PART II

Item 5. *Market for Registrant's Shares, Related Shareholder Matters and Issuer Purchases of Equity Securities*

Market Information, Holders and Dividends

Our Class A shares are listed and traded on the New York Stock Exchange under the symbol "PAGP." In connection with the closing of the Simplification Transactions on November 15, 2016, as discussed further below, we effected a reverse split of our Class A and Class B shares, in each case, at a ratio of approximately 1-for-2.663. The effect of this reverse split has been retroactively applied to all share and per share amounts presented in this Form 10-K.

As of February 12, 2018, the closing market price for our Class A shares was $21.88 per share and there were approximately 20,100 record holders and beneficial owners (held in street name). As of February 12, 2018, there were 157,011,139 Class A shares outstanding.

The following table sets forth high and low sales prices for our Class A shares and the cash distributions declared per Class A share:

	Class A Share Price Range		
	High	Low	Cash Distributions [1]
2017			
4th Quarter	$ 22.31	$ 18.98	$ 0.30
3rd Quarter	$ 27.75	$ 19.60	$ 0.30
2nd Quarter	$ 31.77	$ 23.33	$ 0.55
1st Quarter	$ 35.58	$ 30.38	$ 0.55
2016			
4th Quarter	$ 36.59	$ 28.84	$ 0.55
3rd Quarter	$ 35.10	$ 25.59	$ 0.55
2nd Quarter	$ 30.70	$ 20.98	$ 0.62
1st Quarter	$ 25.80	$ 12.57	$ 0.62

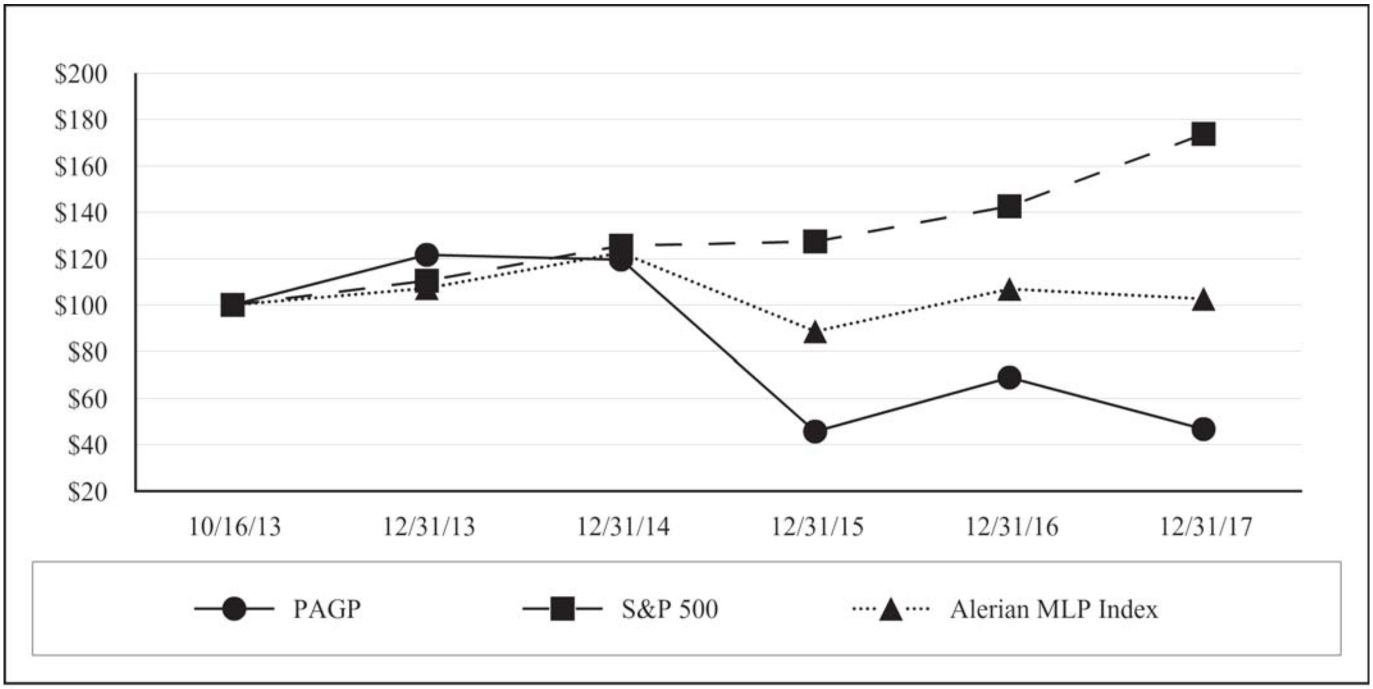
(1) Cash distributions pertaining to the quarter presented. These distributions were declared and paid in the following calendar quarter. See the "Cash Distribution Policy" section below for a discussion of our policy regarding distribution payments.

Our Class A shares are also used as a form of compensation to our directors. See Note 16 to our Consolidated Financial Statements for additional information regarding our equity-indexed compensation plans.

Our Class B shares and Class C shares are not listed or traded on any stock exchange.

Performance Graph

The following graph compares the total unitholder return performance of our Class A shares with the performance of: (i) the Standard & Poor's 500 Stock Index ("S&P 500") and (ii) the Alerian MLP Index. The Alerian MLP Index is a composite of the 50 most prominent energy master limited partnerships that provides investors with a comprehensive benchmark for this asset class. The graph assumes that $100 was invested in our Class A shares and each comparison index beginning on October 16, 2013, the date our Class A shares began trading on the NYSE, and that all distributions were reinvested on a quarterly basis.



	10/16/2013	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017
PAGP	$ 100.00	$ 121.68	$ 119.57	$ 45.73	$ 68.94	$ 46.79
S&P 500	$ 100.00	$ 110.51	$ 125.64	$ 127.38	$ 142.61	$ 173.75
Alerian MLP Index	$ 100.00	$ 107.29	$ 122.55	$ 88.72	$ 107.00	$ 102.64

This information shall not be deemed to be "soliciting material" or to be "filed" with the Commission or subject to Regulation 14A or 14C under the Exchange Act, other than as provided in Item 201(e) of Regulation S-K, or to the liabilities of Section 18 of the Exchange Act, and shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act, except to the extent that we specifically request that such information be treated as soliciting material or specifically incorporate it by reference into a filing under the Securities Act or the Exchange Act.

Recent Sales of Unregistered Securities

In connection with our IPO and related transactions, the Legacy Owners acquired the following interests (collectively, the "Stapled Interests"): (i) AAP units representing an economic limited partner interest in AAP; (ii) general partner units representing a non-economic membership interest in our general partner; and (iii) Class B shares representing a non-economic limited partner interest in us. The Legacy Owners and any permitted transferees of their Stapled Interests have the right to exchange (the "Exchange Right") all or a portion of such Stapled Interests for an equivalent number of Class A shares. In connection with the exercise of the Exchange Right, the Stapled Interests are transferred to us and the applicable Class B shares are canceled. Although we issue one Class A share for each Stapled Interest that is exchanged, we also receive one AAP unit and one general partner unit. As a result, the exercise by Legacy Owners of the Exchange Right is not dilutive. During the three months ended December 31, 2017, certain Legacy Owners or their permitted transferees exercised the Exchange Right, which resulted in the issuance of 1,567,946 Class A shares. The issuance of Class A shares in connection with the exercise of the Exchange Rights was exempt from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereof.

Issuer Purchases of Equity Securities

None.

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. See Note 1 to our Consolidated Financial Statements for further discussion of the Simplification Transactions.

Cash Distribution Policy

Our partnership agreement requires that, within 55 days following the end of each quarter, we distribute all of our available cash to Class A shareholders of record on the applicable record date. Available cash generally means, for any quarter ending prior to liquidation, all cash on hand at the date of determination of available cash for the distribution in respect of such quarter (including expected distributions from AAP in respect of such quarter), less the amount of cash reserves established by our general partner, which will not be subject to a cap, to:

- comply with applicable law or any agreement binding upon us or our subsidiaries (exclusive of PAA and its subsidiaries);
- provide funds for distributions to shareholders;
- provide for future capital expenditures, debt service and other credit needs as well as any federal, state, provincial or other income tax that may affect us in the future; or
- provide for the proper conduct of our business, including with respect to the matters described under our partnership agreement.

Our available cash also includes cash on hand resulting from borrowings, if any, made after the end of the quarter.

Our principal sources of cash flow are derived from our indirect investment in PAA. As of December 31, 2017, we directly and indirectly owned approximately 156.1 million AAP units, which represented an approximate 55% limited partner interest in AAP. AAP currently receives all of its cash flows from its ownership of PAA common units. Therefore, our cash flow and resulting ability to make distributions will be completely dependent upon the ability of PAA to make distributions to AAP in respect of the common units AAP owns. As of December 31, 2017, AAP owned approximately 284.0 million PAA common units. The actual amount of cash that PAA, and correspondingly AAP, will have available for distribution will primarily depend on the amount of cash PAA generates from its operations. Also, under the terms of the agreements governing PAA's debt, PAA is prohibited from declaring or paying any distribution to unitholders if a default or event of default (as defined in such agreements) exists. No such default has occurred. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Agreements, Commercial Paper Program and Indentures."

Our general partner owns a non-economic general partner interest in us, which does not entitle it to receive cash distributions.

Item 6. ***Selected Financial Data***

The following tables set forth selected historical consolidated financial and other information for PAGP as of the dates and for the periods indicated. The selected consolidated statements of operations data for the year ended December 31, 2013 include results attributable to PAGP from October 21, 2013 (the date of closing PAGP's IPO) through December 31, 2013, plus results for GP LLC, the predecessor entity to PAGP, prior to October 21, 2013.

The financial information below was derived from the audited financial statements of PAGP (and GP LLC as discussed above) as of December 31, 2017, 2016, 2015, 2014 and 2013 and for the years then ended.

The selected financial data should be read in conjunction with Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations," and the Consolidated Financial Statements, including the notes thereto, in Item 8. "Financial Statements and Supplementary Data."

	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(in millions, except per share data and volumes)				
Statement of operations data:					
Total revenues	$ 26,223	$ 20,182	$ 23,152	$ 43,464	$ 42,249
Operating income	$ 1,147	$ 990	$ 1,258	$ 1,791	$ 1,734
Net income/(loss) [1]	$ (41)	$ 660	$ 809	$ 1,328	$ 1,374
Net income/(loss) attributable to PAGP [1]	$ (731)	$ 94	$ 118	$ 70	$ 15
Per share data:					
Basic net income/(loss) per Class A share [1] [2]	$ (5.03)	$ 0.94	$ 1.41	$ 1.28	$ 0.25
Diluted net income/(loss) per Class A share [1] [2]	$ (5.03)	$ 0.94	$ 1.41	$ 1.25	$ 0.25
Declared distributions per Class A share [3]	$ 1.95	$ 2.40	$ 2.35	$ 1.78	N/A
Balance sheet data (at end of period):					
Property and equipment, net	$ 14,105	$ 13,890	$ 13,493	$ 12,292	$ 10,841
Total assets	$ 26,753	$ 26,103	$ 24,142	$ 23,923	$ 21,411
Long-term debt	$ 9,183	$ 10,124	$ 10,932	$ 9,238	$ 7,188
Total debt	$ 9,920	$ 11,839	$ 11,931	$ 10,525	$ 8,301
Partners' capital:					
Partners' capital (excluding Noncontrolling interests)	$ 1,695	$ 1,737	$ 1,762	$ 1,657	$ 1,035
Noncontrolling interests	$ 10,663	$ 8,970	$ 7,472	$ 7,724	$ 7,244
Total Partners' capital	$ 12,358	$ 10,707	$ 9,234	$ 9,381	$ 8,279
Other data:					
Net cash provided by operating activities [4]	$ 2,496	$ 718	$ 1,347	$ 2,007	$ 1,966
Net cash used in investing activities	$ (1,570)	$ (1,273)	$ (2,530)	$ (3,296)	$ (1,653)
Net cash provided by/(used in) financing activities [4]	$ (940)	$ 571	$ 813	$ 1,653	$ (292)
Capital expenditures:					
Acquisition capital	$ 1,323	$ 289	$ 105	$ 1,099	$ 19
Expansion capital	$ 1,135	$ 1,405	$ 2,170	$ 2,026	$ 1,622
Maintenance capital	$ 247	$ 186	$ 220	$ 224	$ 176

	Year Ended December 31,				
	2017	2016	2015	2014	2013
Volumes [5] [6]					
Transportation segment (average daily volumes in thousands of barrels per day):					
Tariff activities	5,083	4,523	4,340	3,952	3,595
Trucking	103	114	113	127	117
Transportation segment total volumes	5,186	4,637	4,453	4,079	3,712
Facilities segment:					
Liquids storage (average monthly capacity in millions of barrels)	112	107	100	95	94
Natural gas storage (average monthly working capacity in billions of cubic feet)	82	97	97	97	96
NGL fractionation (average volumes in thousands of barrels per day)	126	115	103	96	96
Facilities segment total volumes (average monthly volumes in millions of barrels)	130	127	120	114	113
Supply and Logistics segment (average daily volumes in thousands of barrels per day):					
Crude oil lease gathering purchases	945	894	943	949	859
NGL sales	274	259	223	208	215
Supply and Logistics segment total volumes	1,219	1,153	1,166	1,157	1,074

(1) During the year ended December 31, 2017, we recorded approximately $823 million related to the re-measurement of our existing deferred tax asset as a result of the reduction in our effective tax rate from the change in corporate federal income tax rate from 35% to 21%. See Note 13 to our Consolidated Financial Statements for additional information.

(2) Basic and diluted net income per Class A share for 2013 were calculated based on net income attributable to PAGP for the period following the closing of our initial public offering on October 21, 2013 and basic weighted average Class A shares outstanding weighted for the same period.

(3) Represents cash distributions declared and paid per share during the year presented. See Note 11 to our Consolidated Financial Statements for further discussion regarding our distributions.

(4) Amounts for 2013 through 2016 have been retroactively restated to reflect the impact of our adoption of Accounting Standards Update 2016-09, *Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting*. See Note 2 to our Consolidated Financial Statements for additional information.

(5) Average volumes are calculated as the total volumes (attributable to our interest) for the year divided by the number of days or months in the year.

(6) Facilities segment total is calculated as the sum of: (i) liquids storage capacity; (ii) natural gas storage working capacity divided by 6 to account for the 6:1 thousand cubic feet ("mcf") of natural gas to crude British thermal unit ("Btu") equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) NGL fractionation volumes multiplied by the number of days in the year and divided by the number of months in the year.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations and should be read in conjunction with our historical consolidated financial statements and accompanying notes. Unless the context otherwise requires, references to "we," "us," "our," and "PAGP" are intended to mean the business and operations of PAGP and its consolidated subsidiaries.

Our discussion and analysis includes the following:

- Executive Summary
- Acquisitions and Capital Projects
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements
- Results of Operations
- Outlook
- Liquidity and Capital Resources

Executive Summary

Company Overview

We are a Delaware limited partnership formed on July 17, 2013 that has elected to be taxed as a corporation for United States federal income tax purposes. As of December 31, 2017, our sole assets consisted of (i) a 100% managing member interest in GP LLC, an entity that has also elected to be taxed as a corporation for United States federal income tax purposes and (ii) an approximate 55% limited partner interest in AAP through our direct ownership of approximately 155.1 million AAP units and indirect ownership of approximately 1.0 million AAP units through GP LLC. GP LLC is a Delaware limited liability company that also holds the non-economic general partner interest in AAP. AAP is a Delaware limited partnership that, as of December 31, 2017, directly owned a limited partner interest in PAA through its ownership of approximately 284.0 million PAA common units (approximately 36% of PAA Common Unit Equivalents). AAP is the sole member of PAA GP, a Delaware limited liability company that directly holds the non-economic general partner interest in PAA.

PAA owns and operates midstream energy infrastructure and provides logistics services primarily for crude oil, NGL and natural gas. PAA owns 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.

Overview of Operating Results, Capital Investments and Other Significant Activities

The crude oil market downturn over the last three years created a challenging environment for the overall midstream industry. See the "Outlook—Market Overview and Outlook" section below for further discussion. We recognized a net loss of $41 million in 2017 as compared to net income of $660 million recognized in 2016. The net loss in 2017 was primarily due to $823 million of deferred income tax expense recognized in the fourth quarter of 2017 related to the re-measurement of PAGP's deferred tax asset following the signing into law of the Tax Cuts and Jobs Act of 2017. The remaining variance between the comparative periods also reflects:

- Contributions from our recently completed acquisitions and capital expansion projects and favorable variances from the mark-to-market impact of certain derivative instruments, partially offset by less favorable crude oil and NGL market conditions and margin compression caused by continued competition;

- Higher depreciation and amortization expense largely driven by (i) an increase in impairments, accelerated depreciation and canceled projects during the 2017 period, (ii) additional depreciation associated with acquisitions and the completion of various capital expansion projects and (iii) smaller net gains from non-core assets sales and joint venture formations recognized in the 2017 period;

- Higher interest expense primarily related to financing activities associated with our capital investments;
- A net loss of $40 million recognized in 2017 related to the early redemption of senior notes; and
- The mark-to-market of the Preferred Distribution Rate Reset Option, resulting in a smaller gain recognized in 2017 compared to the gain recognized in the 2016 period.

See further discussion of our segment operating results in the "—Results of Operations—Analysis of Operating Segments" and "—Other Income and Expenses" sections below.

We invested approximately $1.1 billion in midstream infrastructure projects during 2017, which included the newly constructed Diamond and STACK extension joint venture pipelines, both of which were placed in service in late 2017, as well as capacity expansions for the Cactus I and BridgeTex pipelines. Additionally, we completed $1.3 billion of acquisitions in 2017, which primarily consisted of pipeline assets in the Permian Basin. See the "—Acquisitions and Capital Projects" section below for additional information.

To fund such capital activities, we sold (i) PAGP and PAA equity securities for net proceeds of approximately $1.7 billion (all of which occurred in the first four months of the year) and (ii) 800,000 newly issued PAA Series B preferred units in October 2017 for net proceeds of $788 million. In addition, we continued to advance our divestiture program, completing non-core asset sales during 2017 for cash proceeds of approximately $1.1 billion, and progressed the PAA Leverage Reduction Plan, as discussed below. We also paid approximately $1.4 billion of cash distributions to our Class A Shareholders and noncontrolling interests during 2017.

PAA Leverage Reduction Plan

On August 25, 2017, PAA announced that it was implementing an action plan to strengthen its balance sheet, reduce leverage, enhance its distribution coverage, minimize new issuances of common equity and position PAA for future distribution growth. The action plan ("PAA Leverage Reduction Plan"), which was endorsed by our Board, included PAA's intent to achieve certain objectives. As of early 2018, the status of PAA's efforts to implement the PAA Leverage Reduction Plan is summarized below:

PAA Leverage Reduction Plan Objective	PAA Status
Reset PAA's annualized distribution per common unit to $1.20, starting with the third-quarter distribution payable in November 2017, which would reduce PAA's annual distribution outflow by approximately $725 million per year, representing approximately $1.1 billion over 6 quarters	The reduction of PAA's annualized distribution per common unit to $1.20 commenced with the November 2017 distribution, resulting in an improved distribution coverage ratio
Complete pending and/or in-progress non-core/strategic asset sales totaling approximately $700 million	Since announcing the PAA Leverage Reduction Plan in August 2017, PAA has closed on approximately $700 million of non-core/strategic asset sales
Reduce hedged crude oil and NGL inventory volumes and related debt by approximately $300 million (based on current prices) relative to June 30, 2017 levels	As of December 31, 2017, PAA reduced its hedged inventory debt by approximately $375 million relative to June 30, 2017 levels
Fund second-half 2017 and full-year 2018 expansion capital program with a combination of non-convertible, perpetual preferred PAA equity (target of approximately $600 million) and asset sales proceeds	In October 2017, PAA completed an $800 million offering ($200 million over target) of 6.125% non-convertible Series B preferred units for net proceeds of $788 million
Apply retained cash flows and remaining asset sales proceeds to steadily reduce PAA's total debt as of June 30, 2017 by approximately $1.4 billion through March 31, 2019	In December 2017, PAA retired two series of senior notes totaling $950 million that would otherwise have matured in 2018 and 2019

There can be no assurance that the objectives of PAA's Leverage Reduction Plan remaining to be achieved will be achieved, or that they will be achieved within PAA's desired time frame or in the desired amounts. Achievement of such objectives is subject to risks and uncertainties, many of which are outside of PAA's control. Please see "Risk Factors—Risks Related to PAA's Business."

Acquisitions and Capital Projects

We completed a number of acquisitions and capital projects in 2017, 2016 and 2015 that have impacted our results of operations. The following table summarizes our expenditures for acquisition capital, expansion capital and maintenance capital for such periods (in millions):

	Year Ended December 31,		
	2017	2016	2015
Acquisition capital [1]	$ 1,323	$ 289	$ 105
Expansion capital [1] [2]	1,135	1,405	2,170
Maintenance capital [2]	247	186	220
	$ 2,705	$ 1,880	$ 2,495

(1) Acquisitions of initial investments or additional interests in unconsolidated entities are included in "Acquisition capital." Subsequent contributions to unconsolidated entities related to expansion projects of such entities are recognized in "Expansion capital." We account for our investments in such entities under the equity method of accounting.

(2) 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."

Acquisitions

Acquisitions are financed using a combination of equity and debt, including borrowings under the PAA commercial paper program or credit facilities and the issuance of PAA senior notes. In addition, we use proceeds from sales of non-core assets for funding. Businesses acquired impact our results of operations commencing on the closing date of each acquisition. Our acquisition, divestiture and capital expansion activities are discussed further in "—Liquidity and Capital Resources." Information regarding acquisitions completed in 2017, 2016 and 2015 is set forth in the table below (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Alpha Crude Connector Gathering System	February 2017	$ 1,215	Transportation
Other	Various	108	Transportation and Facilities
2017 Total		$ 1,323	
Western Canada NGL Assets	August 2016	$ 204	Transportation and Facilities
Other	Various	85	Transportation
2016 Total		$ 289	
2015 Total	Various	$ 105	Transportation and Facilities

Expansion Capital Projects

Our 2017 projects primarily included the construction and expansion of pipeline systems and storage and terminal facilities. The following table summarizes our 2017, 2016 and 2015 projects (in millions):

Projects	2017	2016	2015
Diamond Pipeline [1]	$ 318	$ 104	$ 6
Permian Basin Area Projects [2]	243	200	470
Fort Saskatchewan Facility Projects [2]	83	200	272
STACK JV Projects [3]	60	12	—
Cushing Terminal Expansions [2]	37	62	39
Eagle Ford JV Projects [2] [4]	27	29	93
St. James Terminal Expansions [2]	13	51	45
Red River Pipeline	10	306	143
Cactus I Pipeline	10	26	134
Saddlehorn Pipeline [5]	5	108	103
Other Projects	329	307	865
Total	$ 1,135	$ 1,405	$ 2,170

(1) Represents contributions related to our 50% interest in Diamond Pipeline LLC.

(2) These projects will continue into 2018. See "—Liquidity and Capital Resources—Acquisitions, Investments, Expansion Capital Expenditures and Divestitures —2018 Capital Projects."

(3) Represents contributions related to our 50% interest in STACK Pipeline LLC.

(4) Represents contributions related to our 50% interest in Eagle Ford Pipeline and our 50% interest in Eagle Ford Terminals.

(5) Represents contributions related to our 40% interest in Saddlehorn Pipeline.

Our recent expansion capital programs were primarily driven by investment in midstream infrastructure projects to address the need for additional takeaway capacity in regions impacted by the increase in crude oil and liquids-rich gas production growth in North America, as well as the long-term needs of both the upstream and downstream sectors of the crude oil space. Substantially all of the expansion capital spent in the years presented was invested in our fee-based Transportation and Facilities segments.

We currently expect to spend approximately $1.4 billion for expansion capital in 2018. See "—Liquidity and Capital Resources—Acquisitions, Investments, Expansion Capital Expenditures and Divestitures —2018 Capital Projects" and "Outlook—Market Overview and Outlook" for additional information.

Divestitures

During 2016, we initiated a program to evaluate potential sales of non-core assets and/or sales of partial interests in assets to strategic joint venture partners to optimize our asset portfolio and strengthen our balance sheet and leverage metrics. Information regarding non-core asset sales completed since 2016 is set forth in the table below (in millions):

Year	Operating Segment	Proceeds
2017 Total	Transportation and Facilities	$ 1,083
2016 Total	Transportation and Facilities	$ 569 [1]

(1) Net of amounts paid for the remaining interest in a non-core pipeline that was subsequently sold.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP and rules and regulations of the SEC requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, as well as the disclosure of contingent assets and liabilities, at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Although we believe these estimates are reasonable, actual results could differ from these estimates. On a regular basis, we evaluate our assumptions, judgments and estimates. We also discuss our critical accounting policies and estimates with the Audit Committee of the Board of Directors.

We believe that the assumptions, judgments and estimates involved in the accounting for our (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 have the greatest potential impact on our Consolidated Financial Statements. These areas are key components of our results of operations and are based on complex rules which require us to make judgments and estimates. Therefore, we consider these to be our critical accounting policies and estimates, which are discussed further as follows. For further information on all of our significant accounting policies, see Note 2 to our Consolidated Financial Statements.

Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets. In accordance with FASB guidance regarding business combinations, with each acquisition, we allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. If the initial accounting for the business combination is incomplete when the combination occurs, an estimate will be recorded. With exception to acquisitions of equity method investments, we also expense the transaction costs as incurred in connection with each acquisition. In addition, we are required to recognize intangible assets separately from goodwill.

Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer relationships, acreage dedications and other contracts, involves professional judgment and is ultimately based on acquisition models and management's assessment of the value of the assets acquired and, to the extent available, third party assessments.

Impairment Assessments of Goodwill and Intangible Assets. Goodwill and intangible assets with indefinite lives are not amortized but are instead periodically assessed for impairment. See Note 7 to our Consolidated Financial Statements for further discussion of goodwill. Intangible assets with finite lives are amortized over their estimated useful life as determined by management.

Impairment testing entails estimating future net cash flows relating to the business, based on management's estimate of future revenues, future cash flows and market conditions including pricing, demand, competition, operating costs and other factors, such as weighted average cost of capital. Uncertainties associated with these estimates include changes in production decline rates, production interruptions, fluctuations in refinery capacity or product slates, economic obsolescence factors in the area and potential future sources of cash flow. We cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Resolutions of these uncertainties have resulted, and in the future may result, in impairments that impact our results of operations and financial condition.

Fair Value of Derivatives. The fair value of a derivative at a particular period end does not reflect the end results of a particular transaction, and will most likely not reflect the gain or loss at the conclusion of a transaction. We reflect estimates for these items based on our internal records and information from third parties. We have commodity derivatives, interest rate derivatives and foreign currency derivatives that are accounted for as assets and liabilities at fair value in our Consolidated Balance Sheets. The valuations of our derivatives that are exchange traded are based on market prices on the applicable exchange on the last day of the period. For our derivatives that are not exchange traded, the estimates we use are based on indicative broker quotations or an internal valuation model. Our valuation models utilize market observable inputs such as price, volatility, correlation and other factors and may not be reflective of the price at which they can be settled due to the lack of a liquid market. Less than 1% of total annual revenues are based on estimates derived from internal valuation models.

We also have embedded derivatives in PAA's Series A preferred units that are recorded at fair value on our Consolidated Balance Sheets. These embedded derivatives are valued using a model that contains inputs, including PAA common unit price, ten-year U.S. Treasury rates, default probabilities and timing estimates, which involve management judgment.

Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Note 12 to our Consolidated Financial Statements for a discussion regarding our derivatives and risk management activities.

Accruals and Contingent Liabilities. We record accruals or liabilities for, among other things, environmental remediation, natural resource damage assessments, governmental fines and penalties, potential legal claims and fees for legal services associated with loss contingencies, and bonuses. Accruals are made when our assessment indicates that it is probable that a liability has occurred and the amount of liability can be reasonably estimated. Our estimates are based on all known facts at the time 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 environmental 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, the duration of the natural resource damage assessment and the ultimate amount of damages determined, the determination and calculation of fines and penalties, the possibility of existing legal claims giving rise to additional claims and the nature, extent and cost of legal services that will be required in connection with lawsuits, claims and other matters. Our estimates for contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. A hypothetical variance of 5% in our aggregate estimate for the accruals and contingent liabilities discussed above would have an impact on earnings of up to approximately $16 million. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Equity-Indexed Compensation Plan Accruals. We accrue compensation expense (referred to herein as equity-indexed compensation expense) for outstanding equity-indexed compensation awards. Under GAAP, we are required to estimate the fair value of our outstanding equity-indexed compensation awards and recognize that fair value as compensation expense over the service period. For equity-indexed compensation awards that contain a performance condition, the fair value of the award is recognized as equity-indexed compensation expense only if the attainment of the performance condition is considered probable. Uncertainties involved in this estimate include future distribution levels and whether or not a performance condition will be attained. In addition, the unit price at the end of each period (and at the time of vesting) will impact the amount of compensation expense recorded in each period for certain awards. We cannot provide assurance that the actual fair value of our equity-indexed compensation awards will not vary significantly from estimated amounts.

We recognized equity-indexed compensation expense of $41 million, $60 million and $27 million in 2017, 2016 and 2015, respectively, related to awards granted under our various equity-indexed compensation plans. A hypothetical variance of 5% in our aggregate estimate for the equity-indexed compensation expense would have an impact on our total costs and expenses of less than 1%. See Note 16 to our Consolidated Financial Statements for a discussion regarding our equity-indexed compensation plans.

Property and Equipment, Depreciation and Amortization Expense, Asset Retirement Obligations and Impairments. We compute depreciation and amortization using the straight-line method based on estimated useful lives. These estimates are based on various factors including condition, manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives and salvage values that we believe are reasonable. However, subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization.

We record retirement obligations associated with tangible long-lived assets based on estimates related to the costs associated with cleaning, purging and, in some cases, completely removing the assets and returning the land to its original state. In addition, our estimates include a determination of the settlement date or dates for the potential obligation, which may or may not be determinable. Uncertainties that impact these estimates include the costs associated with these activities and the timing of incurring such costs.

We periodically evaluate property and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. Any evaluation is highly dependent on the underlying assumptions of related cash flows. We consider the fair value estimate used to calculate impairment of property and equipment a critical accounting estimate. In determining the existence of an impairment of carrying value, we make a number of subjective assumptions as to:

- whether there is an event or circumstance that may be indicative of an 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.

As discussed in the "—Outlook— Market Overview and Outlook" section below, the downturn in the crude oil industry that started in mid-to-late 2014 has adversely impacted most companies in the midstream industry, including us. As a result of such market conditions, during 2017 and 2016, we recognized approximately $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. Despite the modest recovery in crude oil prices at the end of 2017 and early 2018, we continue to monitor appropriate indicators of potential impairment.

We did not recognize any material impairment of long-lived assets during the year ended December 31, 2015. See Note 5 to our Consolidated Financial Statements for further discussion regarding impairments.

Allowance for Doubtful Accounts. We perform credit evaluations of our customers and grant credit based on past payment history, financial conditions and anticipated industry conditions. Customer payments are regularly monitored and a provision for doubtful accounts is established based on specific situations and overall industry conditions. Our history of bad debt losses has been minimal (less than $2 million in the aggregate over the years ended December 31, 2017, 2016 and 2015) and generally limited to specific customer circumstances; however, credit risks can change suddenly and without notice. See Note 2 to our Consolidated Financial Statements for additional discussion.

Inventory Valuations. Inventory, including long-term inventory, primarily consists of crude oil, NGL and natural gas and is 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 use estimates and judgment when making any adjustments necessary to reduce the carrying value to net realizable value. Among the uncertainties that impact our estimates are the applicable quality and location differentials to include in our net realizable value analysis. Additionally, we estimate the upcoming liquidation timing of the inventory. Changes in assumptions made as to the timing of a sale can materially impact net realizable value. 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 valuation adjustment of our crude oil, NGL and natural gas inventory due to declines in prices. See Note 4 to our Consolidated Financial Statements for further discussion regarding inventory.

Recent Accounting Pronouncements

See Note 2 to our Consolidated Financial Statements for information regarding the effect of recent accounting pronouncements on our Consolidated Financial Statements, including the impact of our adoption of revised employee share-based payment accounting guidance on prior period financial statements.

Results of Operations

The following table sets forth an overview of our consolidated financial results calculated in accordance with GAAP (in millions, except per share amounts):

	Year Ended December 31,			Variance 2017-2016		Variance 2016-2015	
	2017	2016	2015	$	%	$	%
Transportation segment adjusted EBITDA [1]	$ 1,287	$ 1,141	$ 1,056	$ 146	13 %	$ 85	8 %
Facilities segment adjusted EBITDA [1]	734	667	588	67	10 %	79	13 %
Supply and Logistics segment adjusted EBITDA [1]	60	359	568	(299)	(83)%	(209)	(37)%
Adjustments:							
Depreciation and amortization of unconsolidated entities	(45)	(50)	(45)	5	10 %	(5)	(11)%
Selected items impacting comparability - segment adjusted EBITDA	33	(434)	(290)	467	**	(144)	**
Unallocated general and administrative expenses	(4)	(3)	(3)	(1)	(33)%	—	— %
Depreciation and amortization	(628)	(495)	(433)	(133)	(27)%	(62)	(14)%
Interest expense, net	(510)	(480)	(443)	(30)	(6)%	(37)	(8)%
Other income/(expense), net	(31)	33	(7)	(64)	**	40	**
Income tax expense	(937)	(78)	(182)	(859)	**	104	57 %
Net income/(loss)	(41)	660	809	(701)	(106)%	(149)	(18)%
Net income attributable to noncontrolling interests	(690)	(566)	(691)	(124)	(22)%	125	18 %
Net income/(loss) attributable to PAGP	$ (731)	$ 94	$ 118	$ (825)	**	$ (24)	(20)%
Basic and diluted net income/(loss) per Class A share	$ (5.03)	$ 0.94	$ 1.41	$ (5.97)	**	$ (0.47)	(33)%
Basic and diluted weighted average Class A shares outstanding	145	99	83	46	46 %	16	19 %

** Indicates that variance as a percentage is not meaningful.

(1) Segment adjusted EBITDA is the measure of segment performance that is utilized by our Chief Operating Decision Maker ("CODM") to assess performance and allocate resources among our operating segments. This measure is adjusted for certain items, including those that our CODM believes impact comparability of results across periods. See Note 19 to our Consolidated Financial Statements for additional discussion of such adjustments.

Non-GAAP Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses additional measures known as “non-GAAP financial measures” in its evaluation of past performance and prospects for the future. The primary additional measure used by management is earnings before interest, taxes, depreciation and amortization (including our proportionate share of depreciation and amortization and gains and losses on significant asset sales of unconsolidated entities) and adjusted for certain selected items impacting comparability (“Adjusted EBITDA”).

Management believes that the presentation of such additional financial measure provides useful information to investors regarding our performance and results of operations because this measure, when used to supplement related GAAP financial measures, (i) provide additional information about our core operating performance, (ii) provide investors with the same financial analytical framework upon which management bases financial, operational, compensation and planning/budgeting decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. This non-GAAP measure may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) 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), the mark-to-market related to our Preferred Distribution Rate Reset Option, gains and losses on derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable, (iii) long-term inventory costing adjustments, (iv) items that are not indicative of our core operating results and business outlook and/or (v) other items that we believe should be excluded in understanding our core operating performance. This measure may further be adjusted to include amounts related to deficiencies associated with minimum volume commitments whereby we have billed the counterparties for their deficiency obligation and such amounts are recognized as deferred revenue in “Accounts payable and accrued liabilities” in our Consolidated Financial Statements. Such amounts are presented net of applicable amounts subsequently recognized into revenue. We have defined all such items as “selected items impacting comparability.” We do not necessarily consider all of our selected items impacting comparability to be non-recurring, infrequent or unusual, but we believe that an understanding of these selected items impacting comparability is material to the evaluation of our operating results and prospects.

Although we present selected items impacting comparability that management considers in evaluating our performance, you should also be aware that the items presented do not represent all items that affect comparability between the periods presented. Variations in our operating results are also caused by changes in volumes, prices, exchange rates, mechanical interruptions, acquisitions, expansion projects and numerous other factors as discussed, as applicable, in “Analysis of Operating Segments.”

Our definition and calculation of certain non-GAAP financial measures may not be comparable to similarly-titled measures of other companies. Adjusted EBITDA is reconciled to Net Income, the most directly comparable measure as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our Consolidated Financial Statements and footnotes.

The following table sets forth the reconciliation of our non-GAAP financial performance measure from Net Income (in millions):

	Year Ended December 31,			Variance 2017-2016		Variance 2016-2015	
	2017	2016	2015	$	%	$	%
Net income/(loss)	$ (41)	660	$ 809	$ (701)	(106)%	$ (149)	(18)%
Add/(Subtract):							
Interest expense, net	510	480	443	30	6 %	37	8 %
Income tax expense	937	78	182	859	**	(104)	(57)%
Depreciation and amortization	628	495	433	133	27 %	62	14 %
Depreciation and amortization of unconsolidated entities (1)	45	50	45	(5)	(10)%	5	11 %
Selected Items Impacting Comparability - Adjusted EBITDA:							
(Gains)/losses from derivative activities net of inventory valuation adjustments (2)	(46)	404	110	(450)	**	294	**
Long-term inventory costing adjustments (3)	(24)	(58)	99	34	**	(157)	**
Deficiencies under minimum volume commitments, net (4)	2	46	—	(44)	**	46	**
Equity-indexed compensation expense (5)	23	33	27	(10)	**	6	**
Net (gain)/loss on foreign currency revaluation (6)	(26)	9	(29)	(35)	**	38	**
Line 901 incident (7)	32	—	83	32	**	(83)	**
Significant acquisition-related expenses (8)	6	—	—	6	**	—	**
Selected Items Impacting Comparability - segment adjusted EBITDA	(33)	434	290	(467)	**	144	**
Gains from derivative activities (2)	(13)	(30)	—	17	**	(30)	**
Net (gain)/loss on foreign currency revaluation (6)	5	(1)	8	6	**	(9)	**
Net loss on early repayment of senior notes (9)	40	—	—	40	**	—	**
Selected Items Impacting Comparability - Adjusted EBITDA (10)	(1)	403	298	(404)	**	105	**
Adjusted EBITDA (10)	$ 2,078	$ 2,166	$ 2,210	$ (88)	(4)%	$ (44)	(2)%

** Indicates that variance as a percentage is not meaningful.

(1) Over the past several years, we have increased our participation in pipeline strategic joint ventures, which are accounted for under the equity method of accounting. We exclude our proportionate share of the depreciation and amortization expense and gains and losses on significant asset sales of such unconsolidated entities when reviewing Adjusted EBITDA, similar to our consolidated assets.

(2) 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 of operations, 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 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, as well as the mark-to-market adjustment related to our Preferred Distribution Rate Reset Option. See Note 12 to our Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities and our Preferred Distribution Rate Reset Option.

(3) 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 treat 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 as a selected item impacting comparability. See Note 4 to our Consolidated Financial Statements for additional inventory disclosures.

(4) 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. We believe the inclusion of the contractually committed revenues associated with that period is meaningful to investors 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 years prior to 2016 were not significant.

(5) Our total equity-indexed compensation expense includes expense associated with awards that will or may be settled in PAA common units and awards that will or may be settled in cash. The awards that will or may be settled in PAA common units are included in PAA's diluted net income per unit calculation when the applicable performance criteria have been met. We consider the compensation expense associated with these awards as a selected item impacting comparability as the dilutive impact of the outstanding awards is included in PAA's diluted net income per unit calculation, as applicable, and the majority of the awards are expected to be settled in PAA common units. The portion of compensation expense associated with awards that are certain to be settled in cash is not considered a selected item impacting comparability. See Note 16 to our Consolidated Financial Statements for a comprehensive discussion regarding our equity-indexed compensation plans.

(6) During the periods presented, there were fluctuations in the value of the Canadian dollar ("CAD") to the U.S. dollar ("USD"), resulting in gains and losses that were not related to our core operating results for the period and were thus classified as a selected item impacting comparability. See Note 12 to our Consolidated Financial Statements for discussion regarding our currency exchange rate risk hedging activities.

(7) 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 to our Consolidated Financial Statements for additional information regarding the Line 901 incident.

(8) Includes acquisition-related expenses associated with the ACC Acquisition. See Note 6 to our Consolidated Financial Statements for additional information.

(9) Includes net losses incurred in connection with the early redemption of our (i) $600 million, 6.50% senior notes due May 2018 and (ii) $350 million, 8.75% senior notes due May 2019. See Note 10 to our Consolidated Financial Statements for additional information.

(10) Adjusted EBITDA includes Other income/(expense), net adjusted for selected items impacting comparability comprised of net gains of $1 million, $2 million and $1 million for the years ended December 31, 2017, 2016 and 2015, respectively. Segment adjusted EBITDA does not include adjusted Other income/(expense), net.

Analysis of Operating Segments

We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. Our CODM (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment adjusted EBITDA, segment volumes, segment adjusted EBITDA per barrel and maintenance capital investment.

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) the mark-to-market of 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 understand our core segment operating performance. See Note 19 to our Consolidated Financial Statements for a reconciliation of segment adjusted EBITDA to net income attributable to PAGP.

Our segment analysis involves an element of judgment relating to the allocations between segments. In connection with its operations, the Supply and Logistics segment secures transportation and facilities services from our other two segments as well as third-party service providers under month-to-month and multi-year arrangements. Intersegment transportation service rates are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market. Facilities segment services are also obtained at rates generally consistent with rates charged to third parties for similar services. Intersegment activities are eliminated in consolidation and we believe that the estimates with respect to these rates are reasonable. Also, our segment operating and general and administrative expenses reflect direct costs attributable to each segment; however, we also allocate certain operating expenses and general and administrative overhead expenses between segments based on management's assessment of the business activities for the period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period. We believe that the estimates with respect to these allocations are reasonable.

Revenues and expenses from our Canadian based subsidiaries, which use CAD as their functional currency, are translated at the prevailing average exchange rates for each month.

Transportation Segment

Our Transportation segment operations generally consist of fee-based activities associated with transporting crude oil and NGL on pipelines, gathering systems, trucks and barges. The Transportation segment generates revenue through a combination of tariffs, third-party pipeline capacity agreements and other transportation fees.

The following tables set forth our operating results from our Transportation segment:

				Variance			
Operating Results [1]	**Year Ended December 31,**			**2017-2016**		**2016-2015**	
(in millions, except per barrel data)	**2017**	**2016**	**2015**	**$**	**%**	**$**	**%**
Revenues	$ 1,718	$ 1,584	$ 1,594	$ 134	8 %	$ (10)	(1)%
Purchases and related costs	(123)	(94)	(108)	(29)	(31)%	14	13 %
Field operating costs	(593)	(551)	(657)	(42)	(8)%	106	16 %
Segment general and administrative expenses [2]	(101)	(103)	(95)	2	2 %	(8)	(8)%
Equity earnings in unconsolidated entities	290	195	183	95	49 %	12	7 %
Adjustments [3]:							
Depreciation and amortization of unconsolidated entities	45	50	45	(5)	(10)%	5	11 %
Deficiencies under minimum volume commitments, net	2	44	—	(42)	**	44	**
Equity-indexed compensation expense	11	16	11	(5)	**	5	**
Line 901 incident	32	—	83	32	**	(83)	**
Significant acquisition-related expenses	6	—	—	6	**	—	**
Segment adjusted EBITDA	$ 1,287	$ 1,141	$ 1,056	$ 146	13 %	$ 85	8 %
Maintenance capital	$ 120	$ 121	$ 144	$ (1)	(1)%	$ (23)	(16)%
Segment adjusted EBITDA per barrel	$ 0.68	$ 0.67	$ 0.65	$ 0.01	1 %	$ 0.02	3 %

Average Daily Volumes (in thousands of barrels per day) [4]	Year Ended December 31,			Variance 2017-2016		Variance 2016-2015	
	2017	2016	2015	Volumes	%	Volumes	%
Tariff activities volumes							
Crude oil pipelines (by region):							
Permian Basin [5]	2,855	2,146	1,849	709	33 %	297	16 %
South Texas / Eagle Ford [5]	360	284	306	76	27 %	(22)	(7)%
Central [5]	420	394	413	26	7 %	(19)	(5)%
Gulf Coast	349	497	532	(148)	(30)%	(35)	(7)%
Rocky Mountain [5]	393	449	440	(56)	(12)%	9	2 %
Western	184	188	215	(4)	(2)%	(27)	(13)%
Canada	352	381	392	(29)	(8)%	(11)	(3)%
Crude oil pipelines	4,913	4,339	4,147	574	13 %	192	5 %
NGL pipelines	170	184	193	(14)	(8)%	(9)	(5)%
Tariff activities total volumes	5,083	4,523	4,340	560	12 %	183	4 %
Trucking volumes	103	114	113	(11)	(10)%	1	1 %
Transportation segment total volumes	5,186	4,637	4,453	549	12 %	184	4 %

** Indicates that variance as a percentage is not meaningful.

(1) Revenues and costs and expenses include intersegment amounts.

(2) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

(3) Represents adjustments included in the performance measure utilized by our CODM in the evaluation of segment results. See Note 19 to our Consolidated Financial Statements for additional discussion of such adjustments.

(4) Average daily volumes are calculated as the total volumes (attributable to our interest) for the year divided by the number of days in the year.

(5) Region includes volumes (attributable to our interest) from pipelines owned by unconsolidated entities.

Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment results generated by our tariff and other fee-related activities depend on the volumes transported on the pipeline and the level of the tariff and other fees charged, as well as the fixed and variable field costs of operating the pipeline. 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.

The following is a discussion of items impacting Transportation segment operating results for the periods indicated.

Revenues, Purchases and Related Costs, Equity Earnings in Unconsolidated Entities and Volumes. The following table presents variances in revenues, purchases and related costs and equity earnings in unconsolidated entities by region for the comparative periods presented:

	Favorable/(Unfavorable) Variance 2017-2016			Favorable/(Unfavorable) Variance 2016-2015		
(in millions)	Revenues	Purchases and Related Costs	Equity Earnings	Revenues	Purchases and Related Costs	Equity Earnings
Tariff activities:						
Permian Basin region	$ 196	(22)	$ 30	$ 98	—	$ 7
South Texas / Eagle Ford region	(2)	—	40	(7)	—	(1)
Central region	—	—	14	(23)	—	2
Gulf Coast region	(22)	—	—	(19)	—	—
Rocky Mountain region	(20)	—	9	(18)	—	10
Other (including trucking and pipeline loss allowance revenue)	(18)	(7)	2	(41)	14	(6)
Total variance	$ 134	(29)	$ 95	$ (10)	14	$ 12

- *Permian Basin region.* The increase in revenues for 2017 compared to 2016 was largely driven by (i) higher volumes on our Basin and Cactus pipelines, which also favorably impacted volumes on our McCamey pipeline system, (ii) results from the ACC gathering system, which we acquired in February 2017, and (iii) higher volumes from increased production and new lease connections to our gathering systems in the Permian Basin. Equity earnings also increased in 2017 compared to 2016 due to higher earnings from our 50% interest in BridgeTex resulting from higher volumes in the 2017 period. These increases were partially offset by an increase in purchases and related costs for the year ended December 31, 2017 over the year ended December 31, 2016.

  The increase in revenues for 2016 compared to 2015 was primarily driven by (i) higher volumes associated with the expansion of our pipeline systems in the Delaware Basin, (ii) higher volumes on our takeaway pipelines and (iii) a full year of service of our Cactus pipeline, which was placed in service in April 2015.

- *South Texas / Eagle Ford region.* Equity earnings from our 50% interest in Eagle Ford Pipeline LLC increased in 2017 compared to 2016 primarily due to higher volumes from our Cactus pipeline.

- *Central region.* Revenues for the year ended December 31, 2017 were flat compared to the year ended December 31, 2016, as increases from the start-up of our Red River pipeline in December 2016 were offset by (i) lower volumes on certain pipelines due to production declines and (ii) volumes shifting to our recently formed joint venture pipelines. The decrease in revenues for 2016 compared to 2015 was largely driven by lower volumes due to production declines in the Mid-Continent area, as well as the sale of 50% of our investment in STACK in August 2016, subsequent to which it was accounted for under the equity method of accounting.

  Equity earnings increased in 2017 compared to 2016 primarily due to earnings from (i) our 50% interest in STACK, which was formed in mid-2016 and which completed extensions of the joint venture pipeline in 2017, (ii) our 50% interest in Caddo, which placed the joint venture pipeline in service in late 2016, and (iii) our 50% interest in Diamond, which placed the joint venture pipeline in service in late 2017.

- *Gulf Coast region.* Revenues and volumes decreased for each of the comparative periods primarily due to the sale of certain of our Gulf Coast pipelines in March and July 2016. Such decreases were partially offset during 2016 as compared to 2015 by increased volumes on the Capline and Pascagoula pipelines, which were favorably impacted by higher refinery demand, but were at lower tariff rates than the pipelines that were sold.

- *Rocky Mountain region.* The decrease in revenues in 2017 compared to 2016 was largely driven by (i) lower volumes on certain Salt Lake City area pipelines due to proactively shutting down our Wahsatch pipeline for approximately 30 days during the first quarter of 2017 as a precautionary measure in response to indications of soil movement identified by our monitoring systems, (ii) the sale of certain Bakken and Salt Lake City area pipelines in October 2017 and (iii) the sale of 50% of our investment in Cheyenne in June 2016, subsequent to which it was accounted for under the equity method of accounting. The decrease in revenues for 2016 compared to 2015 was largely driven by (i) lower volumes due to production declines and increased competition and (ii) the sale of 50% of our investment in Cheyenne Pipeline.

  Equity earnings increased for each of the comparative periods due to earnings from (i) our 40% investment in Saddlehorn, which began operations in the third quarter of 2016, and (ii) our 50% investment in Cheyenne, as discussed above. Such increases were partially offset during 2017 as compared to 2016 by decreased equity earnings from our 35.67% interest in White Cliffs due to lower volumes on the joint venture pipeline.

- *Other*. The revenues variance for the year ended December 31, 2016 compared to the same 2015 period was primarily related to lower pipeline loss allowance revenue due to a lower average realized price per barrel. The decrease in purchases and related costs for the year ended December 31, 2016 compared to the same 2015 period was due to lower trucking costs driven by lower contract services rates.

Adjustments: Deficiencies under minimum volume commitments, net. Many industry infrastructure projects developed and completed over the last several years were underpinned by long-term minimum volume commitment contracts whereby the shipper, based on an expectation of continued production growth, agreed to either: (i) ship and pay for certain stated volumes or (ii) pay the agreed upon price for a minimum contract quantity. During 2016 and 2017, as presented in the table above, we had net collections for deficiencies under minimum volume commitments resulting in deferred revenues and an increase to segment adjusted EBITDA. However, such net collections in 2017 were substantially offset by (i) shippers utilizing credits associated with previous deficiencies or (ii) credits expiring, which resulted in the recognition of previously deferred revenue. Such amounts were not material to periods prior to 2016 and, thus, are not included in the table for 2015.

Field Operating Costs. Field operating costs increased for the year ended December 31, 2017 compared to the year ended December 31, 2016 primarily due to an increase in estimated costs associated with the Line 901 incident (which impact our field operating costs but are excluded from segment adjusted EBITDA and thus are reflected as an “Adjustment” in the table above). See Note 17 to our Consolidated Financial Statements for additional information regarding the Line 901 incident. The increase in field operating costs was further driven by an increase in power costs resulting from higher volumes and incremental operating costs from the ACC gathering system acquisition in February 2017, partially offset by cost reduction efforts and decreased costs due to the sale of certain Gulf Coast pipelines in March and July 2016.

The decrease in field operating costs for the year ended December 31, 2016 compared to the year ended December 31, 2015 was primarily due to net estimated costs of $83 million recognized during 2015 associated with the Line 901 incident (which impact our field operating costs but are excluded from segment adjusted EBITDA and thus are reflected as an “Adjustment” in the table above). The decrease in field operating costs was further driven by lower utilities and maintenance costs, costs associated with a release of crude oil at a pump station in Illinois (the MP 29 release) during 2015, lower operating costs due to the sale of certain of our Gulf Coast pipelines in 2016, as noted above, and a favorable foreign exchange impact of $5 million, partially offset by an increase in insurance premiums.

Maintenance Capital. 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. The decrease in maintenance capital for the year ended December 31, 2016 compared to the year ended December 31, 2015 was primarily driven by completion of several large projects in earlier years and lower third-party service costs.

Facilities Segment

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. The Facilities segment generates revenue through a combination of month-to-month and multi-year agreements.

The following tables set forth our operating results from our Facilities segment:

Operating Results [1] (in millions, except per barrel data)	Year Ended December 31, 2017	2016	2015	Variance 2017-2016 $	2017-2016 %	Variance 2016-2015 $	2016-2015 %
Revenues	$ 1,173	$ 1,107	$ 1,050	$ 66	6 %	$ 57	5 %
Natural gas related costs	(24)	(26)	(24)	2	8 %	(2)	(8)%
Field operating costs	(350)	(352)	(377)	2	1 %	25	7 %
Segment general and administrative expenses [2]	(73)	(68)	(70)	(5)	(7)%	2	3 %
Adjustments [3]:							
(Gains)/losses from derivative activities net of inventory valuation adjustments	4	(2)	4	6	**	(6)	**
Deficiencies under minimum volume commitments, net	—	2	—	(2)	**	2	**
Equity-indexed compensation expense	4	7	5	(3)	**	2	**
Net gain on foreign currency revaluation	—	(1)	—	1	**	(1)	**
Segment adjusted EBITDA	$ 734	$ 667	$ 588	$ 67	10 %	$ 79	13 %
Maintenance capital	$ 114	$ 55	$ 68	$ 59	107 %	$ (13)	(19)%
Segment adjusted EBITDA per barrel	$ 0.47	$ 0.44	$ 0.41	$ 0.03	7 %	$ 0.03	7 %

Volumes [4]	Year Ended December 31, 2017	2016	2015	Variance 2017-2016 Volumes	2017-2016 %	Variance 2016-2015 Volumes	2016-2015 %
Liquids storage (average monthly capacity in millions of barrels)	112	107	100	5	5 %	7	7%
Natural gas storage (average monthly working capacity in billions of cubic feet) [5]	82	97	97	(15)	(15)%	—	—%
NGL fractionation (average volumes in thousands of barrels per day)	126	115	103	11	10 %	12	12%
Facilities segment total volumes (average monthly volumes in millions of barrels) [6]	130	127	120	3	2 %	7	6%

** Indicates that variance as a percentage is not meaningful.

(1) Revenues and costs and expenses include intersegment amounts.

(2) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

(3) Represents adjustments included in the performance measure utilized by our CODM in the evaluation of segment results. See Note 19 to our Consolidated Financial Statements for additional discussion of such adjustments.

(4) Average monthly volumes are calculated as total volumes for the year divided by the number of months in the year.

(5) The decrease in average monthly working capacity of natural gas storage facilities in 2017 was driven by adjustments for (i) the sale of our Bluewater natural gas storage facility in June 2017, (ii) changes in base gas and (iii) the net capacity change between capacity additions from fill and dewater operations and capacity losses from salt creep.

(6) Facilities segment total volumes is calculated as the sum of: (i) liquids storage capacity; (ii) natural gas storage working capacity divided by 6 to account for the 6:1 mcf of natural gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) NGL fractionation volumes multiplied by the number of days in the year and divided by the number of months in the year.

The following is a discussion of items impacting Facilities segment operating results for the periods indicated.

Revenues and Volumes. Variances in revenues and average monthly volumes for the comparative periods were primarily driven by:

- NGL Storage, NGL Fractionation and Canadian Gas Processing — Revenues increased by $99 million and $53 million, respectively, for the comparative periods presented primarily due to contributions from (i) the Western Canada NGL assets we acquired in August 2016, (ii) ongoing expansion projects at our Fort Saskatchewan facility, which have increased storage and fractionation capacity, and (iii) higher rates at certain of our NGL storage and fractionation facilities, which were largely incurred in our Supply and Logistics segment. The increased revenue for the year ended December 31, 2016 compared to the same period in 2015 was partially offset by unfavorable foreign exchange fluctuation impacts of $10 million, which were also largely offset in our Supply and Logistics segment results.

- Crude Oil Storage — Revenues for the year ended December 31, 2017 were relatively flat compared to the year ended December 31, 2016. Higher 2017 revenues from our Cushing terminal driven by increased terminal throughput and capacity expansions of approximately 2 million barrels were offset by (i) decreased utilization at certain of our Southern California terminals and (ii) the sale of certain of our East Coast terminals in April 2016.

  For the year ended December 31, 2016, crude oil storage revenues increased by $24 million over the year ended December 31, 2015 primarily due to (i) aggregate capacity expansions of approximately 4 million barrels at our St. James and Cushing terminals and (ii) increased utilization at certain of our West Coast terminals. Such increases were partially offset by lower results due to the sale of certain of our East Coast terminals in April 2016.

- Natural Gas Storage — Revenues decreased slightly for the year ended December 31, 2017 compared to the same 2016 period. Lower results due to the June 2017 sale of our Bluewater natural gas storage facility were largely offset by contributions from higher rates on new contracts replacing expiring contracts and more favorable market conditions for hub services.

- Rail Terminals — Revenues decreased by $26 million for the year ended December 31, 2017 compared to the year ended December 31, 2016 primarily due to lower activity at our U.S. terminals resulting from less favorable market conditions, partially offset by revenues and volumes from our Fort Saskatchewan, Alberta rail terminal that came online in April 2016.

  For the year ended December 31, 2016, rail terminals revenues decreased by $17 million compared to the year ended December 31, 2015 primarily due to lower activity at our U.S. terminals as a result of production declines in the Bakken and less favorable market conditions, partially offset by (i) revenue associated with minimum volume commitments at certain of our terminals and (ii) revenues and volumes from our Fort Saskatchewan rail terminal.

Field Operating Costs. Field operating costs decreased for the year ended December 31, 2017 compared to the same 2016 period due to reduced rail activity, cost reduction efforts and the sales of our Bluewater natural gas storage facility in June 2017 and certain of our East Coast terminals in April 2016. Such decreases were largely offset by an increase in operating costs associated with the Western Canada NGL assets acquired in August 2016 and increased power costs.

The decrease in field operating costs for the year ended December 31, 2016 compared to December 31, 2015 was primarily due to (i) lower costs related to contract services, largely at our rail terminals and, to a lesser extent, at our processing facilities, (ii) the impact from the sale of certain of our East Coast terminals in April 2016, (iii) lower turnaround and inspection costs and (iv) favorable foreign exchange fluctuation impacts of $4 million. Such decreases were partially offset by an increase in operating costs due to the Western Canada NGL assets acquired in August 2016.

Maintenance Capital. The increase in maintenance capital for 2017 compared to 2016 was primarily due to increased investment in our integrity management program, primarily on assets at our Southern California terminals. Total maintenance costs related to our integrity management program at these terminals increased by approximately $49 million for 2017 compared to 2016. While routine assessments and repairs will be required in the future, we expect significant reductions to our maintenance capital costs at these terminals going forward.

The decrease in maintenance capital for 2016 compared to 2015 was primarily due to lower spending on various tank and other maintenance capital projects, partially due to the timing of certain 2015 projects at our NGL storage and fractionation facilities.

Supply and Logistics Segment

Our revenues from supply and logistics activities reflect the sale of gathered and bulk-purchased crude oil, as well as sales of NGL volumes and natural gas sales attributable to activities that were previously performed by the natural gas storage commercial optimization group. Generally, our segment results are impacted by (i) increases or decreases in our Supply and Logistics segment volumes (which consist of lease gathering crude oil purchases volumes and NGL sales volumes), (ii) the effects of competition on our lease gathering and NGL margins and (iii) the overall volatility and strength or weakness of market conditions and the allocation of our assets among our various risk management strategies. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. Although our segment results may be adversely affected during certain transitional periods as discussed further below, our crude oil and NGL supply, logistics and distribution operations are not directly affected by the absolute level of prices, but are affected by overall levels of supply and demand for crude oil and NGL, market structure and relative fluctuations in market-related indices and regional differentials.

The following tables set forth our operating results from our Supply and Logistics segment:

Operating Results (1) (in millions, except per barrel data)	Year Ended December 31, 2017	2016	2015	Variance 2017-2016 $	%	Variance 2016-2015 $	%
Revenues	$ 25,065	$ 19,018	$ 21,945	$ 6,047	32 %	$ (2,927)	(13)%
Purchases and related costs	(24,557)	(18,627)	(21,018)	(5,930)	(32)%	2,391	11 %
Field operating costs	(254)	(292)	(433)	38	13 %	141	33 %
Segment general and administrative expenses (2)	(102)	(108)	(113)	6	6 %	5	4 %
Adjustments (3):							
(Gains)/losses from derivative activities net of inventory valuation adjustments	(50)	406	106	(456)	**	300	**
Long-term inventory costing adjustments	(24)	(58)	99	34	**	(157)	**
Equity-indexed compensation expense	8	10	11	(2)	**	(1)	**
Net (gain)/loss on foreign currency revaluation	(26)	10	(29)	(36)	**	39	**
Segment adjusted EBITDA	$ 60	$ 359	$ 568	$ (299)	(83)%	$ (209)	(37)%
Maintenance capital	$ 13	$ 10	$ 8	$ 3	30 %	$ 2	25 %
Segment adjusted EBITDA per barrel	$ 0.13	$ 0.85	$ 1.33	$ (0.72)	(85)%	$ (0.48)	(36)%

Average Daily Volumes (in thousands of barrels per day)	Year Ended December 31, 2017	2016	2015	Variance 2017-2016 Volume	%	Variance 2016-2015 Volume	%
Crude oil lease gathering purchases	945	894	943	51	6 %	(49)	(5)%
NGL sales	274	259	223	15	6 %	36	16 %
Supply and Logistics segment total volumes	1,219	1,153	1,166	66	6 %	(13)	(1)%

** Indicates that variance as a percentage is not meaningful.

(1) Revenues and costs include intersegment amounts.

(2) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

(3) Represents adjustments included in the performance measure utilized by our CODM in the evaluation of segment results. See Note 19 to our Consolidated Financial Statements for additional discussion of such adjustments.

The following table presents the range of the NYMEX West Texas Intermediate benchmark price of crude oil (in dollars per barrel):

During the Year Ended December 31,	NYMEX WTI Crude Oil Price Low	High
2017	$ 43	$ 60
2016	$ 26	$ 54
2015	$ 35	$ 61

Because the commodities that we buy and sell are generally indexed to the same pricing indices for both sales and purchases, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those sales and purchases will not necessarily have a corresponding increase or decrease. The absolute amount of our revenues and purchases increased for the year ended December 31, 2017 compared to the year ended December 31, 2016 primarily due to higher crude oil prices and volumes during the 2017 period. The absolute amount of our revenues and purchases decreased for the year ended December 31, 2016 compared to the same 2015 period primarily due to lower crude oil and NGL prices and lower NGL volumes during the period. Additionally, revenues and purchases were impacted by net gains and losses from certain derivative activities during the periods.

Our NGL operations are sensitive to weather-related demand, particularly during the approximate five-month peak heating season of November through March, and temperature differences from period-to-period may have a significant effect on NGL demand and thus our financial performance.

The following is a discussion of items impacting Supply and Logistics segment operating results for the periods indicated.

Net Revenues and Volumes. Our Supply and Logistics results have been impacted by crude oil and NGL margin compression and reduced arbitrage opportunities. However, for the year ended December 31, 2017, segment revenues, net of purchases and related costs, increased by $117 million over the year ended December 31, 2016 as lower results from these less favorable market conditions were offset by a favorable impact from certain derivative activities (as discussed further below). Revenues, net of purchases and related costs, decreased by $536 million for the year ended December 31, 2016 compared to the same 2015 period (of which $144 million was related to the mark-to-market impact of certain derivatives and long-term inventory costing adjustments). The following summarizes the significant items impacting the comparative periods:

- Crude Oil Operations — Net revenues from our crude oil supply and logistics operations decreased for each comparative period primarily due to lower unit margins from continued and intensifying competition, largely due to overbuilt infrastructure underwritten with volume commitments, and the effect of such on differentials, which reduced arbitrage opportunities. See the “Market Overview and Outlook” section below for additional discussion of recent market conditions.

- NGL Operations — Net revenues from our NGL operations decreased for the year ended December 31, 2017 compared to the year ended December 31, 2016, largely due to (i) higher supply costs and tighter differentials driven by competition, which more than offset higher sales volume from the Western Canada NGL assets acquired in August 2016, (ii) warmer weather during the first-quarter 2017 heating season and (iii) higher storage and processing fees for the 2017 period, which were largely offset in our Facilities segment results.

  Net revenues from our NGL operations decreased for the year ended December 31, 2016 compared to the year ended December 31, 2015, largely due to (i) higher storage and processing fees for the 2016 periods, which were largely offset in our Facilities segment, and (ii) higher supply costs driven by competition, which more than offset higher sales volumes.

- Impact from Certain Derivative Activities, Net of Inventory Valuation Adjustments — The impact from certain derivative activities on our net revenues includes mark-to-market and other gains and losses resulting from certain derivative instruments that are related to underlying activities in another period (or the reversal of mark-to-market gains and losses from a prior period) and inventory valuation adjustments, as applicable. See Note 12 to our Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities. These gains and losses impact our net revenues but are excluded from segment adjusted EBITDA and thus are reflected as an “Adjustment” in the table above.

- Long-Term Inventory Costing Adjustments — Our net revenues are impacted by changes in the weighted average cost of our crude oil and NGL inventory pools that result from price movements during the periods. These costing adjustments related to long-term inventory necessary to meet our minimum inventory requirements in third-party assets and other working inventory that was 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. These costing adjustments impact our net revenues but are excluded from segment adjusted EBITDA and thus are reflected as an “Adjustment” in the table above.

- Foreign Exchange Impacts — Our net revenues are impacted by fluctuations in the value of CAD to USD, resulting in foreign exchange gains and losses on U.S. denominated net assets within our Canadian operations. These gains and losses impact our net revenues but are excluded from segment adjusted EBITDA and thus are reflected as an “Adjustment” in the table above.

Field Operating Costs. Field operating costs decreased for the year ended December 31, 2017 compared to the same 2016 period primarily due to lower trucking costs as pipeline expansion projects were placed into service.

The decrease in field operating costs for the year ended December 31, 2016 compared to the year ended December 31, 2015 was primarily due to a combination of (i) lower lease gathering volumes, (ii) shorter truck hauls and reduced use of third-party trucking services as pipeline expansion projects were placed into service, (iii) lower driver wages and (iv) a decrease in fuel prices.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense increased for the year ended December 31, 2017 compared to the same period in 2016 largely driven by (i) an increase in impairments, accelerated depreciation and canceled projects during the 2017 period primarily associated with certain of our rail and other terminal assets, (ii) additional depreciation associated with acquisitions and the completion of various capital expansion projects and (iii) smaller net gains from non-core asset sales and joint venture formations recognized in the 2017 period.

Depreciation and amortization expense for the year ended December 31, 2016 includes net gains of approximately $100 million, which were primarily associated with non-core asset sales and joint venture formations during the period. Excluding such gains, depreciation and amortization expense increased for the year ended December 31, 2016 compared to the same period in 2015 primarily due to (i) additional depreciation associated with the completion of various capital expansion projects, (ii) the write-off of $33 million of costs associated with the discontinuation of certain capital projects during 2016 and (iii) an $18 million charge in 2016 related to assets taken out of service. In addition, the 2016 period was further impacted by impairments of $80 million associated with certain of our rail and other terminal assets.

See Note 5 and Note 6 to our Consolidated Financial Statements for additional information.

Interest Expense

Interest expense is primarily impacted by:

- our weighted average debt balances;
- the level and maturity of fixed rate debt and interest rates associated therewith;
- market interest rates and our interest rate hedging activities on floating rate debt; and
- interest capitalized on capital projects.

The following table summarizes the components impacting the interest expense variance (in millions, except percentages):

		Average LIBOR	Weighted Average Interest Rate [1]
Interest expense for the year ended December 31, 2015	$ 443	0.2%	4.4%
Impact of issuance and retirement of PAA senior notes	15		
Impact of borrowings under credit facilities and PAA commercial paper program	14		
Impact of lower capitalized interest	10		
Other	(2)		
Interest expense for the year ended December 31, 2016	$ 480	0.5%	4.4%
Impact of borrowings under credit facilities and PAA commercial paper program	4		
Impact of lower capitalized interest	12		
Other	14		
Interest expense for the year ended December 31, 2017	$ 510	1.1%	4.4%

(1) Excludes commitment and other fees.

See Note 10 to our Consolidated Financial Statements for additional information regarding our debt activities during the periods presented.

Other Income/(Expense), Net

The following table summarizes the components impacting Other income/(expense), net (in millions):

	Year Ended December 31,		
	2017	2016	2015
Loss on early redemption of senior notes [1]	$ (40)	$ —	$ —
Gains related to mark-to-market adjustment of the Preferred Distribution Rate Reset Option [2]	13	30	—
Other	(4)	3	(7)
	$ (31)	$ 33	$ (7)

(1) See Note 10 to our Consolidated Financial Statements for additional information.

(2) See Note 12 to our Consolidated Financial Statements for additional information.

Income Tax Expense

Income tax expense increased for the year ended December 31, 2017 compared to the year ended December 31, 2016 due to (i) deferred tax expense recorded in the fourth quarter of 2017 related to the re-measurement of our deferred tax asset as a result of the enactment on December 22, 2017 of the Tax Cuts and Jobs Act, (ii) higher year-over-year income as impacted by fluctuations in derivative mark-to-market valuations in our Canadian operations during the 2017 period and (iii) higher deferred tax expense recorded in the first quarter of 2017 related to a change in our effective tax rate. See Note 13 to our Consolidated Financial Statements for additional information regarding the re-measurement of our deferred tax asset.

The decrease in income tax expense for the year ended December 31, 2016 compared to the year ended December 31, 2015 was primarily due to lower year-over-year income as impacted by fluctuations in derivative mark-to-market valuations in our Canadian operations during the 2016 period and the cumulative revaluation of Canadian net deferred tax liabilities resulting from a 2% Alberta, Canada provincial tax increase in the second quarter of 2015.

Outlook

Market Overview and Outlook

2017 marked the third full calendar year of a harsh downturn in the crude oil industry that started in mid-to-late 2014. This downturn has adversely impacted both the upstream and midstream sectors, but the near-term and long-term implications for each have varied. For example, the upstream sector was severely impacted initially, however, improvements in drilling and completion technology and efficiency and reductions in cost per barrel substantially reduced the oil price level required to generate attractive returns. In a +/- $50 per barrel oil price environment, these advancements provide long-term visibility for sustained U.S. production levels generally and significant growth opportunities in several regions, particularly with respect to the Permian Basin. Oil prices increased near the end of 2017 and have averaged above $60 per barrel in early 2018.

With respect to the crude oil midstream sector, the initial adverse impacts were somewhat muted as volume growth continued through mid-2015, but soon thereafter were adversely impacted by a variety of interrelated issues. These included production decreases or lower than anticipated growth throughout the U.S. which, in combination with the completion of multi-year infrastructure projects and new midstream entrants backed by private institutional capital, created excess takeaway capacity. The excess takeaway capacity resulted in competition that was amplified by excess minimum volume commitments, which also had a dramatic impact on historical regional differentials. The net effect of these developments lowered minimum return thresholds, increased risk and decreased margins of many of the larger established business platforms. As one of the largest U.S. crude oil midstream businesses, we experienced all of these challenges.

We believe the long-term view for the crude oil midstream sector and for PAA is strong. Underpinned by technological advancements, U.S. Lower 48 crude oil production is positioned to grow significantly over the next several years, with the Permian Basin representing the most attractive and significant growth region. We believe we are well positioned to grow our fee-based businesses due to our leading crude oil midstream positions in substantially all U.S. regions and crude oil hubs, including our significant Permian Basin gathering, marketing, pipeline and terminalling network. In addition, PAA has made a number of meaningful investments that will be commencing operations in the near future or continuing to ramp up to full run-rate cash flow.

Despite this positive long-term positioning, over the last few years we have generated lower than expected multi-year growth in our fee-based segments and experienced reduced profitability in our Supply and Logistics segment; in turn, these developments have elevated our credit metrics relative to our targeted range and our trailing distribution coverage has been below levels we consider sustainable. Additionally, access to conventional financial markets historically relied upon by master limited partnerships (“MLP”) to finance growth-oriented projects and manage debt levels has been both challenging and limited.

Taking all these factors into account, as well as the dilutive costs of accessing traditional MLP equity markets to reduce leverage or finance growth in a weak MLP equity environment, in August 2017 we announced a number of significant actions designed to enable us to deliver operating and financial performance in line with our plans and enhance the long-term franchise value for all of our stakeholders. The cumulative effect of these actions should meaningfully reduce debt, improve our credit metrics, significantly reduce and/or eliminate the need to issue incremental common equity for routine expansion activities and enhance our ability to capitalize on attractive industry opportunities. Importantly, these actions are consistent with our objective to defend our investment grade credit metrics, restore strong distribution coverage and drive sustainable distribution growth capacity.

Relative to mid-year 2017 balances, the leverage reduction plan is designed to reduce debt by approximately $1.4 billion over a six quarter period ending March 31, 2019. We believe we are on track with our plan and we expect to achieve our deleveraging objectives and targeted credit metrics by the original March 31, 2019 target date, while maintaining a strong distribution coverage ratio comprised predominantly of fee-based cash flow sources.

However, we can provide no assurance that we will be able to achieve the objectives set forth above or that our efforts will generate targeted results. See Item 1A. “Risk Factors—Risks Related to PAA’s Business.”

Outlook for Certain Idled and Underutilized Assets

During 2015, we shut down Line 901 and a portion of Line 903 in California following the release of crude oil from Line 901 (see Note 17 to our Consolidated Financial Statements for additional information). During the period since these pipelines were idled, we have been assessing potential alternatives in order to return them to operation. Some of the alternatives under consideration could result in incurring costs associated with retiring certain assets or an impairment of some or all of the carrying value of the idled property and equipment, which was approximately $127 million as of December 31, 2017.

We own a 54% undivided joint interest in the Capline system, which originates in St. James, Louisiana and terminates in Patoka, Illinois. The construction of new crude oil pipeline infrastructure and the ongoing changing crude oil flows in the United States may result in a decline in volumes on the Capline system to levels that cannot sustain operations. The owners of the Capline system are considering various alternatives for the use of the pipeline system, including an assessment of the commercial potential to reverse the pipeline direction within the next several years. In early October 2017, the Capline owners launched a non-binding open season to gauge shipper interest in a possible reversal of the Capline system. This non-binding open season concluded in November, and in December 2017 the operator of the Capline system announced that the owners are proceeding with planning for a potential reversal of the Capline system and are planning to evaluate next steps required for a potential binding open season. If the Capline system were to not be reversed, this could result in the Capline owners incurring costs associated with retiring certain assets and/or an impairment of the carrying value of our interest in the Capline system, which was $195 million as of December 31, 2017.

Liquidity and Capital Resources

General

On a consolidated basis, our primary sources of liquidity are (i) cash flow from operating activities as further discussed below in the section entitled "—Cash Flow from Operating Activities," (ii) borrowings under PAA's credit facilities or the PAA commercial paper program and (iii) funds received from sales of equity and debt securities. In addition, we may supplement these sources of liquidity with proceeds from our asset sales program, as further discussed below in the section entitled "—Acquisitions, Investments, Expansion Capital Expenditures and Divestitures." Our primary cash requirements include, but are not limited to, (i) ordinary course of business uses, such as the payment of amounts related to the purchase of crude oil, NGL and other products, other expenses and interest payments on outstanding debt, (ii) expansion and maintenance activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on long-term debt and (v) distributions to our Class A shareholders and noncontrolling interests. We generally expect to fund our short-term cash requirements through cash flow generated from operating activities and/or borrowings under the PAA commercial paper program or PAA's credit facilities. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions and refinancing long-term debt, through a variety of sources (either separately or in combination), which may include the sources mentioned above as funding for short-term needs and/or the issuance of additional equity or debt securities and the sale of assets. As of December 31, 2017, although we had a working capital deficit of $530 million, we had approximately $3.0 billion of liquidity available to meet our ongoing operating, investing and financing needs, subject to continued covenant compliance, as noted below (in millions):

	As of December 31, 2017
Availability under PAA senior unsecured revolving credit facility [1] [2]	$ 1,534
Availability under PAA senior secured hedged inventory facility [1] [2]	515
Availability under PAA senior unsecured 364-day revolving credit facility	1,000
Amounts outstanding under PAA commercial paper program	(126)
Subtotal	2,923
Cash and cash equivalents	40
Total	$ 2,963

(1) Represents availability prior to giving effect to amounts outstanding under the PAA commercial paper program, which reduce available capacity under the facilities.

(2) Available capacity under the PAA senior unsecured revolving credit facility and the PAA senior secured hedged inventory facility was reduced by outstanding letters of credit of $66 million and $100 million, respectively.

We believe that we have, and will continue to have, the ability to access the PAA commercial paper program and credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains strong and we have sufficient liquidity; however, extended disruptions in the financial markets and/or energy price volatility that adversely affect our business may have a materially adverse effect on our financial condition, results of operations or cash flows. In addition, usage of the PAA credit facilities, which provide a financial backstop for the PAA commercial paper program, is subject to ongoing compliance with covenants. As of December 31, 2017, PAA was in compliance with all such covenants. Also, see Item 1A. "Risk Factors" for further discussion regarding such risks that may impact our liquidity and capital resources.

Cash Flow from Operating Activities

The primary drivers of cash flow from operating activities are (i) the collection of amounts related to the sale of crude oil, NGL and other products, the transportation of crude oil and other products for a fee, and the provision of storage and terminalling services for a fee and (ii) the payment of amounts related to the purchase of crude oil, NGL and other products and other expenses, principally field operating costs, general and administrative expenses and interest expense.

Cash flow from operating activities can be materially impacted by the storage of crude oil in periods of a contango market, when the price of crude oil for future deliveries is higher than current prices. In the month we pay for the stored crude oil, we borrow under the credit facilities or the PAA commercial paper program (or use cash on hand) to pay for the crude oil, which negatively impacts operating cash flow. Conversely, cash flow from operating activities increases during the period in which we collect the cash from the sale of the stored crude oil. Similarly, the level of NGL and other product inventory stored and held for resale at period end affects our cash flow from operating activities.

In periods when the market is not in contango, we typically sell our crude oil during the same month in which we purchase it and we do not rely on borrowings under the credit facilities or the PAA commercial paper program to pay for the crude oil. During such market conditions, our accounts payable and accounts receivable generally move in tandem as we make payments and receive payments for the purchase and sale of crude oil in the same month, which is the month following such activity. In periods during which we build inventory, regardless of market structure, we may rely on the credit facilities or the PAA commercial paper program to pay for the inventory. In addition, we use derivative instruments to manage the risks associated with the purchase and sale of our commodities. Therefore, our cash flow from operating activities may be impacted by the margin deposit requirements related to our derivative activities. See Note 12 to our Consolidated Financial Statements for a discussion regarding our derivatives and risk management activities.

Net cash provided by operating activities for the years ended December 31, 2017, 2016 and 2015 was approximately $2.5 billion, $0.7 billion and $1.3 billion, respectively, and primarily resulted from earnings from our operations. Additionally, as discussed further below, changes in our inventory levels during these years impacted our cash flow from operating activities.

During 2017, net cash provided by operating activities for the 2017 period was positively impacted by decreases in (i) the volume of crude oil inventory that we held and (ii) the margin balances required as part of our hedging activities, both of which had been funded by short-term debt. This was consistent with our plan to reduce our hedged inventory volumes, and the cash inflows associated with these items resulted in a favorable impact on our cash provided by operating activities. However, the favorable effects from such activities were partially offset by higher weighted average prices and volumes for NGL inventory that was purchased and stored at the end of the 2017 period in anticipation of the 2017-2018 heating season.

During 2016, we increased our inventory levels and margin balances required as part of our hedging activities that were funded by short-term debt, resulting in an unfavorable impact on our cash provided by operating activities. Furthermore, cash provided by operating activities as compared to prior periods was unfavorably impacted by the decrease in cash from overall earnings.

During 2015, we increased the amount of our inventory; however, these volumetric increases were largely offset by lower prices for our inventory stored at the end of the year compared to prior year amounts.

Acquisitions, Investments, Expansion Capital Expenditures and Divestitures

In addition to our operating needs discussed above, on a consolidated basis, we also use cash for our acquisition activities and expansion capital projects. Historically, we have financed these expenditures primarily with cash generated by operating activities and the financing activities discussed in "—Equity and Debt Financing Activities" below. In the near term, we also intend to use proceeds from our asset sales program, as discussed further below. We have made and will continue to make capital expenditures for acquisitions, expansion capital projects and maintenance activities. Also see "—Acquisitions and Capital Projects" for further discussion of such capital expenditures.

Acquisitions. The price of acquisitions includes cash paid, assumed liabilities and net working capital items. Because of the non-cash items included in the total price of the acquisition and the timing of certain cash payments, the net cash paid may differ significantly from the total price of the acquisitions completed during the year. During the years ended December 31, 2017, 2016 and 2015, we paid cash of $1.280 billion (net of cash acquired of $4 million), $282 million (net of cash acquired of $7 million) and $105 million, respectively, for acquisitions.

Acquisitions completed in 2017 primarily included the ACC System located in the Northern Delaware Basin in Southeastern New Mexico and West Texas. The ACC acquisition was initially funded through borrowings under PAA's senior unsecured revolving credit facility. Such borrowings were subsequently repaid with proceeds from PAA's March 2017 issuance of its common units to AAP pursuant to the Omnibus Agreement and in connection with our underwritten equity offering. Additionally, we and an affiliate of Noble Midstream Partners LP completed the acquisition of Advantage Pipeline, L.L.C. through a newly formed 50/50 joint venture. For our 50% share ($66.5 million), PAA contributed approximately 1.3 million of its common units and approximately $26 million in cash. See Note 6 to our Consolidated Financial Statements for discussion of our acquisition activities.

Divestitures. In 2016, we initiated a program to evaluate potential sales of non-core assets and/or sales of partial interests in assets to strategic joint venture partners to optimize our asset portfolio and strengthen our balance sheet and leverage metrics. During the years ended December 31, 2017 and 2016, we received proceeds of $1.083 billion and $569 million (net of $85 million paid for a remaining interest in a pipeline that was subsequently sold during 2016), respectively. Such proceeds were used to fund a portion of our expansion capital projects during each year and for general partnership purposes. See Note 6 to our Consolidated Financial Statements for additional information regarding these asset sales and divestitures.

2018 Capital Projects. The majority of our 2018 expansion capital program will be invested in our fee-based Transportation and Facilities segments. We expect that our investments will have minimal contributions to our 2018 results, but will provide growth for 2019 and beyond. Our 2018 capital program includes the following projects as of February 2018 with the estimated cost for the entire year (in millions):

Projects		**2018**
Permian Basin Takeaway Pipeline Projects	$	765
Complementary Permian Basin Projects		375
Selected Facilities Projects [(1)]		50
Other Projects		210
Total Projected 2018 Expansion Capital Expenditures [(2)]	$	1,400

(1) Includes projects at our St. James, Fort Saskatchewan and other terminals.

(2) Amounts reflect our expectation that certain projects will be owned in a joint venture structure with a proportionate share of the project cost dispersed among the partners.

Credit Agreements, Commercial Paper Program and Indentures

At December 31, 2017, PAA had four primary credit arrangements. These include a $1.6 billion senior unsecured revolving credit facility maturing in 2022, a $1.4 billion senior secured hedged inventory facility maturing in 2020 and a $1 billion, 364-day senior unsecured credit facility maturing in August 2018. Additionally, PAA has a $3.0 billion unsecured commercial paper program that is backstopped by its revolving credit facility and its hedged inventory facility. The PAA credit agreements (which impact the ability to access the PAA commercial paper program because they provide the financial backstop that supports PAA's short-term credit ratings) and the indentures governing PAA's senior notes contain cross-default provisions. A default under PAA's credit agreements would permit the lenders to accelerate the maturity of the outstanding debt. As long as PAA is in compliance with the provisions in its credit agreements, PAA's ability to make distributions of available cash is not restricted. PAA was in compliance with the covenants contained in its credit agreements and indentures as of December 31, 2017.

During the year ended December 31, 2017, we had net repayments on the credit facilities and PAA commercial paper program of $654 million. The net repayments resulted primarily from cash flow from operating activities and cash received from PAA's equity activities and asset divestitures, which offset borrowings during the period related to funding needs for (i) acquisition and capital investments, (ii) repayment of PAA's $400 million, 6.13% senior notes in January 2017, (iii) repayment of PAA's $600 million, 6.50% senior notes and $350 million, 8.75% senior notes in December 2017 and (iv) other general partnership purposes.

During the year ended December 31, 2016, we had net repayments under the credit facilities and PAA commercial paper program of $676 million. The net repayments resulted primarily from cash flow from operating activities as well as cash received from PAA's equity issuances and asset divestitures, which offset borrowings during the period related to funding needs for (i) inventory purchases and related margin balances required as part of our hedging activities, (ii) capital investments, (iii) repayment of PAA's $175 million senior notes in August 2016, (iv) repayment of $642 million of borrowings that PAA assumed under AAP's senior secured credit agreement in connection with the Simplification Transactions and (v) other general partnership purposes.

During the year ended December 31, 2015, we had net borrowings under the credit facilities and PAA commercial paper program of $954 million. These net borrowings resulted primarily from funding needs for (i) capital investments, (ii) repayment of PAA senior notes that matured during 2015 and (iii) other general partnership purposes, and were partially offset by repayments from cash received from PAA's debt and equity issuances.

Equity and Debt Financing Activities

On a consolidated basis, our financing activities primarily relate to funding expansion capital projects, acquisitions and refinancing of debt maturities, as well as short-term working capital and hedged inventory borrowings related to our NGL business and contango market activities. Our financing activities have primarily consisted of PAA equity offerings, PAA senior notes offerings and borrowings and repayments under the credit facilities or the PAA commercial paper program, as well as payment of distributions to our Class A shareholders and noncontrolling interests.

PAGP Registration Statements. We have filed with the SEC a shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $1.0 billion of equity securities (the "PAGP Traditional Shelf"). Our issuances of equity securities associated with our Continuous Offering Program have been issued pursuant to the PAGP Traditional Shelf. At December 31, 2017, we had approximately $939 million of unsold securities available under the PAGP Traditional Shelf. Additionally, in February 2017, we filed a universal shelf registration statement (the "PAGP WKSI Shelf"), which provides us with the ability to offer and sell an unlimited amount of equity securities, subject to market conditions and capital needs. Our 2017 underwritten equity offering was conducted under the PAGP WKSI Shelf.

Sales of Class A Shares. The following table summarizes our sales of Class A shares during the year ended December 31, 2017, all of which occurred in the first four months of the year (net proceeds in millions). We did not sell any Class A shares during the years ended December 31, 2016 or 2015.

Type of Offering	Class A Shares Issued	Net Proceeds [1]
Continuous Offering Program	1,786,326	$ 61 [2] [3]
Underwritten Offering	48,300,000	1,474 [3]
	50,086,326	**$ 1,535**

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

(2) We pay commissions to our sales agents in connection with issuances of Class A shares under our Continuous Offering Program. We paid $1 million of such commissions during the year ended December 31, 2017.

(3) Pursuant to the Omnibus Agreement entered into in conjunction with the Simplification Transactions, we used the net proceeds from the sale of our 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 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 us to purchase from PAA an equivalent number of common units of PAA.

PAA Registration Statements. PAA periodically accesses the capital markets for both equity and debt financing. PAA has filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows PAA to issue up to an aggregate of $2.0 billion of debt or equity securities (the " PAA Traditional Shelf"). All issuances of PAA equity securities associated with PAA's continuous offering program have been issued pursuant to the PAA Traditional Shelf. At December 31, 2017, PAA had approximately $1.1 billion of unsold securities available under the PAA Traditional Shelf. PAA also has access to a universal shelf registration statement ("PAA WKSI Shelf"), which provides it with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and capital needs. The issuance of PAA's Series B preferred units in October 2017, discussed below, was conducted under the PAA WKSI Shelf.

PAA Sales of Common Units. The following table summarizes the sales of PAA's common units during the three years ended December 31, 2017 (net proceeds in millions):

Year	Type of Offering	Units Issued	Net Proceeds [1]
2017 Total	**Continuous Offering Program**	**4,033,567**	**$ 129** [2]
2016 Total	**Continuous Offering Program**	**26,278,288**	**$ 796** [2]
2015	Continuous Offering Program	1,133,904	$ 58 [2]
2015	Underwritten Offering	21,000,000	1,041 [3]
2015 Total		**22,133,904**	**$ 1,099**

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

(2) PAA pays commissions to its sales agents in connection with common unit issuances under its Continuous Offering Program. PAA paid $1 million, $8 million and $1 million of such commissions during 2017, 2016 and 2015, respectively. The net proceeds from these offerings were used for general partnership purposes.

(3) A portion of the net proceeds from such offering was used to repay borrowings under the PAA commercial paper program and the remaining net proceeds were used for general partnership purposes, including expenditures for our 2015 capital program.

Omnibus Agreement. PAA may sell common units to AAP pursuant to the Omnibus Agreement entered into by the Plains Entities. During the year ended December 31, 2017, pursuant to the Omnibus Agreement, PAA sold (i) approximately 1.8 million common units to AAP in connection with our issuance of Class A shares under our Continuous Offering Program and (ii) 48.3 million common units to AAP in connection with our March 2017 underwritten offering. See Note 11 to our Consolidated Financial Statements for additional information.

PAA Series A Preferred Units. In January 2016, PAA completed the private placement of approximately 61.0 million Series A preferred units at a price of $26.25 per unit resulting in total net proceeds, after deducting offering expenses and the 2% transaction fee due to the purchasers, of approximately $1.6 billion. The net proceeds were used for capital expenditures, repayment of debt and general partnership purposes. See Note 11 to our Consolidated Financial Statements for further discussion of PAA's Series A preferred units.

PAA Series B Preferred Units. On October 10, 2017, PAA issued 800,000 Series B preferred units at a price to the public of $1,000 per unit. PAA 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 its credit facilities and commercial paper program and for general partnership purposes, including expenditures for our capital program. See Note 11 to our Consolidated Financial Statements for additional information regarding PAA's Series B preferred units.

While PAA's Series A and Series B preferred units are considered equity securities and are classified within partners' capital on our Consolidated Balance Sheet, two out of the three rating agencies only ascribe 50% equity credit with the remaining 50% considered debt for purposes of determining PAA's credit ratings. The remaining rating agency ascribes 100% equity credit.

Issuances of PAA Senior Notes. During 2016 and 2015, PAA issued senior unsecured notes as summarized in the table below (in millions). PAA did not issue any senior unsecured notes during the year ended December 31, 2017.

Year	Description	Maturity	Face Value	Gross Proceeds[(1)]	Net Proceeds[(2)]
2016	4.50% PAA Senior Notes issued at 99.716% of face value [(3)]	December 2026	$ 750	$ 748	$ 741
2015	4.65% PAA Senior Notes issued at 99.846% of face value [(3)]	October 2025	$ 1,000	$ 998	$ 990

(1) Face value of notes less the applicable premium or discount (before deducting for initial purchaser discounts, commissions and offering expenses).

(2) Face value of notes less the applicable premium or discount, initial purchaser discounts, commissions and offering expenses.

(3) The net proceeds from this offering were used to repay outstanding borrowings under PAA's credit facilities or the PAA commercial paper program and for general partnership purposes.

Repayments of PAA Senior Notes. During the last three years, PAA repaid the following senior unsecured notes (in millions):

Year	Description	Repayment Date	
2017	$400 million 6.13% PAA Senior Notes due January 2017	January 2017	(1)
2017	$600 million 6.50% PAA Senior Notes due May 2018	December 2017	(1) (2)
2017	$350 million 8.75% PAA Senior Notes due May 2019	December 2017	(1) (2)
2016	$175 million 5.88% PAA Senior Notes due August 2016	August 2016	(1)
2015	$150 million 5.25% PAA Senior Notes due June 2015	June 2015	(3)
2015	$400 million 3.95% PAA Senior Notes due September 2015	September 2015	(3)

(1) These senior notes were repaid with cash on hand and proceeds from borrowings under the PAA credit facilities and commercial paper program.

(2) In conjunction with the early redemptions of these PAA senior notes, we recognized a loss of approximately $40 million, recorded to Other income/(expense), net in our Consolidated Statement of Operations.

(3) These senior notes were repaid with proceeds from borrowings under the PAA commercial paper program.

Distributions to our Class A shareholders

We distribute 100% of our available cash within 55 days following the end of each quarter to Class A shareholders 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 discretion of our general partner for future requirements. On February 14, 2018, we paid a quarterly distribution of $0.30 per Class A share ($1.20 per Class A share on an annualized basis). See Note 11 to our Consolidated Financial Statements for details of distributions paid during the three years ended December 31, 2017. Also, see Item 5. "Market for Registrant's Shares, Related Shareholder Matters and Issuer Purchases of Equity Securities—Cash Distribution Policy" for additional discussion regarding distributions.

Distributions to noncontrolling interests. During the years ended December 31, 2017, 2016 and 2015, distributions of approximately $1.1 billion, $1.4 billion and $1.5 billion, respectively, were paid to noncontrolling interests. These amounts represent distributions paid on interests in PAA, AAP and SLC Pipeline LLC that were not owned by us.

We believe that we have sufficient liquid assets, cash flow from operating activities and borrowing capacity under the credit agreements to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. We are, however, subject to business and operational risks that could adversely affect our cash flow. A prolonged material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity.

Contingencies

For a discussion of contingencies that may impact us, see Note 17 to our Consolidated Financial Statements.

Commitments

Contractual Obligations. In the ordinary course of doing business, we purchase crude oil and NGL from third parties under contracts, the majority of which range in term from thirty-day evergreen to five years, with a limited number of contracts with remaining terms extending up to ten years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between purchases on the one hand and sales and future delivery obligations on the other. The table below includes purchase obligations related to these activities. Where applicable, the amounts presented represent the net obligations associated with our counterparties (including giving effect to netting buy/sell contracts and those subject to a net settlement arrangement). We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to entities that we deem creditworthy or who have provided credit support we consider adequate.

The following table includes our best estimate of the amount and timing of these payments as well as others due under the specified contractual obligations as of December 31, 2017 (in millions):

	2018	2019	2020	2021	2022	2023 and Thereafter	Total
Long-term debt and related interest payments (1)	$ 657	$ 910	$ 870	$ 941	$ 1,073	$ 9,987	$ 14,438
Leases, rights-of-way easements and other (2)	188	155	127	107	90	363	1,030
Other obligations (3)	297	192	155	161	122	452	1,379
Subtotal	1,142	1,257	1,152	1,209	1,285	10,802	16,847
Crude oil, natural gas, NGL and other purchases (4)	8,250	5,307	4,488	4,156	3,742	9,032	34,975
Total	$ 9,392	$ 6,564	$ 5,640	$ 5,365	$ 5,027	$ 19,834	$ 51,822

(1) Includes debt service payments, interest payments due on PAA's senior notes and the commitment fee on assumed available capacity under the PAA credit facilities and long-term borrowings under the PAA commercial paper program. Although there may be short-term borrowings under the PAA credit facilities and the PAA commercial paper program, we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no short-term borrowings were outstanding on the PAA credit facilities or the PAA commercial paper program) in the amounts above. For additional information regarding our debt obligations, see Note 10 to our Consolidated Financial Statements.

(2) Leases are primarily for (i) railcars, (ii) land and surface rentals, (iii) office buildings, (iv) pipeline assets and (v) vehicles and trailers. Includes operating and capital leases as defined by FASB guidance, as well as obligations for rights-of-way easements.

(3) Includes (i) other long-term liabilities, (ii) storage, processing and transportation agreements and (iii) non-cancelable commitments related to our capital expansion projects, including projected contributions for our share of the capital spending of our equity method investments. The transportation agreements include approximately $760 million associated with 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.

(4) Amounts are primarily based on estimated volumes and market prices based on average activity during December 2017. The actual physical volume purchased and actual settlement prices will vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with 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. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the product 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 approximately $166 million and $73 million, respectively.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements as defined by Item 303 of Regulation S-K.

Investments in Unconsolidated Entities

We have invested in entities that are not consolidated in our financial statements. None of these entities are borrowers under credit facilities, and we are neither a co-borrower nor a guarantor under any facilities of such entities. We may elect at any time to make additional capital contributions to any of these entities. The following table sets forth selected information regarding these entities as of December 31, 2017 (unaudited, dollars in millions):

Entity	Type of Operation	Our Ownership Interest	Total Entity Assets	Total Cash and Restricted Cash	Total Entity Debt
Advantage Pipeline, L.L.C.	Crude Oil Pipeline	50%	$ 140	$ 6	$ —
BridgeTex Pipeline Company, LLC	Crude Oil Pipeline	50%	$ 909	$ 46	$ —
Caddo Pipeline LLC	Crude Oil Pipeline (1)	50%	$ 130	$ 4	$ —
Cheyenne Pipeline LLC	Crude Oil Pipeline (1)	50%	$ 58	$ 4	$ —
Diamond Pipeline LLC	Crude Oil Pipeline (1)	50%	$ 904	$ 2	$ —
Eagle Ford Pipeline LLC	Crude Oil Pipeline (1)	50%	$ 808	$ 19	$ —
Eagle Ford Terminals Corpus Christi LLC	Crude Oil Terminal and Dock (2)	50%	$ 138	$ 2	$ —
Midway Pipeline LLC	Crude Oil Pipeline (1)	50%	$ 40	$ 2	$ —
Saddlehorn Pipeline Company, LLC	Crude Oil Pipeline	40%	$ 583	$ 32	$ —
Settoon Towing, LLC	Barge Transportation Services	50%	$ 74	$ 6	$ —
STACK Pipeline LLC	Crude Oil Pipeline (1)	50%	$ 160	$ 16	$ —
White Cliffs Pipeline, L.L.C.	Crude Oil Pipeline	36%	$ 529	$ 7	$ —

(1) We serve as operator of the pipeline.

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

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

We are exposed to various market risks, including (i) commodity price risk, (ii) interest rate risk and (iii) currency exchange rate risk. We use various derivative instruments to manage such risks and, in certain circumstances, to realize incremental margin during volatile market conditions. Our risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring our exchange-cleared and over-the-counter positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity. We have a risk management function that has direct responsibility and authority for our risk policies, related controls around commercial activities and certain aspects of corporate risk management. Our risk management function also approves all new risk management strategies through a formal process. The following discussion addresses each category of risk.

Commodity Price Risk

We use derivative instruments to hedge price risk associated with the following commodities:

- *Crude oil*

  We utilize crude oil derivatives to hedge commodity price risk inherent in our Supply and Logistics and Transportation segments. Our objectives for these derivatives include hedging anticipated purchases and sales, stored inventory, and storage capacity utilization. We manage these exposures with various instruments including exchange-traded and over-the-counter futures, forwards, swaps and options.

- *Natural gas*

  We utilize natural gas derivatives to hedge commodity price risk inherent in our Supply and Logistics and Facilities segments. Our objectives for these derivatives include hedging anticipated purchases of natural gas. We manage these exposures with various instruments including exchange-traded futures, swaps and options.

- *NGL and other*

  We utilize NGL derivatives, primarily propane and butane derivatives, to hedge commodity price risk inherent in our Supply and Logistics segment. Our objectives for these derivatives include hedging anticipated purchases and sales and stored inventory. We manage these exposures with various instruments including exchange-traded and over-the-counter futures, forwards, swaps and options.

See Note 12 to our Consolidated Financial Statements for further discussion regarding our hedging strategies and objectives.

The fair value of our commodity derivatives and the change in fair value as of December 31, 2017 that would be expected from a 10% price increase or decrease is shown in the table below (in millions):

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
Crude oil	$ (62)	$ 7	$ (5)
Natural gas	(39)	$ 7	$ (7)
NGL and other	(180)	$ (61)	$ 61
Total fair value	$ (281)		

The fair values presented in the table above reflect the sensitivity of the derivative instruments only and do not include the effect of the underlying hedged commodity. Price-risk sensitivities were calculated by assuming an across-the-board 10% increase or decrease in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of an actual 10% change in near-term commodity prices, the fair value of our derivative portfolio would typically change less than that shown in the table as changes in near-term prices are not typically mirrored in delivery months further out.

Interest Rate Risk

Our use of variable rate debt and any forecasted issuances of fixed rate debt expose us to interest rate risk. Therefore, from time to time, we use interest rate derivatives to hedge interest rate risk associated with anticipated interest payments and, in certain cases, outstanding debt instruments. All of PAA's senior notes are fixed rate notes and thus are not subject to interest rate risk. Our variable rate debt outstanding at December 31, 2017, approximately $911 million, was subject to interest rate re-sets that range from less than one week to approximately three weeks. The average interest rate on variable rate debt that was outstanding during the year ended December 31, 2017 was 2.1%, based upon rates in effect during the year. The fair value of our interest rate derivatives was a liability of $36 million as of December 31, 2017. A 10% increase in the forward LIBOR curve as of December 31, 2017 would have resulted in an increase of $32 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of December 31, 2017 would have resulted in a decrease of $32 million to the fair value of our interest rate derivatives. See Note 12 to our Consolidated Financial Statements for a discussion of our interest rate risk hedging activities.

Currency Exchange Rate Risk

We use foreign currency derivatives to hedge foreign currency exchange rate risk associated with our exposure to fluctuations in the USD-to-CAD exchange rate. Because a significant portion of our Canadian business is conducted in CAD we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. The fair value of our foreign currency derivatives was an asset of $4 million as of December 31, 2017. A 10% increase in the exchange rate (USD-to-CAD) would have resulted in a decrease of $56 million to the fair value of our foreign currency derivatives. A 10% decrease in the exchange rate (USD-to-CAD) would have resulted in an increase of $56 million to the fair value of our foreign currency derivatives. See Note 12 to our Consolidated Financial Statements for a discussion of our currency exchange rate risk hedging.

Preferred Distribution Rate Reset Option

The Preferred Distribution Rate Reset Option of PAA's Series A preferred units is an embedded derivative that must be bifurcated from the related host contract, PAA's partnership agreement, and recorded at fair value on our Consolidated Balance Sheets. The valuation model utilized for this embedded derivative contains inputs including PAA's common unit price, ten-year U.S. treasury rates and default probabilities to ultimately calculate the fair value of PAA's Series A preferred units with and without the Preferred Distribution Rate Reset Option. The fair value of this embedded derivative was a liability of $22 million as of December 31, 2017. A 10% increase or decrease in the fair value would have an impact of $2 million. See Note 12 to our Consolidated Financial Statements for a discussion of embedded derivatives.

Item 8. ***Financial Statements and Supplementary Data***

See "Index to the Consolidated Financial Statements" on page F-1.

Item 9. ***Changes In and Disagreements With Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Disclosure Controls and Procedures

We maintain written disclosure controls and procedures, which we refer to as our "DCP." Our DCP is designed to ensure that information required to be disclosed by us in reports that we file under the Securities Exchange Act of 1934 (the "Exchange Act") is (i) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (ii) accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure.

Applicable SEC rules require an evaluation of the effectiveness of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our DCP as of December 31, 2017, the end of the period covered by this report, and, based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our DCP is effective.

Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. “Internal control over financial reporting” is a process designed by, or under the supervision of, our Chief Executive Officer and our Chief Financial Officer, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Our management, including our Chief Executive Officer and our Chief Financial Officer, has evaluated the effectiveness of our internal control over financial reporting as of December 31, 2017. See “Management’s Report on Internal Control Over Financial Reporting” on page F-2 of our Consolidated Financial Statements.

Our independent registered public accounting firm, PricewaterhouseCoopers LLP, assessed the effectiveness of our internal control over financial reporting, as stated in the firm’s report. See “Report of Independent Registered Public Accounting Firm” on page F-3 of our Consolidated Financial Statements.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting during the fourth quarter of 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Certifications

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a) are filed with this report as Exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. 1350 are furnished with this report as Exhibits 32.1 and 32.2.

Item 9B. ***Other Information***

There was no information that was required to be disclosed in a report on Form 8-K during the fourth quarter of 2017 that has not previously been reported.