeline, LLC
WTI	=	West Texas Intermediate
WTS	=	West Texas Sour

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present and discuss our consolidated financial position as of December 31, 2010 and 2009, and the consolidated results of our operations, cash flows, changes in partners' capital, comprehensive income and changes in accumulated other comprehensive income for the years ended December 31, 2010, 2009 and 2008. All significant intercompany transactions have been eliminated in consolidation, and certain reclassifications have been made to information from previous years to conform to the current presentation. These reclassifications do not affect net income attributable to Plains. The accompanying consolidated financial statements include Plains and all of its wholly owned subsidiaries. Investments in entities over which we have significant influence but not control are accounted for by the equity method. We evaluate our equity investments for impairment in accordance with FASB guidance with respect to the equity method of accounting for investments in common stock. An impairment of an equity investment results when factors indicate that the investment's fair value is less than its carrying value and the reduction in value is other than temporary in nature.

Subsequent events have been evaluated through the financial statements issuance date and have been included within the following footnotes where applicable.

Note 2—Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. We make significant estimates with respect to (i) purchases and sales accruals, (ii) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (iii) mark-to-market gains and losses on derivative instruments (pursuant to guidance issued by the FASB regarding fair value measurements), (iv) accruals and contingent liabilities, (v) equity compensation plan accruals, (vi) property and equipment and depreciation expense and (vii) allowance for doubtful accounts. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Revenue Recognition

Supply and Logistics Segment Revenues. Revenues from sales of crude oil, LPG and refined products are recognized at the time title to the product sold transfers to the purchaser, which occurs upon delivery of the product to the purchaser or its designee. Sales of crude oil, LPG and refined products consist of outright sales contracts and buy/sell arrangements as well as exchanges. Inventory purchases and sales under buy/sell transactions are treated as inventory exchanges and are presented net within Supply and Logistics segment revenues in our consolidated statements of operations.

Additionally, we may utilize derivatives in connection with the transactions described above. For commodity derivatives that are designated as cash flow hedges, derivative gains and losses are deferred to AOCI and recognized in revenues in the periods during which the underlying physical hedged transaction impacts earnings. Also, the ineffective portion of the change in fair value of cash flow hedges is recognized in revenues each period along with the change in fair value of derivatives that do not qualify for hedge accounting or are not designated for hedge accounting.

Transportation Segment Revenues. Revenues from pipeline tariffs and fees are associated with the transportation of crude oil and refined products at a published tariff, as well as revenues associated with line leases for committed space on a particular system that may or may not be utilized. Tariff revenues are recognized either at the point of delivery or at the point of receipt pursuant to specifications outlined in the regulated and non-regulated tariffs. Revenues associated with line-lease fees are recognized in the month to which the lease applies, whether or not the space is actually utilized, and are subject to make up rights for take or pay arrangements. All pipeline tariff and fee revenues are based on actual volumes and rates. As is common in the industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. In addition, we have certain agreements that require counterparties to ship a minimum volume over an agreed upon period. Revenue is recognized at the latter of when the volume is shipped (pursuant to specifications outlined in the tariffs) or when the counterparty’s ability to make up the minimum volume has expired.

Facilities Segment Revenues. Storage and terminalling revenues include (i) storage fees that are generated when we lease storage capacity, (ii) terminalling fees, or throughput fees, that are generated when we receive crude oil, refined products, LPG or natural gas from one connecting pipeline and redeliver the applicable product to another connecting carrier, (iii) hub service fees for the movement of natural gas across our header systems and (iv) fees from LPG fractionation and isomerization services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements. Storage fees resulting from short-term and long-term contracts are typically recognized in revenue ratably over the term of the contract regardless of the actual storage capacity utilized. Terminal fees are recognized as the crude oil, LPG or refined product exits the terminal and is delivered to the connecting carrier or third-party terminal. Hub service fees are recognized in the period the natural gas moves across our header system. In addition, we have certain agreements that require counterparties to throughput a minimum volume over an agreed upon period. Revenue is recognized at the latter of when the volume exits the terminal or when the counterparty’s ability to make up the minimum volume has expired.

Purchases and Related Costs

Purchases and related costs include (i) the cost of crude oil, LPG and refined products obtained in outright purchases, (ii) fees incurred for third-party transportation and storage, whether by pipeline, truck, ship or barge, (iii) interest cost attributable to borrowings for inventory stored in a contango market and (iv) performance-related bonus accruals. These costs are recognized when incurred except in the case of products purchased, which are recognized at the time title transfers to us.

Field Operating Costs and General and Administrative Expenses

Field operating costs consist of various field operating expenses, including fuel and power costs, telecommunications, payroll and benefit costs (including equity compensation expense) for truck drivers and field personnel, maintenance and integrity management costs, regulatory compliance, environmental remediation, insurance, vehicle leases, and property taxes. General and administrative expenses consist primarily of payroll and benefit costs (including equity compensation expense), certain information systems and legal costs, office rent, contract and consultant costs and audit and tax fees.

Foreign Currency Transactions

Certain of our subsidiaries are based in Canada and use the Canadian dollar as their functional currency. Assets and liabilities of subsidiaries with a Canadian dollar functional currency are translated at period-end rates of exchange, and revenues and expenses are translated at average exchange rates prevailing for each month. The resulting translation adjustments are made directly to a separate component of other comprehensive income in Partners' Capital reflected on our consolidated balance sheet.

Certain of our subsidiaries also enter into transactions and have monetary assets and liabilities that are denominated in a currency other than the entities' respective functional currencies. Gains and losses from the revaluation of foreign currency transactions and monetary assets and liabilities are included in the consolidated statements of operations. The revaluation of foreign currency transactions and monetary assets and liabilities resulted in a gain of approximately $2 million for the year ended December 31, 2010, a gain of approximately $13 million for the year ended December 31, 2009 and a loss of approximately $22 million for the year ended December 31, 2008.

Cash and Cash Equivalents

Cash and cash equivalents consist of all unrestricted demand deposits and funds invested in highly liquid instruments with original maturities of three months or less and typically exceed federally insured limits. We periodically assess the financial condition of the institutions where these funds are held and believe that our credit risk is minimal. In accordance with our policy, outstanding checks are classified as accounts payable rather than negative cash. As of December 31, 2010 and 2009, accounts payable included approximately $40 million and $50 million, respectively, of outstanding checks that were reclassified from cash and cash equivalents.

Restricted Cash

Restricted cash at December 31, 2010 consists of $20 million held by an escrow agent in connection with PNG's acquisition of SG Resources. See Note 3 for further discussion of this acquisition. We had no restricted cash at December 31, 2009.

Accounts Receivable

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of LPG, refined products and natural gas storage. These purchasers include, but are not limited to refineries, producers, marketing and trading companies and financial institutions that are active in the physical and financial commodity markets. The majority of our accounts receivable relate to our crude oil supply and logistics activities that can generally be described as high volume and low margin activities, in many cases involving exchanges of crude oil volumes.

During 2008 and 2009, U.S. and world financial markets and energy prices were extremely volatile and global economies substantially weakened. During 2010, such financial markets and energy prices were not as volatile; however, there continues to be relatively weak economic growth and varied predictions regarding future economic recovery. This financial market volatility and fluctuation in energy prices primarily experienced during 2008 and 2009 coupled with the relatively weak economic recovery that persists has caused liquidity issues impacting many companies, which in turn have increased the potential credit risks associated with certain counterparties with which we do business.

To mitigate such credit risks, we have in place a rigorous credit review process. We closely monitor these conditions in order to make a determination with respect to the amount, if any, of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit, "parental" guarantees or advance cash payments. At December 31, 2010 and 2009, we had received approximately $197 million and $212 million, respectively, of advance cash payments from third parties to mitigate credit risk. In addition, we enter into netting arrangements (contractual agreements that allow us and the counterparty to offset receivables and payables between the two) that cover a significant part of our transactions and also serve to mitigate credit risk.

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. We do not apply actual balances against the reserve until we have exhausted substantially all collection efforts. At December 31, 2010 and 2009, substantially all of our accounts receivable (net of allowance for doubtful accounts) were less than 60 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled $5 million and $9 million at December 31, 2010 and 2009, respectively. The decrease in our allowance for doubtful

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accounts receivable balance during the year ended December 31, 2010 primarily is due to the collection and related settlement of claims for receivables that had been reserved for during the years ended December 31, 2009 and 2008. Although we consider our allowance for doubtful trade accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

Inventory, Linefill, Base Gas and Long-term Inventory

Inventory primarily consists of crude oil, LPG, refined products and natural gas in pipelines, storage facilities and rail cars that are valued at the lower of cost or market, with cost determined using an average cost method within specific inventory pools.

At the end of each reporting period, we assess the carrying value of our inventory and make any adjustments necessary to reduce the carrying value to the applicable net realizable value. During 2010 and 2008, we recorded non-cash charges of approximately $3 million and $168 million, respectively, related to the writedown of such inventory. We recognized no such writedowns during 2009. Linefill, base gas and minimum working inventory requirements in assets we own are recorded at historical cost and consist of crude oil, LPG and natural gas. We classify as linefill those barrels (i) used to pack the pipeline such that when an incremental product is injected into or enters a pipeline it forces product out at another location and (ii) that represent the minimum working requirements in tanks that we own. Base gas requirements of natural gas, as well as the minimum amount of crude oil and refined products, are used to operate our storage and terminalling facilities, similar to linefill in the pipelines. During 2010, 2009 and 2008, we recorded gains of approximately $21 million, $4 million and $3 million, respectively, on the sale of pipeline linefill for proceeds of approximately $72 million, $24 million and $23 million, respectively.

Minimum working inventory requirements in third-party assets and other working inventory in our assets that is needed for our commercial operations are included within specific inventory pools in inventory (a current asset) in determining the average cost of operating inventory. At the end of each period, we reclassify the inventory not expected to be liquidated within the succeeding twelve months out of inventory, at average cost, and into long-term inventory, which is reflected as a separate line item within other assets on the consolidated balance sheet.

Inventory, linefill, base gas and long-term inventory consisted of the following (barrels in thousands, natural gas volumes in millions and total value in millions):

	December 31, 2010				December 31, 2009			
	Volumes	Unit of Measure	Total Value	Price/ Unit [1]	Volumes	Unit of Measure	Total Value	Price/ Unit [1]
Inventory								
Crude oil	14,132	barrels	$ 1,100	$ 77.84	12,232	barrels	$ 886	$ 72.43
LPG	7,395	barrels	366	$ 49.49	6,051	barrels	247	$ 40.82
Refined products	271	barrels	22	$ 81.18	283	barrels	21	$ 74.20
Natural gas [2]	13	mcf	—	$ 3.87	181	mcf	1	$ 3.30
Parts and supplies	N/A		3	N/A	N/A		2	N/A
Inventory subtotal			1,491				1,157	
Linefill and base gas								
Crude oil	9,159	barrels	478	$ 52.19	9,404	barrels	471	$ 50.09
Natural gas [2]	11,194	mcf	37	$ 3.31	9,194	mcf	28	$ 3.04
LPG	77	barrels	4	$ 51.95	52	barrels	2	$ 38.46
Linefill and base gas subtotal			519				501	
Long-term inventory								
Crude oil	1,761	barrels	128	$ 72.69	1,497	barrels	103	$ 68.80
LPG	505	barrels	26	$ 51.49	458	barrels	18	$ 39.30
Long-term inventory subtotal			154				121	
Total			$ 2,164				$ 1,779	

(1) Price per unit represents a weighted average associated with various grades, qualities and locations; accordingly, these prices may not be comparable to published benchmarks for such products.

(2) The volumetric ratio of mcf of natural gas to crude Btu equivalent is 6:1; thus, natural gas volumes can be converted to barrels by dividing by 6.

Property and Equipment

In accordance with our capitalization policy, costs associated with acquisitions and improvements that expand our existing capacity, including related interest costs, are capitalized. For the years ended December 31, 2010, 2009 and 2008, capitalized interest was $16 million, $15 million and $17 million, respectively. We also capitalize expenditures for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production and/or functionality of our existing assets. Repair and maintenance expenditures incurred in order to maintain the day to day operation of our existing assets are expensed as incurred.

Property and equipment, net is stated at cost and consisted of the following (in millions):

	Estimated Useful Lives (Years)	December 31, 2010	December 31, 2009
Crude oil pipelines and facilities	30 - 70	$ 4,303	$ 4,265
Storage and terminal facilities	30 - 70	2,740	2,079
Trucking equipment and other	5 - 15	106	110
Construction in progress	-	304	476
Office property and equipment	2 - 50	95	84
Land and other	N/A	266	226
		7,814	7,240
Accumulated depreciation		(1,123)	(900)
Property and equipment, net		$ 6,691	$ 6,340

Depreciation expense for the years ended December 31, 2010, 2009 and 2008 was $235 million, $216 million and $196 million, respectively.

We calculate our depreciation using the straight-line method, based on estimated useful lives and salvage values of our assets. During 2010, we extended the depreciable lives of several of our crude oil and other storage facilities and pipeline systems based on an ongoing review to assess the useful lives of our property and equipment and to adjust those lives, if appropriate, to reflect current expectations given actual experience and current technology. These depreciable life extensions will prospectively reduce depreciation expense. For the year ended December 31, 2010, these extensions reduced depreciation expense by approximately $23 million. Any historical adjustments to useful lives have not had a material impact on our aggregate depreciation levels from year to year. We also classify gains and losses on sales of assets and asset impairments as a component of depreciation and amortization in the consolidated statements of operations.

Equity Method of Accounting

Our investments in the following entities are accounted for under the equity method of accounting:

Entity	Type of Operation	Our Ownership Interest
Settoon Towing, LLC	Barge Transportation Services	50%
White Cliffs Pipeline, LLC	Crude Oil Pipeline	34%
Frontier Pipeline Company	Crude Oil Pipeline	22%
Butte Pipe Line Company	Crude Oil Pipeline	22%

We do not consolidate any part of the assets or liabilities of our equity investees. Our share of net income or loss is reflected as one line item on the income statement and will increase or decrease, as applicable, the carrying value of our investments on the balance sheet. In addition, we include a proportionate share of our equity method investees' unrealized gains and losses in other comprehensive income on our consolidated balance sheet. We also adjust our investment balances in these investees by the like amount. Distributions to the Partnership will reduce the carrying value of our investments and will be reflected on our cash flow statement netted against equity in earnings. In turn, contributions will increase the carrying value of our investments and will be reflected on our cash flow statement within investing activities.

Noncontrolling Interests

We account for noncontrolling interests in subsidiaries in accordance with FASB guidance specific to noncontrolling interests. FASB guidance requires all entities to report noncontrolling interests in subsidiaries (formerly referred to as minority interest) as a component of equity in the consolidated financial statements. Noncontrolling interest represents the portion of assets and liabilities in a subsidiary that is owned by a third-party. See Note 5 for additional discussion regarding our noncontrolling interests.

Asset Retirement Obligations

FASB guidance establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including estimates related to (i) the time of the liability recognition, (ii) initial measurement of the liability, (iii) allocation of asset retirement cost to expense, (iv) subsequent measurement of the liability and (v) financial statement disclosures. FASB guidance also requires that the cost for asset retirement should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method.

Some of our assets, primarily related to our transportation and facilities segments, have contractual or regulatory obligations to perform remediation and, in some instances, dismantlement and removal activities when the assets are abandoned. These obligations include varying levels of activity including disconnecting inactive assets from active assets, cleaning and purging assets, and in some cases, completely removing the assets and returning the land to its original state. These assets have been in existence for many years and with regular maintenance will continue to be in service for many years to come. It is not possible to predict when demand for these transportation or storage services will cease, and we do not believe that such demand will cease for the foreseeable future. Accordingly, we believe the date when these assets will be abandoned is indeterminate. With no reasonably determinable abandonment date, we cannot reasonably estimate the fair value of the associated asset retirement obligations. We will record asset retirement obligations for these assets in the period in which sufficient information becomes available for us to reasonably determine the settlement dates.

A small portion of our contractual or regulatory obligations is related to assets that are inactive or that we plan to take out of service and, although the ultimate timing and costs to settle these obligations are not known with certainty, we have recorded a reasonable estimate of these obligations. We have estimated that the fair value of these obligations was approximately $5 million at both December 31, 2010 and 2009.

Impairment of Long-Lived Assets

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written down to estimated fair value in accordance with FASB guidance with respect to the accounting for the impairment or disposal of long-lived assets. Under this guidance, a long-lived asset is tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the

carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount by which the carrying value exceeds the fair value of the asset is recognized.

We periodically evaluate property and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. The evaluation is highly dependent on the underlying assumptions of related cash flows. The subjective assumptions used to determine the existence of an impairment in carrying value include:

- whether there is an indication of impairment;
- the grouping of assets;
- the intention of "holding" versus "selling" an asset;
- the forecast of undiscounted expected future cash flow over the asset's estimated useful life; and
- if an impairment exists, the fair value of the asset or asset group.

During 2010, we recognized impairments of approximately $13 million for assets taken out of service. Impairments of less than $1 million and approximately $5 million were recognized during 2009 and 2008, respectively, and were predominantly related to assets that were taken out of service. These assets did not support spending the capital necessary to continue service, and we utilized other assets to handle these activities.

Goodwill

In accordance with FASB guidance, we test goodwill at least annually (as of June 30) and on an interim basis if a triggering event occurs, such as an adverse change in business climate, to determine whether an impairment has occurred. Goodwill is tested for impairment at a level of reporting referred to as a reporting unit. A reporting unit is an operating segment or one level below an operating segment for which discrete financial information is available and regularly reviewed by segment management. Our reporting units are our operating segments. FASB guidance requires a two step approach to testing goodwill for impairment. In Step 1, we compare the fair value of the reporting unit with the respective book values, including goodwill, by using an income approach based on a discounted cash flow analysis. This approach requires us to make long-term forecasts of future revenues, expenses and other expenditures. Those forecasts require the use of various assumptions and estimates, the most significant of which are net revenues (total revenues less purchases and related costs), operating expenses, general and administrative expenses and the weighted average cost of capital. Fair value of the reporting units is determined using significant unobservable inputs, or level 3 inputs in the fair value hierarchy. When the fair value is greater than book value, then the reporting unit's goodwill is not considered impaired. If the book value is greater than fair value, then we proceed to Step 2. In Step 2, we compare the implied fair value of the reporting unit's goodwill with the book value. A goodwill impairment loss is recognized if the carrying amount exceeds its fair value.

In addition, there is a potential indicator of impairment if a company's market capitalization is less than its book equity. Periodically, we compare our market capitalization to our book equity to determine if there is an indicator of potential impairment. Throughout 2010, our market capitalization exceeded the book value of our equity and thus, this indicated that there was no triggering event. There were no other triggering events or indicators of potential impairment of our goodwill during 2010.

Through Step 1 of our annual testing of goodwill for potential impairment, which also includes a sensitivity analysis regarding the excess of our reporting unit's fair value over book value, we determined that the fair value of each reporting unit was substantially greater than its respective book value, and therefore goodwill was not considered impaired. We will continue to monitor various potential indicators (including the financial markets) to determine if a triggering event occurs and will perform another goodwill impairment analysis if necessary. We have not recognized any impairment of goodwill during the last three years.

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The table below reflects our changes in goodwill (in millions):

	Transportation	Facilities	Supply & Logistics	Total [1]
Balance at December 31, 2008	$ 562	$ 283	$ 365	$ 1,210
2009 Goodwill Related Activity :				
PNGS acquisition	—	25	—	25
Other acquisitions	24	—	—	24
Purchase price accounting adjustments [2]	(3)	—	—	(3)
Foreign currency translation adjustments	25	—	6	31
Balance at December 31, 2009	$ 608	$ 308	$ 371	$ 1,287
2010 Goodwill Related Activity:				
Nexen acquisition	18	—	54	72
Purchase price accounting adjustments [2]	3	—	—	3
Foreign currency translation adjustments	11	—	3	14
Balance at December 31, 2010	$ 640	$ 308	$ 428	$ 1,376

(1) As of December 31, 2010, we do not have any accumulated impairment losses.

(2) Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation. This preliminary goodwill balance may be adjusted when the purchase price allocation is finalized. See Note 3 for additional discussion of our acquisitions.

Other Assets, Net

Other assets, net of accumulated amortization consist of the following (in millions):

	December 31, 2010	December 31, 2009
Debt issue costs	$ 47	$ 42
Fair value of derivative instruments	20	77
Intangible assets	311	239
Other	58	65
	436	423
Accumulated amortization	(54)	(54)
	$ 382	$ 369

Costs incurred in connection with the issuance of long-term debt and amendments to our credit facilities are capitalized and amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the “effective interest” method of amortization. Fully amortized debt issue costs and the related accumulated amortization are written off in conjunction with the refinancing or termination of the applicable debt arrangement. We capitalized debt issue costs of approximately $7 million and $12 million in 2010 and 2009, respectively.

Amortization expense related to other assets (including finite-lived intangible assets) for the three years ended December 31, 2010, 2009 and 2008 was $22 million, $19 million and $21 million, respectively. Our amortization expense for finite-lived intangible assets for the years ended December 31, 2010, 2009 and 2008 was $14 million, $14 million and $15 million, respectively.

Intangible assets that have finite lives are tested for impairment when events or circumstances indicate that the carrying value may not be recoverable. Our intangible assets that have finite lives consist of the following (in millions):

	Estimated Useful Lives (Years)	December 31, 2010			December 31, 2009		
		Cost	Accumulated Amortization	Net	Cost	Accumulated Amortization	Net
Customer contracts and relationships	1-30	$ 243	$ (35)	$ 208	$ 171	$ (36)	$ 135
Emission reduction credits [1]	N/A	45	—	45	45	—	45
Property tax abatement	13	23	(2)	21	23	(1)	22
		$ 311	$ (37)	$ 274	$ 239	$ (37)	$ 202

[1] Emission reduction credits are finite lived and are subject to amortization from the date that they are first utilized. At December 31, 2010, none of our emission reduction credits were being utilized because the projects for which they were acquired are not in service.

We estimate that our amortization expense related to finite-lived intangible assets for the next five years will be as follows (in millions):

2011	$ 20
2012	$ 19
2013	$ 17
2014	$ 17
2015	$ 16

Environmental Matters

We record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action. We do not discount our environmental remediation liabilities to present value. We also record receivables for amounts recoverable from insurance or from third parties under indemnification agreements in the period that we determine the costs are probable of recovery.

We expense expenditures that relate to an existing condition caused by past operations that do not contribute to current or future profitability. We record environmental liabilities assumed in business combinations based on the estimated fair value of the environmental obligations caused by past operations of the acquired company. See Note 12 for further discussion of environmental remediation matters.

Income and Other Taxes

We estimate (i) income taxes in the jurisdictions in which we operate, (ii) net deferred tax assets and liabilities based on temporary differences that are expected to be recovered or settled at the enacted tax rates expected in future periods, (iii) valuation allowances for deferred tax assets and (iv) contingent tax liabilities for estimated exposures related to our current tax positions.

We adopted the provisions of the FASB guidance related to accounting for uncertainty in income taxes on January 1, 2007. Pursuant to this guidance, we must recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based on the technical merits of the tax position and also the past administrative practices and precedents of the taxing authority. As of December 31, 2010 and 2009, we have not recognized any material amounts in connection with uncertainty in income taxes.

See Note 7 for discussion of U.S. federal and state taxes and Canadian federal and provincial taxes.

Derivative Instruments and Hedging Activities

We record all open derivative instruments on the balance sheet as either assets or liabilities measured at their fair value per the guidance issued by the FASB. This guidance requires that changes in the fair value of derivative instruments be recognized currently in earnings unless specific hedge accounting criteria are met. For cash flow hedges, the effective portion of the change in fair value is deferred in AOCI and reclassified into earnings when the underlying transaction affects earnings. For fair value hedges, the change in fair value of the derivative instrument is recognized in earnings. Additionally, the change in fair value of the hedged item, attributable to the hedged risk, is recognized as a basis adjustment to the hedged item and is also offset in earnings. See Note 6 for further discussion.

Equity Compensation

See Note 10 for information regarding our accounting for equity compensation awards.

Net Income Per Limited Partner Unit

Basic and diluted net income per unit is determined by dividing our limited partners' interest in net income by the weighted average number of limited partner units outstanding during the period. Pursuant to guidance issued by the FASB on the application of the two-class method for MLPs, the limited partners' interest in net income attributable to Plains is calculated by first reducing net income by the distribution pertaining to the current period's net income, which is to be paid in the subsequent quarter (including the incentive distribution interest in excess of the 2% general partner interest). Then, 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. The adoption of this guidance resulted in a change to our calculation of earnings per unit by using distributions applicable to the period rather than distributions paid in the period (applicable to the previous period). Also, in accordance with this guidance, earnings per unit for prior periods were recast to conform to this revised calculation.

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the years ended 2010, 2009 and 2008:

	Year Ended December 31,		
	2010	2009	2008
Numerator for basic and diluted earnings per limited partner unit:			
Net income attributable to Plains	$ 505	$ 579	$ 437
Less: General partner's incentive distribution paid [1]	(160)	(127)	(106)
Subtotal	345	452	331
Less: General partner 2% ownership [1]	(7)	(9)	(6)
Net income available to limited partners	338	443	325
Adjustment in accordance with application of the two-class method for MLPs [1]	(8)	(9)	(5)
Net income available to limited partners in accordance with the application of the two-class method for MLPs	$ 330	$ 434	$ 320
Denominator:			
Basic weighted average number of limited partner units outstanding	137	130	120
Effect of dilutive securities:			
Weighted average LTIP units [2]	1	1	1
Diluted weighted average number of limited partner units outstanding	138	131	121
Basic net income per limited partner unit	$ 2.41	$ 3.34	$ 2.66
Diluted net income per limited partner unit	$ 2.40	$ 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."

(2) Our LTIP awards (described in Note 10) that contemplate the issuance of common units are considered dilutive unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. LTIP awards that are deemed to be dilutive are reduced by a hypothetical unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB.

Recent Accounting Pronouncements

In December 2010, the FASB issued updated accounting guidance related to the calculation of the carrying amount of a reporting unit when performing the first step of a goodwill impairment test. More specifically, this update will require an entity to use an equity premise when performing the first step of a goodwill impairment test, and if a reporting unit has a zero or negative carrying amount, the entity must assess and consider qualitative factors to determine whether it is more likely than not that a goodwill impairment exists. The new accounting guidance is effective for public entities, for impairment tests performed during entities' fiscal years (and interim periods within those years) that begin after December 15, 2010. Early application is not permitted. We will adopt the new guidance in the first quarter of 2011; however, as we currently do not have any reporting units with a zero or negative carrying amount, we do not expect the adoption of this guidance to have an impact on our financial position, results of operations or cash flows.

In December 2010, the FASB issued updated accounting guidance to clarify that pro forma disclosures should be presented as if a business combination that is determined to be material on an individual or aggregate basis occurred at the beginning of the prior annual period for purposes of preparing both the current reporting period and the prior reporting period pro forma financial information. These disclosures should be accompanied by a narrative description about the nature and amount of material, nonrecurring pro forma adjustments. The new accounting guidance is effective for business combinations consummated in periods beginning after December 15, 2010 and should be applied prospectively as of the date of adoption. Early adoption is permitted. We will adopt the new disclosures in the first quarter of 2011. We do not believe that the adoption of this guidance will have a material impact to our financial position, results of operations or cash flows.

In January 2010, the FASB issued guidance to enhance disclosures related to the existing fair value hierarchy disclosure requirements. A fair value measurement is designated as level 1, 2 or 3 within the hierarchy based on the nature of the inputs used in the valuation process. Level 1 measurements generally reflect quoted market prices in active markets for identical assets or liabilities, level 2 measurements generally reflect the use of significant observable inputs and level 3 measurements typically utilize significant unobservable inputs. This new guidance requires additional disclosures regarding transfers into and out of level 1 and level 2 measurements and requires a gross presentation of activities within the level 3 roll forward. This guidance was effective for the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of the level 3 roll forward, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. We adopted the guidance relating to level 1 and level 2 transfers as of January 1, 2010, and we adopted the guidance relating to level 3 measurements on January 1, 2011. Our adoption did not have any material impact on our financial position, results of operations or cash flows.

In June 2009, the FASB issued guidance that requires an enterprise to perform an analysis to determine whether the enterprise's variable interest(s) provide a controlling financial interest in a VIE. This analysis identifies the primary beneficiary of a VIE as the enterprise that has (i) the power to direct the activities of a VIE that most significantly impact the entity's economic performance and (ii) the obligation to absorb losses of the entity, or the right to receive benefits from the entity, that could potentially be significant to the VIE. This guidance also (i) requires such assessments to be ongoing, (ii) amends certain guidance for determining whether an entity is a VIE and (iii) enhances disclosures that will provide users of financial statements with more transparent information regarding an enterprise's involvement in a VIE. We adopted this guidance as of January 1, 2010. Our adoption did not have any material impact on our financial position, results of operations or cash flows.

In June 2009, the FASB issued guidance to establish the source of authoritative GAAP to be applied by nongovernmental entities in the preparation of financial statements. As this guidance is meant to establish the source of authoritative GAAP and to better organize current accounting guidance, it only affects the referencing to applicable guidance throughout the accompanying consolidated financial statements and the notes thereto. This guidance was effective for interim or annual periods ending after September 15, 2009; therefore, we adopted this guidance as of July 1, 2009. Our adoption did not have any material impact on our financial position, results of operations or cash flows.

In May 2009, the FASB issued guidance that establishes general standards of accounting for and disclosure of subsequent events or events that occur after the balance sheet date but before financial statements are issued. This guidance sets forth (i) the period after the balance sheet date during which management shall evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, (ii) the circumstances under which an entity shall recognize events or transactions occurring after the balance sheet date in its financial statements and (iii) the disclosures that an entity shall make about events or transactions that occurred after the balance sheet date. This guidance was effective for interim or annual periods ending after June 15, 2009; therefore, we adopted this guidance as of April 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

In April 2009, the FASB issued guidance that increases the frequency of fair value disclosures from annual to quarterly in an effort to provide financial statement users with more timely and transparent information about the effects of current market conditions on financial instruments. This is intended to address concerns raised by some financial statement users about the lack of comparability resulting from the use of different measurement attributes for financial instruments. These disclosures are also intended to stimulate more robust discussions about financial instrument valuations between users and reporting entities. We adopted this guidance as of April 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

In November 2008, the FASB issued guidance that addresses certain accounting considerations, including initial measurement, decreases in investment value, and changes in the level of ownership or degree of influence related to equity method investments. We adopted this guidance as of January 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

In April 2008, the FASB issued guidance that amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under previous guidance over goodwill and other intangible assets. The intent of this guidance is to improve the consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure the fair value of the asset under GAAP. We adopted this guidance as of January 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

In March 2008, the FASB issued guidance that amends previous guidance with respect to disclosures of derivative instruments and hedging activities. This guidance requires enhanced disclosures about (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under the guidance and its related interpretations and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The provisions of this guidance were effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted this guidance as of January 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows. See Note 6 for enhanced disclosure of derivative instruments and hedging activities.

In March 2008, the FASB issued guidance that addresses the application of the two-class method in determining income per unit for MLPs having multiple classes of securities that may participate in partnership distributions. The two-class method is an earnings allocation formula that determines earnings per unit for each class of common units and participating securities according to participation rights in undistributed earnings. We adopted this guidance as of January 1, 2009. This guidance has been applied retrospectively for all financial statement periods presented. Adoption impacted the net income available to limited partners used in our computation of earnings per unit, but did not impact our net income, distributions to limited partners, financial position, results of operations or cash flows.

Note 3—Acquisitions and Dispositions

The following acquisitions were accounted for using the purchase method of accounting and the purchase price was allocated in accordance with such method.

Acquisitions Closed Subsequent to December 31, 2010

In February 2011, PNG completed the acquisition of SG Resources from SGR Holdings, L.L.C. ("Southern Pines Acquisition") for consideration of approximately $746 million, subject to certain post closing adjustments. The primary asset of SG Resources is the Southern Pines Energy Center ("Southern Pines"), a FERC-regulated, salt-cavern natural gas storage facility located at Greene County, Mississippi. Southern Pines is permitted for 40 Bcf of working gas capacity from four storage caverns. This acquisition will be reflected within our facilities segment.

In connection with the transaction, PNG completed a private placement of PNG common units to third-party purchasers and we purchased additional common units. See Note 5 for further discussion.

2010 Acquisitions

Nexen Acquisition. On December 30, 2010, we acquired from Nexen Holdings U.S.A. Inc. entities that hold crude oil gathering and transportation assets that primarily service Bakken area producers. The purchase price was approximately $229 million, in cash, including approximately $170 million for the business and physical assets and approximately $59 million for approximately 460,000 barrels of inventory and other working capital adjustments. The assets are primarily located in Northwestern North Dakota and Northeastern Montana and include (i) a lease gathering business that currently handles approximately 55,000 barrels per day, (ii) the Robinson Lake pipeline, a FERC-regulated 20-mile, 8-inch pipeline that currently handles approximately 30,000 barrels per day, (iii) eight truck terminals and (iv) various other contractual rights. These assets are included within our transportation and supply and logistics segments. We recognized goodwill of approximately $72 million associated with this acquisition; however, such purchase price amounts are preliminary and may change as a result of our final valuation.

Other 2010 Acquisitions. During 2010, we completed five additional acquisitions for aggregate consideration of approximately $178 million. These acquisitions included (i) a 34% interest in White Cliffs that is reflected within our transportation segment, (ii) an additional 11% interest in Capline pipeline that is reflected within our transportation segment and (iii) various other assets reflected within both our transportation and facilities segments. We did not recognize any goodwill for these acquisitions.

2009 Acquisitions

PNGS Acquisition. On September 3, 2009, we acquired the remaining 50% indirect interest in PAA/Vulcan for an aggregate purchase price of $215 million (“PNGS Acquisition”). The $215 million purchase price consisted of $90 million in cash paid at closing, approximately $91 million in equivalent value of PAA common units (1,907,305 PAA common units based on a 20 business-day average closing price per unit) issued to Vulcan Gas Storage LLC at closing, and up to $40 million of deferred/contingent cash consideration. The deferred/contingent consideration is payable in cash in two installments of $20 million each upon the achievement of certain performance milestones and events expected to occur over the next several years. Upon completion of the PNG IPO in May 2010, we paid the first $20 million installment. See Note 5 for additional discussion of the PNG IPO. The fair value of the remaining contingent consideration is approximately $17 million at December 31, 2010.

As a result of the transaction, we owned 100% of PNGS’s natural gas storage business and related operating entities, which were accounted for on a consolidated basis beginning in September 2009. We historically accounted for our 50% indirect interest in PAA/Vulcan under the equity method. We recorded a net gain of approximately $9 million, recorded in other income, in connection with (i) adjusting our previously owned 50% investment in PAA/Vulcan to fair value and (ii) terminating an agreement to supply natural gas to PNGS.

At the time of the PNGS Acquisition, PNGS owned and operated two natural gas storage facilities located in Louisiana and Michigan that had an aggregate working gas storage capacity of 40 Bcf and an aggregate peak injection and withdrawal capacity of 1.7 Bcf per day and 3.2 Bcf per day, respectively. Substantially all of PNGS’s revenues were derived from the provision of firm storage services under multi-year, fee-based contracts. The gas storage operations are reflected in our facilities segment.

The purchase price consisted of the following (in millions):

Cash	$	90
PAA equity		91
Paid at closing		181
Fair value of contingent consideration [1]		34
Total purchase price	$	215

[1] The deferred contingent cash consideration is payable in cash in two installments of $20 million each upon the achievement of certain performance milestones and events expected to occur over the next several years. The fair value of the deferred contingent cash consideration was based on a discounted cash flow model utilizing a discount rate of approximately 9%. Upon completion of the PNG IPO in May 2010, we paid the first $20 million contingent consideration installment.

The allocation of fair value to the assets and liabilities related to the PNGS Acquisition was as follows (in millions):

Property, plant and equipment	$	791
Base gas		28
Goodwill		25
Intangible assets		23
Working capital and other long-term assets and liabilities		9
Debt		(446)
Total	$	430

Other 2009 Acquisitions. During 2009, we completed six additional acquisitions for an aggregate consideration of approximately $178 million. These acquisitions included an additional 21% undivided joint interest in Capline and associated tankage, as well as various crude oil pipelines and pipeline systems that are all included within our transportation segment. We also acquired a natural gas processing business, a refined products terminal and various crude oil storage tanks and other related assets that are all included within our facilities segment. The goodwill associated with such acquisitions was approximately $27 million as of December 31, 2010.

2008 Acquisitions

Rainbow. In May 2008, we completed the acquisition of Rainbow for approximately $687 million (CAD to USD foreign exchange rate at the date of closing was $0.993:1). The assets acquired include approximately (i) 480 miles of mainline crude oil pipelines, (ii) 119 miles of gathering pipelines, (iii) 570,000 barrels of tankage along the system and (iv) 1 million barrels of crude oil linefill. The system has a throughput capacity of approximately 200,000 barrels per day. The acquired operations are reflected primarily in our transportation segment. The goodwill associated with this acquisition was approximately $191 million. In anticipation of closing the Rainbow acquisition, we entered into forward currency exchange contracts, which exchanged CAD and USD, to hedge the foreign currency exchange risk inherent in the acquisition price. Additionally, we entered into a financial option strategy, whereby we established a minimum and maximum per barrel price to hedge the commodity price risk associated with the anticipated purchase of crude oil linefill. We recognized a gain on those positions of approximately $8 million and $3 million, respectively, which is reflected in our 2008 consolidated results of operations in the "Other income/(expense), net" line.

The purchase price consisted of the following (in millions):

Cash payment to sellers	$	659
Assumption of Rainbow debt (at estimated fair value)		26
Estimated transaction costs		2
Total purchase price	$	687

The purchase price allocation was as follows (in millions):

Property, plant and equipment	$	425
Pipeline linefill in owned assets		143
Intangible assets		52
Goodwill		191
Future income tax liability		(110)
Assumption of working capital and other long-term assets and liabilities, including cash [(1)]		(14)
Total	$	687

(1) Includes approximately $16 million associated with environmental liabilities.

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During 2008, we completed one additional acquisition for aggregate consideration of approximately $44 million. This acquisition is reflected in our facilities segment and included the purchase of a storage facility and other assets. There was no goodwill associated with this acquisition.

Dispositions

During 2010, 2009 and 2008, we sold various property and equipment for proceeds totaling approximately $3 million, $4 million and $12 million, respectively. A gain of less than $1 million, a loss of less than $1 million and a gain of approximately $6 million were recognized in 2010, 2009 and 2008, respectively, related to these sales.

Note 4—Debt

Debt consisted of the following (in millions):

	December 31, 2010	December 31, 2009
SHORT-TERM DEBT		
Credit Facilities:		
Senior secured hedged inventory facility bearing interest at a rate of 2.1% and 2.5% at December 31, 2010 and 2009, respectively	$ 500	$ 300
PAA senior unsecured revolving credit facility, bearing interest at a rate of 0.7% and 0.8% at December 31, 2010 and 2009, respectively [1]	824	772
Other	2	2
Total short-term debt	1,326	1,074
LONG-TERM DEBT		
Senior Notes:		
4.25% senior notes due September 2012	500	500
7.75% senior notes due October 2012	200	200
5.63% senior notes due December 2013	250	250
5.25% senior notes due June 2015	150	150
3.95% senior notes due September 2015	400	—
6.25% senior notes due September 2015	—	175
5.88% senior notes due August 2016	175	175
6.13% senior notes due January 2017	400	400
6.50% senior notes due May 2018	600	600
8.75% senior notes due May 2019	350	350
5.75% senior notes due January 2020	500	500
6.70% senior notes due May 2036	250	250
6.65% senior notes due January 2037	600	600
Unamortized discounts	(12)	(14)
Senior notes, net of unamortized discounts	4,363	4,136
Credit Facilities and Other:		
PNG senior unsecured revolving credit facility, bearing interest at a rate of 3.2% at December 31, 2010	260	—
Other	8	6
Total long-term debt [1] [2]	4,631	4,142
Total debt	$ 5,957	$ 5,216

[1] We classify as short-term our borrowings under our PAA senior unsecured revolving credit facility. These borrowings are designated as working capital borrowings, must be repaid within one year and are primarily for hedged LPG and crude oil inventory and NYMEX and ICE margin deposits.

[2] Our fixed-rate senior notes have a face value of approximately $4.4 billion as of December 31, 2010. We estimate the aggregate fair value of these notes to be approximately $4.7 billion and $4.4 billion at December 31, 2010 and 2009, respectively. Our fixed-rate senior notes are traded among institutions, which trades are routinely published by a reporting service. Our determination of fair value is based on reported trading activity near year end.

Credit Facilities

PAA Senior Secured Hedged Inventory Facility. In October 2010, we renewed our 364-day committed hedged inventory credit facility, which matures in October 2011. The facility has a borrowing capacity of $500 million, which may be increased to $1.2 billion, subject to obtaining additional lender commitments. Borrowings under this facility will be used to finance (i) the purchase of hedged crude oil inventory for storage activities and (ii) foreign import activities. At December 31, 2010, borrowings of approximately $500 million were outstanding under this facility. At December 31, 2009, borrowings of approximately $300 million were outstanding under our previous committed hedged inventory facility.

PAA Senior Unsecured Revolving Credit Facility. As of both December 31, 2010 and 2009, the aggregate borrowing capacity of our senior unsecured revolving credit facility was $1.6 billion (including the respective sub-facility for Canadian borrowings of $400 million and $600 million). This credit facility has a maximum debt-to-EBITDA coverage ratio of 4.75 to 1.00 (5.50 to 1.00 during an acquisition period) and a maturity date of July 2012. Also, the senior unsecured revolving credit facility can be expanded to $2.0 billion, subject to additional lender commitments. At December 31, 2010 and 2009, amounts outstanding under this facility and together with committed letters of credit were $899 million and $848 million, respectively.

PNG Senior Unsecured Revolving Credit Facility. In April 2010, our consolidated subsidiary PNG entered into a three year, $400 million senior unsecured revolving credit facility that matures in May 2013. This credit facility, which bears interest based on LIBOR plus an applicable margin determined based on funded debt-to-EBITDA levels (as defined by the credit agreement), may be expanded to $600 million, subject to additional lender commitments and with approval of the administrative agent for the credit facility.

This credit facility restricts, among other things, PNG's ability to make distributions of available cash to unitholders if any default or event of default, as defined in the credit agreement, exists or would result therefrom. In addition, the credit facility contains restrictive covenants, including those that restrict PNG's ability to incur additional indebtedness, engage in certain transactions with affiliates, grant (or permit to exist) liens or enter into certain restricted contracts, make any material change to the nature of PNG's business, make a disposition of all or substantially all of PNG's assets or enter into a merger, consolidate, liquidate, wind up or dissolve. Also, the credit facility contains certain financial covenants which, among other things, requires PNG to maintain a debt-to-EBITDA coverage ratio that will not be greater than 4.75 to 1.00 on outstanding debt (5.50 to 1.00 on all outstanding debt during an acquisition period) and also requires that PNG maintain an EBITDA-to-interest coverage ratio that will not be less than 3.00 to 1.00, as such terms are defined in the credit agreement.

PAA 364-Day Credit Agreement. In January 2011, we entered into a 364-day senior unsecured credit facility with an aggregate borrowing capacity of $500 million. This credit facility has a maximum debt-to-EBITDA coverage ratio of 4.75 to 1.00 (5.50 to 1.00 during an acquisition period) and matures in January 2012. Borrowings under this facility may be used for any partnership purpose, including financing the Southern Pines Acquisition. See Note 3 for discussion regarding this acquisition.

Senior Note Issuances

In January 2011, we completed the issuance of $600 million of 5.00% senior notes due February 1, 2021. The senior notes were sold at 99.521% of face value. Interest payments are due on February 1 and August 1 of each year, beginning on August 1, 2011. We used the net proceeds from this offering to reduce outstanding borrowings under our credit facilities and for general partnership purposes. Amounts repaid under our credit facilities may be reborrowed, as necessary, to fund our ongoing expansion capital program, future acquisitions, retirement of other long-term debt, investments in PNG, including for purposes of financing the Southern Pines Acquisition, or for general partnership purposes.

In July 2010, we completed the issuance of $400 million of 3.95% senior notes due September 15, 2015. The senior notes were sold at 99.889% of face value. Interest payments are due on March 15 and September 15 of each year, which began on September 15, 2010. We used the net proceeds from this offering to repay outstanding indebtedness under our credit facilities.

In September 2009, we completed the issuance of $500 million of 5.75% senior notes due January 15, 2020. The senior notes were sold at 99.523% of face value. Interest payments are due on January 15 and July 15 of each year, which began on January 15, 2010. We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities, a portion of which was used to fund the cash requirements of the PNGS Acquisition (which included repayment of all of PNGS's debt). See Note 3 for further discussion of the PNGS Acquisition.

In July 2009, we completed the issuance of $500 million of 4.25% senior notes due September 1, 2012. The senior notes were sold at 99.802% of face value. Interest payments are due on March 1 and September 1 of each year, which began on March 1, 2010. We use the net proceeds from this offering to supplement the capital available from our existing senior secured hedged inventory facility to fund working capital needs associated with base levels of routine foreign crude oil import and for seasonal LPG inventory requirements. As of December 31, 2010 and 2009, approximately $466 million and $222 million, respectively, had been used to fund hedged inventory and would be reclassified as short-term debt if funded on our credit facilities. Concurrent with the issuance of these senior notes, we entered into interest rate swaps whereby we

receive fixed payments at 4.25% and pay three-month LIBOR plus a spread on a notional principal amount of $150 million maturing in two years and an additional $150 million notional principal amount maturing in three years.

In April 2009, we completed the issuance of $350 million of 8.75% senior notes due May 1, 2019. The senior notes were sold at 99.994% of face value. Interest payments are due on May 1 and November 1 of each year, which began on November 1, 2009. We used the net proceeds from this offering to reduce outstanding borrowings under our credit facilities.

In each instance, the notes were co-issued by Plains All American Pipeline, L.P. and a 100% owned consolidated finance subsidiary (neither of which have independent assets or operations) and are fully and unconditionally guaranteed, jointly and severally, by certain of our subsidiaries. See Note 13 for information regarding our guarantor and non-guarantor subsidiaries.

Senior Note Repayments and Redemptions

On February 7, 2011, our $200 million 7.75% senior notes due 2012 were redeemed in full. In conjunction with the early redemption, we recognized a loss of approximately $23 million in the first quarter of 2011. We utilized cash on hand and available capacity under our credit facilities to redeem these notes.

On September 15, 2010, our $175 million, 6.25% senior notes due 2015 were redeemed in full. In conjunction with the early redemption, we recognized a loss of approximately $6 million. We utilized cash on hand and available capacity under our credit facilities to redeem these notes.

On August 15, 2009, we repaid our $175 million 4.75% senior notes that matured on that date. Additionally, on October 5, 2009, we redeemed all of our outstanding $250 million 7.13% senior notes due 2014. In conjunction with the early redemption, we recognized a loss of approximately $4 million.

Maturities

The weighted average life of our long-term debt outstanding at December 31, 2010 was approximately 9 years and the aggregate maturities for the next five years and thereafter are as follows (in millions):

Calendar Year	Payment
2011	$ —
2012 [1]	700
2013	510
2014	—
2015	550
Thereafter	2,875
Total [2]	$ 4,635

(1) During February 2011, we redeemed our $200 million 7.75% senior notes due 2012.

(2) Excludes aggregate unamortized net discount of $12 million, a basis adjustment of $4 million related to fair value hedge accounting requirements and other long-term obligations of $4 million.

Covenants and Compliance

Our credit agreements and the indentures governing the senior notes contain cross-default provisions. Our credit agreements prohibit distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, the agreements contain various covenants limiting our ability to, among other things:

- incur indebtedness if certain financial ratios are not maintained;
- grant liens;
- engage in transactions with affiliates;
- enter into sale-leaseback transactions; and
- sell substantially all of our assets or enter into a merger or consolidation.

Our PAA senior unsecured revolving credit facility treats a change of control as an event of default and also requires us to maintain a debt-to-EBITDA coverage ratio that will not be greater than 4.75 to 1.00 on outstanding debt, and 5.50 to 1.00 on all outstanding debt during an acquisition period (generally, the period consisting of three fiscal quarters following an acquisition greater than $50 million).

For covenant compliance purposes, letters of credit and borrowings to fund hedged inventory and margin requirements are excluded when calculating the debt coverage ratio.

A default under our credit facilities would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit agreements, our ability to make distributions of available cash is not restricted. As of December 31, 2010, we were in compliance with the covenants contained in our credit agreements and indentures.

Letters of Credit

In connection with our crude oil supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. These letters of credit are issued under our PAA senior unsecured revolving credit facility, and our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. At December 31, 2010 and 2009, we had outstanding letters of credit of approximately $75 million and $76 million, respectively.

Note 5—Partners' Capital and Distributions

Units Outstanding

Partners' capital at December 31, 2010 consists of 141,199,175 common units outstanding, representing a 98% effective aggregate ownership interest in the Partnership and its subsidiaries after giving effect to the 2% general partner interest.

Distributions

We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter, less reserves established by our general partner for future requirements.

General Partner Incentive Distributions

Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, the general partner is typically entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per unit, referred to as our MQD, 25% of the amounts we distribute in excess of $0.495 per unit and 50% of amounts we distribute in excess of $0.675 per unit (referred to as "incentive distributions").

Per unit cash distributions on our outstanding units and the portion of the distributions representing an excess over the MQD were as follows:

	Year					
	2010		2009		2008	
	Distribution [1]	Excess over MQD	Distribution [1]	Excess over MQD	Distribution [1]	Excess over MQD
First Quarter	$ 0.9275	$ 0.4775	$ 0.8925	$ 0.4425	$ 0.8500	$ 0.4000
Second Quarter	$ 0.9350	$ 0.4850	$ 0.9050	$ 0.4550	$ 0.8650	$ 0.4150
Third Quarter	$ 0.9425	$ 0.4925	$ 0.9050	$ 0.4550	$ 0.8875	$ 0.4375
Fourth Quarter	$ 0.9500	$ 0.5000	$ 0.9200	$ 0.4700	$ 0.8925	$ 0.4425

(1) Distributions represent those declared and paid in the applicable period.

In order to enhance our distribution coverage ratio and liquidity following a significant acquisition, our general partner may agree to reduce the amounts due to it as incentive distributions. Upon closing of the Pacific acquisition in

November 2006, the Rainbow acquisition in May 2008 and the PNGS Acquisition in September 2009, our general partner agreed to reduce the amounts due to it as incentive distributions. The total reduction in incentive distributions related to the Pacific, Rainbow and PNGS acquisitions is $83 million as displayed on an annual basis in the following table (in millions):

Acquisition	2007	2008	2009	2010	2011	Total
Pacific	$ 20	$ 15	$ 15	$ 10	$ 5	$ 65
Rainbow	—	3	6	1	—	10
PNGS	—	—	1	5	2	8
Total	$ 20	$ 18	$ 22	$ 16	$ 7	$ 83

Following the distribution in February 2011 (as discussed below), the aggregate remaining incentive distribution reductions are approximately $5 million.

Total cash distributions made were as follows (in millions, except per unit amounts):

	Distributions Paid				Distributions per limited partner unit
	Common	General Partner			
Year	Units	Incentive	2%	Total	
2010	$ 512	$ 160	$ 10	$ 682	$ 3.76
2009	$ 468	$ 127	$ 10	$ 605	$ 3.62
2008	$ 418	$ 106	$ 8	$ 532	$ 3.50

On January 12, 2011, we declared a cash distribution of $0.9575 per unit on our outstanding common units. The distribution was paid on February 14, 2011 to unitholders of record on February 4, 2011, for the period October 1, 2010 through December 31, 2010. The total distribution paid was approximately $184 million, with approximately $135 million paid to our common unitholders and $3 million and $46 million paid to our general partner for its general partner and incentive distribution interests, respectively.

Noncontrolling Interests in a Subsidiary

As of December 31, 2010, the noncontrolling interests consisted of the following: (i) the approximate 23% limited partner interest in PNG and (ii) the 25% interest in SLC Pipeline.

PNG Initial Public Offering

On May 5, 2010, PNG completed its IPO of 13,478,000 common units representing limited partner interests at $21.50 per common unit. The number of units issued at closing included 1,758,000 common units issued pursuant to the full exercise of the underwriters' over-allotment option. Net proceeds received by PNG from the sale of the 13,478,000 common units were approximately $268 million and were used to repay amounts outstanding under our credit facilities and for general partnership purposes. The common units offered represented approximately 23% of the outstanding equity of PNG. We own the remaining 77% equity interest in PNG. We continue to control the entity, and therefore, consolidate the financial results.

Prior to the PNG IPO, we owned 100% of PNGS' natural gas storage business, the predecessor of PNG, and related operating entities. Immediately prior to the closing of the IPO, we contributed 100% of the equity interests in PNGS and its subsidiaries to PNG in exchange for approximately 18.1 million common units, approximately 13.9 million Series A subordinated units, 11.5 million Series B subordinated units and a 2% general partner interest and incentive distribution rights. In conjunction with the offering, we recorded noncontrolling interest of $167 million associated with the book value of PNG sold to the public. We also recorded an increase to our partners' capital of approximately $101 million associated with the net increase from our share of the proceeds received in the offering partially offset by the dilution of our interest in PNG resulting from the IPO.

PAA Modification of Holdings in PNG Subordinated Units

On August 16, 2010, the Amended and Restated Agreement of Limited Partnership of PNG was amended and restated (the "Second Amended and Restated Agreement") to reduce the number of Series A subordinated units by 2.0 million and increase the number of Series B subordinated units by an equivalent amount. The Second Amended and Restated Agreement also increased the number of potential conversion tranches on Series B subordinated units from three to five. In addition, the terms of the Series B subordinated units were modified to extend the conversion period by raising the operating and financial performance benchmarks of approximately one-third of the Series B subordinated units outstanding prior to this modification. This amendment was intended to increase the distribution coverage and organic growth profile of PNG's common and Series A subordinated units and improve PNG's posture with respect to potential acquisitions. We accounted for this transaction as an exchange between entities under common control and accordingly, we reclassified the book value of the 2.0 million Series A subordinated units at the time of the modification to Series B subordinated units.

The following table sets forth the changes made to our holdings in the limited partner units of PNG from May 5, 2010 through December 31, 2010 (units in millions):

	Prior to Modification	Modification	Post Modification
PNG Units Owned by PAA:			
Common Units	18.1	—	18.1
Series A Subordinated Units	13.9	(2.0)	11.9
Common & Series A Subordinated Unit Subtotal	32.0	(2.0)	30.0
Series B Subordinated Units (Performance Thresholds):			
Tranche 1 ($1.44 / 29.6 Bcf)	4.6	(2.0)	2.6
Tranche 2 ($1.53 / 35.6 Bcf)	3.8	(1.0)	2.8
Tranche 3 ($1.63 / 41.6 Bcf)	3.1	(1.0)	2.1
Tranche 4 ($1.71 / 48.0 Bcf)	—	3.0	3.0
Tranche 5 ($1.80 / 48.0 Bcf)	—	3.0	3.0
Series B Subordinated Unit Subtotal	11.5	2.0	13.5
Total PNG Units Owned by PAA [1]	43.5	—	43.5

[1] See "PNG Transaction Grants" in Note 10.

Series A and Series B Subordinated Units. The Series A subordinated units are not entitled to receive any distributions until the common units have received the MQD ($1.35 on an annualized basis) plus any arrearages in the payment of the MQD from prior quarters. The Series A subordinated units will convert to common units once certain earnings and distribution targets are met for three consecutive, non-overlapping four-quarter periods. The Series B subordinated units are not entitled to participate in quarterly distributions until they convert into Series A subordinated units. The Series B subordinated units will convert into Series A subordinated units upon satisfaction of the following operational and financial conditions:

- 2,600,000 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 29.6 Bcf, (b) PNG generates distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.36 per unit (representing an annualized distribution of $1.44 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and (c) PNG makes a quarterly distribution of available cash of at least $0.36 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on PNG's general partner's 2% interest and the related distributions on the incentive distribution rights;

- 2,833,333 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 35.6 Bcf, (b) PNG generates distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.3825 per unit (representing an annualized distribution of $1.53 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior bullet and (c) PNG makes a quarterly distribution of available cash of at least $0.3825 per quarter for two consecutive quarters on all outstanding common units and

Series A subordinated units and the corresponding distributions on PNG's general partner's 2% interest and the related distributions on the incentive distribution rights;

- 2,066,667 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 41.6 Bcf, (b) PNG generates distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.4075 per unit (representing an annualized distribution of $1.63 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior two bullets and (c) PNG makes a quarterly distribution of available cash of at least $0.4075 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on PNG's general partner's 2% interest and the related distributions on the incentive distribution rights;

- 3,000,000 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 48.0 Bcf, (b) PNG generates distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.4275 per unit (representing an annualized distribution of $1.71 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior three bullets and (c) PNG makes a quarterly distribution of available cash of at least $0.4275 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on PNG's general partner's 2% interest and the related distributions on the incentive distribution rights; and

- 3,000,000 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 48.0 Bcf, (b) PNG generates distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.45 per unit (representing an annualized distribution of $1.80 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior four bullets and (c) PNG makes a quarterly distribution of available cash of at least $0.45 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on PNG's general partner's 2% interest and the related distributions on the incentive distribution rights.

PNG's general partner will determine whether the in-service operational tests set forth above have been satisfied. To the extent that the operational tests described above are satisfied prior to or during the two-quarter period applicable to the financial tests described above, the holder of the Series B subordinated units subject to conversion will be entitled to receive the quarterly distribution payable with respect to the second quarter of such two-quarter period. In all other circumstances, where the operational tests are satisfied following the two-quarter period applicable to the financial tests, the holder of the Series B subordinated units subject to conversion will be entitled to receive any distribution payable following the satisfaction of such operational tests.

Any Series B subordinated units that remain outstanding as of December 31, 2018 will automatically be cancelled.

Following conversion of any Series B subordinated units into Series A subordinated units, such converted Series B subordinated units will further convert into common units (together with any other outstanding Series A subordinated units) to the extent that the tests for conversion of the Series A subordinated units are satisfied. In determining whether such conversion tests have been satisfied, the Series B subordinated units that have converted into Series A subordinated units will be treated as Series A subordinated units from and after the date of their conversion into Series A subordinated units.

If at the time the above operational and financial tests are satisfied, the subordination period has already ended and all outstanding Series A subordinated units have converted into common units, the Series B subordinated units will instead convert directly into common units on a one-for-one basis and participate in the quarterly distribution payable to common units.

PNG transactions subsequent to December 31, 2010

PNG Common Unit Issuance. During February 2011, in connection with the Southern Pines Acquisition, PNG completed a private placement of approximately 17.4 million PNG common units to third-party purchasers for net proceeds of approximately $370 million. In addition, we purchased approximately 10.2 million PNG common units for approximately $230 million, including our proportionate general partner contribution of $12 million. As a result of these transactions, our aggregate ownership interest in PNG decreased from approximately 77% to approximately 64%.

Formation of SLC Pipeline LLC

During the fourth quarter of 2008, we completed construction on a 94-mile expansion of the Salt Lake City Area system from Wahsatch, Utah to Salt Lake City. During the first quarter of 2009, this pipeline became fully operational. Pursuant to a master formation agreement, we contributed the pipeline with a book value of approximately $254 million to a newly formed joint venture, SLC Pipeline. HEP contributed approximately $26 million in cash for a 25% ownership in SLC Pipeline. We own the remaining 75% interest in SLC Pipeline and control the joint venture, and therefore, have consolidated the financial results. We recognized a loss in partners' capital of approximately $38 million related to the formation of the SLC Pipeline joint venture during 2009. This loss represented the difference between HEP's contribution of cash and the book value of its 25% interest in the net assets of SLC Pipeline.

Noncontrolling Interests Rollforward

The following table reflects the changes in the noncontrolling interests in partners' capital (in millions):

	For the Year Ended December 31, 2010	2009
Beginning balance	$ 63	$ —
Sale of noncontrolling interests in subsidiaries	167	64
Net income attributable to noncontrolling interests	9	1
Distributions to noncontrolling interests	(10)	(2)
Equity compensation expense	3	—
Other	(1)	—
Ending Balance	$ 231	$ 63

Equity Offerings

During the three years ended December 31, 2010, we completed the following equity offerings of our common units as shown in the table below (in millions, except unit and per unit data). See "PNGS Acquisition" below for discussion of additional common units issued in 2009 in connection with such acquisition.

Period	Units Issued	Gross Unit Price	Proceeds from Sale	General Partner Contribution	Costs	Net Proceeds
November 2010 (1)	4,780,000	$ 62.60	$ 299	$ 6	$ (9)	$ 296
2010 Total	**4,780,000**		**$ 299**	**$ 6**	**$ (9)**	**$ 296**
September 2009 (1)	5,290,000	$ 46.70	$ 247	$ 5	$ (6)	$ 246
March 2009 (1)	5,750,000	36.90	212	4	(6)	210
2009 Total	**11,040,000**		**$ 459**	**$ 9**	**$ (12)**	**$ 456**
May 2008 (1)	6,900,000	$ 46.31	$ 320	$ 6	$ (11)	$ 315
2008 Total	**6,900,000**		**$ 320**	**$ 6**	**$ (11)**	**$ 315**

(1) These offerings of common units were underwritten transactions that required us to pay a gross spread. The net proceeds from these offerings were used to reduce outstanding borrowings under our credit facilities and for general partnership purposes.

PNGS Acquisition

In September 2009, we issued 1,907,305 common units valued at approximately $91 million in order to satisfy a portion of the PNGS Acquisition purchase price. In conjunction with the issuance, we received a contribution from our general partner of approximately $2 million. See Note 3 for further discussion.

Class B Units of Plains AAP, L.P.

In August 2007, the owners of Plains AAP, L.P. authorized the board of directors of Plains All American GP LLC to issue Class B units of Plains AAP, L.P. ("AAP LP Class B units"). At December 31, 2010, approximately 175,500 AAP LP Class B units were outstanding, of which 80,063 were earned. A total of 24,500 AAP LP Class B units are reserved for future issuances. See Note 10 for further discussion of the AAP LP Class B units.

Canadian Withholding Tax

For federal income tax purposes, we are treated as a partnership. Our unitholders are required to report their share of our income, gains, losses and deductions on their federal income tax return. In certain cases, we are subject to, and have paid, Canadian income and withholding taxes. The withholding tax payments are considered to be paid on behalf of our unitholders and thus are treated as distributions for financial reporting purposes. During 2009, we paid approximately $6 million of Canadian withholding taxes.

Note 6—Derivatives and Hedging Instruments

We identify the risks that underlie our core business activities and use risk management strategies to mitigate those risks when we determine that there is value in doing so. Our policy is to use derivative instruments only for risk management purposes. We use various derivative instruments to (i) manage our exposure to commodity price risk as well as to optimize our profits, (ii) manage our exposure to interest rate risk and (iii) manage our exposure to currency exchange rate risk. Our commodity risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring NYMEX, ICE and over-the-counter positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity. Our interest rate and currency exchange rate risk management policies and procedures are designed to monitor our positions and ensure that those positions are consistent with our objectives and approved strategies. Our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategies for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives used in a transaction are highly effective in offsetting changes in cash flows or the fair value of hedged items.

Commodity Price Risk Hedging

Our core business activities contain certain commodity price-related risks that we manage in various ways, including the use of derivative instruments. Our policy is (i) to only purchase product for which we have a market, (ii) to structure our sales contracts so that price fluctuations do not materially affect our operating income and (iii) not to acquire and hold physical inventory or derivatives for the purpose of speculating on commodity price changes. The material commodity related risks inherent in our business activities can be summarized into the following general categories:

Commodity Purchases and Sales — In the normal course of our operations, we purchase and sell commodities. We use derivatives to manage the associated risks and to optimize profits. As of December 31, 2010, net derivative positions related to these activities included:

- An approximate 176,700 barrels per day net long position (total of 5.3 million barrels) associated with our crude oil activities, which was unwound ratably during January 2011 to match monthly average pricing.

- A net short spread position averaging approximately 40,600 barrels per day (total of 28 million barrels), which hedges a portion of our anticipated crude oil lease gathering purchases through December 2012. These derivatives also hedge the margin associated with anticipated crude oil purchases. These derivatives in the aggregate do not result in exposure to outright price movements.

- A net short spread position averaging approximately 13,200 barrels per day (total of 4.8 million barrels) of calendar spread call options for the period February 2011 through January 2012. These derivatives also hedge the margin associated with anticipated crude oil purchases. These derivatives in the aggregate do not result in exposure to outright price movements.

- Approximately 4,400 barrels per day on average (total of 3.1 million barrels) of WTS/WTI crude oil basis swaps through December 2012, which hedge anticipated sales of crude oil (WTI).

Storage Capacity Utilization — We own approximately 65 million barrels of crude oil, LPG and refined products storage capacity that is not used in our transportation operations. This storage may be leased to third parties or utilized in our own supply and logistics activities, including for the storage of inventory in a contango market. For capacity allocated to our supply and logistics operations, we have utilization risk if the market structure is backwardated. As of December 31, 2010, we used derivatives to manage the risk of not utilizing approximately 2.4 million barrels per month of storage capacity through 2012. These positions are a combination of calendar spread options and NYMEX futures contracts. These positions involve no outright price exposure, but instead represent potential offsetting purchases and sales between time periods (first month versus second month for example).

Inventory Storage — At times, we elect to purchase and store crude oil, LPG, natural gas and refined products inventory in conjunction with our supply and logistics activities. When we purchase and store inventory, we enter into physical sales contracts or use derivatives to mitigate price risk associated with the inventory. As of December 31, 2010, we had derivatives totaling approximately 16.7 million barrels hedging our inventory.

We also purchase foreign cargoes of crude oil and may enter into derivatives to mitigate various price risks associated with the purchase and ultimate sale of foreign crude inventory. As of December 31, 2010, we had approximately 1.6 million barrels of crude oil derivatives hedging the anticipated sale of foreign crude inventory.

Pipeline Loss Allowance Oil — As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We utilize derivative instruments to hedge a portion of the anticipated sales of the allowance oil that is to be collected under our tariffs. As of December 31, 2010, we had PLA hedges consisting of (i) a net short position consisting of crude oil futures and swaps for an average of approximately 2,600 barrels per day (total of 1.8 million barrels) through December 2012, (ii) a long put option position of approximately 0.4 million barrels through December 2012 and (iii) a long call option position of approximately 1.1 million barrels through December 2012.

Natural Gas Purchases and Sales — Our gas storage facilities require minimum levels of natural gas (“base gas”) to operate. For our natural gas storage facilities that are under construction, we anticipate purchasing base gas in future periods as construction is completed. We use derivatives to hedge such anticipated purchases of natural gas. As of December 31, 2010, we had a long position of approximately 1 Bcf consisting of natural gas futures contracts through August 2011 and natural gas call options for approximately 1 Bcf through August 2011. Additionally, we use derivatives to hedge anticipated sales of operational gas when that gas is no longer needed for cavern development purposes.

All of our commodity derivatives that qualify for hedge accounting are designated as cash flow hedges. We have determined that substantially all of our physical purchase and sale agreements qualify for the NPNS exclusion. Physical commodity contracts that meet the definition of a derivative but are ineligible, or not designated, for the NPNS scope exception are recorded on the balance sheet at fair value, with changes in fair value recognized in earnings.

Interest Rate Risk Hedging

We use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and outstanding debt instruments. The derivative instruments we use to manage this risk consist primarily of interest rate swaps and treasury locks. As of December 31, 2010, AOCI includes deferred losses of $8 million that relate to terminated interest rate swaps and treasury locks that were designated for hedge accounting. These terminated interest rate derivatives

were cash-settled in connection with the issuance or refinancing of debt agreements. The deferred loss related to these instruments is being amortized to interest expense over the original terms of the hedged debt instruments.

During July 2009, we entered into four interest rate swaps. For the interest rate swaps, we receive fixed interest payments and pay floating-rate interest payments based on three-month LIBOR plus an average spread of 2.42% on a semi-annual basis. The swaps have an aggregate notional amount of $300 million with fixed rates of 4.25%. Two of the swaps terminate in 2011 and two of the swaps terminate in 2012. The swaps that terminate in 2012 are designated as a fair value hedge.

During October 2010, we entered into three forward starting interest rate swaps to hedge the underlying benchmark interest rate related to forecasted debt issuances through 2013. The following table summarizes the terms of our forward starting interest rate swaps (notional amounts in millions):

Hedged Transaction	Number and Types of Derivatives Employed	Notional Amount	Mandatory Termination Date	Average Rate Locked	Accounting Treatment
Anticipated debt offering	1 forward starting swap (30-year)	$ 50	12/15/2013	3.87%	Cash flow hedge
Anticipated debt offering	2 forward starting swaps (10-year)	$ 50	10/15/2012	3.30%	Cash flow hedge

These swaps were terminated in January 2011.

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use foreign currency derivatives to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. As of December 31, 2010, AOCI includes net deferred gains of $15 million that relate to open and settled foreign currency derivatives that were designated for hedge accounting. These foreign currency derivatives hedge the cash flow variability associated with CAD-denominated interest payments on a CAD-denominated intercompany note as a result of changes in the exchange rate.

As of December 31, 2010, our outstanding foreign currency derivatives also include derivatives we use to hedge USD-denominated crude oil purchases and sales in Canada. In addition, we may from time to time hedge the commodity price risk associated with a CAD-denominated commodity transaction with a USD-denominated commodity derivative. In conjunction with entering into the commodity derivative, we may enter into a foreign currency derivative to hedge the resulting foreign currency risk. These foreign currency derivatives are generally short-term in nature and are not designated for hedge accounting.

At December 31, 2010, our open foreign currency derivatives included forward exchange contracts that exchange CAD for USD on a net basis as follows (in millions):

	CAD	USD	Average Exchange Rate
2011	$ 15	$ 15	CAD $1.01 to US $1.00
2012	$ 15	$ 15	CAD $1.01 to US $1.00
2013	$ 9	$ 9	CAD $1.00 to US $1.00

Summary of Financial Impact

For derivatives that qualify as a cash flow hedge, changes in fair value of the effective portion of the hedges are deferred to AOCI and recognized in earnings in the periods during which the underlying physical transactions impact earnings. For our interest rate swaps that qualify as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the underlying hedged item, attributable to the hedged risk, are recognized in earnings each period. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that are not highly effective in offsetting changes in cash flows of the hedged items are recognized in earnings each period. Cash settlements associated with our derivative activities are reflected as operating cash flows in our consolidated statements of cash flows.

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A summary of the impact of our derivative activities recognized in earnings for the years ended December 31, 2010 and 2009 is as follows (in millions):

Location of gain/(loss)	Year Ended December 31, 2010 Derivatives in Hedging Relationships [1] [2] [3]	Year Ended December 31, 2010 Derivatives Not Designated as a Hedge [4]	Year Ended December 31, 2010 Total	Year Ended December 31, 2009 Derivatives in Cash Flow Hedging Relationships [1] [2]	Year Ended December 31, 2009 Derivatives Not Designated as a Hedge [4]	Year Ended December 31, 2009 Total
Commodity Derivatives						
Supply and Logistics segment revenues	$ 14	$ 2	$ 16	$ (98)	$ (10)	$ (108)
Transportation segment revenues	2	—	2	4	—	4
Facilities segment revenues	—	—	—	(1)	—	(1)
Purchases and related costs	8	(12)	(4)	69	122	191
Field operating costs	—	3	3	—	—	—
Interest Rate Derivatives						
Other income, net	—	—	—	—	(1)	(1)
Interest expense	1	2	3	(1)	3	2
Foreign Exchange Derivatives						
Supply and Logistics segment revenues	—	2	2	—	7	7
Purchases and related costs	—	2	2	1	3	4
Other income, net	—	(1)	(1)	10	(7)	3
Total Gain/(Loss) on Derivatives Recognized in Income	**$ 25**	**$ (2)**	**$ 23**	**$ (16)**	**$ 117**	**$ 101**

(1) Amounts represent derivative gains and losses that were reclassified from AOCI to earnings during the period to coincide with the earnings impact of the respective hedged transaction.

(2) Amounts include losses of approximately $1 million and $8 million for the years ended December 31, 2010 and December 31, 2009 respectively, that represent the ineffective portion of our cash flow hedges. These amounts relate to commodity derivatives and are recognized in Supply and Logistics segment revenues during such periods.

(3) Interest expense includes a net gain of approximately $1 million associated with outstanding interest rate swaps, which are designated as a fair value hedge.

(4) Includes realized and unrealized gains or losses for derivatives not designated for hedge accounting during the period.

The following table summarizes the derivative assets and liabilities on our consolidated balance sheet on a gross basis as of December 31, 2010 (in millions):

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 71	Other current assets	$ (70)
			Other long-term assets	(1)
			Other current liabilities	(1)
Interest rate derivatives	Other current assets	10		
Total derivatives designated as hedging instruments		$ 81		$ (72)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 11	Other current assets	$ (68)
	Other long-term assets	20		
	Other current liabilities	2	Other current liabilities	(10)
Interest rate derivatives	Other current assets	4		
	Other long-term assets	1		
Foreign currency derivatives	Other current assets	1		
Total derivatives not designated as hedging instruments		$ 39		$ (78)
Total derivatives		$ 120		$ (150)

The following table summarizes the derivative assets and liabilities on our consolidated balance sheet on a gross basis as of December 31, 2009 (in millions):

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 153	Other current liabilities	$ (140)
	Other long-term assets	34	Other long-term liabilities	(1)
Foreign currency derivatives	Other long-term assets	2		
Total derivatives designated as hedging instruments		$ 189		$ (141)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 34	Other current liabilities	$ (91)
	Other long-term assets	41	Other long-term liabilities	(34)
Interest rate derivatives	Other current assets	1		
	Other long-term assets	1		
Foreign currency derivatives	Other current assets	2	Other current liabilities	(3)
Total derivatives not designated as hedging instruments		$ 79		$ (128)
Total derivatives		$ 268		$ (269)

As of December 31, 2010, there was a net loss of $79 million deferred in AOCI. The total amount of deferred net loss recorded in AOCI is expected to be reclassified to future earnings contemporaneously with (i) the earnings recognition of the underlying hedged commodity transaction, (ii) interest expense accruals associated with underlying debt instruments or (iii) the recognition of a foreign currency gain or loss upon the remeasurement of certain CAD-denominated intercompany balances. Of the total net loss deferred in AOCI at December 31, 2010, we expect to reclassify a net loss of approximately $88 million to earnings in the next twelve months. Of the remaining deferred gain in AOCI, approximately $12 million is expected to be reclassified to earnings prior to 2014 with the remaining deferred loss being reclassified to earnings through 2019. These amounts are predominately based on market prices at the current period end, thus actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

During the twelve months ended December 31, 2009, we discontinued a cash flow hedge as a result of the hedged transaction becoming no longer probable of occurring and reclassified a deferred gain of approximately $5 million from AOCI to other income. During the twelve months ended December 31, 2010, all of our hedged transactions were probable of occurring.

The net deferred gain/(loss) recognized in AOCI for derivatives during the twelve months ended December 31, 2010 and 2009 are as follows (in millions):

	For the Years Ended December 31,	
	2010	**2009**
Commodity derivatives	$ (82)	$ (145)
Foreign currency derivatives	(2)	(4)
Interest rate derivatives	8	(2)
Total	$ (76)	$ (151)

Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting agreement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our exchange-traded derivatives are transacted through brokerage accounts and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. As of December 31, 2010, we had a net broker receivable of approximately $99 million (consisting of initial margin of $56 million increased by $43 million of variation margin that had been posted by us). As of December 31, 2009, we had a net broker receivable of approximately $53 million (consisting of initial margin of $71 million reduced by $18 million of variation margin that had been returned to us). At December 31, 2010 and 2009, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2010. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which does affect the placement of assets and liabilities within the fair value hierarchy levels.

	Fair Value as of December 31, 2010 (in millions)				Fair Value as of December 31, 2009 (in millions)			
Recurring Fair Value Measures [1]	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivatives	$ (16)	$ —	$ (30)	$ (46)	$ 27	$ —	$ (31)	$ (4)
Interest rate derivatives	—	—	15	15	—	—	2	2
Foreign currency derivatives	—	—	1	1	—	—	1	1
Total	$ (16)	$ —	$ (14)	$ (30)	$ 27	$ —	$ (28)	$ (1)

(1) Derivative assets and liabilities are presented above on a net basis but do not include related cash margin deposits.

The determination of the fair values above includes not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit) but also the impact of our nonperformance risk on our liabilities. The fair value of our commodity derivatives, interest-rate derivatives and foreign currency derivatives includes adjustments for credit risk. We measure credit risk by deriving a probability of default from market-observed credit default swap spreads as of the measurement date. The probability of default is applied to the net credit exposure of each of

our counterparties and includes a recovery rate adjustment. The recovery rate is an estimate of what would ultimately be recovered through a bankruptcy proceeding in the event of default. There were no changes to any of our valuation techniques during the period.

Level 1

Included within level 1 of the fair value hierarchy are exchange-traded commodity derivatives such as futures, options and swaps. The fair value of exchange-traded commodity derivatives is based on unadjusted quoted prices in active markets and is therefore classified within level 1 of the fair value hierarchy.

Level 2

There was no activity during the period within level 2 of the fair value hierarchy.

Level 3

Included within level 3 of the fair value hierarchy are the following derivatives:

- Commodity Derivatives: Level 3 commodity derivatives include over-the-counter commodity derivatives such as forwards, swaps and options and certain physical commodity contracts. The fair value of our level 3 commodity derivatives is based on either an indicative broker or dealer price quotation or a valuation model. Our valuation models utilize inputs such as forward price and volatility but do not involve significant management judgments.

- Interest Rate Derivatives: Level 3 interest rate derivatives include interest rate swaps. The fair value of our interest rate derivatives is based on indicative broker or dealer price quotations. Broker or dealer price quotations are corroborated with objective inputs including forward interest rates obtained from pricing services.

- Foreign Currency Derivatives: Level 3 foreign currency derivatives include foreign currency swaps, forward exchange contracts and options. The fair value of our foreign currency derivatives is based on indicative broker or dealer price quotations. Broker or dealer price quotations are corroborated with objective inputs including forward CAD/USD forward exchange rates obtained from pricing services.

The majority of our level 3 derivatives are classified as such because the broker or dealer price quotations used to measure fair value and the pricing services used to corroborate the quotations are indicative quotations rather than quotations whereby the broker or dealer is ready and willing to transact. However, the fair value of these level 3 derivatives is not based upon significant management assumptions or subjective inputs.

Rollforward of Level 3 Net Liability

The following table provides a reconciliation of changes in fair value of the beginning and ending balances for our derivatives classified as level 3 (in millions):

	Year Ended December 31,	
	2010	2009
Beginning Balance	$ (28)	$ 74
Unrealized gains/(losses):		
Included in earnings [1]	(22)	46
Included in other comprehensive income	3	(43)
Settlements and derivatives entered into during the period	33	(105)
Ending Balance	$ (14)	$ (28)
Change in unrealized gains/(losses) included in earnings relating to level 3 derivatives still held at the end of the periods	$ (27)	$ 31

(1) We reported unrealized gains and losses associated with level 3 commodity derivatives in our consolidated statements of operations as Supply and Logistics segment revenues. Gains and losses associated with interest rate derivatives are

reported in our consolidated statements of operations as Interest expense. Gains and losses associated with foreign currency derivatives are reported in our consolidated statements of operations as either Supply and Logistics segment revenues, Purchases and related costs, or Other income, net.

We believe that a proper analysis of our level 3 gains or losses must incorporate the understanding that these items are generally used to hedge our commodity price risk, interest rate risk and foreign currency exchange risk and will therefore be offset by gains or losses on the underlying transactions.

Note 7—Income Taxes

U.S. Federal and State Taxes

As an MLP, we are not subject to U.S. federal income taxes; rather the tax effect of our operations is passed through to our unitholders. Although we are subject to state income taxes in some states, the impact to the years ended December 31, 2010, 2009 and 2008 was immaterial.

Canadian Federal and Provincial Taxes

In 2010 and prior years, our Canadian operations were operated through a combination of corporate entities subject to Canadian federal and provincial taxes and a limited partnership which was treated as a flow-through entity for tax purposes. Due to changes in Canadian legislation and the Fifth Protocol to the U.S./Canada Tax Treaty, we restructured our Canadian investment on January 1, 2011. As of this date, all of our Canadian operations are conducted within entities that are treated as corporations for Canadian tax purposes (flow through for U.S. tax purposes) and that are subject to Canadian federal and provincial taxes. Payments of interest and dividends from Canada to other Plains entities will be subject to Canadian withholding tax that is treated as a distribution to unitholders.

Tax Components

Components of income tax expense are as follows (in millions):

	Year Ended December 31,		
	2010	2009	2008
Current tax (benefit)/expense:			
State income tax	$ 1	$ 2	$ 1
Canadian federal and provincial income tax	(2)	13	8
Total current tax (benefit)/expense	$ (1)	$ 15	$ 9
Deferred tax (benefit)/expense:			
State income tax	$ 1	$ —	$ —
Canadian federal and provincial income tax	(1)	(9)	(1)
Total deferred tax (benefit)/expense	$ —	$ (9)	$ (1)
Total income tax (benefit)/expense	$ (1)	$ 6	$ 8

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The difference between tax expense based on the statutory federal income tax rate and our effective tax expense is summarized as follows (in millions):

	Year Ended December 31,		
	2010	2009	2008
Income before tax	$ 513	$ 586	$ 445
Partnership earnings not subject to current Canadian tax	(509)	(585)	(422)
	$ 4	$ 1	$ 23
Canadian federal and provincial corporate tax rate	28.0%	29.0%	29.5%
Income tax at statutory rate	$ 1	$ —	$ 7
Current tax expense:			
Canadian period tax as a result of book versus tax differences	—	4	4
Canadian permanent differences between book and tax	(3)	9	(3)
State income tax	1	2	1
Current income tax (benefit)/expense	$ (1)	$ 15	$ 9
Deferred tax expense:			
State deferred income tax	1	—	—
Canadian deferred tax (benefit)/expense as a result of book versus tax differences	(1)	(9)	(1)
Deferred income tax (benefit)/expense	$ —	$ (9)	$ (1)
Total income tax (benefit)/expense	$ (1)	$ 6	$ 8

Deferred tax assets and liabilities, which are included net within other long-term liabilities and deferred credits in our consolidated balance sheet, result from the following (in millions):

	December 31,	
	2010	2009
Deferred tax assets:		
Book accruals in excess of current tax deductions	$ 4	$ 13
Total deferred tax assets	4	13
Deferred tax liabilities:		
Property, plant and equipment in excess of tax values	(128)	(134)
Total deferred tax liabilities	(128)	(134)
Net deferred tax liabilities	$ (124)	$ (121)

Generally, tax returns for our Canadian entities are open to audit from 2006 through 2010. Our U.S. and state tax years are open to examination from 2006 to 2010.

Note 8—Major Customers and Concentration of Credit Risk

Marathon Oil Corporation and its affiliates accounted for 14% of our revenues for each of the three years ended December 31, 2010, 2009 and 2008. ConocoPhillips Company accounted for 10%, 12% and 12% of our revenues for the years ended December 31, 2010, 2009 and 2008, respectively. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2010. The majority of revenues from these customers pertain to our supply and logistics operations. We believe that the loss of these customers would have only a short-term impact on our operating results. There is risk, however, that we would not be able to identify and access a replacement market at comparable margins.

Financial instruments that potentially subject us to concentrations of credit risk consist principally of trade receivables. Our accounts receivable are primarily from purchasers and shippers of crude oil. This industry concentration has the potential to impact our overall exposure to credit risk in that the customers may be similarly affected by changes in economic, industry or other conditions. We review credit exposure and financial information of our counterparties and generally require letters of credit for receivables from customers that are not considered creditworthy, unless the credit risk can otherwise be reduced. See Note 2 for additional discussion of our accounts receivable and our review of credit exposure.

Note 9—Related Party Transactions

Reimbursement of Expenses of Our General Partner and its Affiliates

We do not pay our general partner a management fee, but we do reimburse our general partner for all direct and indirect costs of services provided to us or incurred on our behalf, including the costs of employee, officer and director compensation and benefits allocable to us as well as all other expenses necessary or appropriate to the conduct of our business (other than expenses related to grants of AAP LP Class B units). We record these costs on the accrual basis in the period in which our general partner incurs them. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion. Total costs reimbursed by us to our general partner for the years ended December 31, 2010, 2009 and 2008 were $374 million, $328 million and $289 million, respectively.

Vulcan Energy Corporation

In December 2010, Vulcan Energy Corporation ("Vulcan Energy") sold its 50.1% ownership interest in our general partner. Substantially all of the interest sold was acquired by existing owners of our general partner or their affiliates. Vulcan Energy retained its limited partner interest in us. As of December 31, 2010, Vulcan Energy owned approximately 9% of our outstanding limited partner units.

Voting Agreements. In August 2005, in connection with an increase in Vulcan Energy's ownership interest in our general partner, Vulcan Energy entered into a voting agreement that restricted its ability to unilaterally elect or remove the independent directors serving on our audit committee. Lynx Holdings I, LLC, also agreed to restrict certain of its voting rights with respect to its membership interest in Plains All American GP LLC. Our Chief Executive Officer and Chief Operating Officer agreed, subject to certain ongoing conditions, to waive certain change-of-control payment rights that would otherwise have been triggered by the increase in Vulcan Energy's ownership interest.

These voting rights agreements were terminated in December 2010 in connection with the sale by Vulcan Energy of its 50.1% interest in our general partner. Vulcan Energy has agreed that prior to the earlier of December 23, 2015 and the date, if any, of certain changes in our senior-most management, it will not vote any of its limited partner interests in favor of any proposal to remove Plains All American GP LLC as our general partner.

Administrative Services Agreement. On October 14, 2005, Plains All American GP LLC and Vulcan Energy entered into an Administrative Services Agreement, effective as of September 1, 2005 (the "Services Agreement"). Pursuant to the Services Agreement, Plains All American GP LLC provided administrative services to Vulcan Energy for consideration of an annual fee of $1 million, plus certain expenses. The Services Agreement was terminated in December 2010 in connection with the sale by Vulcan Energy of its 50.1% interest in our general partner. However, we have agreed to provide transition services and assistance to Vulcan Energy until June 2011 for consideration of a $1 million fee.

Indemnification Arrangement. In 2001, in connection with the transfer of interests in our general partner, Vulcan Energy (as successor in interest to the owner of our former general partner) agreed to indemnify us for (i) any claims relating to securities laws or regulations in connection with the upstream or midstream businesses, based on acts or omissions, or alleged acts or omissions, occurring on or prior to June 8, 2001, or (ii) any claims relating to the operation of the upstream business, whenever arising. In addition, we agreed to indemnify Vulcan Energy for any claims relating to the operation of the midstream business, whenever arising.

Occidental Petroleum Corporation

As of December 31, 2010, a subsidiary of Occidental Petroleum Corporation ("Oxy") owned approximately 35% of our general partner interest and had a representative on the board of directors of Plains All American GP LLC. During the three years ended December 31, 2010, we received sales and transportation storage revenues and purchased petroleum products from companies associated with Oxy, as detailed below (in millions):

	For the Year Ended December 31,		
	2010	2009	2008
Total revenues	$ 2,189	$ 181	$ 159
Purchases and related costs	$ 221	$ 164	$ 224

We currently have a netting arrangement with Oxy. Our gross receivable and payable amounts with affiliates of Oxy were as follows (in millions):

	At December 31,	
	2010	2009
Trade accounts receivable and other receivables, net	$ 379	$ 82
Accounts payable	$ 124	$ 103

Natural Gas Storage Investment

In September 2005, we and Vulcan Gas Storage LLC, a subsidiary of Vulcan LLC, an investment arm of Paul G. Allen, formed PAA/Vulcan to acquire ECI (subsequently known as PAA Natural Gas Storage, LLC or "PNGS"), an indirect subsidiary of Sempra Energy, for approximately $250 million. We and Vulcan Gas Storage each made an initial cash investment of approximately $113 million and Bluewater Natural Gas Storage, LLC, a subsidiary of PAA/Vulcan, entered into a $90 million credit facility contemporaneously with closing.

From September 2005 until September 3, 2009, we owned 50% of PAA/Vulcan and Vulcan Gas Storage LLC owned the other 50%. Giving effect to all contributions and distributions made during the period from January 1, 2007 through September 3, 2009, we and Vulcan Gas Storage each made a net contribution of $39 million. Such contributions and distributions did not result in an increase or decrease to our ownership interest.

On September 3, 2009, one of our subsidiaries acquired the remaining 50% interest in PAA/Vulcan from Vulcan Gas Storage LLC, which resulted in our ownership of a 100% interest in PNGS. See Note 3 for further discussion of the PNGS Acquisition.

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Note 10—Equity Compensation Plans

PAA Long-Term Incentive Plan Awards

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the "1998 Plan"), the 2005 Long-Term Incentive Plan (the "2005 Plan") and the PPX Successor Long-Term Incentive Plan (the "PPX Successor Plan") for employees and directors, as well as the Plains All American GP LLC 2006 Long-Term Incentive Tracking Unit Plan (the "2006 Plan") for non-officer employees. The 1998 Plan, 2005 Plan and PPX Successor Plan authorize the issuance of an aggregate of 5.4 million common units deliverable upon vesting. Although other types of awards are contemplated under the plans, currently outstanding awards are limited to "phantom units," which mature into the right to receive common units of PAA (or cash equivalent) upon vesting. Some awards also include distribution equivalent rights ("DERs"). Subject to applicable vesting criteria, a DER entitles the grantee to a cash payment equal to the cash distribution paid on an outstanding common unit. The 2006 Plan authorizes the grant of approximately 2.1 million "tracking units" which, upon vesting, represent the right to receive a cash payment in an amount based upon the market value of a common unit at the time of vesting. Our general partner is entitled to reimbursement by us for any costs incurred in settling obligations under the plans.

At December 31, 2010, the following LTIP awards, denominated in PAA units, were outstanding (units in millions):

LTIP Units Outstanding	PAA Distribution Required	Estimated Unit Vesting Date				
		2011	2012	2013	2014	2015
2.8[1]	$3.50 - $4.45	0.4	0.8	0.5	0.6	0.5
1.6[2]	$3.50 - $4.25	0.2	0.8	0.3	0.2	0.1
4.4[3] [4]		0.6	1.6	0.8	0.8	0.6

(1) These LTIP awards have performance conditions requiring the attainment of an annualized PAA distribution of between $3.50 and $4.45 and vest upon the later of a certain date or the attainment of such levels. If the performance conditions are not attained while the grantee remains employed by us, or the grantee does not meet employment requirements, these awards will be forfeited. For purposes of this disclosure, vesting dates are based on an estimate of future distribution levels and assume that all grantees remain employed by us through the vesting date.

(2) These LTIP awards have performance conditions requiring the attainment of an annualized PAA distribution of between $3.50 and $4.25. For these LTIP awards, fifty percent will vest at specified dates regardless of whether the performance conditions are attained. For purposes of this disclosure, vesting dates are based on an estimate of future distribution levels and assume that all grantees remain employed by us through the vesting date.

(3) Approximately 2.4 million of our approximately 4.4 million outstanding LTIP awards also include DERs, of which 0.9 million are currently vested.

(4) LTIP units outstanding do not include Class B units of Plains AAP, L.P. ("AAP LP Class B units") described below.

PNG Long-Term Incentive Plan Awards

During April 2010, PNG's general partner adopted the PAA Natural Gas Storage, L.P. 2010 Long Term Incentive Plan (the "PNG Plan") for employees, directors and consultants. The PNG Plan limits the number of PNG common units that may be delivered pursuant to awards under the plan to 3 million units. Although other types of awards are contemplated under the plan, currently outstanding awards are limited to phantom units, which mature into the right to receive common units of PNG (or cash equivalent) upon vesting. Some awards also include DERs.

At December 31, 2010, the following LTIP awards, denominated in PNG units, were outstanding (units in millions):

LTIP Units Outstanding	PNG Distribution Required	Estimated Unit Vesting Date				
		2011	2012	2013	2014	2015
0.3[1]	$1.55 - $1.90	—	—	0.1	—	0.2
0.3[2]	Other	0.1	0.1	0.1	—	—
0.6[3] [4]		0.1	0.1	0.2	—	0.2

(1) These LTIP awards have performance conditions requiring the attainment of an annualized PNG distribution of between $1.55 and $1.90 and vest upon the later of a certain date or the attainment of such levels. For purposes of this disclosure, vesting dates are based on an estimate of future distribution levels and assume that all grantees remain employed by us through the vesting date.

(2) These LTIP awards have performance conditions requiring the conversion of PNG's Series A and Series B subordinated units (see Note 5). For purposes of this disclosure, vesting dates are based on an estimate of future distribution levels and assume that all grantees remain employed by us through the vesting date.

(3) Approximately 0.3 million of these LTIP awards also include DERs, of which none are currently vested.

(4) LTIP units outstanding do not include the PNG Transaction Grants or Class B units of PNGS GP LLC described below.

Our LTIP awards include both liability classified and equity classified awards. In accordance with FASB guidance regarding share-based payments, the fair value of our liability classified LTIP awards is calculated based on the closing market price of the underlying PAA or PNG units at each balance sheet date and adjusted for the present value of any distributions that are estimated to occur on the underlying units over the vesting period that will not be received by the award recipients. The fair value of our equity classified LTIP awards is calculated based on the closing market price of the PAA or PNG units on the respective grant dates and adjusted for the present value of any distributions that are estimated to occur on the underlying units over the vesting period that will not be received by the award recipient. This fair value is recognized as compensation expense over the service period.

Our LTIP awards typically contain performance conditions based on the attainment of certain annualized distribution levels and vest upon the later of a certain date or the attainment of such levels. For awards with performance conditions (such as distribution targets), expense is accrued over the service period only if the performance condition is considered to be probable of occurring. When awards with performance conditions that were previously considered improbable become probable, we incur additional expense in the period that our probability assessment changes. This is necessary to bring the accrued liability associated with these awards up to the level it would be as if we had been accruing for these awards since the grant date. Our DER awards typically contain performance conditions based on the attainment of certain annualized distribution levels and become earned upon the attainment of such levels. The DERs terminate with the vesting or forfeiture of the underlying LTIP award. For liability classified awards, we recognize DER payments in the period the payment is earned as compensation expense. For equity classified awards, we recognize DER payments in the period it is paid as a reduction of partners' capital.

Prior to PNG's IPO and adoption of the PNG Plan, certain PNG officers and other individuals were granted LTIP awards under the PAA LTIP Plans. In connection with the adoption of the PNG plan, substantially all of the then outstanding PAA LTIP awards held by PNG officers were converted to PNG LTIP awards. We recognized incremental compensation expense of less than $1 million during the twelve months ended December 31, 2010 as a result of this modification.

Our accrued liability at December 31, 2010 related to all outstanding LTIP awards and DERs is approximately $102 million. This liability includes accruals associated with our assessments that the following performance conditions are probable of occurring: (i) an annualized PAA distribution of $4.00, (ii) an annualized PNG distribution of $1.45 and (iii) the conversion of PNG's Series A subordinated units and the first tranche of PNG's Series B subordinated units. At December 31, 2009, the accrued liability was approximately $87 million, which includes accruals associated with our assessment that an annualized PAA distribution of $3.90 was probable of occurring.

PNG Transaction Grants

During September 2010, we entered into agreements with certain of our officers, pursuant to which these officers acquired an aggregate of 375,000 phantom common units, phantom Series A subordinated units, and phantom Series B subordinated units representing a portion of the limited partner interests of PNG issued to us in the IPO. The awards, referred to herein as "PNG Transaction Grants," will vest upon the completion of the service period and certain performance conditions, including the conversion of PNG's Series A subordinated units into common units of PNG and the conversion of PNG's Series B subordinated units into Series A subordinated units of PNG. Upon vesting, these awards will be settled with outstanding common or Series A subordinated units of PNG currently owned by us, resulting in a dilution of our interest in PNG.

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Our equity compensation activity for awards denominated in PAA and PNG units is summarized in the following table (units in millions):

	PAA Units [1]		PNG Units [2][3]	
	Units	Weighted Average Grant Date Fair Value per Unit	Units	Weighted Average Grant Date Fair Value per Unit
Outstanding, December 31, 2007	3.6	$ 37.75	—	$ —
Granted	0.5	$ 31.79	—	$ —
Vested	(0.1)	$ 32.44	—	$ —
Cancelled or forfeited	(0.1)	$ 36.14	—	$ —
Outstanding, December 31, 2008	3.9	$ 36.44	—	$ —
Granted	0.6	$ 32.20	—	$ —
Vested	(0.6)	$ 34.55	—	$ —
Cancelled or forfeited	(0.1)	$ 37.82	—	$ —
Acquired	0.1	$ 26.24	—	$ —
Outstanding, December 31, 2009	3.9	$ 36.40	—	$ —
Granted	2.0	$ 45.66	1.1	$ 20.49
Vested	(1.1)	$ 32.20	—	$ —
Cancelled or forfeited	(0.4)	$ 35.62	(0.1)	$ 19.22
Outstanding, December 31, 2010	4.4	$ 41.69	1.0	$ 20.55

(1) Amounts do not include Class B units of Plains AAP, L.P. as discussed below.
(2) Amounts do not include Class B units of PNGS GP LLC as discussed below.
(3) Amounts include PNG Transaction Grants.

Class B Units of Plains AAP, L.P.

In August 2007, the owners of Plains AAP, L.P. authorized the issuance of up to 200,000 "AAP LP Class B Units". AAP LP Class B units become earned in various increments upon the achievement of PAA distribution levels of between $3.50 and $4.50 (or in some cases, within six months thereof). When earned, the AAP LP Class B unit awards are entitled to participate in distributions paid by Plains AAP, L.P. in excess of $11 million (as adjusted for debt service costs and excluding special distributions funded by debt) per quarter. Assuming all 200,000 AAP LP Class B units were granted and earned, the maximum participation would be 8% of Plains AAP, L.P.'s distribution in excess of $11 million (as adjusted) each quarter. The following table contains a summary of AAP LP Class B unit awards:

	Reserved for Future Grants	Outstanding	Outstanding Units Earned	Grant Date Fair Value Of Outstanding Class B Units [1] (in millions)
Balance as of December 31, 2009	34,500	165,500	38,500	$ 36
Class B unit issuance	(13,000)	13,000	—	5
Class B unit forfeitures	3,000	(3,000)		(1)
Class B units earned	—	—	41,563	—
Balance as of December 31, 2010	24,500	175,500	80,063	$ 40

(1) Of the grant date fair value, approximately $9 million and $5 million was recognized as expense during the years ended December 31, 2010 and 2009, respectively.

Although the entire economic burden of the AAP LP Class B units, which are equity classified, is borne solely by Plains AAP, L.P. and does not impact our cash or units outstanding, the intent of the AAP LP Class B units is to provide a performance incentive and encourage retention for certain members of our senior management. Therefore, we recognize the grant date fair value of the AAP LP Class B units as compensation expense over the service period. The expense is also reflected as a capital contribution and thus, results in a corresponding credit to Partners' Capital in our Consolidated Financial Statements.

Class B Units of PNGS GP LLC

During July 2010, the Board of Directors of PNG's general partner authorized the issuance of 165,000 Class B units of PNGS GP LLC ("PNGS GP LLC Class B units"). Approximately 90,750 PNGS GP LLC Class B units were awarded and the remaining units are reserved for future grants. The PNGS GP LLC Class B units earn the right to participate in distributions (i.e. become "earned") in 25% increments 180 days following annualized PNG distribution levels of $2.00, $2.30, $2.50 and $2.70. In addition, 50% of the applicable earned units vest immediately upon becoming earned units and the remaining 50% vest on the fifth anniversary of the date of grant. If PNGS GP LLC Class B units become earned units after the fifth anniversary of the date of grant, 100% of such units will vest immediately upon becoming earned units. When earned, the PNGS GP LLC Class B units participate in quarterly distributions paid to PNG's general partner to the extent such distributions exceed $2.5 million per quarter. Assuming all 165,000 PNGS GP LLC Class B units were granted and earned, the maximum participation rate would be 6% of PNG's quarterly general partner distribution in excess of $2.5 million. As the PNG distribution levels required for vesting are not currently considered to be probable of occurring, no expense was recognized for the PNGS GP LLC Class B Units during the year ended December 31, 2010.

Other Consolidated Equity Compensation Information

We refer to our LTIP Plans, PNG Transaction Grants, AAP LP Class B units and PNGS GP LLC Class B units collectively as "Equity compensation plans." The table below summarizes the expense recognized and the value of vesting (settled both in units and cash) related to our equity compensation plans (in millions):

	2010	2009	2008
Equity compensation expense	$ 98	$ 68	$ 24
LTIP unit settled vestings [(1)]	$ 26	$ 19	$ 1
LTIP cash settled vestings	$ 36	$ 8	$ 2
DER cash payments	$ 4	$ 4	$ 4

(1) All unit vestings were settled with PAA units.

Approximately 0.5 million, 0.5 million and 0.1 million PAA units were issued net of tax withholding in 2010, 2009 and 2008 respectively, in connection with the settlement of vested awards. The remaining 0.6 million and 0.1 million of awards that vested during 2010 and 2009 respectively, were settled in cash. Based on the December 31, 2010 fair value measurement and probability assessment regarding future distributions, we expect to recognize approximately $84 million of additional expense over the life of our outstanding awards related to the remaining unrecognized fair value. Actual amounts may differ materially as a result of a change in the market price of our units and/or probability assessments regarding future distributions. We estimate that the remaining fair value will be recognized in expense as shown below (in millions):

Year	Equity Compensation Plan Fair Value Amortization [(1) (2)]
2011	$ 46
2012	28
2013	7
2014	2
2015	1
Total	$ 84

(1) Amounts do not include fair value associated with awards containing performance conditions that are not considered to be probable of occurring at December 31, 2010.

(2) Includes unamortized fair value associated with AAP LP Class B units, PNGS GP LLC Class B units and PNG Transaction Grants.

Note 11—Commitments and Contingencies

Commitments

We lease certain real property, equipment and operating facilities under various operating and capital leases. We also incur costs associated with leased land, rights-of-way, permits and regulatory fees, the contracts for which generally extend beyond one year but can be cancelled at any time should they not be required for operations. Future non-cancelable commitments related to these items at December 31, 2010, are summarized below (in millions):

2011	$	77
2012		62
2013		40
2014		27
2015		20
Thereafter		277
Total	$	503

Expenditures related to leases for 2010, 2009 and 2008 were $97 million, $90 million and $82 million, respectively.

Litigation

United States Environmental Protection Agency v. Plains All American Pipeline, L.P. In September 2010, the United States District Court for the Southern District of Texas entered an order approving a Consent Decree that represented our settlement agreement with the U.S. Environmental Protection Agency ("EPA") and the U.S. Department of Justice ("DOJ") regarding a 2004 crude oil release that reached the Pecos River and a 2005 crude oil release that reached the Sabine River, as well as eight smaller releases. Pursuant to the Consent Decree, we paid $3.25 million in civil penalties, which we had fully reserved in our contingency accrual. Over the last several years we have proactively developed and implemented risk assessment, pipeline integrity and leak detection procedures that are incremental to those mandated by regulation. As a result of this effort and the ongoing process with EPA and DOJ, many of the operational requirements contained in the Consent Decree have already been incorporated into our operating practices, and the anticipated costs of compliance have been incorporated into our planning.

SemCrude L.P., et al — Debtors/Samson Resources Company (U.S. Bankruptcy Court — Delaware). We will from time to time have claims relating to insolvent suppliers, customers or counterparties, such as the bankruptcy proceedings of SemCrude, which commenced in July 2008. Statutory protections and our contractual rights of setoff covered substantially all of our pre-petition claims against SemCrude and such claims have now been resolved. In separate actions certain creditors of SemCrude, led by Samson Resources Company, have also filed state court actions alleging a producer's lien on crude oil sold to SemCrude and its affiliates, and the continuation of such lien when SemCrude and its affiliates subsequently sold the oil to purchasers such as us. On May 29, 2009, we filed a complaint for declaratory relief to resolve these claims. Fourteen state court actions have been consolidated in Bankruptcy Court. One action is in Federal Court in New Mexico. We intend to vigorously defend our contractual and statutory rights.

ExxonMobil Corp. v. GATX Corp. (Superior Court of New Jersey — Gloucester County). This Pacific legacy matter was filed by ExxonMobil in April 2003 and involves the allocation of responsibility for remediation of MTBE and other petroleum product contamination at our terminal facility in Paulsboro, New Jersey, which we acquired in the Pacific merger. We estimate that the cost to effectively remediate will be approximately $3.5 million, which amount may be higher or lower depending on the nature and extent of the cleanup. Both ExxonMobil and GATX were prior owners of the terminal. We contend that ExxonMobil and/or GATX are primarily responsible for the majority of the remediation costs. We are in dispute with Kinder Morgan (as successor in interest to GATX) regarding the indemnity by GATX in favor of Pacific in connection with Pacific's purchase of the facility. We are vigorously defending against any claim that PPT is directly or indirectly liable for damages or costs associated with the MTBE contamination.

New Jersey Department of Environmental Protection v. ExxonMobil Corp. et al. In a matter related to ExxonMobil v. GATX, in June 2007, the NJDEP brought suit against GATX, ExxonMobil and Plains Products Terminals LLC (formerly Pacific Atlantic Terminals LLC) to recover natural resources damages associated with, and to require remediation of, the contamination. ExxonMobil and GATX have filed third-party demands against PPT, seeking indemnity and contribution. The

natural resources damages have been settled and set at $1.1 million payable to the State of New Jersey; however, PPT's allocated share of this liability is being disputed by PPT with GATX. Court approval of the settlement is pending.

EPA v. Rocky Mountain Pipeline System. In February 2009, we received a request for information from EPA regarding aspects of the fuel handling activities of RMPS, a subsidiary acquired in the Pacific merger, at two truck terminals in Colorado. These activities included the mixture of certain blendstocks with gasoline. We provided the information requested, and cooperated in EPA's investigation of such activities. In January 2010, we received a notice of violations from EPA, alleging failure of RMPS to comply with provisions of the Clean Air Act related to registration, sampling, recording and reporting in connection with such activities. EPA further alleges that the violations occurred on an ongoing basis from October 2006 through February 2009. EPA has referred the matter to the DOJ. We continue to engage in discussion with EPA, and to emphasize those factors that should mitigate the severity of any penalties imposed. In December 2009, RMPS self-reported late filing of certain reports required under Clean Air Act Diesel Fuel Regulations. All reports have now been filed.

General. In the ordinary course of business, we are involved in various legal proceedings. To the extent we are able to assess the likelihood of a negative outcome for these proceedings, our assessments of such likelihood range from remote to probable. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue the estimated amount. We do not believe that the outcome of these legal proceedings, individually or in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows. Although we believe that our operations are presently in material compliance with applicable requirements, as we acquire and incorporate additional assets it is possible that EPA or other governmental entities may seek to impose fines, penalties or performance obligations on us (or on a portion of our operations) as a result of any past noncompliance whether such noncompliance initially developed before or after our acquisition.

Environmental

Although we believe that our efforts to enhance our leak prevention and detection capabilities have produced positive results, we have experienced (and likely will experience future) releases of hydrocarbon products into the environment from our pipeline and storage operations. These releases can result from unpredictable man-made or natural forces and may reach "navigable waters" or other sensitive environments. Whether current or past, damages and liabilities associated with any such releases from our assets may substantially affect our business.

As we expand our pipeline assets through acquisitions, we typically improve on (reduce) the releases from such assets (in terms of frequency or volume) as we implement our integrity management procedures, remove selected assets from service and spend capital to upgrade the assets. However, the inclusion of additional miles of pipe in our operations may result in an increase in the absolute number of releases company-wide compared to prior periods.

At December 31, 2010, our reserve for environmental liabilities totaled approximately $66 million, of which approximately $10 million is classified as short-term and $56 million is classified as long-term. At December 31, 2010, we have recorded receivables totaling approximately $5 million for amounts that are probable of recovery under insurance and from third parties under indemnification agreements.

In some cases, the actual cash expenditures may not occur for three to five years. Our estimates used in these reserves are based on information currently available to us and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing legal claims giving rise to additional claims. Therefore, although we believe that the reserve is adequate, costs incurred may be in excess of the reserve and may potentially have a material adverse effect on our financial condition, results of operations or cash flows.

Insurance

A pipeline, terminal or other facility may experience damage as a result of an accident, natural disaster or terrorist activity. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and certain assets. The insurance policies are subject to deductibles or self-insured retentions that we consider reasonable. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, we may not be able to maintain adequate insurance in the future at rates we consider reasonable. As a result, we may elect to self-insure or utilize higher deductibles in certain insurance programs. In addition, although we believe that we have established adequate reserves to the extent that such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

Note 12—Environmental Remediation

We currently own or lease, and in the past have owned and leased, properties where hazardous liquids, including hydrocarbons, are or have been handled. These properties and the hazardous liquids or associated wastes disposed thereon may be subject to CERCLA, RCRA and state and Canadian federal and provincial laws and regulations. Under such laws and regulations, we could be required to remove or remediate hazardous liquids or associated wastes (including wastes disposed of or released by prior owners or operators) and to clean up contaminated property (including contaminated groundwater).

We maintain insurance of various types with varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. Consistent with insurance coverage generally available in the industry, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences.

In conjunction with our acquisitions, we typically make an assessment of potential environmental exposure and determine whether to negotiate an indemnity, what the terms of any indemnity should be and whether to obtain environmental risk insurance, if available. These contractual indemnifications typically are subject to specific monetary requirements that must be satisfied before indemnification will apply, and have term and total dollar limits. For instance, in connection with the purchase of former TNM pipeline assets from Link in 2004, we identified a number of environmental liabilities for which we received a purchase price reduction from Link and recorded a total environmental reserve of $20 million, of which we agreed in an arrangement with TNM to bear the first $11 million in costs of pre-May 1999 environmental issues. TNM also agreed to pay all costs in excess of $20 million (excluding certain deductibles). TNM's obligations are guaranteed by SOP. As of December 31, 2010, we had incurred approximately $19 million of remediation costs associated with these sites, while SOP's share has been approximately $8 million.

Other assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified.

We have in the past experienced and in the future likely will experience releases of crude oil into the environment from our pipeline and storage operations. We also may discover environmental impacts from past releases that were previously unidentified. See Note 11 for further environmental discussion.

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Note 13—Supplemental Condensed Consolidating Financial Information

Some but not all of our 100% owned subsidiaries have issued full, unconditional and joint and several guarantees of our Senior Notes. Given that certain, but not all, subsidiaries are guarantors of our Senior Notes, we are required to present the following supplemental condensed consolidating financial information. For purposes of the following footnote:

- we are referred to as “Parent;”
- the “Guarantor Subsidiaries” are all subsidiaries other than the Non-Guarantor Subsidiaries defined below; and
- The “Non-Guarantor Subsidiaries” as of December 31, 2010 include two California Public Utilities Commission regulated entities, our natural gas storage subsidiaries and other minor subsidiaries.

The following supplemental condensed consolidating financial information reflects the Parent's separate accounts, the combined accounts of the Guarantor Subsidiaries, the combined accounts of the Non-Guarantor Subsidiaries, the combined consolidating adjustments and eliminations and the Parent's consolidated accounts for the dates and periods indicated. For purposes of the following condensed consolidating information, the Parent's investments in its subsidiaries and the Guarantor Subsidiaries' investments in their subsidiaries are accounted for under the equity method of accounting (in millions):

Condensed Consolidating Balance Sheets

	As of December 31, 2010				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 3,460	$ 4,394	$ 510	$ (3,983)	$ 4,381
Property and equipment, net	2	4,870	1,819	—	6,691
Investments in unconsolidated entities	6,302	2,173	—	(8,275)	200
Other assets, net	28	1,976	553	(126)	2,431
Total assets	$ 9,792	$ 13,413	$ 2,882	$ (12,384)	$ 13,703
LIABILITIES AND PARTNERS' CAPITAL					
Total current liabilities	$ 853	$ 6,836	$ 509	$ (3,983)	$ 4,215
Long-term debt	4,366	5	386	(126)	4,631
Other long-term liabilities	—	270	14	—	284
Total liabilities	5,219	7,111	909	(4,109)	9,130
Partners' capital excluding noncontrolling interests	4,342	6,241	1,973	(8,214)	4,342
Noncontrolling interests	231	61	—	(61)	231
Total partners' capital	4,573	6,302	1,973	(8,275)	4,573
Total liabilities and partners' capital	$ 9,792	$ 13,413	$ 2,882	$ (12,384)	$ 13,703

	As of December 31, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 3,428	$ 3,831	$ 209	$ (3,810)	$ 3,658
Property and equipment, net	—	4,606	1,734	—	6,340
Investments in unconsolidated entities	5,295	1,652	—	(6,865)	82
Other assets, net	29	2,342	367	(460)	2,278
Total assets	$ 8,752	$ 12,431	$ 2,310	$ (11,135)	$ 12,358
LIABILITIES AND PARTNERS' CAPITAL					
Total current liabilities	$ 456	$ 6,849	$ 287	$ (3,810)	$ 3,782
Long-term debt	4,137	15	450	(460)	4,142
Other long-term liabilities	—	271	4	—	275
Total liabilities	4,593	7,135	741	(4,270)	8,199
Partners' capital excluding noncontrolling interest	4,096	5,233	1,569	(6,802)	4,096
Noncontrolling interest	63	63	—	(63)	63
Total partners' capital	4,159	5,296	1,569	(6,865)	4,159
Total liabilities and partners' capital	$ 8,752	$ 12,431	$ 2,310	$ (11,135)	$ 12,358

Condensed Consolidating Statements of Operations

	Year Ended December 31, 2010				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues [1]	$ —	$ 1,749	$ 223	$ —	$ 1,972
Field operating costs	—	(632)	(57)	—	(689)
General and administrative expenses	—	(230)	(30)	—	(260)
Depreciation and amortization	(4)	(207)	(45)	—	(256)
Operating income/(loss)	(4)	680	91	—	767
Equity earnings in unconsolidated entities	778	86	—	(861)	3
Interest income/(expense)	(254)	13	(7)	—	(248)
Other income/(expense), net	(6)	(3)	—	—	(9)
Income tax benefit	—	1	—	—	1
Net income	514	777	84	(861)	514
Less: Net income attributable to noncontrolling interests	(9)	(2)	—	2	(9)
Net income attributable to Plains	$ 505	$ 775	$ 84	$ (859)	$ 505

	Year Ended December 31, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues [1]	$ —	$ 1,707	$ 157	$ —	$ 1,864
Field operating costs	—	(589)	(49)	—	(638)
General and administrative expenses	—	(196)	(15)	—	(211)
Depreciation and amortization	(4)	(200)	(32)	—	(236)
Operating income/(loss)	(4)	722	61	—	779
Equity earnings in unconsolidated entities	822	64	—	(871)	15
Interest income/(expense)	(234)	14	(4)	—	(224)
Other income, net	(4)	20	—	—	16
Income tax expense	—	(6)	—	—	(6)
Net income	580	814	57	(871)	$ 580
Less: Net income attributable to noncontrolling interest	(1)	(1)	—	1	(1)
Net income attributable to Plains	$ 579	$ 813	$ 57	$ (870)	$ 579

	Year Ended December 31, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues [1]	$ —	$ 1,469	$ 113	$ —	$ 1,582
Field operating costs	—	(575)	(42)	—	(617)
General and administrative expenses	—	(149)	(11)	—	(160)
Depreciation and amortization	(3)	(187)	(21)	—	(211)
Operating income/(loss)	(3)	558	39	—	594
Equity earnings in unconsolidated entities	629	45	—	(660)	14
Interest expense	(195)	(1)	—	—	(196)
Other income, net	6	26	1	—	33
Income tax expense	—	(8)	—	—	(8)
Net income	$ 437	$ 620	$ 40	$ (660)	$ 437

(1) Net operating revenues are calculated as “Total revenues” less “Purchases and related costs.”

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Condensed Consolidating Statements of Cash Flows

	Year Ended December 31, 2010				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 514	$ 777	$ 84	$ (861)	$ 514
Reconciliation of net income to net cash provided by/(used in) operating activities:					
Depreciation and amortization	4	207	45	—	256
Equity compensation expense	—	95	3	—	98
Gain on sale of linefill	—	(21)	—	—	(21)
Equity earnings in unconsolidated entities, net of distributions	(778)	(77)	—	861	6
Other	8	3	—	—	11
Changes in assets and liabilities, net of acquisitions	(250)	(610)	255	—	(605)
Net cash provided by/(used in) operating activities	(502)	374	387	—	259
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions, net of cash acquired	(20)	(242)	(145)	—	(407)
Restricted cash in escrow for acquisitions	—	—	(20)	—	(20)
Additions to property, equipment and other	—	(323)	(128)	—	(451)
Cash received for sale of noncontrolling interest in a subsidiary	268	—	—	—	268
Net cash received/(paid) for sales and purchases of linefill and base gas	—	35	(10)	—	25
Proceeds from sales of assets and other investing activities	—	2	—	—	2
Net cash provided by/(used in) investing activities	248	(528)	(303)	—	(583)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net borrowings/(repayments) on Plains revolving credit facility	412	(363)	—	—	49
Net borrowings on PNG revolving credit facility	—	—	260	—	260
Net borrowings on short-term letter of credit and hedged inventory facility	—	200	—	—	200
Net borrowings/(repayments) on intercompany notes	—	332	(332)	—	—
Proceeds from issuance of senior notes	400	—	—	—	400
Net proceeds from the issuance of common units	296	—	—	—	296
Repayments of senior notes	(175)	—	—	—	(175)
Distributions paid to common unitholders and general partner	(682)	—	—	—	(682)
Distributions paid to noncontrolling interests	—	—	(10)	—	(10)
Other financing activities	(2)	3	(3)	—	(2)
Net cash provided by/(used in) financing activities	249	172	(85)	—	336
Effect of translation adjustment on cash	—	(1)	—	—	(1)
Net increase/(decrease) in cash and cash equivalents	(5)	17	(1)	—	11
Cash and cash equivalents, beginning of period	1	19	5	—	25
Cash and cash equivalents, end of period	$ (4)	$ 36	$ 4	$ —	$ 36

	Year Ended December 31, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 580	$ 814	$ 57	$ (871)	$ 580
Reconciliation of net income to net cash provided by/(used in) operating activities:					
Depreciation and amortization	4	200	32	—	236
Equity compensation expense	—	67	1	—	68
Equity earnings in unconsolidated entities, net of distributions	(818)	(61)	—	871	(8)
Other	—	(50)	—	—	(50)
Changes in assets and liabilities, net of acquisitions	(616)	155	—	—	(461)
Net cash provided by/(used in) operating activities	(850)	1,125	90	—	365
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions, net of cash acquired	—	(219)	—	—	(219)
Additions to property, equipment and other	—	(387)	(73)	—	(460)
Investment in unconsolidated entities	(4)	—	—	—	(4)
Cash received for sale of noncontrolling interest in a subsidiary	—	26	—	—	26
Net cash paid for linefill in assets owned	—	(9)	—	—	(9)
Proceeds from sales of assets and other	—	6	—	—	6
Net cash used in investing activities	(4)	(583)	(73)	—	(660)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net borrowings/(repayments) on revolving credit facility	95	(114)	—	—	(19)
Net borrowings on short-term letter of credit and hedged inventory facility	—	20	—	—	20
Repayment of PNGS debt	—	(446)	—	—	(446)
Net borrowings/(repayments) on intercompany notes	—	10	(10)	—	—
Proceeds from issuance of senior notes	1,346	—	—	—	1,346
Repayments of senior notes	(430)	—	—	—	(430)
Net proceeds from the issuance of common units	458	—	—	—	458
Distributions paid to common unitholders and general partner	(605)	—	—	—	(605)
Other financing activities	(11)	1	(2)	—	(12)
Net cash provided by/(used in) financing activities	853	(529)	(12)	—	312
Effect of translation adjustment on cash	—	(3)	—	—	(3)
Net increase/(decrease) in cash and cash equivalents	(1)	10	5	—	14
Cash and cash equivalents, beginning of period	2	9	—	—	11
Cash and cash equivalents, end of period	$ 1	$ 19	$ 5	$ —	$ 25

	Year Ended December 31, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 437	$ 620	$ 40	$ (660)	$ 437
Reconciliation of net income to net cash provided by/(used in) operating activities:					
Depreciation and amortization	3	187	21	—	211
Inventory valuation adjustment	—	168	—	—	168
Equity compensation expense	—	24	—	—	24
Gain on foreign currency revaluation	—	22	—	—	22
Equity earnings in unconsolidated entities, net of distributions	(622)	(42)	—	660	(4)
Deferred income tax benefit	—	(1)	—	—	(1)
Other	17	(15)	—	—	2
Changes in assets and liabilities, net of acquisitions	(375)	389	(16)	—	(2)
Net cash provided by/(used in) operating activities	(540)	1,352	45	—	857
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions, net of cash acquired	—	(709)	—	—	(709)
Additions to property, equipment and other	—	(544)	(45)	—	(589)
Investment in unconsolidated entities	(37)	—	—	—	(37)
Net cash paid for linefill in assets owned	—	(55)	—	—	(55)
Proceeds from sales of assets and other	—	51	—	—	51
Net cash used in investing activities	(37)	(1,257)	(45)	—	(1,339)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net borrowings on revolving credit facility	204	82	—	—	286
Net repayments on short-term letter of credit and hedged inventory facility	—	(196)	—	—	(196)
Proceeds from issuance of senior notes	597	—	—	—	597
Net proceeds from the issuance of common units	315	—	—	—	315
Distributions paid to common unitholders and general partner	(532)	—	—	—	(532)
Other financing activities	(6)	—	—	—	(6)
Net cash provided by/(used in) financing activities	578	(114)	—	—	464
Effect of translation adjustment on cash	—	5	—	—	5
Net increase/(decrease) in cash and cash equivalents	1	(14)	—	—	(13)
Cash and cash equivalents, beginning of period	1	23	—	—	24
Cash and cash equivalents, end of period	$ 2	$ 9	$ —	$ —	$ 11

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Note 14—Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total [1]
	(in millions, except per unit data)				
2010					
Revenues	$ 6,125	$ 6,124	$ 6,414	$ 7,231	$ 25,893
Gross margin [2]	$ 273	$ 248	$ 206	$ 300	$ 1,027
Operating income	$ 211	$ 192	$ 150	$ 213	$ 767
Net income	$ 151	$ 133	$ 84	$ 146	$ 514
Net income attributable to Plains	$ 151	$ 131	$ 81	$ 142	$ 505
Basic net income per limited partner unit	$ 0.80	$ 0.65	$ 0.28	$ 0.68	$ 2.41
Diluted net income per limited partner unit	$ 0.80	$ 0.65	$ 0.28	$ 0.67	$ 2.40
Cash distributions per common unit [3]	$ 0.9275	$ 0.9350	$ 0.9425	$ 0.9500	$ 3.76
2009					
Revenues	$ 3,302	$ 4,282	$ 4,857	$ 6,078	$ 18,520
Gross margin [2]	$ 302	$ 237	$ 218	$ 231	$ 990
Operating income	$ 256	$ 183	$ 166	$ 173	$ 779
Net income	$ 211	$ 136	$ 122	$ 110	$ 580
Net income attributable to Plains	$ 211	$ 136	$ 122	$ 110	$ 579
Basic net income per limited partner unit	$ 1.42	$ 0.79	$ 0.65	$ 0.53	$ 3.34
Diluted net income per limited partner unit	$ 1.41	$ 0.78	$ 0.65	$ 0.52	$ 3.32
Cash distributions per common unit [3]	$ 0.8925	$ 0.9050	$ 0.9050	$ 0.9200	$ 3.62

(1) The sum of the four quarters may not equal the total year due to rounding.

(2) Gross margin is calculated as Total revenues less (i) Purchases and related costs, (ii) Field operating costs and (iii) Depreciation and amortization.

(3) Represents cash distributions declared and paid in the applicable period.

Note 15—Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. See "*Revenue Recognition*" within Note 2 for a summary of the types of products and services from which each segment derives its revenues.

Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. We define segment profit as revenues and equity earnings in unconsolidated entities less (i) purchases and related costs, (ii) field operating costs and (iii) segment general and administrative ("G&A") expenses. Each of the items above excludes depreciation and amortization. As an MLP, we make quarterly distributions of our "available cash" (as defined in our partnership agreement) to our unitholders. We look at each period's earnings before non-cash depreciation and amortization as an important measure of segment performance. The exclusion of depreciation and amortization expense could be viewed as limiting the usefulness of segment profit as a performance measure because it does not account in current periods for the implied reduction in value of our capital assets, such as crude oil pipelines and facilities, caused by aging and wear and tear. We compensate for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance investments, which acts to partially offset the wear and tear and age-related decline in the value of our principal fixed assets. These maintenance investments are a component of field operating costs included in segment profit or in maintenance capital, depending on the nature of the cost. Maintenance capital, which is deducted in determining "available cash," consists of capital expenditures for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production and/or functionality of our existing assets. Capital expenditures made to expand the existing earnings capacity of our assets are considered expansion capital expenditures, not maintenance capital. Repair and maintenance expenditures incurred in order to maintain the day to day operation of our existing assets are charged to expense as incurred. The following table reflects certain financial data for each segment for the periods indicated (in millions):

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	Transportation	Facilities	Supply & Logistics	Total
Twelve Months Ended December 31, 2010				
Revenues:				
External Customers	$ 565	$ 339	$ 24,989	$ 25,893
Intersegment [1]	480	151	1	632
Total revenues of reportable segments	$ 1,045	$ 490	$ 24,990	$ 26,525
Equity earnings in unconsolidated entities	$ 3	$ —	$ —	$ 3
Segment profit [2] [3]	$ 516	$ 270	$ 240	$ 1,026
Capital expenditures	$ 329	$ 270	$ 163	$ 762
Total assets	$ 4,701	$ 3,303	$ 5,699	$ 13,703
Maintenance capital	$ 67	$ 17	$ 9	$ 93
Twelve Months Ended December 31, 2009				
Revenues:				
External Customers	$ 536	$ 227	$ 17,757	$ 18,520
Intersegment [1]	425	135	2	562
Total revenues of reportable segments	$ 961	$ 362	$ 17,759	$ 19,082
Equity earnings in unconsolidated entities	$ 7	$ 8	$ —	$ 15
Segment profit [2] [3]	$ 477	$ 208	$ 345	$ 1,030
Capital expenditures	$ 183	$ 564	$ 10	$ 757
Total assets	$ 4,468	$ 3,097	$ 4,793	$ 12,358
Maintenance capital	$ 57	$ 16	$ 8	$ 81
Twelve Months Ended December 31, 2008				
Revenues:				
External Customers	$ 556	$ 157	$ 29,348	$ 30,061
Intersegment [1]	371	113	2	486
Total revenues of reportable segments	$ 927	$ 270	$ 29,350	$ 30,547
Equity earnings in unconsolidated entities	$ 5	$ 9	$ —	$ 14
Segment profit [2] [3]	$ 445	$ 153	$ 221	$ 819
Capital expenditures	$ 935	$ 265	$ 26	$ 1,226
Total assets	$ 3,930	$ 2,048	$ 4,054	$ 10,032
Maintenance capital	$ 54	$ 23	$ 4	$ 81

(1) Segment revenues and purchases and related costs include intersegment amounts. Intersegment sales are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates.

(2) Supply and logistics segment profit includes interest expense (related to hedged inventory purchases) of $17 million, $11 million and $21 million for the years ended December 31, 2010, 2009 and 2008, respectively.

[3] The following table reconciles segment profit to net income attributable to Plains (in millions):

	Year Ended December 31,		
	2010	2009	2008
Segment profit	$ 1,026	$ 1,030	$ 819
Depreciation and amortization	(256)	(236)	(211)
Interest expense	(248)	(224)	(196)
Other income/(expense), net	(9)	16	33
Income tax benefit/(expense)	1	(6)	(8)
Net income	514	580	437
Less: Net income attributable to noncontrolling interests	(9)	(1)	—
Net income attributable to Plains	$ 505	$ 579	$ 437

Geographic Data

We have operations in the United States and Canada. Set forth below are revenues and long-lived assets attributable to these geographic areas (in millions):

	For the Year Ended December 31,		
Revenues [1]	2010	2009	2008
United States	$ 21,471	$ 15,439	$ 25,183
Canada	4,422	3,081	4,878
	$ 25,893	$ 18,520	$ 30,061

[1] Revenues are attributed to each region based on where the customers are located.

	As of December 31,	
Long-Lived Assets [1]	2010	2009
United States	$ 7,502	$ 6,945
Canada	1,800	1,678
	$ 9,302	$ 8,623

[1] Excludes long-term derivative assets.

EXHIBIT INDEX

3.1	—	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 27, 2001).
3.2	—	Amendment No. 1 dated April 15, 2004 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	—	Amendment No. 2 dated November 15, 2006 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed November 21, 2006).
3.4	—	Amendment No. 3 dated August 16, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 22, 2007).
3.5	—	Amendment No. 4 effective as of January 1, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed April 15, 2008).
3.6	—	Amendment No. 5 dated May 28, 2008 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed May 30, 2008).
3.7	—	Amendment No. 6 dated September 3, 2009 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed September 3, 2009).
3.8	—	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.9†	—	Amendment No. 1 dated December 31, 2010 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P.
3.10†	—	Amendment No. 2 dated January 1, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P.
3.11	—	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.12	—	Fifth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated December 23, 2010 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed December 30, 2010).
3.13	—	Sixth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated December 23, 2010 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed December 30, 2010).

3.14	—	Certificate of Incorporation of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.15	—	Bylaws of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.16	—	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K filed January 4, 2008).
4.1	—	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	—	First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.3	—	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003).
4.4	—	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168).
4.5	—	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).
4.6	—	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 12, 2006).
4.7	—	Seventh Supplemental Indenture dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed May 12, 2006).
4.8	—	Eighth Supplemental Indenture dated August 25, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed August 25, 2006).
4.9	—	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006).
4.10	—	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to

Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006).

4.11	—	Eleventh Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed November 21, 2006).
4.12	—	Twelfth Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.21 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.13	—	Thirteenth Supplemental Indenture (Series A and Series B 6.5% Senior Notes due 2018) dated April 23, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 23, 2008).
4.14	—	Fourteenth Supplemental Indenture dated July 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.15 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).
4.15	—	Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 20, 2009).
4.16	—	Sixteenth Supplemental Indenture (4.25% Senior Notes due 2012) dated July 23, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 23, 2009).
4.17	—	Seventeenth Supplemental Indenture (5.75% Senior Notes due 2020) dated September 4, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed September 4, 2009).
4.18	—	Eighteenth Supplemental Indenture (3.95% Senior Notes due 2015) dated July 14, 2010 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 13, 2010).
4.19	—	Nineteenth Supplemental Indenture (5.00% Senior Notes due 2021) dated January 14, 2011 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed January 11, 2011).
4.20	—	Registration Rights Agreement dated September 3, 2009 by and between Plains All American Pipeline, L.P. and Vulcan Gas Storage LLC (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-3, File No. 333-162477).
10.1	—	Second Amended and Restated Credit Agreement dated as of July 31, 2006 by and among Plains All American Pipeline, L.P., as US Borrower; PMC (Nova Scotia) Company and Plains Marketing Canada, L.P., as Canadian Borrowers; Bank of America, N.A., as Administrative Agent; Bank of America, N.A., acting through its Canada Branch, as Canadian Administrative Agent; Wachovia Bank, National Association and J. P. Morgan Chase Bank, N.A., as Co-Syndication Agents; Fortis Capital Corp., Citibank, N.A., BNP Paribas, UBS Securities LLC, SunTrust Bank, and The Bank of Nova Scotia, as Co-Documentation Agents; the Lenders party thereto; and Banc of America Securities LLC

		and Wachovia Capital Markets, LLC, as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 4, 2006).
10.2	—	Amended and Restated Crude Oil Marketing Agreement dated as of July 23, 2004, among Plains Resources Inc., Calumet Florida Inc. and Plains Marketing, L.P. (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
10.3	—	Amended and Restated Omnibus Agreement dated as of July 23, 2004, among Plains Resources Inc., Plains All American Pipeline, L.P., Plains Marketing, L.P., Plains Pipeline, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
10.4	—	Contribution, Assignment and Amendment Agreement dated as of June 27, 2001, among Plains All American Pipeline, L.P., Plains Marketing, L.P., All American Pipeline, L.P., Plains AAP, L.P., Plains All American GP LLC and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 27, 2001).
10.5	—	Contribution, Assignment and Amendment Agreement dated as of June 8, 2001, among Plains All American Inc., Plains AAP, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 11, 2001).
10.6	—	Separation Agreement dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc., Plains All American GP LLC, Plains AAP, L.P. and Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed June 11, 2001).
10.7**	—	Pension and Employee Benefits Assumption and Transition Agreement dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed June 11, 2001).
10.8**	—	Plains All American GP LLC 2005 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 26, 2005).
10.9**	—	Plains All American GP LLC 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to Registration Statement on Form S-8, File No. 333-74920) as amended June 27, 2003 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003).
10.10**	—	Plains All American 2001 Performance Option Plan (incorporated by reference to Exhibit 99.2 to the Registration Statement on Form S-8 filed December 11, 2001, File No. 333-74920).
10.11**	—	Amended and Restated Employment Agreement between Plains All American GP LLC and Greg L. Armstrong dated as of June 30, 2001 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.12**	—	Amended and Restated Employment Agreement between Plains All American GP LLC and Harry N. Pefanis dated as of June 30, 2001 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.13	—	Asset Purchase and Sale Agreement dated February 28, 2001 between Murphy Oil Company Ltd. and Plains Marketing Canada, L.P. (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed May 10, 2001).
10.14	—	Transportation Agreement dated July 30, 1993, between All American Pipeline Company and Exxon Company, U.S.A. (incorporated by reference to Exhibit 10.9 to the Registration Statement on Form S-1 filed September 23, 1998, File No. 333-64107).
10.15	—	Transportation Agreement dated August 2, 1993, among All American Pipeline Company, Texaco Trading and Transportation Inc., Chevron U.S.A. and Sun Operating Limited Partnership (incorporated by reference to Exhibit 10.10 to the Registration Statement on Form S-1 filed September 23, 1998, File

No. 333-64107).

10.16	—	First Amendment to Contribution, Conveyance and Assumption Agreement dated as of December 15, 1998 (incorporated by reference to Exhibit 10.13 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.17	—	Agreement for Purchase and Sale of Membership Interest in Scurlock Permian LLC between Marathon Ashland LLC and Plains Marketing, L.P. dated as of March 17, 1999 (incorporated by reference to Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.18**	—	Plains All American Inc. 1998 Management Incentive Plan (incorporated by reference to Exhibit 10.5 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.19**	—	PMC (Nova Scotia) Company Bonus Program (incorporated by reference to Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2004).
10.20**	—	Quarterly Bonus Program Summary (incorporated by reference to Exhibit 10.21 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.21**†	—	Directors' Compensation Summary.
10.22	—	Master Railcar Leasing Agreement dated as of May 25, 1998 (effective June 1, 1998), between Pivotal Enterprises Corporation and CANPET Energy Group, Inc., (incorporated by reference to Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 2001).
10.23**	—	Form of LTIP Grant Letter (Armstrong/Pefanis) (incorporated by reference to Exhibit 10.24 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.24**	—	Form of LTIP Grant Letter (executive officers) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed April 1, 2005).
10.25**	—	Form of LTIP Grant Letter (independent directors) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed February 23, 2005).
10.26**	—	Form of LTIP Grant Letter (designated directors) (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed February 23, 2005).
10.27**	—	Form of LTIP Grant Letter (payment to entity) (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K filed February 23, 2005).
10.28**	—	Form of Performance Option Grant Letter (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed April 1, 2005).
10.29	—	Administrative Services Agreement between Plains All American GP LLC and Vulcan Energy Corporation dated October 14, 2005 (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed October 19, 2005).
10.30	—	Membership Interest Purchase Agreement by and between Sempra Energy Trading Corp. and PAA/Vulcan Gas Storage, LLC dated August 19, 2005 (incorporated by reference to Exhibit 1.2 to the Current Report on Form 8-K filed September 19, 2005).
10.31**†	—	Waiver Agreement dated as of December 23, 2010 between Plains All American GP LLC and Greg L. Armstrong.
10.32**†	—	Waiver Agreement dated as of December 23, 2010 between Plains All American GP LLC and Harry N. Pefanis.

10.33	—	Excess Voting Rights Agreement dated as of August 12, 2005 between Vulcan Energy GP Holdings Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed August 16, 2005).
10.34	—	Excess Voting Rights Agreement dated as of August 12, 2005 between Lynx Holdings I, LLC and Plains All American GP LLC (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed August 16, 2005).
10.35**	—	Form of LTIP Grant Letter (executive officers) (incorporated by reference to Exhibit 10.39 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.36**	—	Employment Agreement between Plains All American GP LLC and John P. vonBerg dated December 18, 2001 (incorporated by reference to Exhibit 10.40 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.37**	—	Form of LTIP Grant Letter (audit committee members) (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 23, 2006).
10.38**	—	Plains All American PPX Successor Long-Term Incentive Plan (incorporated by reference to Exhibit 10.45 to the Annual Report on Form 10-K for the year ended December 31, 2006).
10.39**	—	Forms of LTIP Grant Letters dated February 22, 2007 (Named Executive Officers) (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2007).
10.40	—	First Amendment dated July 31, 2007 to the Second Amended and Restated Credit Agreement [US/Canada Facilities] by and between Plains All American Pipeline, L.P., PMC (Nova Scotia) Company, Plains Marketing Canada, L.P., Rangeland Pipeline Company, Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 6, 2007).
10.41**	—	Separation and Release Agreement dated August 21, 2007 between Plains All American GP LLC and George R. Coiner (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2007).
10.42**	—	Form of Plains AAP, L.P. Class B Restricted Units Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 4, 2008).
10.43	—	Second Restated Credit Agreement dated as of November 6, 2008 by among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party there to (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed November 7, 2008).
10.44	—	Second Amendment to Second Restated Credit Agreement dated as of October 25, 2010, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed October 28, 2010).
10.45	—	Restated Guaranty Agreement dated November 6, 2008 by Plains All American Pipeline, L.P. in favor of Bank of America, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed November 7, 2008).
10.46	—	Contribution and Assumption Agreement dated December 28, 2007, by and between Plains AAP, L.P. and PAA GP LLC (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed January 4, 2008).
10.47	—	Assumption, Ratification and Confirmation Agreement dated January 1, 2008 by Plains Midstream Canada ULC in favor of the Lenders party to the Second Amended and Restated Credit Agreement [US/Canada Facilities], as amended (incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K for the year ended December 31, 2007).
10.48†	—	Assumption, Ratification and Confirmation Agreement dated January 1, 2011 by Plains Midstream

		Canada ULC in favor of the Lenders party to the Second Amended and Restated Credit Agreement [US/Canada Facilities], as amended.
10.49**	—	First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Greg L. Armstrong (incorporated by reference to Exhibit 10.49 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.50**	—	First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Harry N. Pefanis (incorporated by reference to Exhibit 10.50 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.51**	—	First Amendment to Plains All American GP LLC 2005 Long-Term Incentive Plan dated December 4, 2008 (incorporated by reference to Exhibit 10.51 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.52**	—	Second Amendment to Plains All American GP LLC 1998 Long-Term Incentive Plan dated December 4, 2008 (incorporated by reference to Exhibit 10.52 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.53**	—	Form of Amendment to LTIP grant letters (executive officers) (incorporated by reference to Exhibit 10.53 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.54**	—	Form of Amendment to LTIP grant letters (directors) (incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.55	—	Contribution Agreement dated as of April 29, 2010 by and among PAA Natural Gas Storage, L.P., PNGS GP LLC, Plains All American Pipeline, L.P., PAA Natural Gas Storage, LLC, PAA/Vulcan Gas Storage, LLC, Plains Marketing, L.P. and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to PNG's Current Report on Form 8-K filed May 4, 2010).
10.56	—	Omnibus Agreement dated May 5, 2010 by and among Plains All American GP LLC, Plains All American Pipeline, L.P., PNGS GP LLC and PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 10.1 to PNG's Current Report on Form 8-K filed May 11, 2010).
10.57**	—	Form of Transaction Grant Agreement (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2010).
10.58**†	—	Form of 2010 LTIP Grant Letters.
10.59**†	—	Employment Agreement between Plains All American GP LLC and John R. Rutherford dated September 27, 2010.
10.60	—	364-Day Credit Agreement dated January 3, 2011 among Plains All American Pipeline, L.P., as Borrower; Bank of America, N.A., as Administrative Agent; DnB NOR Bank ASA and JPMorgan Chase Bank NA, as Co-Syndication Agents; SunTrust Bank and Wells Fargo Bank, National Association, as Co-Documentation Agents; the Lenders party thereto; and Merrill Lynch, Pierce, Fenner & Smith Incorporated, DnB NOR Markets, Inc. and J.P. Morgan Securities LLC, as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 7, 2011).
12.1†	—	Computation of Ratio of Earnings to Fixed Charges
21.1†	—	List of Subsidiaries of Plains All American Pipeline, L.P.
23.1†	—	Consent of PricewaterhouseCoopers LLP.
31.1†	—	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2†	—	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1†	—	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350

32.2†	—	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350
101†	—	The following financial information from the annual report on Form 10-K of Plains All American Pipeline, L.P. for the year ended December 31, 2010, formatted in XBRL (extensible Business Reporting Language): (i) Consolidated Statements of Operations, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) Consolidated Statements of Changes in Partners' Capital, (v) Consolidated Statements of Comprehensive Income, (vi) Consolidated Statements of Changes in Accumulated Other Comprehensive Income and (vii) Notes to the Consolidated Financial Statements.

† Filed herewith

** Management compensatory plan or arrangement

EXHIBIT 3.9

AMENDMENT NO. 1
TO THE THIRD AMENDED AND RESTATED
AGREEMENT OF LIMITED PARTNERSHIP
OF
PLAINS MARKETING, L.P.

This Amendment No. 1 (this "Amendment") to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P., dated as of April 1, 2004 (and as amended to the date hereof, the "Partnership Agreement"), is hereby adopted effective as of December 31, 2010, by Plains Marketing GP Inc., a Delaware corporation (the "General Partner"), as general partner of the Partnership. Capitalized terms used but not defined herein are used as defined in the Partnership Agreement.

WHEREAS, Section 13.1(d)(i) of the Partnership Agreement provides that the General Partner, without the approval of any Partner, may amend any provision of the Partnership Agreement to reflect a change that, in the discretion of the General Partner, does not adversely affect the Limited Partners in any material respect; and

WHEREAS, the General Partner has determined, in its discretion, that this Amendment does not adversely affect the Limited Partners in any material respect;

NOW, THEREFORE, the General Partner does hereby amend the Partnership Agreement as follows:

Section 1. Section 4.3 is hereby amended to read in full as follows:

> A limited partner may transfer (i) all, but not less than all, of its Partnership Interest as a limited partner in connection with the merger, consolidation or other combination of such limited partner with or into any other Person or the transfer by such limited partner of all or substantially all of its assets to another Person or (ii) all or a portion of its Partnership Interest as a limited partner to one or more Affiliates, and following any such transfer such Person or Affiliate may become a Substituted Limited Partner pursuant to Article X. Except as set forth in the immediately preceding sentence and in Section 5.2, or in connection with any pledge of (or any related foreclosure on) a Partnership Interest as a limited partner solely for the purpose of securing, directly or indirectly, indebtedness of the Partnership or the MLP, and except for the transfers contemplated by Sections 5.2 and 10.1, a limited partner may not transfer all or any part of its Partnership Interest or withdraw from the Partnership.

Section 2. Except as hereby amended, the Partnership Agreement shall remain in full force and effect.

Section 3. This Amendment shall be governed by, and interpreted in accordance with, the laws of the State of Texas, all rights and remedies being governed by such laws without regard to principles of conflicts of laws.

IN WITNESS WHEREOF, this Amendment has been executed as of the date first written above.

GENERAL PARTNER:

PLAINS MARKETING GP INC.

By: /s/ Tim Moore
Name: Tim Moore
Title: Vice President

EXHIBIT 3.10

AMENDMENT NO. 2
TO THE THIRD AMENDED AND RESTATED
AGREEMENT OF LIMITED PARTNERSHIP
OF
PLAINS MARKETING, L.P.

This Amendment No. 2 (this “Amendment”) to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P., a Texas limited partnership (the “Partnership”), is hereby adopted effective as of January 1, 2011, by Plains Marketing GP Inc., a Delaware corporation (the “General Partner”) and PAA Midstream LLC, a Delaware limited liability company (the “Limited Partner” and, together with the General Partner, collectively referred to as the “Partners”). Capitalized terms used but not defined herein shall have their respective meanings as set forth in the Partnership Agreement (defined below).

WHEREAS, the General Partner and Plains All American Pipeline, L.P., a Delaware limited partnership (the “Predecessor Limited Partner”) were parties to that certain Third Amended and Restated Agreement of Limited Partnership dated April 1, 2004, as amended on December 31, 2010 (as amended, the “Partnership Agreement”); and

WHEREAS, on the date hereof, the Predecessor Limited Partner contributed its limited partnership interest in the Partnership to the Limited Partner; and

WHEREAS, the Partners desire to amend the Partnership Agreement to reflect the admission of the Limited Partner as a Substituted Limited Partner.

NOW THEREFORE, the Partners do hereby amend the Partnership Agreement as follows:

1. *Amendment*. The Partnership Agreement is hereby amended to reflect the admission of PAA Midstream LLC as a Substituted Limited Partner.

2. *Ratification of Partnership Agreement*. Except as expressly amended herein, the terms, covenants and conditions of the Partnership Agreement, as amended by this Amendment, shall remain in full force and effect, and the undersigned hereby ratify the same in its entirety.

3. *Governing Law*. This Amendment No. 2 will be governed by and construed in accordance with the laws of the State of Texas.

IN WITNESS WHEREOF, the Partners have executed this Amendment as of the date first stated above.

GENERAL PARTNER:

PLAINS MARKETING GP INC.

By: /s/ Tim Moore
Name: Tim Moore
Title: Vice President

LIMITED PARTNER:

PAA MIDSTREAM LLC

By: /s/ Tim Moore
Name: Tim Moore
Title: Vice President

Exhibit 10.21

Directors' Compensation Summary

Each director of Plains All American GP LLC who is not an employee of Plains All American GP LLC is reimbursed for any travel, lodging and other out-of-pocket expenses related to meeting attendance or otherwise related to service on the board (including, without limitation, reimbursement for continuing education expenses). Each non-employee director is currently paid an annual retainer fee of $45,000. Mr. Armstrong is otherwise compensated for his services as an employee and therefore receives no separate compensation for his services as a director. In addition to the annual retainer, each committee chairman (other than the chairman of the audit committee) receives $2,000 annually. The chairman of the audit committee receives $30,000 annually, and the other members of the audit committee receive $15,000 annually, in each case, in addition to the annual retainer. During 2010, Messrs. Sinnott, Goyanes and Smith served as chairmen of the compensation, audit and governance committees, respectively.

Our non-employee directors receive LTIP awards or cash equivalent awards as part of their compensation. The LTIP awards vest annually in 25% increments over a four-year period and have an automatic re-grant feature such that as they vest, an equivalent amount is granted. The awards have associated distribution equivalent rights that are payable quarterly. The three non-employee directors who serve on the audit committee each have outstanding a grant of 10,000 units (vesting 2,500 units per year). Messrs. Petersen, Raymond and Sinnott each have outstanding a grant of 5,000 units (vesting 1,250 units per year). Upon vesting of the director LTIPs (other than the incremental audit committee awards), a cash payment will be made to Oxy as directed by the Oxy designee. Such cash payment is based on the unit value of Mr. Sinnott's award on the previous year's vesting date.

All LTIP awards held by a director vest in full upon the next following distribution date after the death or disability (as determined in good faith by the board) of the director. For audit committee grants, the awards also vest in full if such director (i) retires (no longer with full-time employment and no longer serving as an officer or director of any public company) or (ii) is removed from the board of directors or is not reelected to the board of directors, unless such removal or failure to reelect is for "good cause," as defined in the letter granting the units.

EXHIBIT 10.31

WAIVER AGREEMENT

WAIVER AGREEMENT (this "Waiver Agreement"), dated as of December 23, 2010, with respect to the AMENDED AND RESTATED EMPLOYMENT AGREEMENT (the "Agreement"), dated as of June 30, 2001, between Plains All American GP LLC, a Delaware limited liability company (the "Company"), and Greg L. Armstrong (the "Employee").

RECITALS:

A. Capitalized terms not otherwise defined in this Waiver Agreement are used with the meanings ascribed to such terms in the Agreement or, if not defined in the Agreement, with the meanings ascribed in the Fifth Amended and Restated Limited Liability Company Agreement of the Company (the "LLC Agreement").

B. Section 8(d)(ii) of the Agreement provides that if the Employee shall terminate his employment upon a Change in Control of the Company pursuant to clause (D) of Section 7(d)(i), then the Employee will be paid a lump sum amount.

C. A transaction was consummated in August 2005 pursuant to which the membership interest in the Company then owned by Sable Investments, L.P. was sold to the other owners of membership interests in the Company. Vulcan Energy Corporation, through a subsidiary thereof (together, "Vulcan Energy") purchased a portion of the membership interests being sold (the "Vulcan Purchase"), resulting in the ownership by Vulcan Energy of a Percentage Interest in excess of 50% of the total Membership Interests in the Company.

D. The Company and the Employee acknowledged, pursuant to a Waiver Agreement, dated as of August 12, 2005, between the Company and Vulcan Energy, that the Vulcan Purchase constituted a Change in Control of the Company and Employee executed a waiver of rights (the "Initial Waiver") otherwise resulting from such Change in Control, contingent on Vulcan Energy's continuing compliance under an ancillary Excess Voting Rights Agreement ("EVRA"), dated as of August 12, 2005, between the Company and Vulcan Energy;

E. The Initial Waiver lapses under certain circumstances, including a subsequent Change in Control or the termination of the EVRA by Vulcan Energy.

F. A transaction is contemplated pursuant to which Vulcan Energy will sell all or substantially all of its Membership Interest in the Company to new and existing owners (the "Vulcan Sale") and, in conjunction therewith, terminate the EVRA.

G. The Company and the Employee wish to clarify and agree with respect to the effect of the Vulcan Sale under the Agreement.

WAIVER

In that regard, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Company and the Employee hereby agree as follows:

1. Acknowledgement of Change in Control. The Company and the Employee both acknowledge that the proposed Vulcan Sale would terminate the EVRA, terminate the Initial Waiver and constitute a Change in Control as defined in Section 7(d) of the Agreement, and that without this Waiver Agreement, Employee would have the power under the Initial Waiver and Section 7(d) of the Agreement to terminate his employment (the "Termination Power") and, having done so, would have the right to the lump sum payment contemplated by Section 8(d)(ii) of the Agreement (the "Payment Right") and, upon such termination without Cause or for Good Reason, the Employee shall immediately vest in any and all unvested long-term incentive arrangements outstanding under the 1998 Long-Term Incentive Plan or the 2005 Long-Term Incentive Plan.

2. Waiver. Subject to the terms and conditions contained herein, the Employee waives his Termination Power and Payment Right (the "Waiver"), in each case only with respect to (i) the Vulcan Sale and (ii) the termination of the EVRA. The Waiver shall not apply to any future purchases or sales of membership interests in the Company or changes in affiliate status among Members.

3. Allocation of Membership Interests. The Waiver is contingent upon and will be effective upon the execution by the Members, Vulcan Energy, Plains AAP, L.P. and the purchasers in the Vulcan Sale of the Transaction Agreement (as defined in the LLC Agreement).

4. Termination of Waiver. The Waiver will terminate, and a Change in Control will be deemed to have occurred coincident with, (a) any termination of the EVRA coupled with a failure to consummate the transactions contemplated by the Transaction Agreement, (b) any occurrence that causes an allocation of Membership Interests in the Company that, as of the consummation of the Vulcan Sale, differs substantially from that contemplated by the Transaction Agreement, or (c) any event that would otherwise constitute a Change in Control. In addition, notwithstanding anything contained herein to the contrary, if the Employee is terminated for any reason other than for Cause within two years of the execution of this Waiver Agreement, the Waiver will be deemed to have terminated on the date immediately preceding such termination or notice of such termination, a Change in Control will be deemed to have occurred as of such date and the Employee will be paid the lump sum payment contemplated by Section 8(d)(ii) of the Agreement as if the Employee had terminated his employment for Good Reason following a Change in Control. In addition, upon such termination without Cause or for Good Reason, the Employee shall immediately vest in any and all unvested long-term incentive arrangements outstanding under the 1998 Long-Term Incentive Plan or the 2005 Long-Term Incentive Plan.

5. Limited Waiver. The Waiver is limited to the effects of the Vulcan Sale, and does not waive any other provisions of the Agreement nor the effects of any past, present or future transaction or event constituting a Change in Control (or any other Good Reason), including without limitation any other direct or indirect purchase or sale of any portion of the Membership Interest in the Company or changes in Affiliate status among Members.

6. No other Changes to Agreement. Other than the Waiver as described herein, the Agreement remains in full force and effect.

7. Notice. For the purpose of this Waiver Agreement, notices and all other communications provided for in this Waiver Agreement must be in writing and will be deemed to have been duly given when delivered or mailed by United States registered mail, return receipt requested, postage prepaid, addressed to the parties at their addresses set forth below, or to such other addresses as either party may have furnished to the other in writing in accordance herewith except that notices of change of address will be effective only upon receipt.

If to the Company:

Plains All American GP LLC
333 Clay Street
Houston, Texas 77002
Attention: Secretary

If to the Employee:

Greg L. Armstrong
322 Tynebrook
Houston, TX 77024

8. Miscellaneous. No provisions of this Waiver Agreement may be modified, waived or discharged unless such waiver, modification or discharge is agreed to in writing. No waiver by either party hereto at any time of any breach by the other party hereto of, or compliance with, any condition or provision of this Agreement to be performed by such other party shall be deemed a waiver of similar or dissimilar provisions or conditions at the same or at any prior or subsequent time. The validity, interpretation, construction and performance of this Waiver Agreement shall be governed by the laws of the State of Texas.

9. Entire Agreement. This Waiver Agreement contains the entire understanding of the parties in respect of its subject matter and supersedes all prior oral and written agreements and understandings between the parties with respect to such subject matter.

IN WITNESS WHEREOF, the parties have executed this Waiver Agreement as of the date first above written.

PLAINS ALL AMERICAN GP LLC

By: /s/ Tim Moore
Tim Moore
Title: Vice President

GREG L. ARMSTRONG

/s/ Greg L. Armstrong
Employee

EXHIBIT 10.32

WAIVER AGREEMENT

WAIVER AGREEMENT (this "Waiver Agreement"), dated as of December 23, 2010, with respect to the AMENDED AND RESTATED EMPLOYMENT AGREEMENT (the "Agreement"), dated as of June 30, 2001, between Plains All American GP LLC, a Delaware limited liability company (the "Company"), and Harry N. Pefanis (the "Employee").

RECITALS:

A. Capitalized terms not otherwise defined in this Waiver Agreement are used with the meanings ascribed to such terms in the Agreement or, if not defined in the Agreement, with the meanings ascribed in the Fifth Amended and Restated Limited Liability Company Agreement of the Company (the "LLC Agreement").

B. Section 8(d)(ii) of the Agreement provides that if the Employee shall terminate his employment upon a Change in Control of the Company pursuant to clause (D) of Section 7(d)(i), then the Employee will be paid a lump sum amount.

C. A transaction was consummated in August 2005 pursuant to which the membership interest in the Company then owned by Sable Investments, L.P. was sold to the other owners of membership interests in the Company. Vulcan Energy Corporation, through a subsidiary thereof (together, "Vulcan Energy") purchased a portion of the membership interests being sold (the "Vulcan Purchase"), resulting in the ownership by Vulcan Energy of a Percentage Interest in excess of 50% of the total Membership Interests in the Company.

D. The Company and the Employee acknowledged, pursuant to a Waiver Agreement, dated as of August 12, 2005, between the Company and Vulcan Energy, that the Vulcan Purchase constituted a Change in Control of the Company and Employee executed a waiver of rights (the "Initial Waiver") otherwise resulting from such Change in Control, contingent on Vulcan Energy's continuing compliance under an ancillary Excess Voting Rights Agreement ("EVRA"), dated as of August 12, 2005, between the Company and Vulcan Energy;

E. The Initial Waiver lapses under certain circumstances, including a subsequent Change in Control or the termination of the EVRA by Vulcan Energy.

F. A transaction is contemplated pursuant to which Vulcan Energy will sell all or substantially all of its Membership Interest in the Company to new and existing owners (the "Vulcan Sale") and, in conjunction therewith, terminate the EVRA.

G. The Company and the Employee wish to clarify and agree with respect to the effect of the Vulcan Sale under the Agreement.

WAIVER

In that regard, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Company and the Employee hereby agree as follows:

1. Acknowledgement of Change in Control. The Company and the Employee both acknowledge that the proposed Vulcan Sale would terminate the EVRA, terminate the Initial Waiver and constitute a Change in Control as defined in Section 7(d) of the Agreement, and that without this Waiver Agreement, Employee would have the power under the Initial Waiver and Section 7(d) of the Agreement to terminate his employment (the "Termination Power") and, having done so, would have the right to the lump sum payment contemplated by Section 8(d)(ii) of the Agreement (the "Payment Right") and, upon such termination without Cause or for Good Reason, the Employee shall immediately vest in any and all unvested long-term incentive arrangements outstanding under the 1998 Long-Term Incentive Plan or the 2005 Long-Term Incentive Plan.

2. Waiver. Subject to the terms and conditions contained herein, the Employee waives his Termination Power and Payment Right (the "Waiver"), in each case only with respect to (i) the Vulcan Sale and (ii) the termination of the EVRA. The Waiver shall not apply to any future purchases or sales of membership interests in the Company or changes in affiliate status among Members.

3. Allocation of Membership Interests. The Waiver is contingent upon and will be effective upon the execution by the Members, Vulcan Energy, Plains AAP, L.P. and the purchasers in the Vulcan Sale of the Transaction Agreement (as defined in the LLC Agreement).

4. Termination of Waiver. The Waiver will terminate, and a Change in Control will be deemed to have occurred coincident with, (a) any termination of the EVRA coupled with a failure to consummate the transactions contemplated by the Transaction Agreement, (b) any occurrence that causes an allocation of Membership Interests in the Company that, as of the consummation of the Vulcan Sale, differs substantially from that contemplated by the Transaction Agreement, or (c) any event that would otherwise constitute a Change in Control. In addition, notwithstanding anything contained herein to the contrary, if the Employee is terminated for any reason other than for Cause within two years of the execution of this Waiver Agreement, the Waiver will be deemed to have terminated on the date immediately preceding such termination or notice of such termination, a Change in Control will be deemed to have occurred as of such date and the Employee will be paid the lump sum payment contemplated by Section 8(d)(ii) of the Agreement as if the Employee had terminated his employment for Good Reason following a Change in Control. In addition, upon such termination without Cause or for Good Reason, the Employee shall immediately vest in any and all unvested long-term incentive arrangements outstanding under the 1998 Long-Term Incentive Plan or the 2005 Long-Term Incentive Plan.

5. Limited Waiver. The Waiver is limited to the effects of the Vulcan Sale, and does not waive any other provisions of the Agreement nor the effects of any past, present or future transaction or event constituting a Change in Control (or any other Good Reason), including without limitation any other direct or indirect purchase or sale of any portion of the Membership Interest in the Company or changes in Affiliate status among Members.

6. No other Changes to Agreement. Other than the Waiver as described herein, the Agreement remains in full force and effect.

7. Notice. For the purpose of this Waiver Agreement, notices and all other communications provided for in this Waiver Agreement must be in writing and will be deemed to have been duly given when delivered or mailed by United States registered mail, return receipt requested, postage prepaid, addressed to the parties at their addresses set forth below, or to such other addresses as either party may have furnished to the other in writing in accordance herewith except that notices of change of address will be effective only upon receipt.

If to the Company:

Plains All American GP LLC
333 Clay Street
Houston, Texas 77002
Attention: Secretary

If to the Employee:

Harry N. Pefanis
P.O. Box 4648
Houston, Texas 77210

8. Miscellaneous. No provisions of this Waiver Agreement may be modified, waived or discharged unless such waiver, modification or discharge is agreed to in writing. No waiver by either party hereto at any time of any breach by the other party hereto of, or compliance with, any condition or provision of this Agreement to be performed by such other party shall be deemed a waiver of similar or dissimilar provisions or conditions at the same or at any prior or subsequent time. The validity, interpretation, construction and performance of this Waiver Agreement shall be governed by the laws of the State of Texas.

9. Entire Agreement. This Waiver Agreement contains the entire understanding of the parties in respect of its subject matter and supersedes all prior oral and written agreements and understandings between the parties with respect to such subject matter.

IN WITNESS WHEREOF, the parties have executed this Waiver Agreement as of the date first above written.

PLAINS ALL AMERICAN GP LLC

By: /s/ Tim Moore
Tim Moore
Title: Vice President

HARRY N. PEFANIS

/s/ Harry N. Pefanis
Employee

Exhibit 10.48

ASSUMPTION, RATIFICATION AND CONFIRMATION AGREEMENT

THIS ASSUMPTION, RATIFICATION AND CONFIRMATION AGREEMENT, dated as of January 1, 2011 (this "Agreement") is by PLAINS MIDSTREAM CANADA ULC, an Alberta unlimited liability company ("PMCULC Amalco"), in favor of the Lender Parties under that certain Second Amended and Restated Credit Agreement [US/Canada Facilities] dated as of July 31, 2006 (as amended by that certain First Amendment to Second Amended and Restated Credit Agreement [US/Canada Facilities] dated as of July 31, 2007, and from time to time amended, the "Credit Agreement"), by and among Plains All American Pipeline, L.P., as US Borrower, PMC (Nova Scotia) Company ("PMCNS"), Plains Marketing Canada, L.P. ("PMCLP") and Plains Midstream Canada ULC ("PMCULC"), as Canadian Borrowers, Bank of America, N.A., as Administrative Agent, Bank of America, N.A., acting through its Canada Branch, as Canadian Administrative Agent, and the Lenders a party thereto. Terms used and not defined herein shall have the meanings given them in the Credit Agreement.

W I T N E S S E T H

WHEREAS, effective as of the date hereof:

(i) PMCULC and certain Subsidiaries of US Borrower have amalgamated under the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9 ("ABCA") and are continuing as PMCULC Amalco (the "Amalgamation"), and by operation of applicable Law and pursuant to the Amalgamation, PMCULC Amalco continues to be liable for all of PMCULC's Obligations and succeeds to all of PMCULC's rights, including as a Canadian Borrower; and

(ii) PMCLP, pursuant to the assignment and transfer by Plains Marketing of its limited partner interest in PMCLP to PMCULC Amalco, ceased to exist as a limited partnership by operation of applicable Law under the *Partnership Act* (Alberta) and continued to exist as a general partnership, and thereafter, pursuant to the assignment and transfer by PMCNS of its general partner interest in PMCLP to PMCULC Amalco, ceased to exist (the "PMCLP Cessation"), and pursuant to the PMCLP Cessation and by operation of applicable Law, PMCULC Amalco is liable for all of PMCLP's Obligations and succeeds to all of PMCLP's rights, including as a Canadian Borrower; and

WHEREAS, the Amalgamation and the PMCLP Cessation took place pursuant to a succession of substantially concurrent transactions completed effective as of January 1, 2011 (the "Canadian Restructuring"); and

WHEREAS, immediately prior to the Canadian Restructuring, each of PMCULC and PMCLP was a Canadian Borrower, and upon completion of the Canadian Restructuring (i) the Obligations of PMCULC and PMCLP as Canadian Borrowers continued as Obligations of PMCULC Amalco and (ii) PMCULC Amalco succeeded to PMCULC's and PMCLP's rights as Canadian Borrowers, in each case by operation of applicable Law; and

WHEREAS, Lender Parties (i) consented to, and waived compliance with Section 7.3 of the Credit Agreement in relation to, among other specified events, the Amalgamation and the PMCLP Cessation, (ii) acknowledged and agreed that pursuant to the Amalgamation and the

PMCLP Cessation, PMCULC Amalco, by operation of applicable Law, succeeded to PMCULC's and PMCLP's rights as a Canadian Borrower, with all references to PMCULC or PMCLP in any and all Loan Documents thereafter referring, *mutatis mutandis*, instead to PMCULC Amalco, and (iii) waived any Default or Event of Default caused thereby pursuant to, and subject to the terms and conditions set forth in, that certain Limited Consent and Waiver dated October 22, 2010 (the "Limited Consent"); and

WHEREAS, it is a condition to the Limited Consent that contemporaneous with the completion of the Canadian Restructuring, Administrative Agent shall receive an assumption, ratification and confirmation by PMCULC Amalco expressly assuming, ratifying and confirming any and all Obligations of PMCULC and PMCLP under any and all Loan Documents, consented to by Guarantors.

NOW, THEREFORE, in consideration of the premises and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, PMCULC Amalco hereby agrees with Lender Parties as follows:

ARTICLE I. ASSUMPTION, RATIFICATION AND CONFIRMATION

Section 1.1. Assumption, Ratification and Confirmation. PMCULC Amalco hereby unconditionally assumes, and shall hereafter pay, perform and discharge, all Obligations of PMCULC and PMCLP under the Credit Agreement and the other Loan Documents, including any and all Obligations of PMCULC and/or PMCLP in its capacity as a Canadian Borrower under the Credit Agreement. PMCULC Amalco hereby ratifies and confirms each such Obligation and confirms that (i) any and all such Obligations constitute the legal, valid and binding obligations of PMCULC Amalco, enforceable in accordance with their terms except as such enforcement may be limited by bankruptcy, insolvency or similar Laws of general application relating to the enforcement of creditors' rights and general principles of equity, and (ii) all rights of Lender Parties under the Loan Documents are preserved unimpaired by the Canadian Restructuring, and all Obligations of PMCULC and/or PMCLP under the Loan Documents are the Obligations of PMCULC Amalco and may be enforced against PMCULC Amalco to the same extent as if said Obligations had been incurred or contracted by PMCULC Amalco.

Section 1.2. PMCULC and PMCLP References. As consented to by Lender Parties pursuant to the Limited Consent, PMCULC Amalco, US Borrower, the other Canadian Borrower, Administrative Agent and Canadian Agent hereby acknowledge and agree that any and all references to "PMCULC" or "PMCLP" in any and all Loan Documents shall hereafter refer, *mutatis mutandis*, instead to PMCULC Amalco.

ARTICLE II. REPRESENTATIONS AND WARRANTIES

Section 2.1. Representations and Warranties of Borrowers. In order to induce Administrative Agent and Lender Parties to accept this Agreement, US Borrower, with respect to itself and its Subsidiaries, and the Canadian Borrowers, represent and warrant to Administrative Agent and each Lender Party that:

(a) The representations and warranties contained in Article V of the Credit Agreement are true and correct at and as of the time of the effectiveness hereof, except to

the extent that such representation and warranty was made as of a specific date or updated, modified or supplemented as of a subsequent date with the consent of Majority Lenders, then in each case such other date. No Default or Event of Default exists as of the date hereof and immediately after giving effect hereto. No Material Adverse Change has occurred since September 30. 2010.

(b) Each Restricted Person is duly authorized to execute and deliver this Agreement, to the extent a party hereto, and US Borrower and each Canadian Borrower is and will continue to be duly authorized to borrow and perform its obligations under the Credit Agreement. Each Restricted Person a party hereto has duly taken all action necessary to authorize the execution and delivery of this Agreement and to authorize the performance of its obligations hereunder.

(c) The execution and delivery by each Restricted Person of this Agreement, to the extent a party hereto, the performance by it of its obligations hereunder, and the consummation of the transactions contemplated hereby, do not and will not (i) violate any provision of any Law applicable to it or of the organizational documents of such Restricted Person, or of any judgment, order or material license or permit applicable to or binding upon any Restricted Person, (ii) result in the acceleration of any Indebtedness owed by it, or (iii) result in the creation of any consensual Lien upon any of its material assets or properties of any Restricted Person, except Permitted Liens, or , without duplication, as expressly contemplated in, or permitted by, the Loan Documents. Except for those which have been duly obtained, or, without duplication, as are expressly contemplated in , or permitted by the Loan Documents, disclosed in the Disclosure Schedule or disclosed pursuant to Section 6.4 of the Credit Agreement, no consent, approval, authorization or order of any Governmental Authority is required on the part of any Restricted Person a party thereto pursuant to the provisions of any material Law applicable to it as a condition to its execution and delivery by each Restricted Person of this Agreement and the performance of its obligations hereunder, to the extent a party hereto, or to consummate the transactions contemplated hereby.

(d) When duly executed and delivered, this Agreement and each of the Loan Documents, as amended hereby, will be a legal and binding instrument and agreement of each Restricted Person to the extent a party hereto, enforceable in accordance with its terms, (subject, as to enforcement of remedies, to applicable bankruptcy, insolvency and similar laws applicable to creditors' rights generally and general principles of equity).

ARTICLE III. MISCELLANEOUS

Section 3.1. Ratification of Agreements. The Credit Agreement, as hereby amended, is hereby ratified and confirmed in all respects. The Loan Documents, as they may be amended or affected by this Agreement, are hereby ratified and confirmed in all respects by US Borrower and each Canadian Borrower. Any reference to the Credit Agreement in any Loan Document shall be deemed to refer to this Agreement also. The execution, delivery and effectiveness of this Agreement shall not, except as expressly provided herein, operate as a waiver of any right, power or remedy of Administrative Agent or any Lender under the Credit Agreement or any other Loan Document nor constitute a waiver of any provision of the Credit Agreement or any other Loan Document.

Section 3.2. Ratification of Security Documents. Borrowers, Administrative Agent, Canadian Administrative Agent and Lenders each acknowledges and agrees that any and all Obligations, including Canadian Loans to PMCULC Amalco, whether consisting of outstanding Canadian Loans to PMCULC or PMCLP assumed hereby or Canadian Loans hereafter made to PMCULC Amalco, are guarantied by the respective Guarantors.

Section 3.3. Survival of Agreements. All representations, warranties, covenants and agreements of each Restricted Person a party hereto shall survive the execution and delivery of this Agreement and the performance hereof, including without limitation the making or granting of each Loan, and shall further survive until all of the Obligations under the Credit Agreement are paid in full. All statements and agreements contained in any certificate or instrument delivered by any Restricted Person hereunder or under the Credit Agreement to Administrative Agent or any Lender shall be deemed to constitute representations and warranties by, or agreements and covenants of, Borrower and each Canadian Borrower under this Agreement and under the Credit Agreement.

Section 3.4. Loan Documents. This Agreement is a Loan Document, and all provisions in the Credit Agreement pertaining to Loan Documents apply hereto.

Section 3.5. GOVERNING LAW. THIS AGREEMENT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK AND ANY APPLICABLE LAWS OF THE UNITED STATES OF AMERICA IN ALL RESPECTS, INCLUDING CONSTRUCTION, VALIDITY AND PERFORMANCE.

Section 3.6. Counterparts. This Agreement may be separately executed in counterparts and by the different parties hereto in separate counterparts, each of which when so executed shall be deemed to constitute one and the same Agreement. Delivery of an executed signature page by facsimile transmission shall be effective as delivery of a manual executed counterpart.

IN WITNESS WHEREOF, this Assumption, Ratification and Confirmation Agreement is executed as of the date first written above and effective as of the date hereof immediately following the consummation of the Canadian Restructuring.

PLAINS MIDSTREAM CANADA ULC

By: /s/ Charles Kingswell-Smith
Charles Kingswell-Smith
Vice President and Treasurer

PLAINS ALL AMERICAN PIPELINE, L.P..,
US Borrower
By: PAA GP LLC, its general partner
By: Plains AAP, L.P., its sole member
By: Plains All American GP LLC,
its general partner

By: /s/ Charles Kingswell-Smith
Charles Kingswell-Smith
Vice President and Treasurer

PMC (NOVA SCOTIA) COMPANY,
a Canadian Borrower

By: /s/ Charles Kingswell-Smith
Charles Kingswell-Smith
Vice President and Treasurer

PLAINS ALL AMERICAN PIPELINE, L.P.,
Guarantor

By: PAA GP, LLC, its general partner
By: Plains AAP, L.P., its sole member
By: Plains All American GP LLC,
its general partner

By: /s/ Charles Kingswell-Smith
Charles Kingswell-Smith
Vice President and Treasurer

AGREED AND ACCEPTED:

BANK OF AMERICA, N.A.,
Administrative Agent

By: ______________________________
Name:
Title:

BANK OF AMERICA, N.A.,
acting through its Canada Branch,
as Canadian Administrative Agent

By: ______________________________
Name:
Title:

CONSENT AND AGREEMENT

Each of the undersigned Guarantors hereby consents to the provisions of this Agreement and the execution and delivery of Canadian Notes by PMCULC Amalco, and the transactions contemplated herein and therein and hereby and thereby (i) acknowledges and agrees that any and all indebtedness, liabilities or obligations of US Borrower and each Canadian Borrower, including PMCULC Amalco, arising under or in connection with the Credit Agreement and the Notes, including Canadian Notes issued by PMCULC Amalco, are Obligations and are guarantied indebtedness under such Guarantor's Guaranty, (ii) ratifies and confirms its Guaranty made by it for the benefit of Administrative Agent and Lenders, and (iii) expressly acknowledges and agrees that such Guarantor guarantees all indebtedness, liabilities and obligations of US Borrower and each Canadian Borrower, including PMCULC Amalco, arising under or in connection with the Credit Agreement and the Notes, including Canadian Notes issued by PMCULC Amalco, pursuant to the terms of such Guaranty, and agrees that its obligations and covenants thereunder are unimpaired hereby and shall remain in full force and effect.

PLAINS MARKETING, L.P.
PLAINS PIPELINE, L.P.
By: Plains Marketing GP Inc., its General Partner

By: ______________________________
Charles Kingswell-Smith
Vice President and Treasurer

PAA FINANCE CORP.
PMC (NOVA SCOTIA) COMPANY
PLAINS MIDSTREAM CANADA ULC

By: ______________________________
Charles Kingswell-Smith
Vice President and Treasurer

PLAINS MARKETING GP INC.

By: ______________________________
Charles Kingswell-Smith
Vice President and Treasurer

PLAINS SOUTHCAP LLC
PICSCO LLC
PLAINS LPG SERVICES GP LLC
PLAINS PRODUCTS TERMINALS LLC
By: Plains Marketing, L.P., its Sole Member
By: Plains Marketing GP Inc., its General Partner

By: ______________________________
Charles Kingswell-Smith
Vice President and Treasurer

PLAINS MARKETING CANADA LLC
By: Plains Marketing, L.P., its Sole Member
By: Plains Marketing GP Inc., its General Partner

By: ____
Charles Kingswell-Smith
Vice President and Treasurer

PLAINS LPG SERVICES, L.P.
By: Plains LPG Services GP LLC,
its General Partner
By: Plains Marketing, L.P., its Sole Member
By: Plains Marketing GP Inc., its General Partner

By: ____
Charles Kingswell-Smith
Vice President and Treasurer

LONE STAR TRUCKING, LLC
By: Plains LPG Services, L.P., its Sole Member
By: Plains LPG Services GP LLC,
its General Partner
By: Plains Marketing, L.P., its Sole Member
By: Plains Marketing GP Inc., its General Partner

By: ____
Charles Kingswell-Smith
Vice President and Treasurer

PACIFIC ENERGY GROUP LLC
AURORA PIPELINE COMPANY LTD.

By: ____
Charles Kingswell-Smith
Vice President and Treasurer

PACIFIC L.A. MARINE TERMINAL LLC
ROCKY MOUNTAIN PIPELINE SYSTEM LLC
By: Pacific Energy Group LLC, its Sole Member

By: ____
Charles Kingswell-Smith
Vice President and Treasurer

PLAINS MIDSTREAM, L.P.
By: Plains Midstream GP LLC, its General Partner
By: Plains Marketing, L.P., its Sole Member
By: Plains Marketing GP Inc., its General Partner

By: ______________________________
Charles Kingswell-Smith
Vice President and Treasurer

PLAINS MIDSTREAM GP LLC
By: Plains Marketing, L.P., its Sole Member
By: Plains Marketing GP Inc., its General Partner

By: ______________________________
Charles Kingswell-Smith
Vice President and Treasurer

EXHIBIT 10.58

February 18, 2010

Grantee Name
Grantee Address
City, State Zip

Re: Grant of Phantom Units

Dear Grantee:

I am pleased to inform you that you have been granted Phantom Units as of the above date pursuant to the Company's 2005 Long-Term Incentive Plan (the "Plan"). In addition, in tandem with each Phantom Unit you have been granted a distribution equivalent right (a "DER"). The terms and conditions of this grant are as set forth below.

1. Subject to the further provisions of this Agreement, your Phantom Units shall vest (become payable in the form of one Common Unit of Plains All American Pipeline, L.P. for each Phantom Unit) as follows: (i) one-third shall vest upon the later to occur of the May 2013 Distribution Date and the date on which the Partnership pays a quarterly distribution of at least $0.975, (ii) one-third shall vest upon the later to occur of the May 2014 distribution date and the date the Partnership pays a quarterly distribution of at least $1.0125, and (iii) one-third shall vest upon the later to occur of the May 2015 distribution date and the date the Partnership pays a quarterly distribution of at least $1.05. Any remaining Phantom Units that are not vested by the May 2016 Distribution Date, and any tandem DERs (regardless of vesting) associated with such Phantom Units, shall expire on such date.

2. Subject to the further provisions of this Agreement, your DERs shall vest (become payable in cash) as follows: (i) one-third shall vest upon and effective with the date on which the Partnership pays a quarterly distribution of at least $0.975 per unit, (ii) one-third shall vest upon and effective with the date on which the Partnership pays a quarterly distribution of at least $1.0125 per unit, and (iii) one-third shall vest upon and effective with the date on which the Partnership pays a quarterly distribution of at least $1.05 per unit.

3. Your DERs shall not accrue payments prior to vesting.

4. Any distribution level required for vesting under paragraphs 1 or 2 above shall be proportionately reduced or increased for any split or reverse split, respectively, of the Units, or any event or transaction having similar effect.

5. Subject to the further provisions of this Agreement, your DERs shall vest (become payable in cash) as follows: (i) one-third shall vest upon and effective with the date on which the Partnership pays a quarterly distribution of at least $0.975 per unit, (ii) one-third shall vest upon and effective with the date on which the Partnership pays a quarterly distribution of at least $1.0125 per unit, and (iii) one-third shall vest upon and effective with the date on which the Partnership pays a quarterly distribution of at least $1.05 per unit.

6. Your DERs shall not accrue payments prior to vesting.

7. Upon vesting of any Phantom Units, an equivalent number of DERs will expire. Any such DERs that are vested prior to, or that would vest as of, the Distribution Date on which the Phantom Units vest, shall be payable on such Distribution Date prior to their expiration.

8. In the event of the termination of your employment with the Company and its Affiliates (other than in connection with a Change in Status or by reason of your death or "disability," as defined in paragraph 7 below), all of your then outstanding DERs (regardless of vesting) and Phantom Units shall automatically be forfeited as of the date of termination; provided, however, that if the Company or its Affiliates terminate your employment other than a Termination for Cause: (i) any unvested Phantom Units that have satisfied all vesting criteria as of the date of termination but for the passage of time shall be deemed nonforfeitable on the date of termination, and shall vest on the next following Distribution Date; (ii) any DERs associated with the unvested, nonforfeitable Phantom Units described in clause (i) shall not be forfeited on the date of termination, but shall be payable and shall expire in accordance with paragraph 5 above; and (iii) any unvested Phantom Units that have satisfied none of the vesting criteria as of the date of termination, and any tandem DERs (regardless of vesting) associated with such Phantom Units, shall automatically be forfeited as of the date of termination.

9. In the event of termination of your employment with the Company and its Affiliates by reason of your death or your "disability" (a physical or mental infirmity that impairs your ability substantially to perform your duties for a period of eighteen months or that the Company otherwise determines constitutes a "disability"), your then outstanding Phantom Units and tandem DERs shall not be forfeited on such date, and (i) such DERs shall vest in accordance with paragraph 2 above and expire in accordance with paragraph 1 or paragraph 5 above, as applicable, and (ii) such Phantom Units shall vest or expire in accordance with paragraph 1 above; *provided, however,* that such vesting of Phantom Units shall occur either (x) on the date the Partnership pays the quarterly distribution specified in clause (i), (ii) or (iii) of paragraph 1 (and in the proportion indicated therein) without regard to any requirement for further passage of time or (y) if the relevant quarterly distribution has been paid prior to the date of termination, on the next following Distribution Date.

As soon as administratively practicable after the vesting of any Phantom Units pursuant to this paragraph 7, payment will be made in cash in an amount equal to the Market Value of the number of Phantom Units vesting.

10. In the event of a Change in Status, all of your then outstanding Phantom Units and tandem DERs shall be deemed 100% non-forfeitable on such date, and such Phantom Units shall vest in full upon the next Distribution Date.

11. Upon payment pursuant to a DER, you agree that the Company may withhold any taxes due from your compensation as required by law. Upon vesting of a Phantom Unit, you agree that the Company may withhold any taxes due from your compensation as required by law, which (in the sole discretion of the Company) may include withholding a number of Common Units otherwise payable to you.

As used herein, the phrase "Distribution Date" means the day in February, May, August or November in any year (as context dictates) that is 45 days after the end of the most recently completed calendar quarter (or, if not a business day, the closest previous business day). "Market Value" means the average of the closing sales prices for a Common Unit on the New York Stock Exchange for the five trading days preceding the then most recent "ex dividend" date for payment of a distribution by the Partnership.

The phrase "Change in Status" means (A) the termination of your employment by the Company other than a Termination for Cause, within two and a half months prior to or one year following a Change of Control (the "Protected Period"), or (B) the termination of your employment by you due to the occurrence during the Protected Period, without your written consent, of (i) any material diminution in your authority, duties or responsibilities, (ii) any material reduction in your base salary or (iii) any other action or inaction that constitutes a material breach of this agreement by the Company. A termination by you shall not be a Change in Status unless (1) you provide written notice to the Company of the condition in (B)(i),(ii) or (iii) that would constitute a Change in Status within 90 days of the initial existence of the condition and (2) the Company fails to remedy the condition within the 30-day period following such notice. As used herein, a termination of the Employee's employment means a "separation from service," for purposes of Section 409A of the Internal Revenue Code of 1986, as amended (the "Code").

The phrase "Change of Control" means, and shall be deemed to have occurred upon the occurrence of, one or more of the following events: (i) the Company ceasing to retain direct or indirect control of the general partner of the Partnership, (ii) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all or substantially all of the assets of the Partnership or the Company to any Person and/or its Affiliates, other than to the Partnership or the Company, including any employee benefit plan thereof; (iii) a consolidation, reorganization, merger or any other similar transaction involving (a) a Person other than the Partnership or the Company and (b) the Partnership, the Company or both, (iv) the Persons who own membership interests in the Company on the date hereof cease to beneficially own, directly

or indirectly, more than 50% of the membership interest in the Company, or (v) any Person, including any partnership, limited partnership, syndicate or other group deemed a “person” for purposes of Section 13(d) or 14(d) of the Securities Exchange Act of 1934, as amended, becoming after the date hereof the beneficial owner, directly or indirectly, of more than 49.9% of the membership interest in the Company. Notwithstanding the foregoing, no Change of Control shall be deemed to have occurred in connection with a restructuring or reorganization related to a securitization and sale to the public of direct or indirect equity interests in the general partner if (x) the Company retains direct or indirect control over the general partner and (y) the Persons who own membership interests in the Company on the date hereof continue to beneficially own, directly or indirectly, more than 50% of the membership interest in the Company.

The phrase “Termination for Cause” shall mean severance of your employment with the Company or its Affiliates based on your (i) failure to perform your job function in accordance with standards described to you in writing, or (ii) violation of the Company’s Code of Business Conduct (unless waived in accordance with the terms thereof), in each case, with the specific failure or violation described to you in writing.

The “Company” refers to Plains All American GP LLC. The “Partnership” refers to Plains All American Pipeline, L.P.

Terms used herein that are not defined herein shall have the meanings set forth in the Plan or, if not defined in the Plan, in the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., as amended (the “Partnership Agreement”). By signing below, you agree that the Phantom Units and DERs granted hereunder are governed by the terms of the Plan. Copies of the Plan and the Partnership Agreement are available upon request.

In order for this grant to be effective you must designate a beneficiary that will be entitled to receive any benefits payable under this grant in the event of your death. Unless you indicate otherwise by checking the appropriate box the named beneficiaries on this form will serve as your beneficiaries for all previous LTIP grants. Please execute and return a copy of this grant letter to me and retain a copy for your records.

PLAINS ALL AMERICAN PIPELINE, L.P.

By: PAA GP LLC
By: PLAINS AAP, L.P.

By: PLAINS ALL AMERICAN GP LLC

By: ______________________________
Name: Tim Moore
Title: Vice President & General Counsel

Beneficiary Designation

Primary Beneficiary Name	Relationship	Percent (Must total 100%)

Secondary Beneficiary Name	Relationship	Percent (Must total 100%)

☐ Check this box only if designation does not apply to prior grants

____
Grantee Name

No. of Units: ______________________________

Dated: ______________________________

Exhibit 10.59

September 27, 2010

John R. Rutherford
5568 Candlewood Lane
Houston, TX 77056

Dear John:

Pursuant to our discussions, the following shall set forth the employment agreement (this "Agreement") between Plains All American GP LLC (the "Company") and John R. Rutherford ("Executive").

1. Title and Position. Executive's position will be Executive Vice President of the Company with primary responsibility for acquisitions and strategic planning. Executive will report to the Chairman and Chief Executive Officer ("CEO") and/or President and Chief Operating Officer ("COO") as appropriate for the circumstances.

2. Compensation. Executive's compensation will include:

a. Base Salary. A monthly salary of $20,833.33, payable semi-monthly in cash for so long as Executive is employed by the Company. This amount may be increased by the Company from time to time, but may not be decreased from this base level, or any future increased level, without Executive's express written approval.

b. Bonus. Executive will participate in the Company's annual discretionary bonus program. The amount of bonus recommended to the Board annually with respect to Executive will be dependent upon the CEO and COO's assessments of both Executive's individual contributions throughout the year and the overall partnership performance. Subject to the continued service requirements described below, for calendar years 2010, 2011 and 2012, Executive's annual bonuses will not be less than $1 million (the "Minimum Annual Bonuses"); provided that, for calendar year 2010, Executive's Minimum Annual Bonus shall be prorated based on his official start date with the Company. The Minimum Annual Bonuses shall be paid in cash on the earlier of the date that the annual bonus payments are made to the other participants in the annual discretionary bonus program or February 28th of the year following the applicable calendar year. The Company's obligation to pay a Minimum Annual Bonus is contingent upon (i) Executive's remaining employed by the Company as of the date on which the applicable Minimum Annual Bonus payment is due (unless Executive's failure to remain employed

results from a "Change in Status," as defined below) and (ii) continued compliance with the terms of the Confidentiality Agreement, as defined in Section 5 below. The phrase "Change in Status" means (A) the termination of Executive's employment by the Company other than a Termination for Cause, or (B) the termination of Executive's employment by Executive due to the occurrence, without Executive's written consent, of (i) any material diminution in authority, duties or responsibilities, (ii) any material reduction in base salary or (iii) any other action or inaction that constitutes a material breach of this agreement by the Company. A termination by Executive shall not constitute a Change in Status unless (1) Executive provides written notice to the Company of the condition in (B)(i),(ii) or (iii) that would constitute a Change in Status within 90 days of the initial existence of the condition, (2) the Company fails to remedy the condition within the 30-day period following such notice and (3) you terminate your employment within 10 days of the end of the 30-day period. As used herein, a termination of the Employee's employment means a "separation from service," for purposes of Section 409A of the Internal Revenue Code of 1986, as amended (the "Code"). "Termination for Cause" shall have the meaning ascribed in the LTIP Grant letter referenced in sub-paragraph c. below.

c. LTIP Grant. Executive will receive an initial grant of 100,000 Phantom Units under the Company's Long-Term Incentive Plan (LTIP) that vest upon the achievement of both performance and minimum service as follows:

Vest	**Performance Qtrly distribution (Annual Rate)**	**Minimum Service**
25%	$0.975/unit ($3.90/unit)	2 yr. Anniv. 2012*
25%	$0.975/unit ($3.90/unit)	May 2013
25%	$1.0125/unit ($4.05/unit)	May 2014
25%	$1.05/unit ($4.20/unit)	May 2015

*earliest vesting will occur on the first distribution date following the anniversary

Grants include distribution equivalent rights (DERs) that vest upon achievement of performance benchmarks.

The terms of Executive's grant of Phantom Units are generally set forth in the form exemplar LTIP Grant letter that has been provided to Executive contemporaneously herewith; provided, however, that in the event of a "change of control" (as defined in the LTIP Grant letter) within the first year of Executive's employment, 25% of Executive's Phantom Units will automatically vest if a Change of Status occurs within one year of such change of control.

d. Class B Units. Executive will receive an initial grant of 10,000 Class B units in Plains AAP, L.P. that earn and vest as follows:

Earn	Performance Qtrly distribution (Annual Rate)	Minimum Vest Service
25%	$0.975/unit ($3.90/unit)	(1)
25%	$1.0125/unit ($4.05/unit)	(1)
25%	$1.05/unit ($4.20/unit)	(1)
25%	$1.125/unit ($4.50/unit)	(1)

(1) Executive will "earn" each tranche of units as described above 180 days after achievement of the respective performance benchmarks. Prior to January 2017, the Company retains a call right on "earned" units such that, if Executive terminates his employment prior to:

a. January 2015, the call right is 50% of the fair market value of Earned Units on date of departure;

b. January 2017, but after January 2015, the call right is 75% of the fair market value of Earned Units on date of departure.

The Company's call right must be exercised within sixty (60) days of Executive's termination, otherwise such units shall vest and not be subject to being called.

The remaining terms of Executive's grant of Class B units are generally set forth in the form exemplar Class B Restricted Units Agreement that has been provided to Executive contemporaneous herewith; provided, however, that: (a) in the event of a "change of control" (as defined in the Class B Restricted Units Agreement) within the first year of Executive's employment, 25% of Executive's Class B units will automatically vest if he is terminated other than for "Cause" (as defined in the Class B Restricted Units Agreement) within one year of such change of control; and (b) in the event of a change of control after the first year of Executive's employment, Executive will vest in any "earned" tranches of Class B units (without regard to the 180 day lag period) as well as the next succeeding incremental tranche of Class B units upon the change of control (without regard to Executive's employment status) and any unvested units will be canceled.

3. Expense Reimbursement. Company shall reimburse Executive for all reasonable business expenses, including travel and entertainment, and membership dues at one country club or athletic club.

4. Benefits. Executive shall receive and be entitled to other employment benefits, including: (a) four weeks paid vacation, (b) up to 10 days sick leave with pay, (c) participation in the Company's 401(K) Plan, and (d) all health and welfare benefits, including insurance, provided to other senior executives of the Company, on the same basis and terms as other senior executives of the Company.

5. Confidentiality and Non-Solicitation. Executive and the Company shall execute a Confidential Information and Non-Solicitation Agreement (the "Confidentiality Agreement") substantially in the form of Exhibit "A" attached hereto. The rights and obligations set forth in the Confidentiality Agreement shall survive the termination of this Agreement.

6. Commencement of Employment; Term and Termination. Employment of Executive shall commence on October 1, 2010. Either party may terminate Executive's employment at any time; however, such termination shall not affect the provisions of this Agreement, including those in sections 2 and 5, that create post-employment duties and rights.

7. Company acknowledges receipt of Executive's agreements with Lazard, as provided to the Company by Executive. Executive represents that: (a) his execution of this Agreement will not violate the terms of any Agreement to which he is currently bound; and (b) he is not subject to an existing confidentiality, non-compete or similar type Agreement that would prevent, limit or otherwise encumber Executive's ability to perform his job with the Company. Executive undertakes to bring to the Company's attention any change of job description or other circumstance that would potentially breach the confidentiality and non-compete aspects of the Lazard agreements, and the Company undertakes to cooperate in commercially reasonable, good faith efforts to reduce or remove the potential for breach.

8. Upon termination of his employment for any reason, Executive shall promptly return to Company all copies of any Company data, records, or materials of whatever nature or kind, including all materials incorporating the proprietary information of Company.

9. If the parties determine, or the Internal Revenue Service asserts, that any payments or benefits to be made or provided to Executive hereunder do not comply with Section 409A of the Internal Revenue Code, then the parties agree to mutually take such actions as are reasonably necessary or appropriate to ensure compliance with Section 409A.

10. Notwithstanding the foregoing, this Agreement is subject to and contingent upon a satisfactory background check in which information that Executive has provided regarding items such as education, work experience, criminal record and professional credentials will be verified. Executive may be asked to provide additional information or assist in the process if Company encounters any difficulties in the verification of this information. If any of the information is found to be untrue or misrepresented, this offer will be withdrawn, or, if employed, Executive's employment will be terminated.

11. By accepting this offer, Executive agrees that he shall at all times:

a. adhere to the Company's Trading and Risk Management Policies and Procedures,

b. adhere to the Company's Code of Business Conduct, and

c. not misrepresent nor conceal information regarding transactions from senior management or any person responsible for the accurate recording and reporting of each transaction.

If the foregoing meets with your understanding of our agreement, please execute, date and return one original Agreement for our files.

Very truly yours,

PLAINS ALL AMERICAN GP LLC

By: ______________________________
Name: Greg L. Armstrong
Title: Chairman and CEO

AGREED TO AND ACCEPTED
this day of September, 2010

____
John R. Rutherford

EXHIBT 12.1

STATEMENT OF COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(in millions)

	Year Ended December 31,				
	2010	2009	2008	2007	2006
EARNINGS [1]					
Pre-tax income from continuing operations before noncontrolling interest and income from equity investees	$ 510	$ 572	$ 430	$ 350	$ 278
add: Fixed charges	321	283	264	233	149
add: Distributed income of equity investees	9	7	10	2	1
add: Amortization of capitalized interest	1	1	1	—	—
less: Capitalized interest	(16)	(12)	(17)	(14)	(6)
Total Earnings	$ 825	$ 851	$ 688	$ 571	$ 422
FIXED CHARGES [1]					
Interest expensed and capitalized [2]	$ 281	$ 247	$ 233	$ 220	$ 141
Amortization of debt expense	8	7	4	3	3
Portion of rent expense related to interest (33.33%)	32	29	27	10	5
Total Fixed Charges	$ 321	$ 283	$ 264	$ 233	$ 149
RATIO OF EARNINGS TO FIXED CHARGES [3]	2.57x	3.00x	2.60x	2.45x	2.83x

(1) For purposes of computing the ratio of earnings to fixed charges, "earnings" consists of pre-tax income from continuing operations before income from equity investees plus fixed charges (excluding capitalized interest), distributed income of equity investees and amortization of capitalized interest. "Fixed charges" represents interest incurred (whether expensed or capitalized), amortization of debt expense (including discounts and premiums relating to indebtedness) and the portion of rental expense on operating leases deemed to be the equivalent of interest.

(2) Includes interest costs attributable to borrowings for hedged inventory purchases of $17 million, $11 million, $21 million, $44 million and $49 million for the years ended December 31, 2010, 2009, 2008, 2007 and 2006, respectively.

(3) Ratios may not recalculate due to rounding.

Exhibit 21.1

SUBSIDIARIES OF
PLAINS ALL AMERICAN PIPELINE, L.P.
(*As of 1/1/11*)

Subsidiary	Jurisdiction of Organization
Aurora Pipeline Company Ltd.	Canada
CDM Max LLC	Texas
Lone Star Trucking, LLC	California
Nexen Marketing USA Inc.	Delaware
Nexen Pipeline USA LLC	Wyoming
PAA Finance Corp.	Delaware
PAA Luxembourg S.a.r.l.	Luxembourg
PAA Midstream LLC	Delaware
PAA/Vulcan Gas Storage, LLC	Delaware
Pacific Energy GP, LP	Delaware
Pacific Energy Group LLC	Delaware
Pacific Energy Management LLC	Delaware
Pacific LA Marine Terminal LLC	Delaware
Pacific Pipeline System LLC	Delaware
PICSCO LLC	Delaware
Plains LPG Services GP LLC	Delaware
Plains LPG Services, L.P.	Delaware
Plains Marketing Bondholder, LLC	Delaware
Plains Marketing Canada LLC	Delaware
Plains Marketing GP Inc.	Delaware
Plains Marketing, L.P.	Texas
Plains Midstream Canada ULC	Alberta
Plains Midstream GP LLC	Delaware
Plains Midstream Luxembourg S.a.r.l.	Luxembourg
Plains Pipeline, L.P.	Texas
Plains Products Terminals LLC	Delaware
Plains Southcap LLC	Delaware
Plains West Coast Terminals LLC	Delaware
PMC (Nova Scotia) Company	Nova Scotia
Rancho LPG Holdings LLC	Delaware
Rocky Mountain Pipeline System LLC	Delaware
Settoon Towing, LLC	Delaware
SLC Pipeline LLC	Delaware
Southcap Pipe Line Company	Delaware
PNGS GP LLC	Delaware
PAA Natural Gas Storage, L.P.	Delaware
Pine Prairie Energy Center, LLC	Delaware
PAA Natural Gas Storage, LLC	Delaware
Bluewater Natural Gas Holding, LLC	Delaware
PNG Marketing, LLC	Delaware
Bluewater Gas Storage LLC	Delaware
BGS Kimball Gas Storage, LLC	Delaware
PPEC Bondholder, LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-138888, 333-155673, 333-162475, 333-162476 and 333-162477) and on Form S-8 (No. 333-91141, 333-54118, 333-74920, 333-122806 and 333-141185) of Plains All American Pipeline, L.P. of our report dated February 25, 2011 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

PricewaterhouseCoopers LLP
Houston, Texas
February 25, 2011

EXHIBIT 31.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PLAINS ALL AMERICAN PIPELINE, L.P.

I, Greg L. Armstrong, certify that:

1. I have reviewed this annual report on Form 10-K of Plains All American Pipeline, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2011

/s/ Greg L. Armstrong
Greg L. Armstrong
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PLAINS ALL AMERICAN PIPELINE, L.P.

I, Al Swanson, certify that:

1. I have reviewed this annual report on Form 10-K of Plains All American Pipeline, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2011

/s/ Al Swanson
Al Swanson
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. 1350

I, Greg L. Armstrong, Chief Executive Officer of Plains All American Pipeline, L.P. (the “Company”), hereby certify that:

(i) the accompanying report on Form 10-K for the period ended December 31, 2010 and filed with the Securities and Exchange Commission on the date hereof (the “Report”) by the Company fully complies with the requirements of Section 13(a) or 15 (d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Greg L. Armstrong
Name: Greg L. Armstrong
Date: February 25, 2011

EXHIBIT 32.2

CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. 1350

I, Al Swanson, Chief Financial Officer of Plains All American Pipeline, L.P. (the "Company"), hereby certify that:

(i) the accompanying report on Form 10-K for the period ended December 31, 2010 and filed with the Securities and Exchange Commission on the date hereof (the "Report") by the Company fully complies with the requirements of Section 13(a) or 15 (d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Al Swanson
Name: Al Swanson
Date: February 25, 2011

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paa-20101231_lab.xml

paa-20101231_pre.xml

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