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*

Exhibit No.		Description
2.1*	—	Share Purchase Agreement dated December 1, 2011 by and among Amoco Canada International Holdings B.V. and Plains Midstream Canada ULC (the schedules and exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K) (incorporated by reference to Exhibit 2.1 to our Annual Report on Form 10-K for the year ended December 31, 2011).
2.2	—	Agreement and Plan of Merger dated as of October 21, 2013, by and among Plains All American Pipeline, L.P., PAA Acquisition Company LLC, PAA Natural Gas Storage, L.P. and PNGS GP LLC (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K filed October 24, 2013).
2.3**	—	Simplification Agreement dated as of July 11, 2016, by and among PAA GP Holdings LLC, Plains GP Holdings, L.P., Plains All American GP LLC, Plains AAP, L.P., PAA GP LLC and Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K filed July 14, 2016).
2.4**	—	Securities Purchase Agreement dated as of January 19, 2017 by and between COG Operating LLC, as seller, and Plains Pipeline, L.P., as purchaser (the schedules and exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K) (incorporated by reference to Exhibit 2.1 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
2.5**	—	Securities Purchase Agreement dated as of January 19, 2017 by and between Frontier Midstream Solutions, LLC, as seller, and Plains Pipeline, L.P., as purchaser (the schedules and exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K) (incorporated by reference to Exhibit 2.2 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
3.1	—	Seventh Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of October 10, 2017 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed October 12, 2017).
3.2	—	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 our Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	—	Amendment No. 1 dated December 31, 2010 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.9 to our Annual Report on Form 10-K for the year ended December 31, 2010).
3.4	—	Amendment No. 2 dated January 1, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.10 to our Annual Report on Form 10-K for the year ended December 31, 2010).
3.5	—	Amendment No. 3 dated June 30, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.7 to our Annual Report on Form 10-K for the year ended December 31, 2013).
3.6	—	Amendment No. 4 dated January 1, 2013 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P (incorporated by reference to Exhibit 3.8 to our Annual Report on Form 10-K for the year ended December 31, 2013).

3.7	—	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 our Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.8	—	Amendment No. 1 dated January 1, 2013 to the Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. (incorporated by reference to Exhibit 3.10 to our Annual Report on Form 10-K for the year ended December 31, 2013).
3.9	—	Seventh Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated November 15, 2016 (incorporated by reference to Exhibit 3.3 to our Current Report on Form 8-K filed November 21, 2016).
3.10	—	Eighth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated November 15, 2016 (incorporated by reference to Exhibit 3.4 to our Current Report on Form 8-K filed November 21, 2016).
3.11	—	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 our Annual Report on Form 10-K for the year ended December 31, 2006).
3.12	—	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 our Annual Report on Form 10-K for the year ended December 31, 2006).
3.13	—	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to our Current Report on Form 8-K filed January 4, 2008).
3.14	—	Certificate of Limited Partnership of Plains GP Holdings, L.P. (incorporated by reference to Exhibit 3.1 to PAGP's Registration Statement on Form S-1 (333-190227) filed July 29, 2013).
3.15	—	Second Amended and Restated Agreement of Limited Partnership of Plains GP Holdings, L.P. dated as of November 15, 2016 (incorporated by reference to Exhibit 3.2 to PAGP's Current Report on Form 8-K filed November 21, 2016).
3.16	—	Certificate of Formation of PAA GP Holdings LLC (incorporated by reference to Exhibit 3.3 to PAGP's Registration Statement on Form S-1 (333-190227) filed July 29, 2013).
3.17	—	Third Amended and Restated Limited Liability Company Agreement of PAA GP Holdings LLC dated as of February 16, 2017 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed February 21, 2017).
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 our Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	—	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 our Current Report on Form 8-K filed May 12, 2006).
4.3	—	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 our Current Report on Form 8-K filed October 30, 2006).
4.4	—	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 our Current Report on Form 8-K filed September 4, 2009).
4.5	—	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 our Current Report on Form 8-K filed January 11, 2011).
4.6	—	Twentieth Supplemental Indenture (3.65% Senior Notes due 2022) dated March 22, 2012 among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed March 26, 2012).

4.7	—	Twenty-First Supplemental Indenture (5.15% Senior Notes due 2042) dated March 22, 2012 among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed March 26, 2012).
4.8	—	Twenty-Second Supplemental Indenture (2.85% Senior Notes due 2023) dated December 10, 2012, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed December 12, 2012).
4.9	—	Twenty-Third Supplemental Indenture (4.30% Senior Notes due 2043) dated December 10, 2012, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed December 12, 2012).
4.10	—	Twenty-Fourth Supplemental Indenture (3.85% Senior Notes due 2023) dated August 15, 2013, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed August 15, 2013).
4.11	—	Twenty-Fifth Supplemental Indenture (4.70% Senior Notes due 2044) dated April 23, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed April 29, 2014).
4.12	—	Twenty-Sixth Supplemental Indenture (3.60% Senior Notes due 2024) dated September 9, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed September 11, 2014).
4.13	—	Twenty-Seventh Supplemental Indenture (2.60% Senior Notes due 2019) dated December 9, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed December 11, 2014).
4.14	—	Twenty-Eighth Supplemental Indenture (4.90% Senior Notes due 2045) dated December 9, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed December 11, 2014).
4.15	—	Twenty-Ninth Supplemental Indenture (4.65% Senior Notes due 2025) dated August 24, 2015, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed August 26, 2015).
4.16	—	Thirtieth Supplemental Indenture (4.50% Senior Notes due 2026) dated November 22, 2016, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed November 29, 2016).
4.17	—	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 our Registration Statement on Form S-3, File No. 333-162477).
4.18	—	Registration Rights Agreement dated as of January 28, 2016 among Plains All American Pipeline, L.P. and the Purchasers named therein (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed February 2, 2016).
4.19	—	Registration Rights Agreement by and among Plains All American Pipeline, L.P. and the Holders defined therein, dated November 15, 2016 (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K filed November 21, 2016).
10.1	—	Credit Agreement dated as of August 19, 2011 among Plains All American Pipeline, L.P., as Borrower; certain subsidiaries of Plains All American Pipeline, L.P. from time to time party thereto, as Designated Borrowers; Bank of America, N.A., as Administrative Agent; and the other Lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed August 25, 2011).

10.2	—	First Amendment to Credit Agreement dated as of June 27, 2012, among Plains All American Pipeline, L.P. and Plains Midstream Canada ULC, as Borrowers; Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer; Wells Fargo Bank, National Association, as an L/C Issuer; and the other Lenders party thereto (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed July 3, 2012).
10.3	—	Second Amendment to Credit Agreement dated as of August 16, 2013, among Plains All American Pipeline, L.P. and Plains Midstream Canada ULC, as Borrowers; Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer; Wells Fargo Bank, National Association, as an L/C Issuer; and the other Lenders party thereto (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed August 20, 2013).
10.4	—	Third Amendment to Credit Agreement dated as of August 11, 2016, among Plains All American Pipeline, L.P. and Plains Midstream Canada ULC, as Borrowers; Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer; Wells Fargo Bank, National Association, as an L/C Issuer; and the other Lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed August 17, 2016).
10.5	—	Third Amended and Restated Credit Agreement dated as of August 19, 2011 by and among Plains Marketing, L.P., as Borrower, Plains All American Pipeline, L.P., as Guarantor, Bank of America, N.A., as Administrative Agent, and the other Lenders party thereto (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed August 25, 2011).
10.6	—	First Amendment to Third Amended and Restated Credit Agreement dated as of June 27, 2012, among Plains Marketing, L.P. and Plains Midstream Canada ULC, as Borrowers; Plains All American Pipeline, L.P., as Guarantor; Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer; and the other Lenders and L/C Issuers party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed July 3, 2012).
10.7	—	Second Amendment to Third Amended and Restated Credit Agreement dated as of August 16, 2013, among Plains Marketing, L.P. and Plains Midstream Canada ULC, as Borrowers; Plains All American Pipeline, L.P., as Guarantor; Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer; Wells Fargo Bank, National Association, as an L/C Issuer; and the other Lenders and L/C Issuers party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed August 20, 2013).
10.8	—	Third Amendment to Third Amended and Restated Credit Agreement dated as of August 11, 2016, among Plains Marketing, L.P. and Plains Midstream Canada ULC, as Borrowers; Plains All American Pipeline, L.P., as Guarantor; Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer; Wells Fargo Bank, National Association, as an L/C Issuer; and the other Lenders and L/C Issuers party thereto (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K filed August 17, 2016).
10.9	—	Fourth Amendment to Third Amended and Restated Credit Agreement dated as of August 16, 2017, among Plains Marketing, L.P. and Plains Midstream Canada ULC, as Borrowers; Plains All American Pipeline, L.P., as Guarantor; Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer; Wells Fargo Bank, National Association, as an L/C Issuer; and the other Lenders and L/C Issuers party thereto (incorporated by reference to Exhibit 10.6 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2017).
10.10	—	364-Day Credit Agreement dated January 16, 2015 among Plains All American Pipeline, L.P., as Borrower; Bank of America, N.A., as Administrative Agent; Citibank, N.A., JPMorgan Chase Bank N.A. and Wells Fargo Bank, National Association, as Co-Syndication Agents; DNB Bank ASA, New York Branch and Mizuho Bank, Ltd., as Co-Documentation Agents; the other Lenders party thereto; and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., DNB Markets, Inc., J.P. Morgan Securities LLC, Mizuho Bank, Ltd. and Wells Fargo Securities, LLC, as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed January 20, 2015).
10.11	—	First Amendment to 364-Day Credit Agreement dated August 14, 2015 among Plains All American Pipeline, L.P., as Borrower; Bank of America, N.A., as Administrative Agent; Citibank, N.A., JPMorgan Chase Bank N.A. and Wells Fargo Bank, National Association, as Co-Syndication Agents; DNB Bank ASA, New York Branch and Mizuho Bank, Ltd., as Co-Documentation Agents; the other Lenders party thereto; and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., DNB Markets, Inc., J.P. Morgan Securities LLC, Mizuho Bank, Ltd. and Wells Fargo Securities, LLC, as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed August 14, 2015).

10.12	—	Second Amendment to 364-Day Credit Agreement dated as of August 11, 2016 among Plains All American Pipeline, L.P., as Borrower; Bank of America, N.A., as Administrative Agent; Citibank, N.A., JPMorgan Chase Bank N.A. and Wells Fargo Bank, National Association, as Co-Syndication Agents; DNB Bank ASA, New York Branch and Mizuho Bank Ltd., as Co-Documentation Agents; the other Lenders party thereto; and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., DNB Markets, Inc., J.P. Morgan Securities LLC, Mizuho Bank, Ltd. and Wells Fargo Securities, LLC, as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed August 17, 2016).
10.13	—	Third Amendment to 364-Day Credit Agreement dated as of August 10, 2017 among Plains All American Pipeline, L.P., as Borrower; Bank of America, N.A., as Administrative Agent; Citibank, N.A., JPMorgan Chase Bank N.A. and Wells Fargo Bank, National Association, as Co-Syndication Agents; DNB Bank ASA, New York Branch and Mizuho Bank Ltd., as Co-Documentation Agents; the other Lenders party thereto; and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., DNB Markets, Inc., J.P. Morgan Securities LLC, Mizuho Bank, Ltd. and Wells Fargo Securities, LLC, as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.5 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2017).
10.14	—	Contribution, Conveyance and Assumption Agreement among Plains All American Pipeline, L.P. and certain other parties dated as of November 23, 1998 (incorporated by reference to Exhibit 10.3 to our Annual Report on Form 10-K for the year ended December 31, 1998).
10.15	—	First Amendment to Contribution, Conveyance and Assumption Agreement dated as of December 15, 1998 (incorporated by reference to Exhibit 10.13 to our Annual Report on Form 10-K for the year ended December 31, 1998).
10.16	—	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 our Current Report on Form 8-K filed June 27, 2001).
10.17	—	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 our Current Report on Form 8-K filed June 11, 2001).
10.18	—	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 our Current Report on Form 8-K filed June 11, 2001).
10.19***	—	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 our Current Report on Form 8-K filed June 11, 2001).
10.20	—	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 our Current Report on Form 8-K filed January 4, 2008).
10.21	—	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 our Current Report on Form 8-K filed May 10, 2001).
10.22	—	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 our Registration Statement on Form S-1 filed September 23, 1998, File No. 333-64107).
10.23	—	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 our Registration Statement on Form S-1 filed September 23, 1998, File No. 333-64107).
10.24	—	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 our Annual Report on Form 10-K for the year ended December 31, 1998).
10.25	—	Membership Interest Purchase Agreement by and between Sempra Energy Trading Corporation and PAA/Vulcan Gas Storage, LLC dated August 19, 2005 (incorporated by reference to Exhibit 1.2 to our Current Report on Form 8-K filed September 19, 2005).

10.26	—	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).
10.27	—	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).
10.28	—	Omnibus Agreement by and among PAA GP Holdings LLC, Plains GP Holdings, L.P., Plains All American GP LLC, Plains AAP, L.P., PAA GP LLC, and Plains All American Pipeline, L.P., dated November 15, 2016 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed November 21, 2016).
10.29	—	Amended and Restated Administrative Agreement by and among PAA GP Holdings LLC, Plains GP Holdings, L.P., Plains All American GP LLC, Plains AAP, L.P., PAA GP LLC, and Plains All American Pipeline, L.P., dated November 15, 2016 (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed November 21, 2016).
10.30***	—	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 our Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.31***	—	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 our Annual Report on Form 10-K for the year ended December 31, 2008).
10.32***	—	Waiver Agreement dated as of December 23, 2010 between Plains All American GP LLC and Greg L. Armstrong (incorporated by reference to Exhibit 10.31 to our Annual Report on Form 10-K for the year ended December 31, 2010).
10.33***	—	Waiver Agreement dated October 21, 2013 to the Amended and Restated Employment Agreement dated June 30, 2001 of Greg L. Armstrong (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed October 25, 2013).
10.34***	—	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 our Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.35***	—	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 our Annual Report on Form 10-K for the year ended December 31, 2008).
10.36***	—	Waiver Agreement dated as of December 23, 2010 between Plains All American GP LLC and Harry N. Pefanis (incorporated by reference to Exhibit 10.32 to our Annual Report on Form 10-K for the year ended December 31, 2010).
10.37***	—	Waiver Agreement dated October 21, 2013 to the Amended and Restated Employment Agreement dated June 30, 2001 of Harry N. Pefanis (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K filed October 25, 2013).
10.38***	—	Employment Agreement between Plains All American GP LLC and Willie Chiang dated July 10, 2015 (incorporated by reference to Exhibit 10.53 to our Annual Report on Form 10-K for the year ended December 31, 2015).
10.39***		First Amendment to Plains AAP, L.P. Class B Restricted Units Agreement dated August 25, 2016 (Willie Chiang) (incorporated by reference to Exhibit 10.8 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2016).
10.40***	—	Amendment dated August 25, 2016 to LTIP Grant Letter dated August 24, 2015 (Willie Chiang) (incorporated by reference to Exhibit 10.7 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2016).
10.41***	—	Quarterly Bonus Program Summary (incorporated by reference to Exhibit 10.21 to our Annual Report on Form 10-K for the year ended December 31, 2005).

10.42***	—	Director Compensation Summary (incorporated by reference to Exhibit 10.43 to our Annual Report on Form 10-K for the year ended December 31, 2016).
10.43***	—	Plains All American GP LLC 2005 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed January 26, 2005).
10.44***	—	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 our Annual Report on Form 10-K for the year ended December 31, 2008).
10.45***	—	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).
10.46***	—	First Amendment to Plains All American GP LLC 1998 Long-Term Incentive Plan dated June 27, 2003 (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2003).
10.47***	—	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 our Annual Report on Form 10-K for the year ended December 31, 2008).
10.48***	—	Plains All American PPX Successor Long-Term Incentive Plan (incorporated by reference to Exhibit 10.45 to our Annual Report on Form 10-K for the year ended December 31, 2006).
10.49***	—	Form of Plains AAP, L.P. Class B Restricted Units Agreement (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed January 4, 2008).
10.50***	—	Form of Amendment to the Plains AAP, L.P. Class B Restricted Units Agreement, dated October 18, 2013 (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K filed October 25, 2013).
10.51***	—	Form of Amendment to Plains AAP, L.P. Class B Restricted Units Agreement dated August 25, 2016 (incorporated by reference to Exhibit 10.6 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2016 filed November 8, 2016).
10.52***	—	Plains All American 2013 Long-Term Incentive Plan (incorporated by reference to Exhibit A to our Definitive Proxy Statement filed on October 3, 2013).
10.53***	—	Plains All American PNG Successor Long-Term Incentive Plan (incorporated by reference to Exhibit 4.4 to our Registration Statement on Form S-8 (333-19319) filed December 31, 2013).
10.54***	—	PAA Natural Gas Storage, L.P. 2010 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to PNG's Current Report on Form 8-K filed May 11, 2010).
10.55***	—	Form of PAA LTIP Grant Letter for Officers (February 2013) (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2013).
10.56***	—	Form of PAA LTIP Grant Letter for Officers (August 2016) (incorporated by reference to Exhibit 10.5 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2016).
10.57***	—	Form of Director LTIP Grant Letter (February 2017) - Director Grant - Designated Directors and Audit Committee Members (PAA Plan) (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
10.58***	—	Form of Director LTIP Grant Letter (February 2017) - Audit Committee Supplement (PAA Plan) (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
10.59***	—	Form of Director LTIP Grant Letter (February 2017) - Independent Director Grant (PAA Plan) (incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
10.60***	—	Form of Director LTIP Grant Letter (February 2017) - Director Grant - Designated Directors and Audit Committee Members (PAGP Plan) (incorporated by reference to Exhibit 10.1 to PAGP's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
10.61***	—	Form of Director LTIP Grant Letter (February 2017) - Audit Committee Supplement (PAGP Plan) (incorporated by reference to Exhibit 10.2 to PAGP's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).

10.62***	—	Form of Director LTIP Grant Letter (February 2017) - Independent Director Grant (PAGP Plan) (incorporated by reference to Exhibit 10.3 to PAGP's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
10.63***	—	Form of LTIP Grant Letter for Officers (July 2017) (incorporated by reference to Exhibit 10.4 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).
10.64***		Plains GP Holdings, L.P. Long Term Incentive Plan, (incorporated by reference to Exhibit 10.3 to PAGP's Current Report on Form 8-K filed October 25, 2013).
12.1 †	—	Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Combined Fixed Charges and Preferred Unit Distributions.
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. INS†	—	XBRL Instance Document
101.SCH†	—	XBRL Taxonomy Extension Schema Document
101.CAL†	—	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF†	—	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB†	—	XBRL Taxonomy Extension Label Linkbase Document
101.PRE†	—	XBRL Taxonomy Extension Presentation Linkbase Document

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† Filed herewith.

†† Furnished herewith.

* Certain confidential portions of this exhibit have been omitted pursuant to an Application for Confidential Treatment under Rule 24b-2 under the Exchange Act. This exhibit, with the omitted language, has been filed separately with the Securities and Exchange Commission.

** Certain schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule will be furnished supplementally to the SEC upon request.

*** Management compensatory plan or arrangement.

Item 16. ***Form 10-K Summary***

None.

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,
Chief Executive Officer of Plains All American GP LLC
(Principal Executive Officer)

February 26, 2018

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

February 26, 2018

By: /s/ Chris Herbold
Chris Herbold,
Vice President—Accounting and Chief Accounting Officer of Plains All American GP LLC
(Principal Accounting Officer)

February 26, 2018

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 and Director of PAA GP Holdings LLC and Chief Executive Officer of Plains All American GP LLC (Principal Executive Officer)	February 26, 2018
/s/ Harry N. Pefanis Harry N. Pefanis	Director of PAA GP Holdings LLC and President and Chief Commercial Officer of Plains All American GP LLC	February 26, 2018
/s/ Willie Chiang Willie Chiang	Director of PAA GP Holdings LLC and Executive Vice President and Chief Operating Officer of Plains All American GP LLC	February 26, 2018
/s/ Al Swanson Al Swanson	Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)	February 26, 2018
/s/ Chris Herbold Chris Herbold	Vice President—Accounting and Chief Accounting Officer of Plains All American GP LLC (Principal Accounting Officer)	February 26, 2018
/s/ Oscar K. Brown Oscar K. Brown	Director of PAA GP Holdings LLC	February 26, 2018
/s/ Victor Burk Victor Burk	Director of PAA GP Holdings LLC	February 26, 2018
/s/ Everardo Goyanes Everardo Goyanes	Director of PAA GP Holdings LLC	February 26, 2018
/s/ Gary R. Petersen Gary R. Petersen	Director of PAA GP Holdings LLC	February 26, 2018
/s/ John T. Raymond John T. Raymond	Director of PAA GP Holdings LLC	February 26, 2018
/s/ Bobby S. Shackouls Bobby S. Shackouls	Director of PAA GP Holdings LLC	February 26, 2018
/s/ Robert V. Sinnott Robert V. Sinnott	Director of PAA GP Holdings LLC	February 26, 2018
/s/ J. Taft Symonds J. Taft Symonds	Director of PAA GP Holdings LLC	February 26, 2018
/s/ Christopher M. Temple Christopher M. Temple	Director of PAA GP Holdings LLC	February 26, 2018

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
INDEX TO THE CONSOLIDATED FINANCIAL STATEMENTS

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 has 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" (2013) 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, 2017.

The effectiveness of the Partnership's internal control over financial reporting as of December 31, 2017 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
Chief Executive Officer 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 26, 2018

Report of Independent Registered Public Accounting Firm

To the Board of Directors of PAA GP Holdings LLC and Unitholders of
Plains All American Pipeline, L.P.:

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Plains All American Pipeline, L.P. and its subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of operations, of comprehensive income, of changes in accumulated other comprehensive income/(loss), of changes in partners' capital, and of cash flows for each of the three years in the period ended December 31, 2017, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Partnership's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Partnership as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 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, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Partnership's management is responsible for these consolidated 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 the Partnership's consolidated financial statements and on the Partnership's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. 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.

Definition and Limitations of Internal Control over Financial Reporting

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.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 26, 2018

We have served as the Partnership's auditor since 1998.

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

	December 31, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 37	$ 47
Trade accounts receivable and other receivables, net	3,029	2,279
Inventory	713	1,343
Other current assets	221	603
Total current assets	4,000	4,272
PROPERTY AND EQUIPMENT	16,862	16,220
Accumulated depreciation	(2,773)	(2,348)
Property and equipment, net	14,089	13,872
OTHER ASSETS		
Goodwill	2,566	2,344
Investments in unconsolidated entities	2,756	2,343
Linefill and base gas	872	896
Long-term inventory	164	193
Other long-term assets, net	904	290
Total assets	$ 25,351	$ 24,210
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 3,457	$ 2,588
Short-term debt	737	1,715
Other current liabilities	337	361
Total current liabilities	4,531	4,664
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discounts and debt issuance costs	8,933	9,874
Other long-term debt	250	250
Other long-term liabilities and deferred credits	679	606
Total long-term liabilities	9,862	10,730
COMMITMENTS AND CONTINGENCIES (NOTE 17)		
PARTNERS' CAPITAL		
Series A preferred unitholders (69,696,542 and 64,388,853 units outstanding, respectively)	1,505	1,508
Series B preferred unitholders (800,000 units outstanding)	788	—
Common unitholders (725,189,138 and 669,194,419 units outstanding, respectively)	8,665	7,251
Total partners' capital excluding noncontrolling interests	10,958	8,759
Noncontrolling interests	—	57
Total partners' capital	10,958	8,816
Total liabilities and partners' capital	$ 25,351	$ 24,210

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

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

	Year Ended December 31, 2017	2016	2015
REVENUES			
Supply and Logistics segment revenues	$ 25,056	$ 19,004	$ 21,927
Transportation segment revenues	612	632	697
Facilities segment revenues	555	546	528
Total revenues	26,223	20,182	23,152
COSTS AND EXPENSES			
Purchases and related costs	22,985	17,233	19,726
Field operating costs	1,183	1,182	1,454
General and administrative expenses	276	279	278
Depreciation and amortization	626	494	432
Total costs and expenses	25,070	19,188	21,890
OPERATING INCOME	1,153	994	1,262
OTHER INCOME/(EXPENSE)			
Equity earnings in unconsolidated entities	290	195	183
Interest expense (net of capitalized interest of $35, $47 and $57, respectively)	(510)	(467)	(432)
Other income/(expense), net	(31)	33	(7)
INCOME BEFORE TAX	902	755	1,006
Current income tax expense	(28)	(85)	(84)
Deferred income tax (expense)/benefit	(16)	60	(16)
NET INCOME	858	730	906
Net income attributable to noncontrolling interests	(2)	(4)	(3)
NET INCOME ATTRIBUTABLE TO PAA	$ 856	$ 726	$ 903
NET INCOME PER COMMON UNIT (NOTE 3):			
Net income allocated to common unitholders — Basic	$ 685	$ 200	$ 305
Basic weighted average common units outstanding	717	464	394
Basic net income per common unit	$ 0.96	$ 0.43	$ 0.78
Net income allocated to common unitholders — Diluted	$ 685	$ 200	$ 305
Diluted weighted average common units outstanding	718	466	396
Diluted net income per common unit	$ 0.95	$ 0.43	$ 0.77

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, 2017	2016	2015
Net income	$ 858	$ 730	$ 906
Other comprehensive income/(loss)	239	72	(614)
Comprehensive income	1,097	802	292
Comprehensive income attributable to noncontrolling interests	(2)	(4)	(3)
Comprehensive income attributable to PAA	$ 1,095	$ 798	$ 289

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 ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)
(in millions)

	Derivative Instruments	Translation Adjustments	Other	Total
Balance at December 31, 2014	$ (159)	$ (308)	$ —	$ (467)
Reclassification adjustments	(45)	—	—	(45)
Deferred gain on cash flow hedges	1	—	—	1
Currency translation adjustments	—	(570)	—	(570)
2015 Activity	(44)	(570)	—	(614)
Balance at December 31, 2015	$ (203)	$ (878)	$ —	$ (1,081)
Reclassification adjustments	8	—	—	8
Deferred loss on cash flow hedges	(33)	—	—	(33)
Currency translation adjustments	—	96	—	96
Other	—	—	1	1
2016 Activity	(25)	96	1	72
Balance at December 31, 2016	$ (228)	$ (782)	$ 1	$ (1,009)
Reclassification adjustments	21	—	—	21
Deferred loss on cash flow hedges	(16)	—	—	(16)
Currency translation adjustments	—	234	—	234
2017 Activity	5	234	—	239
Balance at December 31, 2017	$ (223)	$ (548)	$ 1	$ (770)

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

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

	Year Ended December 31, 2017	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 858	$ 730	$ 906
Reconciliation of net income to net cash provided by operating activities:			
Depreciation and amortization	626	494	432
Equity-indexed compensation expense	41	60	27
Inventory valuation adjustments (Note 4)	35	3	117
Deferred income tax expense/(benefit)	16	(60)	16
Settlement of terminated interest rate hedging instruments	(29)	(29)	(48)
Change in fair value of Preferred Distribution Rate Reset Option (Note 12)	(13)	(30)	—
Equity earnings in unconsolidated entities	(290)	(195)	(183)
Distributions from unconsolidated entities	304	216	214
Other	10	23	(21)
Changes in assets and liabilities, net of acquisitions:			
Trade accounts receivable and other	(511)	(524)	803
Inventory	605	(463)	(90)
Accounts payable and other current liabilities	847	508	(815)
Net cash provided by operating activities	2,499	733	1,358
CASH FLOWS FROM INVESTING ACTIVITIES			
Cash paid in connection with acquisitions, net of cash acquired (Note 6)	(1,280)	(282)	(105)
Investments in unconsolidated entities (Note 8)	(416)	(301)	(253)
Additions to property, equipment and other	(1,024)	(1,334)	(2,079)
Proceeds from sales of assets (Note 6)	1,083	654	5
Return of investment from unconsolidated entities (Note 8)	21	—	—
Cash received from sales of linefill and base gas	49	—	1
Cash paid for purchases of linefill and base gas	(2)	(7)	(133)
Other investing activities	(1)	(3)	34
Net cash used in investing activities	(1,570)	(1,273)	(2,530)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings/(repayments) under commercial paper program (Note 10)	(690)	(564)	631
Net borrowings under senior secured hedged inventory facility (Note 10)	36	447	300
Repayment under AAP senior secured revolving credit facility (Note 10)	—	(92)	—
Repayment of AAP term loan (Note 10)	—	(550)	—
Proceeds from the issuance of senior notes (Note 10)	—	748	998
Repayments of senior notes (Note 10)	(1,350)	(175)	(549)
Net proceeds from the sale of Series A preferred units (Note 11)	—	1,569	—
Net proceeds from the sale of Series B preferred units (Note 11)	788	—	—
Net proceeds from the sale of common units (Note 11)	1,664	796	1,099
Contributions from general partner	—	42	23
Distributions paid to common unitholders (Note 11)	(1,386)	(1,062)	(1,081)
Distributions paid to general partner (Note 11)	—	(565)	(590)
Other financing activities	(5)	(38)	(31)
Net cash provided by/(used in) financing activities	(943)	556	800
Effect of translation adjustment on cash	4	4	(4)
Net increase/(decrease) in cash and cash equivalents	(10)	20	(376)
Cash and cash equivalents, beginning of period	47	27	403
Cash and cash equivalents, end of period	$ 37	$ 47	$ 27
Cash paid for:			
Interest, net of amounts capitalized	$ 486	$ 450	$ 396
Income taxes, net of amounts refunded	$ 50	$ 98	$ 50

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)

	Limited Partners						
	Preferred Unitholders						
	Series A	Series B	Common Unitholders	General Partner	Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Total Partners' Capital
Balance at December 31, 2014	$ —	$ —	$ 7,793	$ 340	$ 8,133	$ 58	$ 8,191
Net income	—	—	314	589	903	3	906
Distributions (Note 11)	—	—	(1,081)	(590)	(1,671)	(3)	(1,674)
Sales of common units	—	—	1,099	22	1,121	—	1,121
Other comprehensive loss	—	—	(602)	(12)	(614)	—	(614)
Other	—	—	57	(48)	9	—	9
Balance at December 31, 2015	$ —	$ —	$ 7,580	$ 301	$ 7,881	$ 58	$ 7,939
Net income	—	—	333	393	726	4	730
Distributions (Note 11)	—	—	(1,062)	(565)	(1,627)	(4)	(1,631)
Sale of Series A preferred units	1,509	—	—	33	1,542	—	1,542
Sales of common units	—	—	796	9	805	—	805
Other comprehensive income	—	—	72	—	72	—	72
Simplification Transactions (Note 1)	—	—	(471)	(171)	(642)	—	(642)
Other	(1)	—	3	—	2	(1)	1
Balance at December 31, 2016	$ 1,508	$ —	$ 7,251	$ —	$ 8,759	$ 57	$ 8,816
Net income	—	11	845	—	856	2	858
Distributions (Note 11)	—	(11)	(1,386)	—	(1,397)	(2)	(1,399)
Sale of Series B preferred units	—	788	—	—	788	—	788
Sales of common units	—	—	1,664	—	1,664	—	1,664
Acquisition of interest in Advantage Joint Venture (Note 6)	—	—	40	—	40	—	40
Sale of interest in SLC Pipeline LLC (Note 6)	—	—	—	—	—	(57)	(57)
Other comprehensive income	—	—	239	—	239	—	239
Other	(3)	—	12	—	9	—	9
Balance at December 31, 2017	$ 1,505	$ 788	$ 8,665	$ —	$ 10,958	$ —	$ 10,958

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 Consolidation and Presentation

Organization

Plains All American Pipeline, L.P. ("PAA") 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 and unless the context indicates otherwise, the terms "Partnership," "we," "us," "our," "ours" and similar terms refer to PAA and its subsidiaries.

We own and operate midstream energy infrastructure and provide logistics services primarily for crude oil, natural gas liquids ("NGL") and natural gas. We own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. Our business activities are conducted through three operating segments: Transportation, Facilities and Supply and Logistics. See Note 19 for further discussion of our operating segments.

Our non-economic general partner interest is held by PAA GP LLC ("PAA GP"), a Delaware limited liability company, whose sole member is Plains AAP, L.P. ("AAP"), a Delaware limited partnership. In addition to its ownership of PAA GP, as of December 31, 2017, AAP also owned a limited partner interest in us through its ownership of approximately 284.0 million of our common units (approximately 36% of our total outstanding common units and Series A preferred units combined). Plains All American GP LLC ("GP LLC"), a Delaware limited liability company, is AAP's general partner. Plains GP Holdings, L.P. ("PAGP") is the sole and managing member of GP LLC, and, at December 31, 2017, owned an approximate 55% limited partner interest in AAP. PAA GP Holdings LLC ("PAGP GP") is the general partner of PAGP.

As the sole member of GP LLC, PAGP has responsibility for conducting our business and managing our operations; however, the board of directors of PAGP GP has ultimate responsibility for managing the business and affairs of PAGP, AAP and us. GP LLC employs our domestic officers and personnel; our Canadian officers and personnel are employed by our subsidiary, Plains Midstream Canada ULC ("PMC").

References to the "PAGP Entities" include PAGP GP, PAGP, GP LLC, AAP and PAA GP. References to our "general partner," as the context requires, include any or all of the PAGP Entities. References to the "Plains Entities" include us, our subsidiaries and the PAGP Entities.

Simplification Transactions

On November 15, 2016, the Plains Entities closed a series of transactions and executed several organizational and ancillary documents (the "Simplification Transactions") intended to simplify our capital structure, better align the interests of our stakeholders and improve our overall credit profile. The Simplification Transactions included, among other things:

- the permanent elimination of our incentive distribution rights ("IDRs") and the economic rights associated with our 2% general partner interest in exchange for the issuance by us to AAP of 245.5 million PAA common units (including approximately 0.8 million units to be issued in the future) and the assumption by us of all of AAP's outstanding debt ($642 million);

- the implementation of a unified governance structure pursuant to which the board of directors of GP LLC was eliminated and an expanded board of directors of PAGP GP assumed oversight responsibility over both us and PAGP;

- the provision for annual PAGP shareholder elections beginning in 2018 for the purpose of electing certain directors, and the participation of our common unitholders and Series A preferred unitholders in such elections through our ownership of Class C shares in PAGP, which provide us, as the sole holder of such Class C shares, the right to vote in elections of eligible PAGP directors together with the holders of PAGP Class A and Class B shares;

- the execution by AAP of a reverse split to adjust the number of AAP Class A units ("AAP units") such that the number of outstanding AAP units (assuming the conversion of AAP Class B units (the "AAP Management Units") into AAP units) equaled the number of our common units received by AAP at the closing of the Simplification Transactions. Simultaneously, PAGP executed reverse splits to adjust the number of (i) PAGP Class A shares outstanding to equal the number of AAP units it owned following AAP's reverse unit split and (ii) PAGP Class B shares outstanding to equal the number of AAP units owned by AAP's unitholders other than PAGP following AAP's reverse unit split.

These reverse splits, along with the Omnibus Agreement, resulted in economic alignment between our common unitholders and PAGP's Class A shareholders, such that the number of outstanding PAGP Class A shares equals the number of AAP units owned by PAGP, which in turn equals the number of our common units held by AAP that are attributable to PAGP's interest in AAP. The Plains Entities also entered into an Omnibus Agreement, pursuant to which such one-to-one relationship will be maintained subsequent to the closing of the Simplification Transactions; and

- the creation of a right for certain holders of the AAP units to cause AAP to redeem such AAP units in exchange for an equal number of our common units held by AAP.

The Simplification Transactions were between and among consolidated subsidiaries of PAGP that are considered entities under common control. These equity transactions did not result in a change in the carrying value of the underlying assets and liabilities.

Definitions

Additional defined terms are used in the following notes and shall have the meanings indicated below:

AOCI	=	Accumulated other comprehensive income/(loss)
ASC	=	Accounting Standards Codification
ASU	=	Accounting Standards Update
Bcf	=	Billion cubic feet
Btu	=	British thermal unit
CAD	=	Canadian dollar
DERs	=	Distribution equivalent rights
EBITDA	=	Earnings before interest, taxes, depreciation and amortization
EPA	=	United States Environmental Protection Agency
FASB	=	Financial Accounting Standards Board
GAAP	=	Generally accepted accounting principles in the United States
ICE	=	Intercontinental Exchange
IPO	=	Initial public offering
LIBOR	=	London Interbank Offered Rate
LTIP	=	Long-term incentive plan
Mcf	=	Thousand cubic feet
MLP	=	Master limited partnership
NGL	=	Natural gas liquids, including ethane, propane and butane
NYMEX	=	New York Mercantile Exchange
Oxy	=	Occidental Petroleum Corporation or its subsidiaries
PLA	=	Pipeline loss allowance
USD	=	United States dollar
WTI	=	West Texas Intermediate

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present and discuss our consolidated financial position as of December 31, 2017 and 2016, and the consolidated results of our operations, cash flows, changes in partners' capital, comprehensive income and changes in accumulated other comprehensive income/(loss) for the years ended December 31, 2017, 2016 and 2015. 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 PAA. The accompanying consolidated financial statements include the accounts of PAA and all of its wholly owned subsidiaries and those entities that it controls. Investments in entities over which we have significant influence but not control are accounted for by the equity method. We apply proportionate consolidation for pipelines and other assets in which we own undivided joint interests.

Subsequent events have been evaluated through the financial statements issuance date and have been included in 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) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (ii) impairment assessments of goodwill and intangible assets, (iii) fair value of derivatives, (iv) accruals and contingent liabilities, (v) equity-indexed compensation plan accruals, (vi) property and equipment, depreciation and amortization expense, asset retirement obligations and impairments, (vii) allowance for doubtful accounts and (viii) inventory valuations. 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, NGL and natural gas 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 and NGL consist of outright sales contracts. Inventory purchases and sales under buy/sell transactions are treated as inventory exchanges. The sales under these exchanges are netted to zero in 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 in 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 or are not designated for hedge accounting.

Transportation Segment Revenues. Our Transportation segment operations generally consist of fee-based activities associated with transporting crude oil and NGL on pipelines, gathering systems and trucks. Revenues from pipeline tariffs and fees are associated with the transportation of crude oil and NGL at a published tariff, as well as revenues associated with agreements for committed space on various assets. Tariff revenues are recognized when the service is provided pursuant to specifications outlined in the tariffs. Revenues associated with fees are recognized in the month to which the fee applies. As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor that is intended to offset losses due to evaporation, measurement and other losses in transit. We value the allowance volumes and actual losses at the estimated net realizable value (including the impact of gains and losses from derivative related activities) in the month of occurrence.

Facilities Segment Revenues. Our Facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services primarily for crude oil, NGL and natural gas, as well as NGL fractionation and isomerization services and natural gas and condensate processing services. Revenues generated in this segment include (i) fees that are generated from storage capacity agreements, (ii) terminal throughput fees that are generated when we receive liquids from one connecting source and deliver the applicable product to another connecting carrier, (iii) fees from NGL fractionation and isomerization, (iv) fees from natural gas and condensate processing services, (v) fees associated with natural gas park and loan activities, interruptible storage services and wheeling and balancing services and (vi) loading and unloading fees at our rail terminals.

We generate revenue through a combination of month-to-month and multi-year agreements. 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 (including throughput and rail fees) are recognized as the liquids enter or exit the terminal and are received from or delivered to the connecting carrier or third-party terminal, as applicable. Hub service fees are recognized in the period the natural gas moves across our header system. Fees from NGL fractionation, isomerization services and gas processing services are recognized in the period when the services are performed.

Minimum Volume Commitments. We have certain agreements that require counterparties to deliver, transport or throughput a minimum volume over an agreed upon period. Some of these agreements include make-up rights if the minimum volume is not met. We record a receivable from the counterparty in the period that services are provided or when the transaction occurs, including amounts for deficiency obligations from counterparties associated with minimum volume commitments. If a counterparty has a make-up right associated with a deficiency, we defer the revenue attributable to the counterparty make-up right and subsequently recognize the revenue at the earlier of when the deficiency volume is delivered or shipped, when the make-up right expires or when it is determined that the counterparty's ability to utilize the make-up right is remote.

At December 31, 2017 and 2016, counterparty deficiencies associated with agreements that include minimum volume commitments totaled $57 million and $66 million, respectively, of which $37 million and $54 million, respectively, was recorded as deferred revenue. The remaining balance of $20 million and $12 million at each respective date was related to deficiencies for which the counterparties had not met their contractual minimum commitments and were not reflected in our Consolidated Financial Statements as we had not yet billed or collected such amounts.

Purchases and Related Costs

Purchases and related costs include (i) the cost of crude oil, NGL and natural gas obtained in outright purchases, (ii) fees incurred for storage and transportation, whether by pipeline, truck, rail, ship or barge and (iii) performance-related bonus costs. These costs are recognized when incurred except in the case of products purchased, which are recognized at the time title transfers to us. Purchases that are part of inventory exchanges under buy/sell transactions are netted with the related sales, with any margin presented in "Purchases and related costs" in our Consolidated Statements of Operations.

Field Operating Costs and General and Administrative Expenses

Field operating costs consist of various field operating expenses, including payroll, compensation and benefits costs for operations personnel; fuel and power costs (including the impact of gains and losses from derivative related activities); third-party trucking transportation costs for our U.S. crude oil operations; maintenance and integrity management costs; regulatory compliance; environmental remediation; insurance; costs for usage of third-party owned pipeline, rail and storage assets; vehicle leases; and property taxes. General and administrative expenses consist primarily of payroll, compensation and benefits costs; certain information systems and legal costs; office rent; contract and consultant costs; and audit and tax fees.

Foreign Currency Transactions/Translation

Certain of our subsidiaries 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, which is reflected in Partners' Capital on our Consolidated Balance Sheets.

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 net gain of $21 million for the year ended December 31, 2017, a net loss of $8 million for the year ended December 31, 2016 and a net gain of $21 million for the year ended December 31, 2015.

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, 2017 and 2016, accounts payable included $60 million and $66 million, respectively, of outstanding checks that were reclassified from cash and cash equivalents.

Accounts Receivable, Net

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of NGL and natural gas. These purchasers include, but are not limited to, refiners, producers, marketing and trading companies and financial institutions. 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.

Prices for crude oil, natural gas and NGLs can fluctuate widely. For example, NYMEX West Texas Intermediate oil prices have been volatile and ranged from a high of $107.26 per barrel in June 2014 to a low of $26.21 per barrel in February 2016. Although prices recovered somewhat in 2017 to close the year at $60.42 per barrel, the sustained decrease in commodity prices since late 2014 has caused liquidity and leverage issues throughout the energy industry, which in turn has increased the potential credit risks associated with certain counterparties with which we do business. To mitigate credit risk related to our accounts receivable, we utilize a rigorous credit review process. We closely monitor market conditions and perform credit reviews of each customer to make a determination with respect to the amount, if any, of open 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 advance cash payments, standby letters of credit, credit insurance or parental guarantees. As of December 31, 2017 and 2016, we had received $117 million and $89 million, respectively, of advance cash payments from third parties to mitigate credit risk. We also received $54 million and $66 million as of December 31, 2017 and 2016, respectively, of standby letters of credit to support obligations due from third parties, a portion of which applies to future business. Additionally, in an effort to mitigate credit risk, a significant portion of our transactions with counterparties are settled on a net-cash basis. Furthermore, we also enter into netting agreements (contractual agreements that allow us to offset receivables and payables with those counterparties against each other on our balance sheet) for the majority of our net-cash arrangements.

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, 2017 and 2016, substantially all of our trade accounts receivable (net of allowance for doubtful accounts) were less than 30 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled $3 million at both December 31, 2017 and 2016. Although we consider our allowance for doubtful accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

Noncontrolling Interests

Noncontrolling interest represents the portion of assets and liabilities in a consolidated subsidiary that is owned by a third party. FASB guidance requires all entities to report noncontrolling interests in subsidiaries as a component of equity in the consolidated financial statements. Following our sale of SLC Pipeline LLC in the fourth quarter of 2017, we no longer have any noncontrolling interests in consolidated subsidiaries. See Note 11 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 $103 million and $44 million, respectively, at December 31, 2017 and 2016 and were primarily reflected in “Other long-term liabilities and deferred credits” on our Consolidated Balance Sheets.

Fair Value Measurements

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 affects the placement of assets and liabilities within the fair value hierarchy levels. The determination of the fair values 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. Our credit adjustment methodology uses market observable inputs and requires judgment. There were no changes to any of our valuation techniques during the period. See Note 12 for further discussion.

Other Significant Accounting Policies

See the respective footnotes for our accounting policies regarding (i) net income per common unit, (ii) inventory, linefill and base gas and long-term inventory, (iii) property and equipment, (iv) acquisitions, (v) goodwill, (vi) investments in unconsolidated entities, (vii) other long-term assets, net, (viii) income allocation for partners’ capital presentation purposes, (ix) derivatives and risk management activities, (x) income taxes, (xi) equity-indexed compensation and (xii) legal and environmental matters.

Recent Accounting Pronouncements

In August 2017, the FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* to better align an entity’s risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results. Under the new guidance, (i) more financial and nonfinancial hedging strategies will be eligible for hedge accounting, (ii) presentation and disclosure requirements are amended and (iii) companies will change the way they assess effectiveness. This guidance is effective for interim and annual periods beginning after December 15, 2018, with early adoption permitted. We expect to adopt this ASU on January 1, 2019 and are currently evaluating the impact of the adoption on our financial position, results of operations and cash flows.

In May 2017, the FASB issued ASU 2017-09, *Compensation—Stock Compensation (Topic 718): Scope of Modification Accounting* to provide guidance about which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting. Under the new guidance, modification accounting is required only if the fair value (or calculated value or intrinsic value, if such alternative method is used), the vesting conditions, or the classification of the award (equity or liability) changes as a result of the change in terms or conditions. This guidance is effective for interim and annual periods beginning after December 15, 2017, with early adoption permitted, and prospective application required. We adopted this ASU on January 1, 2018. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

In February 2017, the FASB issued ASU 2017-05, *Other Income—Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets*. The ASU clarifies what type of transactions involving nonfinancial assets are covered by the ASU and provides guidance on how to account for those transactions, including partial sales of real estate. Within this guidance, all sales and partial sales of businesses, which may have previously been accounted for using the in-substance real estate guidance, should follow the consolidation guidance. This guidance is effective for interim and annual periods beginning after December 15, 2017, and must be adopted at the same time as Topic 606. We adopted this ASU on January 1, 2018, using the modified retrospective approach. The cumulative effect of our adoption resulted in increases in both the carrying value of investments in unconsolidated entities and retained earnings of approximately $110 million related to the retained non-controlling interest in those entities from partial sales of businesses accounted for under in-substance real estate guidance during 2016 and 2017. See Note 8 for discussion of our investments in unconsolidated entities.

In January 2017, the FASB issued ASU 2017-04, *Intangibles—Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment*. The amendments within this ASU eliminate Step 2 from the goodwill impairment test, which currently requires an entity to determine goodwill impairment by calculating the implied fair value of goodwill by hypothetically assigning the fair value of a reporting unit to all of its assets and liabilities as if that reporting unit had been acquired in a business combination. Under the amended standard, goodwill impairment will instead be measured using Step 1 of the goodwill impairment test with goodwill impairment being equal to the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying value of goodwill. This guidance is effective for interim and annual periods beginning after December 15, 2019, with early adoption permitted. We early adopted this ASU in the first quarter of 2017 and applied the amended standard to our 2017 annual goodwill impairment test.

In January 2017, the FASB issued ASU 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business*, which improves the guidance for determining whether a transaction involves the purchase or disposal of a business or an asset. This guidance is effective for interim and annual periods beginning after December 15, 2017, with early adoption permitted, and prospective application required. We adopted this ASU on January 1, 2018 and will apply the new guidance to applicable transactions occurring after that date.

In November 2016, the FASB issued ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force)*, requiring that a statement of cash flows explain the change in total cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents during the period. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period total amounts shown on the statement of cash flows. This guidance is effective for interim and annual periods beginning after December 31, 2017. We adopted this ASU on January 1, 2018. Our adoption did not have a material impact on our statement of cash flows.

In October 2016, the FASB issued ASU 2016-16, *Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory*, to improve the accounting for the income tax consequences of intra-entity transfers of assets other than inventory. This guidance is effective for interim and annual periods beginning after December 15, 2017, with early adoption permitted in the first interim period of an annual reporting period. We adopted this ASU on January 1, 2018. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

In October 2016, the FASB issued ASU 2016-17, *Consolidation (Topic 810): Interests Held through Related Parties That Are under Common Control*, changing how a reporting entity that is the single decision maker of a variable interest entity ("VIE") should treat indirect interests in the entity held through related parties that are under common control with the reporting entity when determining whether it is the primary beneficiary of that VIE. This guidance was effective for interim and annual periods beginning after December 31, 2016. We adopted this ASU on January 1, 2017. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*. This guidance will become effective for interim and annual periods beginning after December 15, 2019, with early adoption permitted by one year. We expect to adopt this ASU on January 1, 2020, and we are currently evaluating the effect that adopting this guidance will have on our financial position results of operations and cash flows.

In March 2016, the FASB issued ASU 2016-09, *Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting*, which simplified several aspects of the accounting for share-based payment transactions, including the income tax consequences, forfeitures, classification of awards as either equity or liabilities and classification of certain related payments on the statement of cash flows. This ASU is effective for interim and annual periods beginning after December 15, 2016, with early adoption permitted. We adopted the applicable provisions of the ASU on January 1, 2017 and (i) elected to account for forfeitures as they occur, utilizing the modified retrospective approach of adoption and (ii) classify cash paid for taxes when directly withholding units from an employee's award for tax-withholding purposes as a financing activity on our Consolidated Statement of Cash Flows. Our adoption did not have a material impact on our financial position or results of operations for the periods presented. We reclassified approximately $7 million and $14 million, respectively, of cash outflows from operating activities to financing activities for the years ended December 31, 2016 and 2015 related to cash paid for minimum statutory withholding requirements for which we withheld units from employees' awards.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, that revises the current accounting model for leases. The most significant changes are the clarification of the definition of a lease and required lessee recognition on the balance sheet of lease assets and liabilities with lease terms of more than 12 months, including extensive quantitative and qualitative disclosures. This ASU will become effective for interim and annual periods beginning after December 15, 2018, with a modified retrospective application required. Early adoption is permitted, including adoption in an interim period. We expect to adopt this ASU on January 1, 2019. We are currently evaluating the effect that adopting this ASU will have on our financial position, results of operations and cash flows. Although our evaluation is ongoing, we do expect that the adoption will impact our financial statements as the standard requires the recognition on the balance sheet of a right of use asset and corresponding lease liability. We are currently analyzing our contracts to determine whether they contain a lease under the revised guidance and have not quantified the amount of the asset and liability that will be recognized on our Consolidated Balance Sheet.

In July 2015, the FASB issued ASU 2015-11, *Inventory (Topic 330): Simplifying the Measurement of Inventory,* which requires entities to measure inventory at the lower of cost and net realizable value; however, inventory measured using last-in, first-out and the retail inventory method is unchanged by this ASU. This guidance was effective for interim and annual periods beginning after December 15, 2016, with prospective application required. We adopted this ASU on January 1, 2017. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers,* followed by a series of related accounting standard updates (collectively referred to as “Topic 606”) with the underlying principle that an entity will recognize revenue to reflect amounts expected to be received in exchange for the provision of goods and services to customers upon the transfer of those goods or services. Topic 606 also requires additional disclosures. Topic 606 can be adopted either with a full retrospective approach or a modified retrospective approach with a cumulative-effect adjustment as of the date of adoption and is effective for interim and annual periods beginning after December 15, 2017. We implemented a process to evaluate the impact of adopting Topic 606 on each type of revenue contract entered into with customers, and our implementation team effected changes to our business processes, systems and controls to support recognition and disclosure under the new standard. We did not identify any material revenue recognition timing differences under Topic 606 as compared to our policies in effect prior to adoption. In addition, we will have an increase in disclosures about the nature, amount, timing and uncertainty of revenue and the related cash flows. We adopted Topic 606 on January 1, 2018, and applied the modified retrospective approach. The cumulative effect of the adoption of Topic 606 was not material.

Note 3—Net Income Per Common Unit

After consideration of distributions to preferred unitholders (whether paid in cash or in-kind), basic and diluted net income per common unit is determined pursuant to the two-class method as prescribed in FASB guidance. This method is an earnings allocation formula that is used to determine allocations to our general partner (for periods prior to the Simplification Transactions), limited partners and participating securities according to distributions pertaining to the current period’s net income and participation rights in undistributed earnings or distributions in excess of earnings. Under the two-class method, net income is reduced by distributions pertaining to the period, and all remaining earnings or distributions in excess of earnings are then allocated to our general partner (for periods prior to the Simplification Transactions), common unitholders and participating securities based on their respective rights to share in distributions, regardless of whether those earnings would actually be distributed during a particular period from an economic or practical perspective. Participating securities include LTIP awards that have vested DERs, which entitle the grantee to a cash payment equal to the cash distribution paid on our outstanding common units.

The Simplification Transactions, which closed on November 15, 2016, included the permanent elimination of our IDRs and the economic rights associated with our 2% general partner interest in exchange for the issuance by us to AAP of approximately 244.7 million common units and the assumption by us of AAP’s debt. In addition, we may issue to AAP up to 0.8 million common units in connection with certain AAP Management Units becoming earned in future periods. As such, beginning with the distribution pertaining to the fourth quarter of 2016, our general partner is no longer entitled to receive distributions on the IDRs or general partner interest. See Note 1 for additional discussion of the Simplification Transactions.

We calculate basic and diluted net income per common unit by dividing net income attributable to PAA (after deducting amounts allocated to the preferred unitholders and participating securities, and for periods prior to the closing of the Simplification Transactions, the 2% general partner’s interest and IDRs) by the basic and diluted weighted average number of common units outstanding during the period.

The diluted weighted average number of common units is computed based on the weighted average number of common units plus the effect of potentially dilutive securities outstanding during the period, which include (i) our Series A preferred units, (ii) our LTIP awards and (iii) common units that are issuable to AAP when certain AAP Management Units become earned. See Note 11 for additional information regarding our Series A preferred units. See Note 16 for a complete discussion of our LTIP awards and the AAP Management Units. When applying the if-converted method prescribed by FASB guidance, the possible conversion of our Series A preferred units was excluded from the calculation of diluted net income per common unit for the years ended December 31, 2017 and 2016 as the effect was antidilutive. Our LTIP awards that contemplate the issuance of common units and certain AAP Management Units that contemplate the issuance of common units to AAP when such AAP Management Units become earned are considered dilutive unless (i) they become vested or earned only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. LTIP awards that were deemed to be dilutive during the three years ended December 31, 2017 were reduced by a hypothetical common unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB. As none of the necessary conditions for the remaining AAP Management Units to become earned had been satisfied by December 31, 2017, no common units issuable to AAP were contemplated in the calculation of diluted net income per common unit for any period presented.

The following table sets forth the computation of basic and diluted net income per common unit (in millions, except per unit data):

	Year Ended December 31,		
	2017	2016	2015
Basic Net Income per Common Unit			
Net income attributable to PAA	$ 856	$ 726	$ 903
Distributions to Series A preferred unitholders	(142)	(122)	—
Distributions to Series B preferred unitholders	(11)	—	—
Distributions to general partner	—	(412)	(608)
Distributions to participating securities	(2)	(4)	(6)
Undistributed loss allocated to general partner	—	14	16
Other	(16)	(2)	—
Net income allocated to common unitholders [1]	$ 685	$ 200	$ 305
Basic weighted average common units outstanding [2]	717	464	394
Basic net income per common unit	$ 0.96	$ 0.43	$ 0.78
Diluted Net Income per Common Unit			
Net income attributable to PAA	$ 856	$ 726	$ 903
Distributions to Series A preferred unitholders	(142)	(122)	—
Distributions to Series B preferred unitholders	(11)	—	—
Distributions to general partner	—	(412)	(608)
Distributions to participating securities	(2)	(4)	(6)
Undistributed loss allocated to general partner	—	14	16
Other	(16)	(2)	—
Net income allocated to common unitholders [1]	$ 685	$ 200	$ 305
Basic weighted average common units outstanding [2]	717	464	394
Effect of dilutive securities:			
LTIP units	1	2	2
Diluted weighted average common units outstanding	718	466	396
Diluted net income per common unit	$ 0.95	$ 0.43	$ 0.77

(1) We calculate net income allocated to common unitholders based on the distributions pertaining to the current period's net income (whether paid in cash or in-kind). After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings ("undistributed loss"), if any, are allocated to the general partner (for periods prior to the Simplification Transactions), common unitholders and participating securities in accordance with the contractual terms of our partnership agreement in effect for the period and as further prescribed under the two-class method.

(2) We considered the common units issued in connection with the Simplification Transactions to be outstanding for the entire fourth quarter of 2016 in the calculation of weighted average common units outstanding to more closely reflect the ownership interests in us with rights to the distributions for the periods included in the calculation of net income allocated to common unitholders.

Note 4—Inventory, Linefill and Base Gas and Long-term Inventory

Inventory primarily consists of crude oil, NGL and natural gas in pipelines, storage facilities and railcars that are valued at the lower of cost or net realizable value, 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. Any resulting adjustments are a component of "Purchases and related costs" on our accompanying Consolidated Statements of Operations. During the years ended December 31, 2017, 2016 and 2015, we recorded charges of $35 million, $3 million and $117 million, respectively, related to the writedown of our crude oil, NGL and natural gas inventory due to declines in prices. A portion of these inventory valuation adjustments was offset by the recognition of gains on derivative instruments being utilized to hedge future sales of our crude oil and NGL inventory. Such gains were recorded to "Supply and Logistics segment revenues" in our accompanying Consolidated Statement of Operations. See Note 12 for discussion of our derivative and risk management activities.

Linefill and base gas in assets we own are recorded at historical cost and consist of crude oil, NGL and natural gas. We classify as linefill or base gas (i) our proportionate share of barrels used to fill a pipeline that we own such that when an incremental barrel is pumped into or enters a pipeline it forces product out at another location, (ii) barrels that represent the minimum working requirements in tanks and caverns that we own and (iii) natural gas required to maintain the minimum operating pressure of natural gas storage facilities we own.

Linefill and base gas carrying amounts are reviewed for impairment in accordance with FASB guidance with respect to accounting for the impairment or disposal of long-lived assets. Carrying amounts that are not expected to be recoverable through future cash flows are written down to estimated fair value. See Note 5 for further discussion regarding impairment of long-lived assets. During 2017, 2016 and 2015, we did not recognize any impairments of linefill and base gas.

Minimum working inventory requirements in third-party assets and other working inventory in our assets that are 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 the average cost of the applicable inventory pools, and into long-term inventory, which is reflected as a separate line item in "Other assets" on our Consolidated Balance Sheets.

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

	December 31, 2017				December 31, 2016			
	Volumes	Unit of Measure	Carrying Value	Price/ Unit [(1)]	Volumes	Unit of Measure	Carrying Value	Price/ Unit [(1)]
Inventory								
Crude oil	7,800	barrels	$ 402	$ 51.54	23,589	barrels	$ 1,049	$ 44.47
NGL	10,774	barrels	294	$ 27.29	13,497	barrels	242	$ 17.93
Natural gas	—	Mcf	—	$ —	14,540	Mcf	32	$ 2.20
Other	N/A		17	N/A	N/A		20	N/A
Inventory subtotal			713				1,343	
Linefill and base gas								
Crude oil	12,340	barrels	719	$ 58.27	12,273	barrels	710	$ 57.85
NGL	1,597	barrels	45	$ 28.18	1,660	barrels	45	$ 27.11
Natural gas	24,976	Mcf	108	$ 4.32	30,812	Mcf	141	$ 4.58
Linefill and base gas subtotal			872				896	
Long-term inventory								
Crude oil	1,870	barrels	105	$ 56.15	3,279	barrels	163	$ 49.71
NGL	2,167	barrels	59	$ 27.23	1,418	barrels	30	$ 21.16
Long-term inventory subtotal			164				193	
Total			$ 1,749				$ 2,432	

(1) Price per unit of measure is comprised of a weighted average associated with various grades, qualities and locations. Accordingly, these prices may not coincide with any published benchmarks for such products.

Note 5—Property and Equipment

In accordance with our capitalization policy, expenditures made to expand the existing operating and/or earnings capacity of our assets are capitalized. We also capitalize certain costs directly related to the construction of such assets, including related internal labor costs, engineering costs and interest costs. For the years ended December 31, 2017, 2016 and 2015, capitalized interest recorded to property and equipment was $17 million, $34 million and $49 million, respectively. In addition, we capitalize interest related to investments in certain unconsolidated entities. See Note 8 for additional information. We also capitalize expenditures for the replacement and/or refurbishment of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity 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, 2017	December 31, 2016
Pipelines and related facilities [(1)]	10 - 70	$ 9,585	$ 9,025
Storage, terminal and rail facilities	30 - 70	5,558	5,305
Trucking equipment and other	3 - 15	414	408
Construction in progress	—	610	826
Office property and equipment	2 - 50	255	222
Land and other	N/A	440	434
Property and equipment, gross		16,862	16,220
Accumulated depreciation		(2,773)	(2,348)
Property and equipment, net		$ 14,089	$ 13,872

(1) We include rights-of-way, which are intangible assets, in our pipeline and related facilities amounts within property and equipment.

We calculate our depreciation using the straight-line method, based on estimated useful lives and salvage values of our assets. Depreciation expense for the years ended December 31, 2017, 2016 and 2015 was $463 million, $470 million and $380 million, respectively (including amounts related to the discontinuation of certain capital projects). We also classify gains and losses on sales of assets and asset impairments as a component of "Depreciation and amortization" in our Consolidated Statements of Operations. See Note 6 for a discussion of our disposition activities. See "Impairment of Long-Lived Assets" below for a discussion of our policy for the recognition of asset impairments.

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 and other long-lived assets 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," "abandoning" or "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.

In addition, when we evaluate property and equipment and other long-lived assets for recoverability, it may also be necessary to review related depreciation estimates and methods.

During the years ended December 31, 2017 and 2016, we recognized $152 million and $80 million, respectively, of non-cash charges related to the write-down of certain of our long-lived rail and other terminal assets included in our Facilities segment due to asset impairments and accelerated depreciation. Such charges are reflected in "Depreciation and amortization" on our Consolidated Financial Statements. The decline in demand for movements of crude oil by rail in the United States due to sustained unfavorable market conditions resulted in expected decreases in future cash flows for certain of our rail terminal assets, which was a triggering event that required us to assess the recoverability of our carrying value of such long-lived assets.

As a result of our impairment review, we wrote off the portion of the carrying amount of these long-lived assets that exceeded their fair value. Our estimated fair values were based upon recent sales prices of comparable facilities, as well as management's expectation of the market values for such assets based on their industry experience. We consider such inputs to be a Level 3 input in the fair value hierarchy.

We did not recognize any impairments during the year ended December 31, 2015.

Note 6—Acquisitions and Dispositions

The following acquisitions, excluding acquired interests accounted for under the equity method of accounting mentioned specifically below, were accounted for using the acquisition method of accounting and the determination of the fair value of the assets and liabilities acquired has been estimated in accordance with the applicable accounting guidance.

Acquisitions

2017

Alpha Crude Connector Acquisition

On February 14, 2017, we acquired all of the issued and outstanding membership interests in Alpha Holding Company, LLC for cash consideration of approximately $1.215 billion, subject to working capital and other adjustments (the "ACC Acquisition"). The ACC Acquisition was initially funded through borrowings under our senior unsecured revolving credit facility. Such borrowings were subsequently repaid with proceeds from our March 2017 issuance of common units to AAP pursuant to the Omnibus Agreement and in connection with a PAGP underwritten equity offering. See Note 11 for additional information.

Upon completion of the ACC Acquisition, we became the owner of a crude oil gathering system known as the "Alpha Crude Connector" (the "ACC System") located in the Northern Delaware Basin in Southeastern New Mexico and West Texas. The ACC System comprises approximately 515 miles of gathering and transmission lines and five market interconnects, including to our Basin Pipeline at Wink. During 2017, we made additional interconnects to our existing Northern Delaware Basin systems as well as additional enhancements to increase the ACC System capacity to approximately 350,000 barrels per day, depending on the level of volume at each delivery point. The ACC System is supported by acreage dedications covering approximately 315,000 gross acres, including a significant acreage dedication from one of the largest producers in the region. The ACC System complements our other Permian Basin assets and enhances the services available to the producers in the Northern Delaware Basin.

The following table reflects the fair value determination (in millions):

Identifiable assets acquired and liabilities assumed:	Estimated Useful Lives (Years)	Recognized amount
Property and equipment	3 - 70	$ 299
Intangible assets	20	646
Goodwill	N/A	269
Other assets and liabilities, net (including $4 million of cash acquired)	N/A	1
		$ 1,215

Intangible assets are included in "Other long-term assets, net" on our Consolidated Balance Sheets. The determination of fair value to intangible assets above is comprised of five acreage dedication contracts and associated customer relationships that will be amortized over a remaining weighted average useful life of approximately 20 years. The value assigned to such intangible assets will be amortized to earnings using methods that closely resemble the pattern in which the economic benefits will be consumed. Amortization expense was approximately $10 million for the period from February 14, 2017 through December 31, 2017, and the future amortization expense is estimated as follows for the next five years (in millions):

2018	$	25
2019	$	34
2020	$	42
2021	$	48
2022	$	54

Goodwill is an intangible asset representing the future economic benefits expected to be derived from other assets acquired that are not individually identified and separately recognized. The goodwill arising from the ACC Acquisition, which is tax deductible, represents the anticipated opportunities to generate future cash flows from undedicated acreage and the synergies created between the ACC System and our existing assets. The assets acquired in the ACC Acquisition, as well as the associated goodwill, are primarily included in our Transportation segment.

During the year ended December 31, 2017, we incurred approximately $6 million of acquisition-related costs associated with the ACC Acquisition. Such costs are reflected as a component of general and administrative expenses in our Consolidated Statements of Operations.

Pro forma financial information assuming the ACC Acquisition had occurred as of the beginning of the calendar year prior to the year of acquisition, as well as the revenues and earnings generated during the period since the acquisition date, were not material for disclosure purposes.

Other Acquisitions

In February 2017, we acquired a propane marine terminal for cash consideration of approximately $41 million. The assets acquired are included in our Facilities segment. We did not recognize any goodwill related to this acquisition.

On April 3, 2017, we and an affiliate of Noble Midstream Partners LP ("Noble") completed the acquisition of Advantage Pipeline, L.L.C. ("Advantage") through a newly formed 50/50 joint venture (the "Advantage Joint Venture"). We account for our interest in the Advantage Joint Venture under the equity method of accounting. See Note 8 for additional discussion of our equity method investments.

2016

During the year ended December 31, 2016, we completed two acquisitions for aggregate cash consideration of $289 million. These acquisitions included (i) an integrated system of NGL assets in Western Canada for cash consideration of approximately $204 million and (ii) the remaining interest in a Gulf Coast pipeline that was subsequently sold during the year. The assets acquired were primarily included in our Transportation and Facilities segments. We did not recognize any goodwill related to these acquisitions.

2015

During the year ended December 31, 2015, we completed three acquisitions for aggregate cash consideration of $105 million. These acquisitions included (i) an additional approximate 28% interest in Frontier Aspen LLC, which is accounted for under the equity method of accounting, (ii) a crude oil terminal included in our Facilities segment and (iii) the remaining interest in a pipeline system included in our Transportation segment. We recognized goodwill of $11 million related to these acquisitions. See Note 8 for additional discussion of our equity method investments.

Dispositions and Divestitures

During the year ended December 31, 2017, we sold certain non-core assets for total proceeds of $1.1 billion, including:

- certain of our Bay Area terminal assets located in California;
- our Bluewater natural gas storage facility located in Michigan;
- certain non-core pipelines in the Rocky Mountain and Bakken regions, including our interest in SLC Pipeline LLC;
- non-core pipeline segments primarily located in the Midwestern United States; and
- a 40% undivided interest in a segment of our Red River Pipeline extending from Cushing, Oklahoma to the Hewitt Station near Ardmore, Oklahoma for our net book value.

The Bay Area terminal assets and the Bluewater natural gas storage facility were reported in our Facilities segment. The pipeline assets were reported in our Transportation segment. See Note 8 for additional discussion.

In the aggregate, including non-cash impairments recognized upon reclassifications to assets held for sale, we recognized a net gain related to pending or completed asset sales of approximately $43 million for the year ended December 31, 2017, which is included in “Depreciation and amortization” on our Consolidated Statement of Operations. Such amount is comprised of gains of $123 million and losses of $80 million.

During the year ended December 31, 2016, we sold several non-core assets, including certain of our Gulf Coast pipelines and East Coast refined products terminals. In addition, we sold interests in Cheyenne Pipeline LLC and STACK Pipeline LLC. See Note 8 for additional discussion. In the aggregate, we recognized a net gain of approximately $100 million related to these transactions, which is included in “Depreciation and amortization” on our Consolidated Statement of Operations. Such amount is comprised of gains of $158 million and losses of $58 million, including $15 million of impairment of goodwill that was included in a disposal group classified as held for sale prior to the closing of such transaction.

During 2015, we sold various property and equipment and recognized a net loss of $2 million, which is included in “Depreciation and amortization” on our Consolidated Statement of Operations.

As of December 31, 2017, we classified approximately $80 million of assets as held for sale on our Consolidated Balance Sheet (in “Other current assets”) primarily related to a definitive agreement to sell non-core property and equipment included in our Facilities segment. We expect the sale to be consummated in the first half of 2018, subject to customary closing conditions, as applicable. As of December 31, 2016, we classified approximately $275 million of assets as held for sale on our Consolidated Balance Sheet (in “Other current assets”) primarily related to a definitive agreement to sell non-core assets, which were property and equipment included in our Facilities segment.

Note 7—Goodwill

Goodwill represents the future economic benefits arising from assets acquired in a business combination that are not individually identified and separately recognized.

In accordance with FASB guidance, we test goodwill to determine whether an impairment has occurred at least annually (as of June 30) and on an interim basis if it is more likely than not that a reporting unit's fair value is less than its carrying value. 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 provides for a quantitative approach to testing goodwill for impairment; however, we may first assess certain qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. In the quantitative test, 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 goodwill is impaired by the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying value of goodwill.

We completed our goodwill impairment test as of June 30, 2017 using a qualitative assessment. We determined that it was more likely than not that the fair value of each reporting unit was greater than its respective book value; therefore, additional impairment testing was not necessary at that time and goodwill was not considered impaired. However, due to a deterioration in the performance of the Supply and Logistics reporting unit and a reduction in projected performance of that reporting unit, we performed a quantitative test for the Supply and Logistics reporting unit as of December 31, 2017.

Through the quantitative test of the Supply and Logistics reporting unit's goodwill for potential impairment, we determined that the fair value of that reporting unit was greater than its respective book value; therefore, goodwill was not considered impaired. However, a further deterioration in the performance of the Supply and Logistics reporting unit could result in an impairment of goodwill.

We did not perform a quantitative test for our other reporting units as of December 31, 2017 as there were no indicators of possible impairment. We did not recognize any impairments of goodwill during the last three years.

Goodwill by segment and changes in goodwill is reflected in the following table (in millions):

	Transportation	Facilities	Supply and Logistics	Total
Balance at December 31, 2015	$ 815	$ 1,087	$ 503	$ 2,405
Foreign currency translation adjustments	6	3	1	10
Dispositions and reclassifications to assets held for sale	(15)	(56)	—	(71)
Balance at December 31, 2016	$ 806	$ 1,034	$ 504	$ 2,344
Acquisitions	269	—	—	269
Foreign currency translation adjustments	16	7	4	27
Dispositions and reclassifications to assets held for sale	(21)	(53)	—	(74)
Balance at December 31, 2017	$ 1,070	$ 988	$ 508	$ 2,566

Note 8—Investments in Unconsolidated Entities

Investments in entities over which we have significant influence but not control are accounted for under the equity method. 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 our Consolidated Statements of Operations entitled "Equity earnings in unconsolidated entities" and will increase or decrease, as applicable, the carrying value of our investments in unconsolidated entities on our Consolidated Balance Sheets. 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.

Our investments in unconsolidated entities consisted of the following (in millions, except percentage data):

Entity [1]	Type of Operation	Ownership Interest at December 31, 2017	December 31, 2017	December 31, 2016
Advantage Pipeline Holdings LLC ("Advantage Joint Venture")	Crude Oil Pipeline	50%	$ 69	$ —
BridgeTex Pipeline Company, LLC ("BridgeTex")	Crude Oil Pipeline	50%	1,093	1,098
Butte Pipe Line Company	Crude Oil Pipeline	N/A	—	11
Caddo Pipeline LLC	Crude Oil Pipeline	50%	67	65
Cheyenne Pipeline LLC ("Cheyenne")	Crude Oil Pipeline	50%	29	30
Diamond Pipeline LLC ("Diamond")	Crude Oil Pipeline	50%	467	143
Eagle Ford Pipeline LLC ("Eagle Ford Pipeline")	Crude Oil Pipeline	50%	378	372
Eagle Ford Terminals Corpus Christi LLC ("Eagle Ford Terminals")	Crude Oil Terminal and Dock [2]	50%	75	53
Frontier Aspen LLC	Crude Oil Pipeline	N/A	—	45
Midway Pipeline LLC	Crude Oil Pipeline	50%	20	—
Saddlehorn Pipeline Company, LLC	Crude Oil Pipeline	40%	217	213
Settoon Towing, LLC	Barge Transportation Services	50%	69	87
STACK Pipeline LLC ("STACK")	Crude Oil Pipeline	50%	73	14
White Cliffs Pipeline, LLC	Crude Oil Pipeline	36%	199	212
Total Investments in Unconsolidated Entities			$ 2,756	$ 2,343

(1) Except for Eagle Ford Terminals, which is reported in our Facilities segment, the financial results from the entities are reported in our Transportation segment.

(2) Asset is currently under construction by the entity and has not yet been placed in service.

On April 3, 2017, we and an affiliate of Noble completed the acquisition of Advantage Pipeline, L.L.C. for a purchase price of $133 million through a newly formed 50/50 joint venture (the "Advantage Joint Venture"). For our 50% share ($66.5 million), we contributed approximately 1.3 million common units with a value of approximately $40 million and approximately $26 million in cash. Through the acquisition, the Advantage Joint Venture owns a 70-mile, 16-inch crude oil pipeline located in the southern Delaware Basin (the "Advantage Pipeline"), which is contractually supported by a third-party acreage dedication and a volume commitment from our wholly-owned marketing subsidiary. Noble serves as operator of the Advantage Pipeline. We account for our interest in the Advantage Joint Venture under the equity method of accounting.

During the fourth quarter of 2017, we sold certain of our non-core pipelines in the Rocky Mountain region which included our ownership interests in Butte Pipe Line Company and Frontier Aspen LLC. Additionally, we and an affiliate of CVR Refining, LP ("CVR Refining") formed a 50/50 joint venture, Midway Pipeline LLC, which acquired from us the Cushing to Broome crude oil pipeline system. The Cushing to Broome pipeline system connects CVR Refining's Coffeyville, Kansas refinery to the Cushing, Oklahoma oil hub. We will continue to serve as operator of the pipeline. We account for our interest in Midway Pipeline LLC under the equity method of accounting.

In June 2016, we sold 50% of our investment in Cheyenne, and in August 2016 we sold 50% of our investment in STACK. As a result of these transactions, we now account for our remaining 50% equity interest in such entities under the equity method of accounting.

See Note 6 for additional information related to certain of these transactions.

Distributions received from unconsolidated entities are classified based on the nature of the distribution approach, which looks to the activity that generated the distribution. We consider distributions received from unconsolidated entities as a return on investment in those entities to the extent that the distribution was generated through operating results, and therefore classify these distributions as cash flows from operating activities in our Consolidated Statement of Cash Flows. Other distributions received from unconsolidated entities are considered a return of investment and classified as cash flows from investing activities on the Consolidated Statement of Cash Flows. During the year ended December 31, 2017, we received $21 million as a return of investment from Settoon Towing, LLC related to the sale of certain of its marine assets.

We generally fund our portion of development, construction or capital expansion projects of our equity method investees through capital contributions. Our contributions to these entities increase the carrying value of our investments and are reflected in our Consolidated Statements of Cash Flows as cash used in investing activities. During the years ended December 31, 2017, 2016 and 2015, we made cash contributions of $398 million, $288 million and $245 million, respectively, to certain of our equity method investees. The contributions for 2017 and 2015 are net of $6 million and $53 million, respectively, of returns of cash contributions made during the periods. In addition, we capitalized interest of $18 million, $13 million and $8 million during the years ended December 31, 2017, 2016 and 2015, respectively, related to contributions to unconsolidated entities for projects under development and construction. We anticipate that we will make additional contributions to Eagle Ford Terminals, Eagle Ford Pipeline, BridgeTex, Diamond and STACK in 2018 related to ongoing projects by such entities.

Our investments in unconsolidated entities exceeded our share of the underlying equity in the net assets of such entities by $736 million and $758 million at December 31, 2017 and 2016, respectively. Such basis differences are included in the carrying values of our investments on our Consolidated Balance Sheets. The portion of the basis differences attributable to depreciable or amortizable assets is amortized on a straight-line basis over the estimated useful life of the related assets, which reduces "Equity earnings in unconsolidated entities" on our Consolidated Statements of Operations. The portion of the basis differences attributable to goodwill is not amortized. The basis difference at both December 31, 2017 and 2016 is primarily related to our acquisition of an interest in BridgeTex in 2014.

Summarized Financial Information of Unconsolidated Entities

Combined summarized financial information for all of our unconsolidated entities is shown in the tables below (in millions). None of our unconsolidated entities have noncontrolling interests.

	December 31,	
	2017	2016
Current assets	$ 311	$ 303
Noncurrent assets	$ 4,162	$ 3,558
Current liabilities	$ 129	$ 241
Noncurrent liabilities	$ 41	$ 162

	Year Ended December 31,		
	2017	2016	2015
Revenues	$ 938	$ 802	$ 769
Operating income	$ 650	$ 469	$ 441
Net income	$ 640	$ 452	$ 424

Note 9—Other Long-Term Assets, Net

Other long-term assets, net of accumulated amortization, consisted of the following (in millions):

	December 31, 2017	December 31, 2016
Intangible assets [(1)]	$ 1,265	$ 603
Other	60	48
	1,325	651
Accumulated amortization	(421)	(361)
	$ 904	$ 290

(1) We include rights-of-way, which are intangible assets, in our pipeline and related facilities amounts within property and equipment. See Note 5 for a discussion of property and equipment.

The increase in intangible assets for the year ended December 31, 2017 was primarily due to acreage dedication contracts and associated customer relationships associated with our ACC Acquisition. See Note 6 for additional information. Amortization expense for finite-lived intangible assets for the years ended December 31, 2017, 2016 and 2015 was $54 million, $44 million and $49 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. We did not recognize any impairments of finite-lived intangible assets during the three years ended December 31, 2017. Our intangible assets that have finite lives consisted of the following (in millions):

		December 31, 2017			December 31, 2016		
	Estimated Useful Lives (Years)	Cost	Accumulated Amortization	Net	Cost	Accumulated Amortization	Net
Customer contracts and relationships	1 – 20	$ 1,188	$ (383)	$ 805	$ 529	$ (330)	$ 199
Property tax abatement	7 – 13	38	(30)	8	38	(26)	12
Other agreements	25 – 70	39	(8)	31	36	(5)	31
		$ 1,265	$ (421)	$ 844	$ 603	$ (361)	$ 242

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

2018	$ 63
2019	$ 68
2020	$ 74
2021	$ 75
2022	$ 76

Note 10—Debt

Debt consisted of the following (in millions):

	December 31, 2017	December 31, 2016
SHORT-TERM DEBT		
Commercial paper notes, bearing a weighted-average interest rate of 2.4% and 1.6%, respectively [1]	$ —	$ 563
Senior secured hedged inventory facility, bearing a weighted-average interest rate of 2.6% and 1.8%, respectively [1]	664	750
Senior notes:		
6.13% senior notes due January 2017	—	400
Other	73	2
Total short-term debt [2]	737	1,715
LONG-TERM DEBT		
Senior notes:		
6.50% senior notes due May 2018 [3]	—	600
8.75% senior notes due May 2019 [3]	—	350
2.60% senior notes due December 2019	500	500
5.75% senior notes due January 2020	500	500
5.00% senior notes due February 2021	600	600
3.65% senior notes due June 2022	750	750
2.85% senior notes due January 2023	400	400
3.85% senior notes due October 2023	700	700
3.60% senior notes due November 2024	750	750
4.65% senior notes due October 2025	1,000	1,000
4.50% senior notes due December 2026	750	750
6.70% senior notes due May 2036	250	250
6.65% senior notes due January 2037	600	600
5.15% senior notes due June 2042	500	500
4.30% senior notes due January 2043	350	350
4.70% senior notes due June 2044	700	700
4.90% senior notes due February 2045	650	650
Unamortized discounts and debt issuance costs	(67)	(76)
Senior notes, net of unamortized discounts and debt issuance costs	8,933	9,874
Other long-term debt:		
Commercial paper notes and senior secured hedged inventory facility borrowings [4]	247	247
Other	3	3
Total long-term debt	9,183	10,124
Total debt [5]	$ 9,920	$ 11,839

(1) We classified these commercial paper notes and credit facility borrowings as short-term as of December 31, 2017 and 2016, as these notes and borrowings were primarily designated as working capital borrowings, were required to be repaid within one year and were primarily for hedged NGL and crude oil inventory and NYMEX and ICE margin deposits.

(2) As of December 31, 2017 and 2016, balance includes borrowings of $212 million and $410 million, respectively, for cash margin deposits with NYMEX and ICE, which are associated with financial derivatives used for hedging purposes.

(3) In December 2017, we redeemed our $600 million, 6.50% senior notes due May 2018 and our $350 million, 8.75% senior notes due May 2019. See the "Senior Notes—Senior Note Repayments and Redemptions" section below for further discussion.

(4) As of December 31, 2017 and 2016, we classified a portion of our commercial paper notes and senior secured hedged inventory facility borrowings as long-term based on our ability and intent to refinance such amounts on a long-term basis.

(5) Our fixed-rate senior notes (including current maturities) had a face value of approximately $9.0 billion and $10.3 billion as of December 31, 2017 and 2016, respectively. We estimated the aggregate fair value of these notes as of December 31, 2017 and 2016 to be approximately $9.1 billion and $10.4 billion, respectively. Our fixed-rate senior notes are traded among institutions, and these trades are routinely published by a reporting service. Our determination of fair value is based on reported trading activity near year end. We estimate that the carrying value of outstanding borrowings under our credit facilities and commercial paper program approximates fair value as interest rates reflect current market rates. The fair value estimates for our senior notes, credit facilities and commercial paper program are based upon observable market data and are classified in Level 2 of the fair value hierarchy.

Commercial Paper Program

We have a commercial paper program under which we may issue (and have outstanding at any time) up to $3.0 billion in the aggregate of privately placed, unsecured commercial paper notes. Such notes are backstopped by our senior unsecured revolving credit facility and our senior secured hedged inventory facility; as such, any borrowings under our commercial paper program reduce the available capacity under these facilities.

Credit Facilities

Senior secured hedged inventory facility. We have a credit agreement that provides for a senior secured hedged inventory facility with a committed borrowing capacity of $1.4 billion, of which $400 million is available for the issuance of letters of credit. Subject to obtaining additional or increased lender commitments, the committed capacity of the facility may be increased to $1.9 billion. Proceeds from the facility are primarily used to finance purchased or stored hedged inventory, including NYMEX and ICE margin deposits. Such obligations under the committed facility are secured by the financed inventory and the associated accounts receivable and are repaid from the proceeds of the sale of the financed inventory. Borrowings accrue interest based, at our election, on either the Eurocurrency Rate or the Base Rate, in each case plus a margin based on our credit rating at the applicable time. The agreement also provides for one or more one-year extensions, subject to applicable approval. In August 2017, we amended this agreement to, among other things, extend the maturity date of the facility to August 2020 for each extending lender. The maturity date with respect to each non-extending lender (which represent aggregate commitments of approximately $60 million out of total commitments of $1.4 billion from all lenders) remains August 2019.

Senior unsecured revolving credit facility. We have a credit agreement that provides for a senior unsecured revolving credit facility with a committed borrowing capacity of $1.6 billion. Subject to obtaining additional or increased lender commitments, the committed capacity may be increased to $2.1 billion. The credit agreement also provides for the issuance of letters of credit. Borrowings accrue interest based, at our election, on the Eurocurrency Rate, the Base Rate or the Canadian Prime Rate, in each case plus a margin based on our credit rating at the applicable time. The agreement also provides for one or more one-year extensions, subject to applicable approval. In August 2017, we amended this agreement to, among other things, extend the maturity date of the facility to August 2022 for each extending lender. The maturity dates with respect to each non-extending lender (which represent aggregate commitments of $120 million out of total commitments of $1.6 billion from all lenders) remain August 2021 or mature one year earlier.

Senior unsecured 364-day revolving credit facility. We have a credit agreement that provides for a 364-day senior unsecured revolving credit facility with a borrowing capacity of $1.0 billion. In August 2017, we amended this agreement to extend the maturity date to August 2018. Additionally, a provision was added whereby we may elect to have the entire principal balance of any loans outstanding on the maturity date converted to a non-revolving term loan with a maturity date of August 2019. Borrowings accrue interest based, at our election, on either the Eurocurrency Rate or the Base Rate, as defined in the agreement, in each case plus a margin based on our credit rating at the applicable time.

AAP senior secured credit agreement. In connection with the Simplification Transactions, on November 15, 2016, we assumed all of AAP's then outstanding borrowings under the AAP senior secured credit agreement, and immediately repaid such amounts and canceled the credit agreement. See Note 1 for further discussion of the Simplification Transactions.

Senior Notes

Our senior notes are co-issued, jointly and severally, by Plains All American Pipeline, L.P. and a 100%-owned consolidated finance subsidiary (neither of which have independent assets or operations) and are unsecured senior obligations of such entities and rank equally in right of payment with existing and future senior indebtedness of the issuers. We may, at our option, redeem any series of senior notes at any time in whole or from time to time in part, prior to maturity, at the redemption prices described in the indentures governing the senior notes. Our senior notes are not guaranteed by any of our subsidiaries.

Senior Notes Issuances

The table below summarizes our issuances of senior unsecured notes during 2016 and 2015 (in millions):

Year	Description	Maturity	Face Value	Interest Payment Dates
2016	4.50% Senior Notes issued at 99.716% of face value	December 2026	$ 750	June 15 and December 15
2015	4.65% Senior Notes issued at 99.846% of face value	October 2025	$ 1,000	April 15 and October 15

We did not issue any senior unsecured notes during the year ended December 31, 2017.

Senior Note Repayments and Redemptions

Our $400 million, 6.13% senior notes matured and were repaid in January 2017. In December 2017, we redeemed our $600 million, 6.50% senior notes due May 2018 and our $350 million, 8.75% senior notes due May 2019. We utilized cash on hand and available capacity under our commercial paper program and credit facilities to repay these notes. In conjunction with the early redemptions, we recognized a loss of approximately $40 million, recorded to Other income/(expense), net in our Consolidated Statements of Operations.

Our $175 million, 5.88% senior notes matured and were repaid in August 2016. We utilized cash on hand and available capacity under our commercial paper program and credit facilities to repay these notes.

Our $150 million, 5.25% senior notes and $400 million, 3.95% senior notes matured and were repaid in June 2015 and September 2015, respectively. We utilized cash on hand and available capacity under our commercial paper program to repay these notes.

Maturities

The weighted average maturity of our long-term debt outstanding at December 31, 2017 was approximately 12 years. The following table presents the aggregate contractually scheduled maturities of such long-term debt for the next five years and thereafter. The amounts presented exclude unamortized discounts and debt issuance costs.

Calendar Year	Payment (in millions)
2018	$ 247
2019	500
2020	500
2021	600
2022	750
Thereafter	6,653

Covenants and Compliance

Our credit agreements (which impact our ability to access our commercial paper program because they provide a financial backstop that supports our short-term credit ratings) and the indentures governing our senior notes contain cross-default provisions. Our credit agreements prohibit declaration or payments of 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:

- grant liens on certain property;
- incur indebtedness, including capital leases;
- sell substantially all of our assets or enter into a merger or consolidation;
- engage in certain transactions with affiliates; and
- enter into certain burdensome agreements.

The credit agreements for our senior unsecured revolving credit facility, senior secured hedged inventory facility and senior unsecured 364-day revolving credit facility treat a change of control as an event of default and also require us to maintain a debt-to-EBITDA coverage ratio that, on a trailing four-quarter basis, will not be greater than 5.00 to 1.00 (or 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 $150 million), and/or during the GP Simplification Period (the period beginning on November 15, 2016 and ending on December 31, 2017)). For covenant compliance purposes, Consolidated EBITDA may include certain adjustments, including those for material projects and certain non-recurring expenses. Additionally, 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, 2017, we were in compliance with the covenants contained in our credit agreements and indentures.

Borrowings and Repayments

Total borrowings under our credit agreements and commercial paper program for the years ended December 31, 2017, 2016 and 2015 were approximately $60.8 billion, $60.3 billion and $62.2 billion, respectively. Total repayments under our credit agreements and commercial paper program were approximately $61.5 billion, $61.0 billion and $61.3 billion for the years ended December 31, 2017, 2016 and 2015, respectively. The variance in total gross borrowings and repayments is impacted by various business and financial factors including, but not limited to, the timing, average term and method of general partnership borrowing activities.

Letters of Credit

In connection with our supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase and transportation of crude oil, NGL and natural gas. These letters of credit are issued under the PAA senior unsecured revolving credit facility and the PAA senior secured hedged inventory 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, NGL or natural gas is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. Additionally, we issue letters of credit to support insurance programs, derivative transactions and construction activities. At December 31, 2017 and 2016, we had outstanding letters of credit of $166 million and $73 million, respectively.

Debt Issuance Costs

Costs incurred in connection with the issuance of senior notes are recorded as a direct deduction from the related debt liability and are 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.

Note 11—Partners' Capital and Distributions

Units Outstanding

At December 31, 2017, partners' capital consisted of outstanding common units and Series A and Series B preferred units, which represent limited partner interests in us, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges as outlined in our partnership agreement. Our general partner has a non-economic interest in us. However, prior to the closing of the Simplification Transactions, our outstanding common units and Series A preferred units represented a 98% effective aggregate ownership interest in us and our subsidiaries after giving effect to the 2% general partner interest. See Note 1 for discussion of the Simplification Transactions.

The following table presents the activity for our preferred and common units:

	Limited Partners		
	Series A Preferred Units	Series B Preferred Units	Common Units
Outstanding at December 31, 2014	—	—	375,107,793
Sales of common units	—	—	22,133,904
Issuances of common units under LTIP	—	—	485,927
Outstanding at December 31, 2015	—	—	397,727,624
Sale of Series A preferred units	61,030,127	—	—
Issuances of Series A preferred units in connection with in-kind distributions	3,358,726	—	—
Sales of common units	—	—	26,278,288
Issuances of common units under LTIP	—	—	480,581
Issuance of common units in connection with Simplification Transactions (Note 1)	—	—	244,707,926
Outstanding at December 31, 2016	64,388,853	—	669,194,419
Issuances of Series A preferred units in connection with in-kind distributions	5,307,689	—	—
Sale of Series B preferred units	—	800,000	—
Sales of common units	—	—	54,119,893
Issuance of common units in connection with acquisition of interest in Advantage Joint Venture (Note 6)	—	—	1,252,269
Issuances of common units under LTIP	—	—	622,557
Outstanding at December 31, 2017	69,696,542	800,000	725,189,138

Equity Offerings

Common Unit Issuances. We have entered into several equity distribution agreements under our Continuous Offering Program, pursuant to which we may offer and sell, through sales agents, common units representing limited partner interests. We may also sell common units through overnight or underwritten offerings. In addition, we may sell common units to AAP pursuant to the Omnibus Agreement entered into by the Plains Entities in connection with the November 2016 Simplification Transactions.

The following table summarizes our sales of common units (net proceeds in millions):

Year	Type of Offering	Common Units Issued	Net Proceeds (1) (2)
2017	Continuous Offering Program	4,033,567	$ 129 (3)
2017	Omnibus Agreement (4)	50,086,326 (5)	1,535
2017 Total		**54,119,893**	**$ 1,664**
2016 Total	**Continuous Offering Program**	**26,278,288**	**$ 805** (3)
2015	Continuous Offering Program	1,133,904	$ 59 (3)
2015	Underwritten Offering	21,000,000	1,062
2015 Total		**22,133,904**	**$ 1,121**

(1) Amounts are net of costs associated with the offerings.

(2) For periods prior to the closing of the Simplification Transactions, amounts include our general partner's proportionate capital contributions of $9 million and $22 million during 2016 and 2015, respectively.

(3) We pay commissions to our sales agents in connection with common unit issuances under our Continuous Offering Program. We paid $1 million, $8 million and $1 million of such commissions during 2017, 2016 and 2015, respectively.

(4) Pursuant to the Omnibus Agreement entered into by the Plains Entities in connection with the Simplification Transactions, PAGP used the net proceeds from the sale of PAGP Class A shares, after deducting the sales agents' commissions and offering expenses, to purchase from AAP a number of AAP units equal to the number of PAGP Class A shares sold in such offering at a price equal to the net proceeds from such offering. Also pursuant to the Omnibus Agreement, immediately following such purchase and sale, AAP used the net proceeds it received from such sale of AAP units to purchase from us an equivalent number of our common units.

(5) Includes (i) approximately 1.8 million common units issued to AAP in connection with PAGP's issuance of Class A shares under its Continuous Offering Program and (ii) 48.3 million common units issued to AAP in connection with PAGP's March 2017 underwritten offering.

Series A Preferred Unit Issuance. On January 28, 2016 (the "Issuance Date"), we completed the private placement of approximately 61.0 million Series A preferred units representing limited partner interests in us for a cash purchase price of $26.25 per unit (the "Issue Price"), resulting in total net proceeds to us, after deducting offering expenses and the 2% transaction fee due to the purchasers and including our general partner's proportionate capital contribution, of approximately $1.6 billion. Certain of the purchasers or their affiliates are related parties. See Note 15 for additional information.

The Series A preferred units rank pari passu with our Series B preferred units, and senior to our common units and to each other class or series of our equity securities with respect to distribution rights and rights upon liquidation. The holders of the Series A preferred units receive cumulative quarterly distributions, subject to customary antidilution adjustments, equal to $0.525 per unit ($2.10 per unit annualized). With respect to each quarter ending on or prior to December 31, 2017 (the "Initial Distribution Period"), we elected to pay distributions on the Series A preferred units in additional Series A preferred units. With respect to any quarter ending after the Initial Distribution Period, we must pay distributions on the Series A preferred units in cash.

The purchasers may convert their Series A preferred units into common units, generally on a one-for-one basis and subject to customary anti-dilution adjustments, at any time after January 28, 2018, in whole or in part, subject to certain minimum conversion amounts (and not more often than once per quarter). We may convert the Series A preferred units into common units at any time (but not more often than once per quarter) after the third anniversary of the Issuance Date (January 28, 2019), in whole or in part, subject to certain minimum conversion amounts, if the closing price of our common units is greater than 150% of the Issue Price for the preceding 20 trading days. The Series A preferred units vote on an as-converted basis with our common units and will have certain other class voting rights with respect to any amendment to our partnership agreement that would adversely affect any rights, preferences or privileges of the Series A preferred units. In addition, upon certain events involving a change of control, the holders of the Series A preferred units may elect, among other potential elections, to convert the Series A preferred units to common units at the then applicable conversion rate.

For a period of 30 days following (a) the fifth anniversary of the Issuance Date of the Series A preferred units and (b) each subsequent anniversary of the Issuance Date, the holders of the Series A preferred units, acting by majority vote, may make a one-time election to reset the distribution rate to equal the then applicable rate of the ten-year U.S. Treasury plus 5.85% (the "Preferred Distribution Rate Reset Option"). The Preferred Distribution Rate Reset Option is accounted for as an embedded derivative. See Note 12 for additional information. If the holders of the Series A preferred units have exercised the Preferred Distribution Rate Reset Option, then, at any time following 30 days after the sixth anniversary of the Issuance Date, we may redeem all or any portion of the outstanding Series A preferred units in exchange for cash, common units (valued at 95% of the volume-weighted average price of the common units for a trading day period specified in our partnership agreement) or a combination of cash and common units at a redemption price equal to 110% of the Issue Price, plus any accrued and unpaid distributions.

Series B Preferred Unit Issuance. On October 10, 2017, we issued 800,000 Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units representing limited partner interests in us (the "Series B preferred units") at a price to the public of $1,000 per unit. We used the net proceeds of $788 million, after deducting the underwriters' discounts and offering expenses, from the issuance of the Series B preferred units to repay amounts outstanding under our credit facilities and commercial paper program and for general partnership purposes.

The Series B preferred units represent perpetual equity interests in us, and they have no stated maturity or mandatory redemption date and are not redeemable at the option of the holders under any circumstances. Holders of the Series B preferred units generally have no voting rights, except for limited voting rights with respect to (i) potential amendments to our partnership agreement that would have a material adverse effect on the existing preferences, rights, powers or duties of the Series B preferred units, (ii) the creation or issuance of any parity securities if the cumulative distributions payable on then outstanding Series B preferred units are in arrears, (iii) the creation or issuance of any senior securities and (iv) the payment of distributions to our common unitholders out of capital surplus. The Series B preferred units rank, as to the payment of distributions and amounts payable on a liquidation event, on par with our outstanding Series A preferred units.

The Series B preferred units have a liquidation preference of $1,000 per unit. Holders of our Series B preferred units are entitled to receive, when, as and if declared by our general partner out of legally available funds for such purpose, cumulative semiannual or quarterly cash distributions, as applicable. Distributions on the Series B preferred units accrue and are cumulative from October 10, 2017, the date of original issue, and are payable semiannually in arrears on the 15th day of May and November through and including November 15, 2022, and after November 15, 2022, quarterly in arrears on the 15th day of February, May, August and November of each year. The initial distribution rate for the Series B preferred units from and including October 10, 2017 to, but not including, November 15, 2022 is 6.125% per year of the liquidation preference per unit (equal to $61.25 per unit per year). On and after November 15, 2022, distributions on the Series B preferred units will accumulate for each distribution period at a percentage of the liquidation preference equal to the then-current three-month LIBOR plus a spread of 4.11%.

Upon the occurrence of certain rating agency events, we may redeem the Series B preferred units, in whole but not in part, at a price of $1,020 (102% of the liquidation preference) per Series B preferred unit plus an amount equal to all accumulated and unpaid distributions thereon to, but not including, the date of redemption, whether or not declared. In addition, at any time on or after November 15, 2022, we may redeem the Series B preferred units, at our option, in whole or in part, at a redemption price of $1,000 per Series B preferred unit plus an amount equal to all accumulated and unpaid distributions thereon to, but not including, the date of redemption, whether or not declared.

Distributions

In accordance with our partnership agreement, after making distributions to holders of outstanding preferred units, we distribute 100% of our available cash within 45 days following the end of each quarter to common unitholders of record. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter, less reserves established in the reasonable discretion of our general partner for future requirements.

The following table details distributions paid to common unitholders (and, prior to the Simplification Transactions, our general partner) during the year presented (in millions, except per unit data):

	Distributions Paid			Distributions per common unit
Year	**Public**	**AAP [1]**	**Total**	
2017	$ 849	$ 537	$ 1,386	$ 1.95
2016	$ 1,062	$ 565	$ 1,627	$ 2.65
2015	$ 1,081	$ 590	$ 1,671	$ 2.76

(1) Prior to the Simplification Transactions, our general partner was entitled to receive (i) distributions with respect to its 2% indirect general partner interest and (ii) as the holder of our IDRs, incentive distributions if the amount we distributed with respect to any quarter exceeded certain specified levels. The Simplification Transactions, which closed on November 15, 2016, included the permanent elimination of our IDRs and the economic rights associated with our 2% general partner interest in exchange for the issuance by us to AAP of approximately 244.7 million common units. As such, beginning with the distribution pertaining to the fourth quarter of 2016, our general partner is no longer entitled to receive distributions on the IDRs or general partner interest. During the year ended December 31, 2017, AAP received distributions on the common units it owned.

On January 8, 2018, we declared a cash distribution of $0.30 per unit on our outstanding common units. The total distribution of $218 million was paid on February 14, 2018 to unitholders of record on January 31, 2018, for the period October 1, 2017 through December 31, 2017. Of this amount, approximately $85 million was paid to AAP.

Series A Preferred Unit Distributions. In 2017, we issued 5,307,689 Series A preferred units in lieu of cash distributions of $139 million. In 2016, we issued 3,358,726 Series A preferred units in lieu of cash distributions of $89 million.

On February 14, 2018, we issued 1,393,926 Series A preferred units in lieu of a cash distribution of $37 million. Since the February 14, 2018 Series A preferred unit distribution was declared as payment-in-kind, the distribution payable was accrued to partners' capital as of December 31, 2017 and thus had no net impact on the Series A preferred unitholders' capital account.

Series B Preferred Unit Distributions. We paid a pro-rated initial distribution on the Series B preferred units on November 15, 2017 to holders of record at the close of business on November 1, 2017 in an amount equal to approximately $5.9549 per unit (a total distribution of approximately $5 million). At December 31, 2017, we had accrued approximately $6 million of distributions payable to our Series B preferred unitholders.

Income Allocation

We allocate net income for partners' capital presentation purposes by applying the allocation methodology in our partnership agreement. Following the closing of the Simplification Transactions, net income is allocated 100% to our common unitholders, after giving effect to income allocations for cash distributions to our Series A preferred unitholders and guaranteed payments attributable to our Series B preferred unitholders. In accordance with our partnership agreement, our Series A preferred unitholders are not allocated income for paid-in-kind distributions for partners' capital presentation purposes.

For periods prior to the Simplification Transactions, our general partner and common unitholders were allocated income based on their respective partnership percentages, after giving effect to income allocations for (i) incentive distributions, if any, to our general partner for distributions declared and paid following the close of each quarter and (ii) cash distributions to our Series A preferred unitholders. Our Series A preferred unitholders were not allocated income for paid-in-kind distributions for partners' capital presentation purposes.

For purposes of determining basic and diluted net income per common unit, income is allocated as prescribed in FASB guidance for calculating earnings per unit, including a deduction to income available to common unitholders for distributions attributable to the period (whether paid in cash or in-kind) on our Series A and Series B preferred units. See Note 3 for additional information.

Noncontrolling Interests in Subsidiaries

During the fourth quarter of 2017, we sold SLC Pipeline LLC, in which we previously owned a 75% interest and had consolidated under GAAP. As a result of this sale, the noncontrolling interest of 25% was derecognized. We did not have any noncontrolling interests in subsidiaries at December 31, 2017. See Note 6 for additional information regarding the sale of SLC Pipeline LLC.

Note 12—Derivatives and Risk Management Activities

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 for risk management purposes and not for the purpose of speculating on hydrocarbon commodity (referred to herein as "commodity") price changes. We use various derivative instruments to manage our exposure to (i) commodity price risk, as well as to optimize our profits, (ii) interest rate risk and (iii) currency exchange rate risk. Our commodity price risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring our derivative 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 derivative positions and ensure that those positions are consistent with our objectives and approved strategies. When we apply hedge accounting, our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives 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 throughout the hedging relationship, we assess whether the derivatives employed are highly effective in offsetting changes in cash flows of anticipated hedged transactions.

Commodity Price Risk Hedging

Our core business activities involve certain commodity price-related risks that we manage in various ways, including through the use of derivative instruments. Our policy is to (i) only purchase inventory for which we have a market, (ii) structure our sales contracts so that price fluctuations do not materially affect our operating income and (iii) not 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 divided 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, 2017, net derivative positions related to these activities included:

- A net long position of 3.3 million barrels associated with our crude oil purchases, which was unwound ratably during January 2018 to match monthly average pricing.
- A net short time spread position of 5.2 million barrels, which hedges a portion of our anticipated crude oil lease gathering purchases through February 2019.
- A crude oil grade basis position of 30.3 million barrels through December 2019. These derivatives allow us to lock in grade basis differentials.
- A net short position of 16.5 million barrels through December 2020 related to anticipated net sales of our crude oil and NGL 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, 2017, our PLA hedges included a net short position consisting of crude oil futures of 1.1 million barrels and a long call option position of 0.9 million barrels through December 2019.

Natural Gas Processing/NGL Fractionation — We purchase natural gas for processing and operational needs. Additionally, we purchase NGL mix for fractionation and sell the resulting individual specification products (including ethane, propane, butane and condensate). In conjunction with these activities, we hedge the price risk associated with the purchase of the natural gas and the subsequent sale of the individual specification products. As of December 31, 2017, we had a long natural gas position of 54.3 Bcf which hedges our natural gas processing and operational needs through December 2020. We also had a short propane position of 8.6 million barrels through December 2018, a short butane position of 2.6 million barrels through December 2018 and a short WTI position of 1.0 million barrels through December 2018. In addition, we had a long power position of 0.4 million megawatt hours, which hedges a portion of our power supply requirements at our Canadian natural gas processing and fractionation plants through December 2019.

Physical commodity contracts that meet the definition of a derivative but are ineligible, or not designated, for the normal purchases and normal sales scope exception are recorded on the balance sheet at fair value, with changes in fair value recognized in earnings. We have determined that substantially all of our physical commodity contracts qualify for the normal purchases and normal sales scope exception.

Interest Rate Risk Hedging

We use interest rate derivatives to hedge the benchmark interest rate associated interest payments occurring as a result of debt issuances. The derivative instruments we use to manage this risk consist of forward starting interest rate swaps and treasury locks. These derivatives are designated as cash flow hedges. As such, changes in fair value are deferred in AOCI and are reclassified to interest expense as we incur the interest expense associated with the underlying debt.

The following table summarizes the terms of our outstanding interest rate derivatives as of December 31, 2017 (notional amounts in millions):

Hedged Transaction	Number and Types of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Anticipated interest payments	16 forward starting swaps (30-year)	$ 400	6/15/2018	2.86%	Cash flow hedge
Anticipated interest payments	8 forward starting swaps (30-year)	$ 200	6/14/2019	2.83%	Cash flow hedge

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in CAD we use foreign currency derivatives to minimize the risk of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts and forwards.

As of December 31, 2017, our outstanding foreign currency derivatives include derivatives we use to hedge currency exchange risk (i) associated with USD-denominated commodity purchases and sales in Canada and (ii) created by the use of USD-denominated commodity derivatives to hedge commodity price risk associated with CAD-denominated commodity purchases and sales.

The following table summarizes our open forward exchange contracts as of December 31, 2017 (in millions):

		USD	CAD	Average Exchange Rate USD to CAD
Forward exchange contracts that exchange CAD for USD:				
	2018	$ 87	$ 109	$1.00 - $1.26
Forward exchange contracts that exchange USD for CAD:				
	2018	$ 645	$ 816	$1.00 - $1.27

Preferred Distribution Rate Reset Option

A derivative feature embedded in a contract that does not meet the definition of a derivative in its entirety must be bifurcated and accounted for separately if the economic characteristics and risks of the embedded derivative are not clearly and closely related to those of the host contract. The Preferred Distribution Rate Reset Option of our Series A preferred units is an embedded derivative that must be bifurcated from the related host contract, our partnership agreement, and recorded at fair value on our Consolidated Balance Sheet. Corresponding changes in fair value are recognized in “Other income/(expense), net” in our Consolidated Statement of Operations. At December 31, 2017 and 2016, the fair value of this embedded derivative was a liability of approximately $22 million and $32 million, respectively. We recognized gains of approximately $13 million and $30 million for the years ended December 31, 2017 and 2016, respectively. See Note 11 for additional information regarding our Series A preferred units and the Preferred Distribution Rate Reset Option.

Summary of Financial Impact

We record all open derivatives on the balance sheet as either assets or liabilities measured at fair value. Changes in the fair value of derivatives are recognized currently in earnings unless specific hedge accounting criteria are met. For derivatives that qualify as cash flow hedges, changes in fair value of the effective portion of the hedges are deferred in AOCI and recognized in earnings in the periods during which the underlying physical transactions are recognized in earnings. 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 classified within the same category as the related hedged item in our Consolidated Statements of Cash Flows.

A summary of the impact of our derivatives recognized in earnings is as follows (in millions):

	Year Ended December 31, 2017		
Location of Gain/(Loss)	**Derivatives in Hedging Relationships (1) (2)**	**Derivatives Not Designated as a Hedge**	**Total**
Commodity Derivatives			
Supply and Logistics segment revenues	$ —	$ (188)	$ (188)
Field operating costs	—	(10)	(10)
Depreciation and amortization	(3)	—	(3)
Interest Rate Derivatives			
Interest expense, net	(18)	—	(18)
Foreign Currency Derivatives			
Supply and Logistics segment revenues	—	8	8
Preferred Distribution Rate Reset Option			
Other income/(expense), net	—	13	13
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ (21)	$ (177)	$ (198)

Location of Gain/(Loss)	Year Ended December 31, 2016 Derivatives in Hedging Relationships [1] [2]	Derivatives Not Designated as a Hedge	Total
Commodity Derivatives			
Supply and Logistics segment revenues	$ 2	$ (344)	$ (342)
Transportation segment revenues	—	5	5
Interest Rate Derivatives			
Interest expense, net	(14)	—	(14)
Foreign Currency Derivatives			
Supply and Logistics segment revenues	—	(3)	(3)
Preferred Distribution Rate Reset Option			
Other income/(expense), net	—	30	30
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ (12)	$ (312)	$ (324)

Location of Gain/(Loss)	Year Ended December 31, 2015 Derivatives in Hedging Relationships [1] [2]	Derivatives Not Designated as a Hedge	Total
Commodity Derivatives			
Supply and Logistics segment revenues	$ 56	$ 152	$ 208
Transportation segment revenues	—	8	8
Field operating costs	—	(18)	(18)
Interest Rate Derivatives			
Interest expense, net	(11)	—	(11)
Foreign Currency Derivatives			
Supply and Logistics segment revenues	—	(31)	(31)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ 45	$ 111	$ 156

[1] During the year ended December 31, 2017, we reclassified losses of approximately $10 million to Interest expense, net. During the year ended December 31, 2016, we reclassified losses of approximately $2 million to Supply and Logistics segment revenues and $2 million to Interest expense, net. During the year ended December 31, 2015, we reclassified a loss of approximately $4 million to Interest expense, net. Each reclassification from AOCI to earnings was due to anticipated hedged transactions being probable of not occurring.

(2) Amounts in Interest expense, net include a loss of $4 million during the year ended December 31, 2016 attributable to the ineffective portion of cash flow hedges. No ineffectiveness was recognized for cash flow hedges during the years ended December 31, 2017 or 2015.

The following table summarizes the derivative assets and liabilities on our Consolidated Balance Sheet on a gross basis as of December 31, 2017 (in millions):

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Derivatives designated as hedging instruments:				
Interest rate derivatives	Other current liabilities	$ 2	Other current liabilities	$ (27)
			Other long-term liabilities and deferred credits	(11)
Total derivatives designated as hedging instruments		$ 2		$ (38)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 73	Other current assets	$ (227)
	Other long-term assets, net	1	Other current liabilities	(131)
	Other current liabilities	5	Other long-term liabilities and deferred credits	(5)
	Other long-term liabilities and deferred credits	3		
Foreign currency derivatives	Other current assets	6	Other current assets	(2)
Preferred Distribution Rate Reset Option		—	Other long-term liabilities and deferred credits	(22)
Total derivatives not designated as hedging instruments		$ 88		$ (387)
Total derivatives		$ 90		$ (425)

The following table summarizes the derivative assets and liabilities on our Consolidated Balance Sheet on a gross basis as of December 31, 2016 (in millions):

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Derivatives designated as hedging instruments:				
Interest rate derivatives		$ —	Other current liabilities	$ (23)
			Other long-term liabilities and deferred credits	(27)
Total derivatives designated as hedging instruments		$ —		$ (50)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 101	Other current assets	$ (344)
	Other long-term assets, net	2	Other long-term assets, net	(1)
	Other long-term liabilities and deferred credits	2	Other current liabilities	(14)
			Other long-term liabilities and deferred credits	(34)
Foreign currency derivatives	Other current liabilities	3	Other current liabilities	(6)
Preferred Distribution Rate Reset Option		—	Other long-term liabilities and deferred credits	(32)
Total derivatives not designated as hedging instruments		$ 108		$ (431)
Total derivatives		$ 108		$ (481)

Our derivative transactions (other than the Preferred Distribution Rate Reset Option) are governed through ISDA (International Swaps and Derivatives Association) master agreements and clearing brokerage agreements. These agreements include stipulations regarding the right of set off in the event that we or our counterparty default on performance obligations. If a default were to occur, both parties have the right to net amounts payable and receivable into a single net settlement between parties.

Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting arrangement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our exchange-traded derivatives are transacted through clearing 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. The following table provides the components of our net broker receivable/(payable):

	December 31, 2017	December 31, 2016
Initial margin	$ 48	$ 119
Variation margin posted	164	291
Net broker receivable	$ 212	$ 410

The following table presents information about derivative financial assets and liabilities that are subject to offsetting, including enforceable master netting arrangements (in millions):

	December 31, 2017		December 31, 2016	
	Derivative Asset Positions	Derivative Liability Positions	Derivative Asset Positions	Derivative Liability Positions
Netting Adjustments:				
Gross position - asset/(liability)	$ 90	$ (425)	$ 108	$ (481)
Netting adjustment	(239)	239	(350)	350
Cash collateral paid	212	—	410	—
Net position - asset/(liability)	$ 63	$ (186)	$ 168	$ (131)
Balance Sheet Location After Netting Adjustments:				
Other current assets	$ 62	$ —	$ 167	$ —
Other long-term assets, net	1	—	1	—
Other current liabilities	—	(151)	—	(40)
Other long-term liabilities and deferred credits	—	(35)	—	(91)
	$ 63	$ (186)	$ 168	$ (131)

As of December 31, 2017, there was a net loss of $223 million deferred in AOCI. The 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 or (ii) interest expense accruals associated with underlying debt instruments. Of the total net loss deferred in AOCI at December 31, 2017, we expect to reclassify a net loss of $8 million to earnings in the next twelve months. The remaining deferred loss of $215 million is expected to be reclassified to earnings through 2049. A portion of these amounts is based on market prices as of December 31, 2017; thus, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

The following table summarizes the net deferred gain/(loss) recognized in AOCI for derivatives (in millions):

	Year Ended December 31,		
	2017	2016	2015
Commodity derivatives, net	$ —	$ —	$ 33
Interest rate derivatives, net	(16)	(33)	(32)
Total	$ (16)	$ (33)	$ 1

At December 31, 2017 and December 31, 2016, 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. Although we may be required to post margin on our cleared derivatives as described above, we do not require our non-cleared derivative counterparties to post collateral with us.

Recurring Fair Value Measurements

Derivative Financial Assets and Liabilities

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 (in millions):

Recurring Fair Value Measures (1)	Fair Value as of December 31, 2017				Fair Value as of December 31, 2016			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Commodity derivatives	$ 5	$ (278)	$ (8)	$ (281)	$ (113)	$ (171)	$ (4)	$ (288)
Interest rate derivatives	—	(36)	—	(36)	—	(50)	—	(50)
Foreign currency derivatives	—	4	—	4	—	(3)	—	(3)
Preferred Distribution Rate Reset Option	—	—	(22)	(22)	—	—	(32)	(32)
Total net derivative asset/(liability)	$ 5	$ (310)	$ (30)	$ (335)	$ (113)	$ (224)	$ (36)	$ (373)

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

Level 1

Level 1 of the fair value hierarchy includes exchange-traded commodity derivatives such as futures and options. The fair value of exchange-traded commodity derivatives is based on unadjusted quoted prices in active markets.

Level 2

Level 2 of the fair value hierarchy includes exchange-cleared commodity derivatives and over-the-counter commodity, interest rate and foreign currency derivatives that are traded in active markets. In addition, it includes certain physical commodity contracts. The fair value of these derivatives is based on broker price quotations which are corroborated with market observable inputs.

Level 3

Level 3 of the fair value hierarchy includes certain physical commodity contracts and the Preferred Distribution Rate Reset Option contained in our partnership agreement which is classified as an embedded derivative.

The fair value of our Level 3 physical commodity contracts is based on a valuation model utilizing timing estimates, which involve management judgment. Significant changes in timing could result in a material change in fair value to our physical commodity contracts. We report unrealized gains and losses associated with these physical commodity contracts in our Consolidated Statements of Operations as Supply and Logistics segment revenues.

The fair value of the embedded derivative feature contained in our partnership agreement is based on a valuation model that estimates the fair value of the Series A preferred units with and without the Preferred Distribution Rate Reset Option. This model contains inputs, including our common unit price, ten-year U.S. treasury rates, default probabilities and timing estimates which involve management judgment. A significant increase or decrease in the value of these inputs could result in a material change in fair value to this embedded derivative feature. We report unrealized gains and losses associated with this embedded derivative in our Consolidated Statements of Operations as “Other income/(expense), net.”

To the extent any transfers between levels of the fair value hierarchy occur, our policy is to reflect these transfers as of the beginning of the reporting period in which they occur.

Rollforward of Level 3 Net Asset/(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, 2017	Year Ended December 31, 2016
Beginning Balance	$ (36)	$ 11
Net gains for the period included in earnings	12	28
Settlements	4	(10)
Derivatives entered into during the period	(10)	(65)
Ending Balance	$ (30)	$ (36)
Change in unrealized gains/(losses) included in earnings relating to Level 3 derivatives still held at the end of the period	$ 5	$ (36)

Note 13—Income Taxes

Income tax expense is estimated using the tax rate in effect or to be in effect during the relevant periods in the jurisdictions in which we operate. Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes and are stated at enacted tax rates expected to be in effect when taxes are actually paid or recovered. To the extent we do not consider it more likely than not that a deferred tax asset will be recovered, a valuation allowance is established. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective. We review contingent tax liabilities for estimated exposures on a more likely than not standard related to our current tax positions.

Pursuant to FASB guidance related to accounting for uncertainty in income taxes, we may 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, 2017 and 2016, we had not recognized any material amounts in connection with uncertainty in 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, 2017, 2016, and 2015 was immaterial.

Canadian Federal and Provincial Taxes

All of our Canadian operations are conducted by entities that are treated as corporations for Canadian tax purposes (flow through for U.S. income tax purposes) and that are subject to Canadian federal and provincial taxes. Additionally, payments of interest and dividends from our Canadian entities to other Plains entities are subject to Canadian withholding tax that is treated as income tax expense.

Tax Components

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

	Year Ended December 31, 2017	2016	2015
Current income tax expense:			
State income tax	$ 1	$ 2	$ 1
Canadian federal and provincial income tax	27	83	83
Total current income tax expense	$ 28	$ 85	$ 84
Deferred income tax expense/(benefit):			
Canadian federal and provincial income tax	$ 16	$ (60)	$ 16
Total deferred income tax expense/(benefit)	$ 16	$ (60)	$ 16
Total income tax expense	$ 44	$ 25	$ 100

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

	Year Ended December 31, 2017	2016	2015
Income before tax	$ 902	$ 755	$ 1,006
Partnership earnings not subject to current Canadian tax	(756)	(723)	(773)
	$ 146	$ 32	$ 233
Canadian federal and provincial corporate tax rate	27%	27%	26%
Income tax at statutory rate	$ 39	$ 8	$ 61
Canadian withholding tax	$ 2	$ 13	$ 14
Canadian permanent differences and rate changes	2	2	24
State income tax	1	2	1
Total income tax expense	$ 44	$ 25	$ 100

Deferred tax assets and liabilities are aggregated by the applicable tax paying entity and jurisdiction and result from the following (in millions):

	December 31, 2017	December 31, 2016
Deferred tax assets:		
Derivative instruments	$ 74	$ 49
Book accruals in excess of current tax deductions	22	24
Net operating losses	3	4
Total deferred tax assets	99	77
Deferred tax liabilities:		
Property and equipment in excess of tax values	(455)	(394)
Other	(50)	(41)
Total deferred tax liabilities	(505)	(435)
Net deferred tax liabilities	$ (406)	$ (358)
Balance sheet classification of deferred tax assets/(liabilities):		
Other long-term assets, net	$ 3	$ 4
Other long-term liabilities and deferred credits	(409)	(362)
	$ (406)	$ (358)

As of December 31, 2017, we had foreign net operating loss carryforwards of $9 million, which will expire beginning in 2034.

Generally, tax returns for our Canadian entities are open to audit from 2008 through 2017. Our U.S. and state tax years are generally open to examination from 2014 to 2017.

Note 14—Major Customers and Concentration of Credit Risk

Marathon Petroleum Corporation and its subsidiaries accounted for 19%, 18% and 17% of our revenues for the years ended December 31, 2017, 2016 and 2015, respectively. ExxonMobil Corporation and its subsidiaries accounted for 11%, 14% and 13% of our revenues for the years ended December 31, 2017, 2016 and 2015, respectively. Phillips 66 Company and its subsidiaries accounted for 11% of our revenues in each of the years ended December 31, 2017 and 2016. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2017. The majority of revenues from these customers pertain to our supply and logistics operations. The sales to these customers occur at multiple locations and 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 and, to a lesser extent, purchasers of NGL and natural gas. 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 15—Related Party Transactions

Ownership of PAGP Class C Shares

As of December 31, 2017 and 2016, we owned 510,925,432 and 491,910,863, respectively, Class C shares of PAGP. The Class C shares represent a non-economic limited partner interest in PAGP that provides us, as the sole holder, a "pass-through" voting right through which our common unitholders and Series A preferred unitholders have the effective right to vote, pro rata with the holders of Class A and Class B shares of PAGP, for the election of eligible PAGP GP directors, commencing in May 2018.

Reimbursement of Our General Partner and its Affiliates

Our general partner provides general and administrative services necessary to manage and operate our business, properties and assets, including employing or retaining personnel. We do not pay our general partner a management fee, but we do reimburse our general partner for all direct and indirect costs it incurs or payments it makes 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. 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, 2017, 2016 and 2015 were $489 million, $514 million and $648 million, respectively.

Omnibus Agreement

In connection with the Simplification Transactions completed in November 2016, the Plains Entities entered into an Omnibus Agreement, which provides for the following:

- that, for all periods following the closing of the Simplification Transactions, we will pay all direct or indirect expenses of any of the PAGP Entities, other than income taxes (including, but not limited to, (i) compensation for the directors of PAGP GP, (ii) director and officer liability insurance, (iii) listing exchange fees, (iv) investor relations expenses and (v) fees related to legal, tax, financial advisory and accounting services). We paid $4 million of such expenses in both 2017 and 2016;

- the ability of PAGP to issue additional Class A shares and use the net proceeds therefrom to purchase a like number of AAP units from AAP, and the corresponding ability of AAP to use the net proceeds therefrom to purchase a like number of our common units from us. During the year ended December 31, 2017, we issued approximately 1.8 million common units to AAP in connection with PAGP's issuance of Class A shares under its Continuous Offering Program and 48.3 million common units to AAP in connection with PAGP's March 2017 underwritten offering (See Note 11 for additional information); and

- the ability of PAGP to lend proceeds of any future indebtedness incurred by it to AAP, and AAP's corresponding ability to lend such proceeds to us, in each case on substantially the same terms as incurred by PAGP.

See Note 1 for discussion of the Simplification Transactions.

Transactions with Oxy

As of December 31, 2017, Oxy had a representative on the board of directors of PAGP GP and owned approximately 11% of the limited partner interests in AAP. During the three years ended December 31, 2017, we recognized sales and transportation revenues and purchased petroleum products from Oxy. These transactions were conducted at posted tariff rates or prices that we believe approximate market. Included in these transactions was a crude oil buy/sell agreement that includes a multi-year minimum volume commitment. The impact to our Consolidated Statements of Operations from those transactions is included below (in millions):

	Year Ended December 31,		
	2017	2016	2015
Revenues	$ 920	$ 655	$ 866
Purchases and related costs [(1)]	$ (253)	$ 42	$ 41

(1) Crude oil purchases that are part of inventory exchanges under buy/sell transactions are netted with the related sales, with any margin presented in “Purchases and related costs” in our Consolidated Statements of Operations.

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

	December 31,	
	2017	2016
Trade accounts receivable and other receivables	$ 1,075	$ 789
Accounts payable	$ 990	$ 836

Transactions with Equity Method Investees

We also have transactions with companies in which we hold an investment accounted for under the equity method of accounting (see Note 8 for information related to these investments). We recorded revenues of $3 million, $14 million and $17 million during the years ended December 31, 2017, 2016 and 2015, respectively. During the three years ended December 31, 2017, we utilized transportation services and purchased petroleum products provided by these companies. Costs related to these services totaled $434 million, $209 million and $164 million for the years ended December 31, 2017, 2016 and 2015, respectively. These transactions were conducted at posted tariff rates or contracted rates or prices that we believe approximate market.

Receivables from our equity method investees totaled $26 million and $39 million at December 31, 2017 and 2016, respectively, and primarily included amounts related to transportation services. In addition, at December 31, 2016, we had prepaid tariff costs related to our equity method investees of $14 million. Accounts payable to our equity method investees were $41 million and $35 million at December 31, 2017 and 2016, respectively, and primarily included amounts related to transportation services.

In addition, we have an agreement to transport crude oil at posted tariff rates on a pipeline that is owned by an equity method investee, in which we own a 50% interest. Our commitment to transport is supported by crude oil buy/sell agreements with third parties (including Oxy) with commensurate quantities.

Series A Preferred Unit Issuance

In January 2016, we completed a private placement of Series A preferred units. Certain of the purchasers of the Series A preferred units or their affiliates are related parties. Kayne Anderson Capital Advisors, L.P. and certain of its affiliates and an affiliate of The Energy Minerals Group hold ownership interests in our general partner. In addition, certain of the current directors of our general partner are affiliated with certain of the purchasers. See Note 11 for additional information about our Series A preferred units.

Note 16—Equity-Indexed Compensation Plans

PAA Long-Term Incentive Plan Awards

Our LTIP awards include both liability-classified and equity-classified awards. In accordance with FASB guidance regarding share-based payments, the fair value of liability-classified LTIP awards is calculated based on the closing market price of the underlying PAA unit 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 equity-classified LTIP awards is calculated based on the closing market price of the underlying PAA unit 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.

Certain LTIP awards 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 probable of occurring. When awards with performance conditions that were previously considered improbable become probable, we incur additional expense in the period that the probability assessment changes. This is necessary to bring the accrued obligation associated with these awards up to the level it would be if we had been accruing for these awards since the grant date.

The following is a summary of the awards authorized under our LTIPs as of December 31, 2017 (in millions):

LTIP	PAA LTIP Awards Authorized
Plains All American 2013 Long-Term Incentive Plan	13.1
Plains All American PNG Successor Long-Term Incentive Plan	1.3
Plains All American GP LLC 2006 Long-Term Incentive Tracking Unit Plan	10.8
Total	25.2

Although other types of awards are contemplated under certain of the LTIPs, currently outstanding awards are limited to “phantom units,” which mature into the right to receive common units of PAA (or cash equivalent) upon vesting, and “tracking units,” which, upon vesting, represent the right to receive a cash payment in an amount based upon the market value of a PAA common unit at the time of vesting. Some awards also include DERs, which, subject to applicable vesting criteria, entitle the grantee to a cash payment equal to the cash distribution paid on an outstanding PAA common unit. The DERs terminate with the vesting or forfeiture of the underlying LTIP award.

As of December 31, 2017, 7.3 million LTIP awards were outstanding. Of this amount, 2.6 million include DERs. The outstanding and probable LTIP awards are expected to vest at various dates between January 1, 2018 and December 31, 2022.

Our accrued liability at December 31, 2017 related to all outstanding liability-classified LTIP awards and DERs was $27 million, of which $15 million was classified as short-term and $12 million was classified as long-term. These short- and long-term accrued LTIP liabilities are reflected in “Accounts payable and accrued liabilities” and “Other long-term liabilities and deferred credits,” respectively, on our Consolidated Balance Sheets. At December 31, 2016, the accrued liability was $38 million, of which $25 million was classified as short-term and $13 million was classified as long-term.

Activity for LTIP awards under our equity-indexed compensation plans denominated in PAA units is summarized in the following table (units in millions):

	PAA Units [1]	
	Units	Weighted Average Grant Date Fair Value per Unit
Outstanding at December 31, 2014	7.3	$ 41.45
Granted	2.1	$ 28.76
Vested	(2.1)	$ 28.91
Cancelled or forfeited	(0.4)	$ 44.56
Outstanding at December 31, 2015	6.9	$ 41.23
Granted	4.5	$ 23.38
Vested	(1.9)	$ 45.91
Modified	—	$ (8.21)
Cancelled or forfeited	(0.6)	$ 37.19
Outstanding at December 31, 2016	8.9	$ 29.62
Granted	0.9	$ 23.52
Vested	(1.7)	$ 42.12
Modified	—	$ (6.04)
Cancelled or forfeited	(0.8)	$ 26.99
Outstanding at December 31, 2017	7.3	$ 24.68

(1) Approximately 0.6 million, 0.5 million and 0.5 million PAA common units were issued, net of tax withholding of approximately 0.2 million, 0.3 million and 0.3 million units during 2017, 2016 and 2015, respectively, in connection with the settlement of vested awards. The remaining PAA awards (approximately 0.9 million, 1.1 million and 1.3 million units) that vested during 2017, 2016 and 2015, respectively, were settled in cash.

AAP Management Units

In August 2007, the owners of AAP authorized the issuance of AAP Management Units (a profits interest) to provide additional long-term incentives and encourage retention for certain members of our senior management. This plan has been discontinued and there will be no new grants of AAP Management Units; however, as of December 31, 2017, 0.8 million outstanding AAP Management Units were unearned. These AAP Management Units will become earned based on the attainment of certain PAA distribution levels and additional performance conditions based on distributable cash flow measures determined by management. Once earned, we will issue to AAP approximately 0.941 common units for each AAP Management Unit, and each AAP Management Unit will be entitled to a distribution equal to approximately 94.1% of the distribution paid by AAP to an AAP unit on a quarterly basis. Once vested, each AAP Management Unit holder is entitled to convert his or her AAP Management Units into AAP units and a like number of PAGP Class B shares based on a conversion ratio of approximately 0.941 AAP units and Class B shares for each AAP Management Unit.

Equity-Indexed Compensation Plan Information

We refer to all of the LTIPs and AAP Management Units collectively as our "equity-indexed compensation plans." The table below summarizes the expense recognized and the value of vested LTIP awards (settled both in common units and cash) under our equity-indexed compensation plans and includes both liability-classified and equity-classified awards (in millions):

	Year Ended December 31,		
	2017	2016	2015
Equity-indexed compensation expense	$ 41	$ 60	$ 27
LTIP unit-settled vestings	$ 16	$ 24	$ 37
LTIP cash-settled vestings	$ 25	$ 28	$ 66

Based on the December 31, 2017 fair value measurement and probability assessment regarding future distributions, we expect to recognize $75 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-Indexed Compensation Plan Fair Value Amortization (1)	
2018	$	42
2019		21
2020		9
2021		2
2022		1
Total	$	75

(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, 2017.

Note 17—Commitments and Contingencies

Commitments

We have commitments, some of which are leases, related to real property, equipment and operating facilities. We also incur costs associated with leased land, rights-of-way, permits and regulatory fees. Future non-cancelable commitments related to these items at December 31, 2017 are summarized below (in millions):

	2018	2019	2020	2021	2022	Thereafter	Total
Leases, rights-of-way easements and other (1)	$ 188	$ 155	$ 127	$ 107	$ 90	$ 363	$ 1,030
Other commitments (2)	205	178	145	127	109	299	1,063
Total	$ 393	$ 333	$ 272	$ 234	$ 199	$ 662	$ 2,093

(1) Includes operating and capital leases as defined by FASB guidance, as well as obligations for rights-of-way easements. Leases are primarily for (i) railcars, (ii) land and surface rentals, (iii) office buildings, (iv) pipeline assets and (v) vehicles and trailers. We recognize expense on a straight-line basis over the life of the agreement, as applicable. Lease expense for 2017, 2016 and 2015 was $207 million, $198 million and $164 million, respectively.

(2) Primarily includes third-party storage and transportation agreements and pipeline throughput agreements, as well as approximately $760 million associated with an agreement to transport crude oil on a pipeline that is owned by an equity method investee, in which we own a 50% interest. Our commitment to transport is supported by crude oil buy/sell agreements with third parties (including Oxy) with commensurate quantities. Expense associated with these storage, transportation and throughput agreements was approximately $197 million, $157 million and $85 million for 2017, 2016 and 2015, respectively.

Loss Contingencies — General

To the extent we are able to assess the likelihood of a negative outcome for a contingency, 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 an undiscounted liability equal to the estimated amount. If a range of probable loss amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then we accrue an undiscounted liability equal to the minimum amount in the range. In addition, we estimate legal fees that we expect to incur associated with loss contingencies and accrue those costs when they are material and probable of being incurred.

We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when the likelihood of loss is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and the impact would be material to our consolidated financial statements, we disclose the nature of the contingency and, where feasible, an estimate of the possible loss or range of loss.

Legal Proceedings — General

In the ordinary course of business, we are involved in various legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to fully protect us from losses arising from current or future legal proceedings.

Taking into account what we believe to be all relevant known facts and circumstances, and based on what we believe to be reasonable assumptions regarding the application of those facts and circumstances to existing laws and regulations, we do not believe that the outcome of the legal proceedings in which we are currently involved (including those described below) will, individually or in the aggregate, have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

Environmental — General

Although over the course of the last several years we have made significant investments in our maintenance and integrity programs, and have hired additional personnel in those areas, we have experienced (and likely will experience future) releases of hydrocarbon products into the environment from our pipeline, rail, storage and other facility operations. These releases can result from accidents or from unpredictable man-made or natural forces and may reach surface water bodies, groundwater aquifers or other sensitive environments. Damages and liabilities associated with any such releases from our existing or future assets could be significant and could have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

We record environmental liabilities when environmental assessments and/or remedial efforts are probable and the amounts can be reasonably estimated. 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 environmental liabilities assumed in business combinations based on the estimated fair value of the environmental obligations caused by past operations of the acquired company. We 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.

Environmental expenditures that pertain to current operations or to future revenues are expensed or capitalized consistent with our capitalization policy for property and equipment. Expenditures that result from the remediation of an existing condition caused by past operations and that do not contribute to current or future profitability are expensed.

At December 31, 2017, our estimated undiscounted reserve for environmental liabilities (including liabilities related to the Line 901 incident, as discussed further below) totaled $162 million, of which $72 million was classified as short-term and $90 million was classified as long-term. At December 31, 2016, our estimated undiscounted reserve for environmental liabilities (including liabilities related to the Line 901 incident) totaled $147 million, of which $61 million was classified as short-term and $86 million was classified as long-term. The short- and long-term environmental liabilities referenced above are reflected in “Accounts payable and accrued liabilities” and “Other long-term liabilities and deferred credits,” respectively, on our Consolidated Balance Sheets. At December 31, 2017, we had recorded receivables totaling $55 million for amounts probable of recovery under insurance and from third parties under indemnification agreements, of which $29 million was reflected in “Trade accounts receivable and other receivables, net” and $26 million was reflected in “Other long-term assets, net” on our Consolidated Balance Sheet. At December 31, 2016, we had recorded $56 million of such receivables, of which $39 million was reflected in “Trade accounts receivable and other receivables, net” and $17 million was reflected in “Other long-term assets, net” on our Consolidated Balance Sheet.

In some cases, the actual cash expenditures associated with these liabilities may not occur for three years or longer. Our estimates used in determining 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 or future legal claims giving rise to additional liabilities. Therefore, although we believe that the reserve is adequate, actual costs incurred (which may ultimately include costs for contingencies that are currently not reasonably estimable or costs for contingencies where the likelihood of loss is currently believed to be only reasonably possible or remote) may be in excess of the reserve and may potentially have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

Specific Legal, Environmental or Regulatory Matters

Line 901 Incident. In May 2015, we experienced a crude oil release from our Las Flores to Gaviota Pipeline (Line 901) in Santa Barbara County, California. A portion of the released crude oil reached the Pacific Ocean at Refugio State Beach through a drainage culvert. Following the release, we shut down the pipeline and initiated our emergency response plan. A Unified Command, which included the United States Coast Guard, the EPA, the California Office of Spill Prevention and Response and the Santa Barbara Office of Emergency Management, was established for the response effort. Clean-up and remediation operations with respect to impacted shoreline and other areas has been determined by the Unified Command to be complete, and the Unified Command has been dissolved. Our estimate of the amount of oil spilled, based on relevant facts, data and information, is approximately 2,934 barrels; of this amount, we estimate that 598 barrels reached the Pacific Ocean.

As a result of the Line 901 incident, several governmental agencies and regulators initiated investigations into the Line 901 incident, various claims have been made against us and a number of lawsuits have been filed against us. We may be subject to additional claims, investigations and lawsuits, which could materially impact the liabilities and costs we currently expect to incur as a result of the Line 901 incident. Set forth below is a brief summary of actions and matters that are currently pending:

On May 21, 2015, we received a corrective action order from the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA"), the governmental agency with jurisdiction over the operation of Line 901 as well as over a second stretch of pipeline extending from Gaviota Pump Station in Santa Barbara County to Emidio Pump Station in Kern County, California (Line 903), requiring us to shut down, purge, review, remediate and test Line 901. The corrective action order was subsequently amended on June 3, 2015; November 13, 2015; and June 16, 2016 to require us to take additional corrective actions with respect to both Lines 901 and 903 (as amended, the "CAO"). Among other requirements, the CAO obligated us to conduct a root cause failure analysis with respect to Line 901 and present remedial work plans and restart plans to PHMSA prior to returning Line 901 and 903 to service; the CAO also imposed a pressure restriction on the section of Line 903 between Pentland Pump Station and Emidio Pump Station and required us to take other specified actions with respect to both Lines 901 and 903. We intend to continue to comply with the CAO and to cooperate with any other governmental investigations relating to or arising out of the release. Excavation and removal of the affected section of the pipeline was completed on May 28, 2015. Line 901 and Line 903 have been purged and are not currently operational, with the exception of the Pentland to Emidio segment of Line 903, which remains in service under a pressure restriction. No timeline has been established for the restart of Line 901 or Line 903.

On February 17, 2016, PHMSA issued a Preliminary Factual Report of the Line 901 failure, which contains PHMSA's preliminary findings regarding factual information about the events leading up to the accident and the technical analysis that has been conducted to date. On May 19, 2016, PHMSA issued its final Failure Investigation Report regarding the Line 901 incident. PHMSA's findings indicate that the direct cause of the Line 901 incident was external corrosion that thinned the pipe wall to a level where it ruptured suddenly and released crude oil. PHMSA also concluded that there were numerous contributory causes of the Line 901 incident, including ineffective protection against external corrosion, failure to detect and mitigate the corrosion and a lack of timely detection and response to the rupture. The report also included copies of various engineering and technical reports regarding the incident. By virtue of its statutory authority, PHMSA has the power and authority to impose fines and penalties on us and cause civil or criminal charges to be brought against us. While to date PHMSA has not imposed any such fines or penalties or any such civil or criminal charges with respect to the Line 901 release, their investigation is still open and we may have fines or penalties imposed upon us, or civil or criminal charges brought against us, in the future.

On September 11, 2015, we received a Notice of Probable Violation and Proposed Compliance Order from PHMSA arising out of its inspection of Lines 901 and 903 in August, September and October of 2013 (the "2013 Audit NOPV"). The 2013 Audit NOPV alleges that the Partnership committed probable violations of various federal pipeline safety regulations by failing to document, or inadequately documenting, certain activities. On October 12, 2015, the Partnership filed a response to the 2013 Audit NOPV. By letter dated September 21, 2017, PHMSA issued a Final Order in this matter withdrawing one alleged violation and affirming a second. With regard to the second violation, PHMSA further determined that compliance had been achieved and included no compliance terms related to it in the Final Order. We therefore consider this matter closed.

In late May of 2015, the California Attorney General's Office and the District Attorney's office for the County of Santa Barbara began investigating the Line 901 incident to determine whether any applicable state or local laws had been violated. On May 16, 2016, PAA and one of its employees were charged by a California state grand jury, pursuant to an indictment filed in California Superior Court, Santa Barbara County (the "May 2016 Indictment"), with alleged violations of California law in connection with the Line 901 incident. The May 2016 Indictment included a total of 46 counts. On July 28, 2016, at an arraignment hearing held in California Superior Court in Santa Barbara County, PAA pled not guilty to all counts. Since May of 2016, 33 of the criminal charges against PAA (including one felony charge) and all of the criminal charges against our employee, have been dismissed. Seven of the remaining 13 charges are misdemeanor charges relating to wildlife allegedly taken as a result of the accidental release. The remaining six counts relate to the release of crude oil or reporting of the release. PAA believes that the criminal charges (including the three felony charges) are unwarranted and that neither PAA nor any of its employees engaged in any criminal behavior at any time in connection with this accident. PAA continues to vigorously defend itself against the charges.

Also in late May of 2015, the United States Attorney for the Department of Justice, Central District of California, Environmental Crimes Section ("DOJ") began an investigation into whether there were any violations of federal criminal statutes in connection with the Line 901 incident, including potential violations of the federal Clean Water Act. We are cooperating with the DOJ's investigation by responding to their requests for documents and access to our employees. The DOJ has already spoken to several of our employees and has expressed an interest in talking to other employees; consistent with the terms of our governing organizational documents, we are funding our employees' defense costs, including the costs of separate counsel engaged to represent such individuals. On August 26, 2015, we received a Request for Information from the EPA relating to Line 901. We have provided various responsive materials to date and we will continue to do so in the future in cooperation with the EPA. While to date no civil actions or criminal charges with respect to the Line 901 release, other than those brought pursuant to the May 2016 Indictment, have been brought against PAA or any of its affiliates, officers or employees by PHMSA, DOJ, EPA, the California Attorney General, the Santa Barbara District Attorney or the California Department of Fish and Wildlife, and no fines or penalties have been imposed by such governmental agencies, the investigations being conducted by such agencies are still open and we may have fines or penalties imposed upon us, our officers or our employees, or civil actions or criminal charges brought against us, our officers or our employees in the future, whether by those or other governmental agencies.

Shortly following the Line 901 incident, we established a claims line and encouraged any parties that were damaged by the release to contact us to discuss their damage claims. We have received a number of claims through the claims line and we are processing those claims for payment as we receive them. In addition, we have also had nine class action lawsuits filed against us, six of which have been administratively consolidated into a single proceeding in the United States District Court for the Central District of California. In general, the plaintiffs are seeking to establish different classes of claimants that have allegedly been damaged by the release. To date, the court has certified two sub-classes of claimants and denied certification of the other proposed sub-classes. The sub-classes that have been certified include (i) commercial fishermen who landed fish in certain specified fishing blocks in the waters adjacent to Santa Barbara County or persons or businesses who resold commercial seafood landed in such areas, and (ii) individuals or businesses who were employed by or had contracts with certain designated oil platforms and related on shore processing facilities in the vicinity of the release as of the date of the release. We are appealing the oil industry class certification. We are also defending a separate class action lawsuit proceeding in the United States District Court for the Central District of California brought on behalf of the Line 901 and Line 903 easement holders seeking injunctive relief as well as compensatory damages.

There have also been two securities law class action lawsuits filed on behalf of certain purported investors in the Partnership and/or PAGP against the Partnership, PAGP and/or certain of their respective officers, directors and underwriters. Both of these lawsuits have been consolidated into a single proceeding in the United States District Court for the Southern District of Texas. In general, these lawsuits allege that the various defendants violated securities laws by misleading investors regarding the integrity of the Partnership's pipelines and related facilities through false and misleading statements, omission of material facts and concealing of the true extent of the spill. The plaintiffs claim unspecified damages as a result of the reduction in value of their investments in the Partnership and PAGP, which they attribute to the alleged wrongful acts of the defendants. The Partnership and PAGP, and the other defendants, denied the allegations in, and moved to dismiss these lawsuits. On March 29, 2017, the Court ruled in our favor dismissing all claims against all defendants. Plaintiffs have refiled their complaint and we are opposing their claims. Consistent with and subject to the terms of our governing organizational documents (and to the extent applicable, insurance policies), we are indemnifying and funding the defense costs of our officers and directors in connection with this lawsuit; we are also indemnifying and funding the defense costs of our underwriters pursuant to the terms of the underwriting agreements we previously entered into with such underwriters.

In addition, four unitholder derivative lawsuits have been filed by certain purported investors in the Partnership against the Partnership, certain of its affiliates and certain officers and directors. Two of these lawsuits were filed in the United States District Court for the Southern District of Texas and were administratively consolidated into one action and later dismissed on the basis that Plains Partnership agreements require that derivative suits be filed in Delaware Chancery Court.

Following the order dismissing the Texas Federal Court suits, a new derivative suit brought by different plaintiffs was filed in Delaware Chancery Court. The other remaining lawsuit was filed in State District Court in Harris County, Texas and subsequently dismissed by the Court. In general, these lawsuits allege that the various defendants breached their fiduciary duties, engaged in gross mismanagement and made false and misleading statements, among other similar allegations, in connection with their management and oversight of the Partnership during the period of time leading up to and following the Line 901 release. The plaintiffs in the remaining lawsuit claim that the Partnership suffered unspecified damages as a result of the actions of the various defendants and seek to hold the defendants liable for such damages, in addition to other remedies. The defendants deny the allegations in this lawsuit and have responded accordingly. Consistent with and subject to the terms of our governing organizational documents (and to the extent applicable, insurance policies), we are indemnifying and funding the defense costs of our officers and directors in connection with this lawsuit.

We have also received several other individual lawsuits and complaints from companies and individuals alleging damages arising out of the Line 901 incident. These lawsuits and claims generally seek compensatory and punitive damages, and in some cases permanent injunctive relief.

In addition to the foregoing, as the “responsible party” for the Line 901 incident we are liable for various costs and for certain natural resource damages under the Oil Pollution Act, and we also have exposure to the payment of additional fines, penalties and costs under other applicable federal, state and local laws, statutes and regulations. To the extent any such costs are reasonably estimable, we have included an estimate of such costs in the loss accrual described below.

Taking the foregoing into account, as of December 31, 2017, we estimate that the aggregate total costs we have incurred or will incur with respect to the Line 901 incident will be approximately $335 million, which estimate includes actual and projected emergency response and clean-up costs, natural resource damage assessments and certain third party claims settlements, as well as estimates for fines, penalties and certain legal fees. We accrued such estimate of aggregate total costs to “Field operating costs” in our Consolidated Statements of Operations. This estimate considers our prior experience in environmental investigation and remediation matters and available data from, and in consultation with, our environmental and other specialists, as well as currently available facts and presently enacted laws and regulations. We have made assumptions for (i) the duration of the natural resource damage assessment process and the ultimate amount of damages determined, (ii) the resolution of certain third party claims and lawsuits, but excluding claims and lawsuits with respect to which losses are not probable and reasonably estimable, and excluding future claims and lawsuits, (iii) the determination and calculation of fines and penalties, but excluding fines and penalties that are not probable and reasonably estimable and (iv) the nature, extent and cost of legal services that will be required in connection with all lawsuits, claims and other matters requiring legal or expert advice associated with the Line 901 incident. Our estimate does not include any lost revenue associated with the shutdown of Line 901 or 903 and does not include any liabilities or costs that are not reasonably estimable at this time or that relate to contingencies where we currently regard the likelihood of loss as being only reasonably possible or remote. We believe we have accrued adequate amounts for all probable and reasonably estimable costs; however, this estimate is subject to uncertainties associated with the assumptions that we have made. For example, the amount of time it takes for us to resolve all of the current and future lawsuits, claims and investigations that relate to the Line 901 incident could turn out to be significantly longer than we have assumed, and as a result the costs we incur for legal services could be significantly higher than we have estimated. In addition, with respect to fines and penalties, the ultimate amount of any fines and penalties assessed against us depends on a wide variety of factors, many of which are not estimable at this time. Where fines and penalties are probable and estimable, we have included them in our estimate, although such estimates could turn out to be wrong. Accordingly, our assumptions and estimates may turn out to be inaccurate and our total costs could turn out to be materially higher; therefore, we can provide no assurance that we will not have to accrue significant additional costs in the future with respect to the Line 901 incident.

As of December 31, 2017, we had a remaining undiscounted gross liability of $94 million related to this event, of which approximately $62 million is presented as a current liability in “Accounts payable and accrued liabilities” on our Consolidated Balance Sheet, with the remainder presented in “Other long-term liabilities and deferred credits”. We maintain insurance coverage, which is subject to certain exclusions and deductibles, in the event of such environmental liabilities. Subject to such exclusions and deductibles, we believe that our coverage is adequate to cover the current estimated total emergency response and clean-up costs, claims settlement costs and remediation costs and we believe that this coverage is also adequate to cover any potential increase in the estimates for these costs that exceed the amounts currently identified. Through December 31, 2017, we had collected, subject to customary reservations, $174 million out of the approximate $220 million of release costs that we believe are probable of recovery from insurance carriers, net of deductibles. Therefore, as of December 31, 2017, we have recognized a receivable of approximately $47 million for the portion of the release costs that we believe is probable of recovery from insurance, net of deductibles and amounts already collected. Of this amount, approximately $22 million is recognized as a current asset in “Trade accounts receivable and other receivables, net” on our Consolidated Balance Sheet, with the remainder in “Other long-term assets, net”. We have completed the required clean-up and remediation work as determined by the Unified Command and the Unified Command has been dissolved; however, we expect to make payments for additional costs associated with restoration of the impacted areas, as well as natural resource damage assessment and compensation, legal, professional and regulatory costs, in addition to fines and penalties, during future periods.

Mesa to Basin Pipeline. On January 6, 2016, PHMSA issued a Notice of Probable Violation and Proposed Civil Penalty relating to an approximate 500 barrel release of crude oil that took place on January 1, 2015 on our Mesa to Basin 12" pipeline in Midland, Texas. PHMSA conducted an accident investigation and reviewed documentation related to the incident, and concluded that we had committed probable violations of certain pipeline safety regulations. In the Notice, PHMSA maintains that we failed to carry out our written damage prevention program and to follow our pipeline excavation/ditching and backfill procedures on four separate occasions, and that such failures resulted in outside force damage that led to the January 1, 2015 release. In early March 2017, PHMSA issued a final order that concluded that we followed our pipeline excavation/ditching and backfill procedures, but maintained that we failed to carry out our written damage prevention program and imposed a civil penalty of $184,300 that was promptly paid.

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 the U.S. federal Comprehensive Environmental Response, Compensation and Liability Act, as amended, and the U.S. federal Resource Conservation and Recovery Act, as amended, as well as 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.

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.

Insurance

Pipelines, terminals, trucks or other facilities or equipment may experience damage as a result of an accident, natural disaster, terrorist attack, cyber event or other event. 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 various types and varying levels of insurance coverage that we consider adequate under the circumstances to cover our operations and properties, and we self-insure certain risks, including gradual pollution and named windstorm. With respect to our insurance, our policies are subject to deductibles and retention levels that we consider reasonable and not excessive. However, such insurance does not cover every potential risk that might occur, associated with operating pipelines, terminals and other facilities and equipment, including the potential loss of significant revenues and cash flows.

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 that we maintain adequate insurance coverage, although insurance will not cover many types of interruptions that might occur, will not cover amounts up to applicable deductibles and will not cover all risks associated with certain of our assets and operations. Additionally we self-insure certain risks including, gradual pollution and named windstorm. With respect to our insurance coverage, no assurance can be given that we will 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 other insurance programs. In addition, although we believe that we have established adequate reserves and liquidity to the extent such risks are not insured, costs incurred in excess of these reserves may be higher or we may not receive insurance proceeds in a timely manner, which may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

Note 18—Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total (1)
	(in millions, except per unit data)				
2017					
Total revenues	$ 6,667	$ 6,078	$ 5,873	$ 7,605	$ 26,223
Gross margin (2)	$ 665	$ 325	$ 112	$ 327	$ 1,429
Operating income	$ 591	$ 257	$ 44	$ 261	$ 1,153
Net income	$ 444	$ 189	$ 34	$ 191	$ 858
Net income attributable to PAA	$ 444	$ 188	$ 33	$ 191	$ 856
Basic net income/(loss) per common unit	$ 0.59	$ 0.21	$ (0.01)	$ 0.19	$ 0.96
Diluted net income/(loss) per common unit	$ 0.58	$ 0.21	$ (0.01)	$ 0.19	$ 0.95
Cash distributions per common unit (3)	$ 0.55	$ 0.55	$ 0.55	$ 0.30	$ 1.95
2016					
Total revenues	$ 4,111	$ 4,950	$ 5,170	$ 5,952	$ 20,182
Gross margin (2)	$ 349	$ 219	$ 419	$ 286	$ 1,273
Operating income	$ 282	$ 146	$ 349	$ 218	$ 994
Net income	$ 203	$ 102	$ 298	$ 127	$ 730
Net income attributable to PAA	$ 202	$ 101	$ 297	$ 126	$ 726
Basic net income/(loss) per common unit	$ 0.07	$ (0.20)	$ 0.40	$ 0.14	$ 0.43
Diluted net income/(loss) per common unit	$ 0.07	$ (0.20)	$ 0.40	$ 0.14	$ 0.43
Cash distributions per common unit (3)	$ 0.70	$ 0.70	$ 0.70	$ 0.55	$ 2.65

(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 period presented.

Note 19—Operating Segments

We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. See "Revenue Recognition" in Note 2 for a summary of the types of products and services from which each segment derives its revenues. Our Chief Operating Decision Maker ("CODM") (our Chief Executive Officer) evaluates segment performance based on measures including segment adjusted EBITDA (as defined below) and maintenance capital investment.

The measure of segment adjusted EBITDA forms the basis of our internal financial reporting and is the primary performance measure used by our CODM in assessing performance and allocating resources among our operating segments. We define segment adjusted EBITDA as revenues and equity earnings in unconsolidated entities less (a) purchases and related costs, (b) field operating costs and (c) segment general and administrative expenses, plus our proportionate share of the depreciation and amortization expense and gains or losses on significant asset sales of unconsolidated entities, and further adjusted for certain selected items including (i) gains or losses on derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), gains and losses on derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable, (ii) long-term inventory costing adjustments, (iii) charges for obligations that are expected to be settled with the issuance of equity instruments, (iv) amounts related to deficiencies associated with minimum volume commitments, net of applicable amounts subsequently recognized into revenue and (v) other items that our CODM believes are integral to understanding our core segment operating performance.

Segment adjusted EBITDA excludes depreciation and amortization. Maintenance capital consists of capital expenditures for the replacement and/or refurbishment of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets. 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 adjusted EBITDA 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 age-related decline and wear and tear. We compensate for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance investments, which act to partially offset the aging and wear and tear in the value of our principal fixed assets. These maintenance investments are a component of field operating costs included in segment adjusted EBITDA or in maintenance capital, depending on the nature of the cost. Capital expenditures made to expand the existing operating and/or earnings capacity of our assets are classified as expansion capital. Capital expenditures for the replacement and/or refurbishment of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets are classified as maintenance capital, which is deducted in determining "available cash". 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 tables reflect certain financial data for each segment (in millions):

	Transportation	Facilities	Supply and Logistics	Intersegment Adjustment	Total
Year Ended December 31, 2017					
Revenues:					
External customers (1)	$ 1,021	$ 555	$ 25,056	$ (409)	$ 26,223
Intersegment (2)	697	618	9	409	1,733
Total revenues of reportable segments	$ 1,718	$ 1,173	$ 25,065	$ —	$ 27,956
Equity earnings in unconsolidated entities	$ 290	$ —	$ —		$ 290
Segment adjusted EBITDA	$ 1,287	$ 734	$ 60		$ 2,081
Capital expenditures (3)	$ 2,126	$ 312	$ 20		$ 2,458
Maintenance capital	$ 120	$ 114	$ 13		$ 247
As of December 31, 2017					
Total assets	$ 12,661	$ 7,313	$ 5,377		$ 25,351
Investments in unconsolidated entities	$ 2,681	$ 75	$ —		$ 2,756

	Transportation	Facilities	Supply and Logistics	Intersegment Adjustment	Total
Year Ended December 31, 2016					
Revenues:					
External customers (1)	$ 954	$ 546	$ 19,004	$ (322)	$ 20,182
Intersegment (2)	630	561	14	322	1,527
Total revenues of reportable segments	$ 1,584	$ 1,107	$ 19,018	$ —	$ 21,709
Equity earnings in unconsolidated entities	$ 195	$ —	$ —		$ 195
Segment adjusted EBITDA	$ 1,141	$ 667	$ 359		$ 2,167
Capital expenditures (3)	$ 1,063	$ 577	$ 54		$ 1,694
Maintenance capital	$ 121	$ 55	$ 10		$ 186
As of December 31, 2016					
Total assets	$ 10,917	$ 7,556	$ 5,737		$ 24,210
Investments in unconsolidated entities	$ 2,290	$ 53	$ —		$ 2,343

	Transportation	Facilities	Supply and Logistics	Intersegment Adjustment	Total
Year Ended December 31, 2015					
Revenues:					
External customers (1)	$ 953	$ 528	$ 21,927	$ (256)	$ 23,152
Intersegment (2)	641	522	18	256	1,437
Total revenues of reportable segments	$ 1,594	$ 1,050	$ 21,945	$ —	$ 24,589
Equity earnings in unconsolidated entities	$ 183	$ —	$ —		$ 183
Segment adjusted EBITDA	$ 1,056	$ 588	$ 568		$ 2,212
Capital expenditures (3)	$ 1,278	$ 813	$ 184		$ 2,275
Maintenance capital	$ 144	$ 68	$ 8		$ 220
As of December 31, 2015					
Total assets	$ 10,345	$ 7,330	$ 4,613		$ 22,288
Investments in unconsolidated entities	$ 1,998	$ 29	$ —		$ 2,027

(1) Transportation revenues from external customers include inventory exchanges that are substantially similar to tariff-like arrangements with our customers. Under these arrangements, our Supply and Logistics segment has transacted the inventory exchange and serves as the shipper on our pipeline systems. See Note 2 for a discussion of our related accounting policy. We have included an estimate of the revenues from these inventory exchanges in our Transportation segment revenue presented above and adjusted those revenues out such that Total revenue from External customers reconciles to our Consolidated Statements of Operations. This presentation is consistent with the information provided to our CODM.

(2) Segment revenues include intersegment amounts that are eliminated in Purchases and related costs and Field operating costs in our Consolidated Statements of Operations. Intersegment sales are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market.

(3) Expenditures for acquisition capital and expansion capital, including investments in unconsolidated entities.

Segment Adjusted EBITDA Reconciliation

The following table reconciles segment adjusted EBITDA to net income attributable to PAA (in millions):

	Year Ended December 31,		
	2017	2016	2015
Segment adjusted EBITDA	$ 2,081	$ 2,167	$ 2,212
Adjustments [1]:			
Depreciation and amortization of unconsolidated entities [2]	(45)	(50)	(45)
Gains/(losses) from derivative activities net of inventory valuation adjustments [3]	46	(404)	(110)
Long-term inventory costing adjustments [4]	24	58	(99)
Deficiencies under minimum volume commitments, net [5]	(2)	(46)	—
Equity-indexed compensation expense [6]	(23)	(33)	(27)
Net gain/(loss) on foreign currency revaluation [7]	26	(9)	29
Line 901 incident [8]	(32)	—	(83)
Significant acquisition-related expenses [9]	(6)	—	—
Depreciation and amortization	(626)	(494)	(432)
Interest expense, net	(510)	(467)	(432)
Other income/(expense), net	(31)	33	(7)
Income before tax	902	755	1,006
Income tax expense	(44)	(25)	(100)
Net income	858	730	906
Net income attributable to noncontrolling interests	(2)	(4)	(3)
Net income attributable to PAA	$ 856	$ 726	$ 903

(1) Represents adjustments utilized by our CODM in the evaluation of segment results.

(2) Includes our proportionate share of the depreciation and amortization and gains or losses on significant asset sales of equity method investments.

(3) We use derivative instruments for risk management purposes and our related processes include specific identification of hedging instruments to an underlying hedged transaction. Although we identify an underlying transaction for each derivative instrument we enter into, there may not be an accounting hedge relationship between the instrument and the underlying transaction. In the course of evaluating our results, we identify the earnings that were recognized during the period related to derivative instruments for which the identified underlying transaction does not occur in the current period and exclude the related gains and losses in determining segment adjusted EBITDA. In addition, we exclude gains and losses on derivatives that are related to investing activities, such as the purchase of linefill. We also exclude the impact of corresponding inventory valuation adjustments, as applicable.

(4) We carry crude oil and NGL inventory that is comprised of minimum working inventory requirements in third-party assets and other working inventory that is needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. Therefore, we classify this inventory as long-term on our balance sheet and do not hedge the inventory with derivative instruments (similar to linefill in our own assets). We exclude the impact of changes in the average cost of the long-term inventory (that result from fluctuations in market prices) and writedowns of such inventory that result from price declines from segment adjusted EBITDA.

(5) We have certain agreements that require counterparties to deliver, transport or throughput a minimum volume over an agreed upon period. Substantially all of such agreements were entered into with counterparties to economically support the return on our capital expenditure necessary to construct the related asset. Some of these agreements include make-up rights if the minimum volume is not met. We record a receivable from the counterparty in the period that services are provided or when the transaction occurs, including amounts for deficiency obligations from counterparties associated with minimum volume commitments. If a counterparty has a make-up right associated with a deficiency, we defer the revenue attributable to the counterparty's make-up right and subsequently recognize the revenue at the earlier of when the deficiency volume is delivered or shipped, when the make-up right expires or when it is determined that the counterparty's ability to utilize the make-up right is remote. We include the impact of amounts billed to counterparties for their deficiency obligation, net of applicable amounts subsequently recognized into revenue, as a selected item impacting comparability. Our CODM views the inclusion of the contractually committed revenues associated with that period as meaningful to segment adjusted EBITDA as the related asset has been constructed, is standing ready to provide the committed service and the fixed operating costs are included in the current period results. Amounts for the year prior to 2016 were not significant to segment adjusted EBITDA ($13 million for the year ended December 31, 2015).

(6) Includes equity-indexed compensation expense associated with awards that will or may be settled in units.

(7) Includes gains and losses from the revaluation of foreign currency transactions and monetary assets and liabilities.

(8) Includes costs recognized during the period related to the Line 901 incident that occurred in May 2015, net of amounts we believe are probable of recovery from insurance. See Note 17 for additional information regarding the Line 901 incident.

(9) Includes acquisition-related expenses associated with the ACC Acquisition. See Note 6 for additional discussion. An adjustment for these non-recurring expenses is included in the calculation of segment adjusted EBITDA for the year ended December 31, 2017 as our CODM does not view such expenses as integral to understanding our core segment operating performance. Acquisition-related expenses for the 2016 and 2015 periods were not significant to segment adjusted EBITDA.

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):

	Year Ended December 31,		
Revenues [1]	**2017**	**2016**	**2015**
United States	$ 21,443	$ 15,599	$ 18,701
Canada	4,780	4,583	4,451
	$ 26,223	$ 20,182	$ 23,152

(1) Revenues are primarily attributed to each region based on where the services are provided or the product is shipped.

	December 31,	
Long-Lived Assets [1]	**2017**	**2016**
United States	$ 17,167	$ 16,041
Canada	4,179	3,895
	$ 21,346	$ 19,936

(1) Excludes long-term derivative assets and long-term deferred tax assets.

Exhibit 12.1

STATEMENT OF COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES AND RATIO OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED UNIT DISTRIBUTIONS
(in millions, except ratio data)

	Year Ended December 31,				
	2017	2016	2015	2014	2013
EARNINGS [1]					
Pre-tax income from continuing operations before noncontrolling interests and income from equity investees	$ 612	$ 560	$ 823	$ 1,449	$ 1,426
add: Fixed charges	613	588	548	457	424
add: Distributed income of equity investees	304	216	214	105	55
add: Amortization of capitalized interest	8	7	6	4	3
less: Capitalized interest	(35)	(47)	(57)	(48)	(38)
Total Earnings	$ 1,502	$ 1,324	$ 1,534	$ 1,967	$ 1,870
FIXED CHARGES [1]					
Interest expensed and capitalized	$ 545	$ 524	$ 495	$ 410	$ 381
Portion of rent expense related to interest (33.33%)	68	64	53	47	43
Total Fixed Charges	$ 613	$ 588	$ 548	$ 457	$ 424
Series A preferred unit distributions [2][3]	142	122	—	—	—
Series B preferred unit distributions [2][4]	11	—	—	—	—
Total Combined Fixed Charges and Preferred Unit Distributions	$ 766	$ 710	$ 548	$ 457	$ 424
RATIO OF EARNINGS TO FIXED CHARGES [5]	2.45x	2.25x	2.80x	4.30x	4.41x
RATIO OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED UNIT DISTRIBUTIONS [2][5]	1.96x	1.86x	—	—	—

(1) For purposes of computing the ratio of earnings to fixed charges and the ratio of earnings to combined fixed charges and preferred unit distributions, "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 leases deemed to be the equivalent of interest.

(2) As no preferred units were outstanding for any of the years ended December 31, 2015, 2014, 2013 and 2012, no historical ratio of earnings to combined fixed charges and preferred unit distributions are presented for those years.

(3) Distributions on our Series A convertible preferred units (the "Series A preferred units") were paid in additional Series A preferred units for the years ended December 31, 2017 and 2016. We issued 5,413,842 and 4,646,499 additional Series A preferred units in lieu of cash distributions of $142 million and $122 million pertaining to the years ended December 31, 2017 and 2016, respectively.

(4) Distributions on our Series B perpetual preferred units accrue and are cumulative at a rate of 6.125% per year from October 10, 2017, the date of original issue, and are payable semiannually.

(5) Ratios may not recalculate due to rounding.

Exhibit 21.1

SUBSIDIARIES OF
PLAINS ALL AMERICAN PIPELINE, L.P.
(As of 1/1/2018)

Subsidiary	Jurisdiction of Organization
Aurora Pipeline Company Ltd.	Canada
Bakersfield Crude Terminal LLC	Delaware
Cactus II Pipeline LLC	Delaware
Eagle Ford Crude Terminal LLC	Delaware
Lone Star Trucking, LLC	California
Niobrara Crude Terminal LLC	Delaware
PAA Finance Corp.	Delaware
PAA Luxembourg S.a.r.l.	Luxembourg
PAA Midstream LLC	Delaware
PAA Natural Gas Canada ULC	Alberta
PAA Natural Gas Storage, LLC	Delaware
PAA Natural Gas Storage, L.P.	Delaware
PAA/Vulcan Gas Storage, LLC	Delaware
Pacific Energy Group LLC	Delaware
Pacific L.A. Marine Terminal LLC	Delaware
Pacific Pipeline System LLC	Delaware
PACONO1, LLC	Delaware
PACONO3 LLC	Delaware
PICSCO LLC	Delaware
Pine Prairie Energy Center, LLC	Delaware
Plains All American Emergency Relief Fund, Inc.	Texas
Plains Capline LLC	Delaware
Plains Gas Solutions, LLC	Texas
Plains GP LLC	Texas
Plains LPG Services GP LLC	Delaware
Plains LPG Services, L.P.	Texas
Plains Marketing Bondholder, LLC	Delaware
Plains Marketing Canada LLC	Delaware
Plains Marketing GP Inc.	Texas
Plains Marketing, L.P.	Texas
Plains Midstream Canada ULC	British Columbia
Plains Midstream Luxembourg S.a.r.l.	Luxembourg
Plains Midstream Superior LLC	Texas
Plains Pipeline, L.P.	Texas
Plains Pipeline Montana LLC	Delaware
Plains Products Terminals LLC	Delaware
Plains Rail Holdings LLC	Delaware
Plains South Texas Gathering LLC	Texas
Plains Terminals North Dakota LLC	Delaware
Plains Towing LLC	Delaware
Plains West Coast Terminals LLC	Delaware

Subsidiary	Jurisdiction of Organization
PLPGS Empress U.S. Corporation	Delaware
PMC (Nova Scotia) Company	Nova Scotia
PNG Marketing, LLC	Delaware
PNGS GP LLC	Delaware
PPEC Bondholder, LLC	Delaware
Rancho LPG Holdings LLC	Delaware
Rocky Mountain Pipeline Montana LLC	Delaware
Rocky Mountain Pipeline System LLC	Texas
SG Resources Mississippi, L.L.C.	Delaware
St. James Rail Terminal LLC	Delaware
Sunrise Pipeline LLC	Delaware
Van Hook Crude Terminal 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, 333-162477, 333-207139, 333-207140, 333-214778 and 333-221845) and on Form S-8 (No. 333-91141, 333-74920, 333-122806, 333-141185, 333-193139, and 333-193140) of Plains All American Pipeline, L.P. of our report dated February 26, 2018 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Houston, Texas
February 26, 2018

EXHIBIT 31.1

CERTIFICATION

I, Greg L. Armstrong, certify that:

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

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 of 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 26, 2018

/s/ Greg L. Armstrong

Greg L. Armstrong
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Al Swanson, certify that:

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

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 of 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 26, 2018

/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, 2017 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, as amended; 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 26, 2018

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, 2017 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, as amended; 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 26, 2018