PART II

Item 5. *Market for Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities*

Our common units are listed and traded on the New York Stock Exchange ("NYSE") under the symbol "PAA." As of February 10, 2017 , the closing market price for our common units was $31.27 per unit and there were approximately 159,000 record holders and beneficial owners (held in street name). As of February 10, 2017 , there were 675,097,184 common units outstanding.

The following table sets forth high and low sales prices for our common units and the cash distributions declared per common unit for the periods indicated:

	Common Unit Price Range		Cash
	High	Low	Distributions [1]
2016			
4th Quarter	$ 33.95	$ 27.17	$ 0.55
3rd Quarter	$ 31.72	$ 26.11	$ 0.55
2nd Quarter	$ 28.50	$ 19.76	$ 0.70
1st Quarter	$ 25.39	$ 14.82	$ 0.70
2015			
4th Quarter	$ 34.98	$ 17.83	$ 0.70
3rd Quarter	$ 44.29	$ 26.71	$ 0.70
2nd Quarter	$ 51.71	$ 43.00	$ 0.70
1st Quarter	$ 52.70	$ 45.81	$ 0.70

(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 common units are also used as a form of compensation to our employees and directors. Additional information regarding our equity-indexed compensation plans is included in Part III of this report under Item 13. " Certain Relationships and Related Transactions, and Director Independence ."

See Item 12. " Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters " for information regarding securities authorized for issuance under equity compensation plans.

Simplification Transactions

On November 15, 2016, the Plains Entities closed a series of transactions and executed several organizational and ancillary documents (the "Simplification Transactions") intended to simplify our capital structure, better align the interests of our stakeholders and improve our overall credit profile. The Simplification Transactions included, among other things: the permanent elimination of our incentive distribution rights ("IDRs") and the economic rights associated with our 2% general partner interest in exchange for the issuance by us to AAP of 245.5 million PAA common units (including approximately 0.8 million units to be issued in the future) and the assumption by us of all of AAP's outstanding debt ($642 million); the implementation of a unified governance structure pursuant to which the board of directors of our general partner was eliminated and an expanded board of directors of PAGP GP assumed oversight responsibility over both us and PAGP; and provision for annual PAGP shareholder elections beginning in 2018 with certain directors with expiring terms in 2018, and the participation of our common unitholders and Series A preferred unitholders in such elections through our ownership of newly issued Class C shares in PAGP, which provide us, as the sole holder, the right to vote in elections of eligible PAGP directors together with the holders of PAGP Class A and Class B shares. In addition, we entered into an Omnibus Agreement with AAP and PAGP to promote economic alignment between our common unitholders and PAGP's Class A shareholders by, among other measures, maintaining a one-to-one relationship between the number of outstanding PAGP Class A shares and the number of our common units indirectly owned by PAGP through AAP.

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

Cash Distribution Policy

In accordance with our partnership agreement, after making distributions to holders of outstanding Series A preferred units, we distribute all of our available cash to our common unitholders within 45 days following the end of each quarter. Available cash generally means, for any quarter ending prior to liquidation, all cash on hand at the end of that quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the general partner to:

- provide for the proper conduct of our business;
- comply with applicable law or any partnership debt instrument or other agreement; or
- provide funds for distributions to unitholders and the general partner in respect of any one or more of the next four quarters.

Under the terms of the agreements governing our debt, we are 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 ."

Under the terms of our partnership agreement, our Series A preferred units rank senior to all classes or series of equity securities in us with respect to distribution rights.

Prior to the Simplification Transactions, our general partner was entitled, directly or indirectly, to receive 2% proportional distributions, as well as incentive distributions if the amount we distributed with respect to any quarter exceeded certain specified levels. See Note 11 to our Consolidated Financial Statements for discussion of the prior quarterly incentive distribution provisions. Also See Item 13. " Certain Relationships and Related Transactions, and Director Independence — Our General Partner ."

Recent Sales of Unregistered Securities

Pursuant to the Omnibus Agreement entered into as part of the Simplification Transactions, PAGP has agreed to use the net proceeds from any public or private offering and sale of 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. The Omnibus Agreement also provides that immediately following such purchase and sale, AAP will use the net proceeds it receives from such sale of AAP units to purchase from us an equivalent number of our common units. Subsequent to December 31, 2016, AAP purchased approximately 1.8 million common units from us for net proceeds of approximately $60 million received from the sale of AAP units to PAGP in connection with PAGP's issuance of Class A shares under its continuous equity offering program. The issuance of such common units to AAP was exempt from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(2) thereof.

Issuer Purchases of Equity Securities

We did not repurchase any of our common units during the fourth quarter of 2016 , and we do not have any announced or existing plans to repurchase any of our common units other than potential repurchases consistent with past practice in providing units for relatively small vestings of phantom units under our long-term incentive plans ("LTIP").

Item 6. *Selected Financial Data*

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2016 , 2015 , 2014 , 2013 and 2012 and for the years then ended. The selected financial data should be read in conjunction with the Consolidated Financial Statements, including the notes thereto, and Item 7. " Management's Discussion and Analysis of Financial Condition and Results of Operations ."

A two-for-one split of our common units was completed on October 1, 2012. The effect of the two-for one split has been retroactively applied to all unit and per-unit amounts presented in this Form 10-K.

	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(in millions, except per unit data)				
Statement of operations data:					
Total revenues	$ 20,182	$ 23,152	$ 43,464	$ 42,249	$ 37,797
Operating income	$ 994	$ 1,262	$ 1,799	$ 1,738	$ 1,434
Net income	$ 730	$ 906	$ 1,386	$ 1,391	$ 1,127
Net income attributable to PAA	$ 726	$ 903	$ 1,384	$ 1,361	$ 1,094
Per unit data:					
Basic net income per common unit	$ 0.43	$ 0.78	$ 2.39	$ 2.82	$ 2.41
Diluted net income per common unit	$ 0.43	$ 0.77	$ 2.38	$ 2.80	$ 2.40
Declared distributions per common unit [1]	$ 2.65	$ 2.76	$ 2.55	$ 2.33	$ 2.11
Balance sheet data (at end of period):					
Property and equipment, net	$ 13,872	$ 13,474	$ 12,272	$ 10,819	$ 9,643
Total assets	$ 24,210	$ 22,288	$ 22,198	$ 20,320	$ 19,196
Long-term debt	$ 10,124	$ 10,375	$ 8,704	$ 6,675	$ 6,281
Total debt	$ 11,839	$ 11,374	$ 9,991	$ 7,788	$ 7,367
Partners' capital	$ 8,816	$ 7,939	$ 8,191	$ 7,703	$ 7,146
Other data:					
Net cash provided by operating activities	$ 726	$ 1,344	$ 2,004	$ 1,954	$ 1,240
Net cash used in investing activities	$ (1,273)	$ (2,530)	$ (3,296)	$ (1,653)	$ (3,392)
Net cash provided by/(used in) financing activities	$ 563	$ 814	$ 1,657	$ (281)	$ 2,151
Capital expenditures:					
Acquisition capital	$ 289	$ 105	$ 1,099	$ 19	$ 2,286
Expansion capital	$ 1,405	$ 2,170	$ 2,026	$ 1,622	$ 1,185
Maintenance capital	$ 186	$ 220	$ 224	$ 176	$ 170
Volumes [2] [3]					
Transportation segment (average daily volumes in thousands of barrels per day):					
Tariff activities	4,523	4,340	3,952	3,595	3,373
Trucking	114	113	127	117	106
Transportation segment total volumes	4,637	4,453	4,079	3,712	3,479
Facilities segment:					
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	107	100	95	94	90
Rail load / unload volumes (average volumes in thousands of barrels per day)	83	210	231	221	—
Natural gas storage (average monthly working capacity in billions of cubic feet)	97	97	97	96	84
NGL fractionation (average volumes in thousands of barrels per day)	115	103	96	96	79
Facilities segment total volumes (average monthly volumes in millions of barrels)	129	126	121	120	106

	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(in millions, except per unit data)				
Supply and Logistics segment (average daily volumes in thousands of barrels per day):					
Crude oil lease gathering purchases	894	943	949	859	818
NGL sales	259	223	208	215	182
Waterborne cargos	7	2	—	4	3
Supply and Logistics segment total volumes	1,160	1,168	1,157	1,078	1,003

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

(2) 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.

(3) Facilities segment total is calculated as the sum of: (i) crude oil, refined products and NGL terminalling and storage capacity; (ii) rail load and unload volumes multiplied by the number of days in the year and divided by the number of months in the year; (iii) 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 (iv) 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.

Our discussion and analysis includes the following:

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

Executive Summary

Company Overview

We own and operate midstream energy infrastructure and provide logistics services for crude oil, NGL, natural gas and refined products. We own an extensive network of pipeline transportation, terminalling, storage, and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. We were formed in 1998, and our operations are conducted directly and indirectly through our operating subsidiaries and are managed through three operating segments: Transportation, Facilities and Supply and Logistics. See "— Results of Operations — Analysis of Operating Segments " for further discussion.

Overview of Operating Results, Capital Investments and Other Significant Activities

The transitioning crude oil market over the last two years created a challenging environment for the overall midstream industry. See the "—Market Overview and Outlook" section below for further discussion. We recognized net income attributable to PAA of $726 million in 2016 as compared to net income attributable to PAA of $903 million recognized in 2015 . This year-over-year decrease was impacted by:

- Lower operating results, primarily due to less favorable crude oil and NGL market conditions, increased competition and the impact of mark-to-market losses on certain derivative instruments, partially offset by (i) contributions from our recently completed acquisition and capital expansion projects and (ii) lower field operating costs, largely due to lower trucking costs associated with our supply and logistics activities and the absence of costs related to the Line 901 incident, which occurred in May 2015;

- Higher depreciation and amortization expense primarily resulting from (i) our recently completed capital expansion projects, (ii) impairment losses related to certain of our rail and other terminal assets and (iii) assets taken out of service and the discontinuation of certain capital projects, all partially offset by net gains related to non-core assets sales and joint venture formations completed during the 2016 period;

- Higher interest expense primarily related to financing activities associated with our capital investments;

- Gains recognized during 2016 related to the mark-to-market impact of our Preferred Distribution Rate Reset Option; and

- Lower income tax expense primarily due to lower earnings from our Canadian operations and the impact from the cumulative revaluation of Canadian net deferred tax liabilities resulting from an Alberta, Canada provincial tax rate increase enacted during the comparative 2015 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 executed a $1.4 billion capital program during 2016 , which we expect will contribute to growth in our fee-based Transportation and Facilities segments in future years. In addition, we paid approximately $1.6 billion of cash distributions to our common unitholders and general partner during 2016 .

To improve our ability to manage through the industry downturn and to position for a recovery, we completed a number of initiatives during 2016 to maintain a solid capital structure, significant liquidity and overall financial flexibility. Such initiatives included (i) executing the Simplification Transactions in November 2016, which lowered our incremental cost of equity through the elimination of our IDRs, and in connection therewith resetting our distribution level, which resulted in an annual reduction in cash distributions of approximately $320 million, (ii) securing approximately $1.6 billion of equity capital through the sale of new Series A preferred units in January 2016, (iii) selectively utilizing our continuous offering program to raise approximately $805 million of net proceeds, (iv) selling non-core assets and entering into strategic joint ventures, which raised approximately $550 million of cash proceeds during 2016 while reducing our capital commitments, and (v) entering into a definitive agreement to sell additional assets for approximately $290 million that is expected to close in the first half of 2017, subject to regulatory approvals.

Subsequent to December 31, 2016, we acquired a crude oil gathering system located in the Northern Delaware Basin for approximately $1.215 billion. In addition, in February 2017, we entered into a definitive agreement to form a 50/50 joint venture to acquire a crude oil pipeline located in the Southern Delaware Basin for $133 million. We also entered into definitive sales agreements for two transactions totaling $310 million, and we completed a third transaction, the sale of a partial interest in a pipeline segment, in January 2017 for proceeds of $70 million. We expect the remaining transactions to close during the first half of 2017, subject to customary closing conditions, including receipt of regulatory approvals.

Acquisitions and Capital Projects

We completed a number of acquisitions and capital projects in 2016 , 2015 and 2014 that have impacted our results of operations. The following table summarizes our expenditures for acquisition capital, expansion capital and maintenance capital for the periods indicated (in millions):

	Year Ended December 31,		
	2016	2015	2014
Acquisition capital [1]	$ 289	$ 105	$ 1,099
Expansion capital [2]	1,405	2,170	2,026
Maintenance capital [2]	186	220	224
	$ 1,880	$ 2,495	$ 3,349

(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 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 our commercial paper program or credit facilities and the issuance of 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 2016 , 2015 and 2014 is set forth in the table below (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Western Canada NGL Assets	August 2016	$ 204	Transportation and Facilities
Other	Various	85	Transportation
2016 Total		$ 289	
2015 Total	Various	$ 105	Transportation and Facilities
BridgeTex Acquisition (50% interest) [1]	November 2014	$ 1,088	Transportation
Other	Various	11	Facilities
2014 Total		$ 1,099	

(1) We account for our 50% interest in BridgeTex under the equity method of accounting. See Note 8 to our Consolidated Financial Statements for further discussion of our equity method investments.

Alpha Crude Connector Gathering System. In February 2017, we acquired the Alpha Crude Connector ("ACC") gathering system for total consideration of $1.215 billion, subject to working capital and other adjustments. The ACC gathering system is located in the Northern Delaware Basin in Southeastern New Mexico and West Texas and is comprised of 515 miles of recently constructed gathering and transmission lines and five market interconnects, including to our Basin Pipeline at Wink. The ACC gathering system is supported by long-term acreage dedications.

Expansion Capital Projects

Our 2016 projects primarily included the construction and expansion of pipeline systems and storage and terminal facilities. The following table summarizes our 2016 , 2015 and 2014 projects (in millions):

Projects	2016	2015	2014
Red River Pipeline (Cushing to Longview) (1)	$ 306	$ 143	$ —
Permian Basin Area Projects (2)	200	470	378
Fort Saskatchewan Facility Projects / NGL Line (2)	200	272	142
Saddlehorn Pipeline (4)	108	103	—
Diamond Pipeline (2) (5)	104	6	29
Cushing Terminal Expansions (2)	62	39	13
St. James Terminal Expansions (2)	51	45	25
Eagle Ford JV Projects (2) (5)	29	93	117
Cactus Pipeline (2)	26	134	350
Rail Terminal Projects (3)	5	294	239
Other Projects	314	571	733
Total	$ 1,405	$ 2,170	$ 2,026

(1) In January 2017, we sold an undivided 40% interest in a segment of the Red River Pipeline.

(2) These projects will continue into 2017. See "— Liquidity and Capital Resources — Acquisitions, Divestitures and Expansion Capital Expenditures — 2017 Capital Projects ."

(3) Includes railcar purchases, as well as rail projects near St. James, LA; Tampa, CO; Bakersfield, CA; Carr, CO; Manitou, ND; Van Hook, ND; Yorktown, VA; and Kerrobert, Canada rail projects.

(4) Represents contributions related to our 40% investment interest in Saddlehorn.

(5) Represents contributions related to our 50% investment interest.

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. A majority of the expansion capital spent in the years presented was invested in our fee-based Transportation and Facilities segments.

However, the meaningful decrease in crude oil prices since the second half of 2014 led to production declines and infrastructure overbuild in a number of onshore resource plays. As such, we have reduced our forecasted capital expansion program in 2017 relative to prior years. We currently expect to spend approximately $800 million for expansion capital in 2017 . See "— Liquidity and Capital Resources — Acquisitions, Divestitures and Expansion Capital Expenditures — 2017 Capital Projects " and "— Market Overview and Outlook " for additional information.

Critical Accounting Policies and Estimates

Critical Accounting Policies

We have adopted various accounting policies to prepare our consolidated financial statements in accordance with GAAP. These critical accounting policies are discussed in Note 2 to our Consolidated Financial Statements.

Critical Accounting 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) fair value of derivatives, (iii) accruals and contingent liabilities, (iv) equity-indexed compensation plan accruals, (v) property and equipment, depreciation expense and asset retirement obligations, (vi) allowance for doubtful accounts and (vii) 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, so we consider these to be our critical accounting estimates. Such critical accounting estimates are discussed further as follows:

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. Any subsequent adjustments to this estimate, if material, will be recognized retroactive to the date of acquisition. 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. Intangible assets with finite lives are amortized over their estimated useful life as determined by management. Goodwill and intangible assets with indefinite lives are not amortized but instead are periodically assessed for impairment.

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 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, although not material, and in the future may result, in impairments that impact our results of operations and financial condition. See Note 7 to our Consolidated Financial Statements for further discussion of goodwill.

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 our preferred units that are accounted for as assets and liabilities at fair value in our Consolidated Balance Sheets. Derivatives related to the embedded derivatives in our preferred units are valued using a model that contains inputs, including our 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 $12 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 the actual unit price at time of vesting, whether or not a performance condition will be attained and the continued employment of personnel with outstanding equity-indexed compensation 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 $60 million , $27 million and $98 million in 2016 , 2015 and 2014 , 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 net income attributable to PAA 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 Expense, Asset Retirement Obligations and Impairments. We compute depreciation 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.

As discussed in the “Market Overview and Outlook” section below, the decline in crude oil prices and its impact on certain differentials and downward pressure on production that has occurred since mid-2014 has adversely impacted most companies in the midstream industry, including us. As a result of such adverse market conditions, during 2016, we recognized approximately $80 million of non-cash impairment losses on certain of our long-lived rail and other terminal assets included in our Facilities segment. Despite the modest recovery in the crude oil market in recent months, 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. During the year ended December 31, 2014, we recognized impairments of $10 million primarily related to assets that were taken out of service. 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, 2016 , 2015 and 2014) 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 market, with cost determined using an average cost method within specific inventory pools. At the end of each reporting period, we assess the carrying value of our inventory and 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, 2016 , 2015 and 2014 , we recorded charges of $3 million , $117 million and $289 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 debt issuance costs 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 unit amounts):

	Year Ended December 31,			Favorable/(Unfavorable) Variance			
				2016-2015		2015-2014	
	2016	2015	2014	$	%	$	%
Transportation segment adjusted EBITDA [1]	$ 1,141	$ 1,056	$ 979	$ 85	8 %	$ 77	8 %
Facilities segment adjusted EBITDA [1]	667	588	597	79	13 %	(9)	(2)%
Supply and Logistics segment adjusted EBITDA [1]	359	568	651	(209)	(37)%	(83)	(13)%
Adjustments:							
Depreciation and amortization of unconsolidated entities	(50)	(45)	(29)	(5)	(11)%	(16)	(55)%
Selected items impacting comparability - segment adjusted EBITDA	(434)	(290)	93	(144)	**	(383)	**
Depreciation and amortization	(494)	(432)	(384)	(62)	(14)%	(48)	(13)%
Interest expense, net	(467)	(432)	(348)	(35)	(8)%	(84)	(24)%
Other income/(expense), net	33	(7)	(2)	40	**	(5)	**
Income tax expense	(25)	(100)	(171)	75	75 %	71	42 %
Net income	730	906	1,386	(176)	(19)%	(480)	(35)%
Net income attributable to noncontrolling interests	(4)	(3)	(2)	(1)	(33)%	(1)	(50)%
Net income attributable to PAA	$ 726	$ 903	$ 1,384	$ (177)	(20)%	$ (481)	(35)%
Basic net income per common unit	$ 0.43	$ 0.78	$ 2.39	$ (0.35)	(45)%	$ (1.61)	(67)%
Diluted net income per common unit	$ 0.43	$ 0.77	$ 2.38	$ (0.34)	(44)%	$ (1.61)	(68)%
Basic weighted average common units outstanding	464	394	367	70	18 %	27	7 %
Diluted weighted average common units outstanding	466	396	369	70	18 %	27	7 %

** 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 measures used by management are earnings before interest, taxes, depreciation and amortization (including our proportionate share of depreciation and amortization of unconsolidated entities) and adjusted for certain selected items impacting comparability (“Adjusted EBITDA”) and implied distributable cash flow (“DCF”).

Management believes that the presentation of such additional financial measures provides useful information to investors regarding our performance and results of operations because these measures, when used to supplement related GAAP financial measures, (i) provide additional information about our core operating performance and ability to fund distributions to our unitholders through cash generated by our operations, (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. These non-GAAP measures may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) 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), 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. These measures 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” on 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 and Implied DCF are 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 these non-GAAP financial performance measures from Net Income (in millions):

	Year Ended December 31,			Favorable/(Unfavorable) Variance 2016-2015		Favorable/(Unfavorable) Variance 2015-2014	
	2016	2015	2014	$	%	$	%
Net income	$ 730	906	$ 1,386	$ (176)	(19)%	$ (480)	(35)%
Add/(Subtract):							
Interest expense, net	467	432	348	35	8 %	84	24 %
Income tax expense	25	100	171	(75)	(75)%	(71)	(42)%
Depreciation and amortization	494	432	384	62	14 %	48	13 %
Depreciation and amortization of unconsolidated entities (1)	50	45	29	5	11 %	16	55 %
Selected Items Impacting Comparability - Adjusted EBITDA:							
(Gains)/losses from derivative activities net of inventory valuation adjustments (2)	404	110	(243)	294	267 %	353	145 %
Deficiencies under minimum volume commitments, net (3)	46	—	—	46	N/A	—	N/A
Long-term inventory costing adjustments (4)	(58)	99	85	(157)	(159)%	14	16 %
Equity-indexed compensation expense (5)	33	27	56	6	22 %	(29)	(52)%
Net (gain)/loss on foreign currency revaluation (6)	9	(29)	9	38	131 %	(38)	(422)%
Line 901 incident (7)	—	83	—	(83)	(100)%	83	N/A
Selected Items Impacting Comparability - segment adjusted EBITDA	434	290	(93)	144	**	383	**
Gains from derivative activities (2)	(30)	—	—	(30)	N/A	—	N/A
Net (gain)/loss on foreign currency revaluation (6)	(1)	8	4	(9)	(113)%	4	100 %
Selected Items Impacting Comparability - Adjusted EBITDA (8)	403	298	(89)	105	**	387	**
Adjusted EBITDA (8)	$ 2,169	$ 2,213	$ 2,229	$ (44)	(2)%	$ (16)	(1)%
Interest expense (9)	(451)	(417)	(334)	(34)	(8)%	(83)	(25)%
Maintenance capital (10)	(186)	(220)	(224)	34	15 %	4	2 %
Current income tax expense	(85)	(84)	(71)	(1)	(1)%	(13)	(18)%
Adjusted equity earnings in unconsolidated entities, net of distributions (11)	(29)	(14)	(32)	(15)	(107)%	18	56 %
Distributions to noncontrolling interests (12)	(4)	(4)	(3)	—	— %	(1)	(33)%
Implied DCF (13)	$ 1,414	$ 1,474	$ 1,565	$ (60)	(4)%	$ (91)	(6)%
Less: Distributions paid (12)	(1,565)	(1,714)	(1,469)				
DCF Excess/(Shortage) (14)	$ (151)	$ (240)	$ 96				

** 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. Our proportionate share of the depreciation and amortization

expense associated with such unconsolidated entities is excluded when reviewing Adjusted EBITDA, similar to our consolidated pipelines.

(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.

(3) 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.

(4) We carry crude oil and NGL inventory that is comprised of minimum working inventory requirements in third-party assets and other working inventory that is needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. Therefore, we classify this inventory as long-term on our balance sheet and do not hedge the inventory with derivative instruments (similar to linefill in our own assets). We 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.

(5) Our total equity-indexed compensation expense includes expense associated with awards that will or may be settled in units and awards that will or may be settled in cash. The awards that will or may be settled in units are included in our 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 our diluted net income per unit calculation, as applicable, and the majority of the awards are expected to be settled in 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.

(8) Adjusted EBITDA includes Other income/(expense), net adjusted for selected items impacting comparability. Segment adjusted EBITDA is exclusive of such amounts.

(9) Excludes certain non-cash items impacting interest expense such as amortization of debt issuance costs and terminated interest rate swaps.

(10) Maintenance capital expenditures are defined as capital expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets.

(11) Does not include the depreciation and amortization expense of unconsolidated entities, as such expenses are excluded in the calculation of Adjusted EBITDA.

(12) Includes distributions that pertain to the current period's net income and are paid in the subsequent period.

(13) Including net costs recognized during the period related to the Line 901 incident that occurred in May 2015, Implied DCF would have been $1,391 million for the year ended December 31, 2015. See Note 17 to our Consolidated Financial Statements for additional information regarding the Line 901 incident.

(14) Excess DCF is retained to establish reserves for future distributions, capital expenditures and other partnership purposes. DCF shortages are funded from previously established reserves, cash on hand or from borrowings under our credit facilities or commercial paper program.

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.

During the fourth quarter of 2016, we modified our primary segment performance measure to segment adjusted EBITDA from segment profit, and thus prior period segment disclosures have been recast to reflect this change. Segment adjusted EBITDA forms the basis of our internal financial reporting and is the measure of segment performance that is utilized by our CODM in assessing performance and allocating resources among our operating segments. Such recasts have no impact on previously reported consolidated financial results.

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 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 PAA.

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; however, certain terminalling and storage rates are discounted to our Supply and Logistics segment to reflect the fact that these services may be canceled on short notice to enable the Facilities segment to provide services to third parties. 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:

				Favorable/(Unfavorable) Variance			
Operating Results [1] **(in millions, except per barrel data)**	**Year Ended December 31,**			**2016-2015**		**2015-2014**	
	2016	**2015**	**2014**	**$**	**%**	**$**	**%**
Revenues							
Tariff activities	$ 1,436	$ 1,439	$ 1,447	$ (3)	— %	$ (8)	(1)%
Trucking	148	155	208	(7)	(5)%	(53)	(25)%
Total transportation revenues	1,584	1,594	1,655	(10)	(1)%	(61)	(4)%
Costs and expenses							
Trucking costs	(94)	(108)	(151)	14	13 %	43	28 %
Field operating costs [2]	(537)	(652)	(560)	115	18 %	(92)	(16)%
Equity-indexed compensation expense - field operating costs	(14)	(5)	(15)	(9)	(180)%	10	67 %
Segment general and administrative expenses [2] [3]	(88)	(89)	(83)	1	1 %	(6)	(7)%
Equity-indexed compensation expense - general and administrative	(15)	(6)	(29)	(9)	(150)%	23	79 %
Equity earnings in unconsolidated entities	195	183	108	12	7 %	75	69 %
Adjustments [4] :							
Depreciation and amortization of unconsolidated entities	50	45	29	5	11 %	16	55 %
Deficiencies under minimum volume commitments, net	44	—	—	44	N/A	—	N/A
Line 901 incident	—	83	—	(83)	(100)%	83	N/A
Equity-indexed compensation expense	16	11	25	5	45 %	(14)	(56)%
Segment adjusted EBITDA	$ 1,141	$ 1,056	$ 979	$ 85	8 %	$ 77	8 %
Maintenance capital	$ 121	$ 144	$ 165	$ (23)	(16)%	$ (21)	(13)%
Segment adjusted EBITDA per barrel	$ 0.67	$ 0.65	$ 0.66	$ 0.02	3 %	$ (0.01)	(2)%

Average Daily Volumes (in thousands of barrels per day) [5]	Year Ended December 31,			Favorable/(Unfavorable) Variance 2016-2015		Favorable/(Unfavorable) Variance 2015-2014	
	2016	2015	2014	Volumes	%	Volumes	%
Tariff activities volumes							
Crude oil pipelines (by region):							
Permian Basin [6]	2,146	1,849	1,512	297	16 %	337	22 %
South Texas / Eagle Ford [6]	284	306	227	(22)	(7)%	79	35 %
Western	188	215	260	(27)	(13)%	(45)	(17)%
Rocky Mountain [6]	449	440	426	9	2 %	14	3 %
Gulf Coast	497	532	492	(35)	(7)%	40	8 %
Central [6]	394	413	450	(19)	(5)%	(37)	(8)%
Canada	381	392	399	(11)	(3)%	(7)	(2)%
Crude oil pipelines	4,339	4,147	3,766	192	5 %	381	10 %
NGL pipelines	184	193	186	(9)	(5)%	7	4 %
Tariff activities total volumes	4,523	4,340	3,952	183	4 %	388	10 %
Trucking volumes	114	113	127	1	1 %	(14)	(11)%
Transportation segment total volumes	4,637	4,453	4,079	184	4 %	374	9 %

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

(2) Field operating costs and Segment general and administrative expenses exclude equity-indexed compensation expense, which is presented separately in the table above.

(3) 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.

(4) 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.

(5) 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.

(6) Area systems include 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 variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative-related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff activities revenues.

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

Revenues from Tariff Activities, Equity Earnings in Unconsolidated Entities and Volumes. The following table presents variances in tariff activities revenues and equity earnings in unconsolidated entities by region for the comparative periods presented:

	Favorable/(Unfavorable) Variance 2016-2015		Favorable/(Unfavorable) Variance 2015-2014	
(in millions)	**Revenues**	**Equity Earnings**	**Revenues**	**Equity Earnings**
Tariff activities:				
Permian Basin region	$ 98	$ 7	$ 75	$ 52
South Texas / Eagle Ford region	(7)	(1)	12	19
Western region	(6)	—	(24)	—
Rocky Mountain region	(18)	10	7	10
Gulf Coast region	(19)	—	10	—
Central region	(23)	2	(8)	—
Canada crude oil	(2)	—	(16)	—
NGL	11	—	(2)	—
Other (including pipeline loss allowance revenue)	(37)	(6)	(62)	(6)
Total variance	$ (3)	$ 12	$ (8)	$ 75

- *Permian Basin region.* 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. Revenues increased for 2015 over 2014 primarily due to (i) results from our Cactus pipeline and (ii) higher volumes related to increased production, primarily associated with the expansion of our pipeline system in the Delaware Basin. The increase in equity earnings for 2015 over 2014 was driven by earnings from our interest in BridgeTex, which we acquired in November 2014.

- *South Texas / Eagle Ford region.* Revenues decreased in 2016 compared to 2015 due to production declines in the region. Revenues increased for 2015 over 2014 due to higher volumes driven by the extension of our gathering system and increased production. Equity earnings increased for 2015 over 2014 due to higher earnings from our interest in Eagle Ford Pipeline LLC, primarily driven by higher throughput on the Eagle Ford pipeline system. The higher throughput was due to a combination of (i) the connection to our Cactus pipeline in April 2015 and (ii) increased crude oil production in the Eagle Ford region.

- *Western region.* Revenues and volumes decreased for each of the comparative periods presented primarily due to pipeline downtime on our All American Pipeline associated with the Line 901 incident that occurred in the second quarter of 2015. See Note 17 to our Consolidated Financial Statements for additional information regarding this incident.

- *Rocky Mountain region.* 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 in June 2016, subsequent to which it was accounted for under the equity method of accounting.

  Equity earnings increased for 2016 over 2015 due to earnings from (i) our 40% investment in the entity that owns Saddlehorn Pipeline, a segment of which was placed in service in the third quarter of 2016, and (ii) our 50% investment in Cheyenne Pipeline, as discussed above.

  The increase in equity earnings for 2015 compared to 2014 was driven by higher earnings from our interest in White Cliffs, primarily as a result of increased throughput on the White Cliffs pipeline due to an expansion of the pipeline that was placed into service in July 2014.

- *Gulf Coast region.* Revenues and volumes decreased for 2016 compared to 2015 primarily due to the sale of certain of our Gulf Coast pipelines in March and July 2016. These decreases were partially offset 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.

The increase in revenues for 2015 over 2014 was primarily driven by (i) results from our Pascagoula pipeline, which was placed in service in April 2014, and which also favorably impacted volumes and demand for storage on our Mississippi/Alabama system, and (ii) higher volumes on Capline due to higher refinery demand.

- *Central region.* 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.

- *Canada.* Revenues decreased for 2016 as compared to 2015 and for 2015 as compared to 2014 due to unfavorable foreign exchange impacts of $9 million and $38 million, respectively, which more than offset revenue increases from higher tariff rates on certain of our pipelines and related system assets in each of the comparative periods.

- *NGL pipelines.* Revenues increased for 2016 as compared to 2015 primarily due to contributions from the Western Canada NGL assets we acquired in August 2016.

  Revenues and volumes from our NGL pipelines were relatively consistent for 2015 compared to 2014, as higher revenue from tariff rate increases was substantially offset by unfavorable foreign exchange fluctuation impacts of $12 million.

- *Other.* The variances for the comparative periods presented were related to pipeline loss allowance revenue. Loss allowance revenue decreased for the comparative periods presented due to a lower average realized price per barrel. The decrease in loss allowance revenue for 2015 compared to 2014 was partially offset by higher volumes.

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. The activity for 2016 presented in the table above primarily reflects the amounts billed in 2016 under minimum volume commitment contracts. Such amounts were not material to periods prior to 2016 and, thus, are not included in the table for prior years.

Adjustments: Depreciation and amortization of unconsolidated entities. The increases for the periods presented were primarily driven by additional depreciation expense associated with newly acquired or completed joint venture pipeline projects.

Trucking Revenues. Trucking revenues for the comparative periods presented were unfavorably impacted by foreign exchange fluctuation impacts of $5 million and $28 million, respectively. The decrease in trucking revenues for 2015 compared to 2014 was further unfavorably impacted by lower producer volumes.

Trucking Costs. The decrease in trucking costs for 2016 compared to 2015 was primarily driven by lower contract services rates. The decrease in trucking costs for 2015 compared to 2014 was primarily driven by lower producer volumes, as discussed above. Trucking costs for the comparative periods presented were further favorably impacted by foreign exchange fluctuation impacts of $4 million and $20 million, respectively.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) decreased for the year ended December 31, 2016 compared to the year ended December 31, 2015 primarily due to net costs of approximately $83 million associated with the Line 901 incident that were recognized during 2015. See Note 17 to our Consolidated Financial Statements for additional information regarding this incident. The decrease in field operating costs was further driven by lower utilities and maintenance costs, costs associated with the MP 29 release during 2015, lower operating costs due to the sale of certain of our Gulf Coast pipelines in March and July 2016 and a favorable foreign exchange impact of $5 million, partially offset by an increase in insurance premiums.

The increase in field operating costs (excluding equity-indexed compensation expense) for the year ended December 31, 2015 compared to the year ended December 31, 2014 was primarily due to the estimated costs of $83 million recognized during 2015 associated with the Line 901 incident, net of amounts we believe are probable of recovery from insurance. The increase in field operating costs was also driven by (i) higher salary and related expenses and property tax expense primarily associated with new assets placed in service in 2015 and (ii) higher maintenance and repairs cost, partially offset by favorable foreign exchange impacts of $22 million.

Segment General and Administrative Expenses. The increase in segment general and administrative expenses (excluding equity-indexed compensation expense) for the year ended December 31, 2015 over the year ended December 31, 2014 was primarily due to increased salaries, benefits and other costs associated with the growth in the segment, partially offset by a $4 million favorable foreign exchange impact.

Equity-Indexed Compensation Expense. The following table presents total equity-indexed compensation expense by segment (in millions):

	Year Ended December 31,			Favorable/(Unfavorable) Variance	
Operating Segment	**2016**	**2015**	**2014**	**2016-2015**	**2015-2014**
Transportation	$ 29	$ 11	$ 44	$ (18)	$ 33
Facilities	15	5	24	(10)	19
Supply and Logistics	16	11	30	(5)	19
	$ 60	$ 27	$ 98	$ (33)	$ 71

Across all segments, equity-indexed compensation expense increased by $33 million for the year ended December 31, 2016 compared to the year ended December 31, 2015, primarily due to the impact of the increase in unit price during the year ended December 31, 2016 compared to the impact of the decrease in unit price during the year ended December 31, 2015, partially offset by the impact of fewer average probable awards outstanding and lower average values per award during the 2016 period compared to the same period in 2015. Across all segments, equity-indexed compensation expense decreased by $71 million for the year ended December 31, 2015 compared to the year ended December 31, 2014, primarily due to the impact of the decrease in unit price during the year ended December 31, 2015 compared to the impact of the decrease in unit price during the year ended December 31, 2014. See Note 16 to our Consolidated Financial Statements for additional information regarding our equity-indexed compensation plans.

Allocations of equity-indexed compensation expense vary over time between field operating costs and general and administrative expenses, as well as between segments, and could result in variances in those expense categories or segments that differ from the consolidated variance explanations above.

Adjustments: Equity-Indexed Compensation Expense. The equity-indexed compensation expense selected item adjustment is primarily associated with equity-classified awards, which are not impacted by changes in unit price. Therefore, the impact of unit price changes is less on the equity-indexed compensation expense selected item adjustment than on equity-indexed compensation expense as a whole.

Maintenance Capital. Maintenance capital consists of capital expenditures for the replacement 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.

The decrease in maintenance capital in 2015 compared to 2014 was primarily due to a reclassification of certain maintenance capital costs from our Facilities segment during the 2014 period. In addition, the decrease in maintenance capital was impacted by favorable foreign exchange rate fluctuations.

Facilities Segment

Our Facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products, 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, 2016	2015	2014	Favorable/(Unfavorable) Variance 2016-2015 $	2016-2015 %	2015-2014 $	2015-2014 %
Revenues	$ 1,107	$ 1,050	$ 1,127	$ 57	5 %	$ (77)	(7)%
Natural gas related storage costs	(26)	(24)	(55)	(2)	(8)%	31	56 %
Field operating costs [2]	(347)	(377)	(404)	30	8 %	27	7 %
Equity-indexed compensation expense - field operating costs	(5)	—	(4)	(5)	N/A	4	100 %
Segment general and administrative expenses [2] [3]	(58)	(65)	(60)	7	11 %	(5)	(8)%
Equity-indexed compensation expense - general and administrative	(10)	(5)	(20)	(5)	(100)%	15	75 %
Adjustments [4]	6	9	13	(3)	(33)%	(4)	(31)%
Segment adjusted EBITDA	$ 667	$ 588	$ 597	$ 79	13 %	$ (9)	(2)%
Maintenance capital	$ 55	$ 68	$ 52	$ (13)	(19)%	$ 16	31 %
Segment adjusted EBITDA per barrel	$ 0.43	$ 0.39	$ 0.41	$ 0.04	10 %	$ (0.02)	(5)%

Volumes [5]	Year Ended December 31, 2016	2015	2014	Favorable/(Unfavorable) Variance 2016-2015 Volumes	2016-2015 %	2015-2014 Volumes	2015-2014 %
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	107	100	95	7	7 %	5	5 %
Rail load / unload volumes (average volumes in thousands of barrels per day)	83	210	231	(127)	(60)%	(21)	(9)%
Natural gas storage (average monthly working capacity in billions of cubic feet)	97	97	97	—	— %	—	— %
NGL fractionation (average volumes in thousands of barrels per day)	115	103	96	12	12 %	7	7 %
Facilities segment total volumes (average monthly volumes in millions of barrels) [6]	129	126	121	3	2 %	5	4 %

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

(2) Field operating costs and Segment general and administrative expenses exclude equity-indexed compensation expense, which is presented separately in the table above.

(3) 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.

(4) 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.

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

(6) Facilities segment total is calculated as the sum of: (i) crude oil, refined products and NGL terminalling and storage capacity; (ii) rail load and unload volumes multiplied by the number of days in the year and divided by the number of

months in the year; (iii) 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 (iv) 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 $53 million for the year ended December 31, 2016 over the same 2015 period primarily due to (i) contributions from the Western Canada NGL assets we acquired in August 2016, (ii) contributions from ongoing expansion projects at our Fort Saskatchewan facility and (iii) higher fees at certain of our NGL storage and fractionation facilities. Such increases were partially offset by unfavorable foreign exchange fluctuation impacts of $10 million, which were largely offset in our Supply and Logistics segment results.

  Revenues decreased by $7 million for the year ended December 31, 2015 compared to the year ended December 31, 2014. This decrease was primarily due to estimated unfavorable foreign exchange fluctuation impacts of $41 million, which offset revenue increases from higher facility fees for the 2015 period. These impacts were largely offset in our Supply and Logistics segment results.

- Crude Oil Storage — Revenues increased by $24 million for the year ended December 31, 2016 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.

  For the year ended December 31, 2015, revenues increased by $9 million over the year ended December 31, 2014 primarily due to capacity expansions of approximately 1 million barrels and higher marine access activity at our St. James terminal.

- Rail Terminals — Revenues decreased by $17 million for the year ended December 31, 2016 compared to the year ended December 31, 2015 primarily due to (i) lower volumes 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 Canadian NGL rail terminal that came online in April 2016.

  For the year ended December 31, 2015, revenues decreased by $26 million compared to the year ended December 31, 2014 due to lower volumes and lower rail fees related to the movement of certain volumes of Bakken crude oil, partially offset by revenues from our Bakersfield rail terminal that came online in the fourth quarter of 2014.

- Gulf Coast Gas Processing — Revenues decreased by $13 million for the year ended December 31, 2015 compared to the same 2014 period, primarily due to lower volumes and decreased margins driven by lower commodity prices. Revenues remained relatively consistent for the year ended December 31, 2016 compared to the same 2015 period.

- Natural Gas Storage Operations — Net revenues decreased by $12 million for the year ended December 31, 2015 compared to the year ended December 31, 2014 primarily due to (i) declines in market rates for natural gas storage, which resulted in lower rates on new contracts replacing expiring contracts, and (ii) reduced hub services opportunities. In addition, the 2014 period was unfavorably impacted by costs incurred to manage deliverability requirements in conjunction with the extended period of severe cold weather experienced during the first quarter of 2014. Revenues remained relatively consistent for the year ended December 31, 2016 compared to the same 2015 period.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) decreased for the year ended December 31, 2016 compared to the same 2015 period 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 of 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.

The decrease in field operating costs (excluding equity-indexed compensation expenses) for the year ended December 31, 2015 compared to the year ended December 31, 2014 was primarily due to (i) decreased maintenance and repairs cost, (ii) lower gas and power costs largely associated with our NGL fractionation and Canadian gas processing activities and (iii) favorable foreign exchange fluctuation impacts of $19 million. Such decreases were partially offset by an increase in expenses associated with new assets placed in service.

Segment General and Administrative Expenses. Segment general and administrative expenses (excluding equity-indexed compensation expense) decreased for the year ended December 31, 2016 compared to the year ended December 31, 2015 due to cost reduction efforts and lower expenses incurred for legal fees.

The increase in general and administrative expenses (excluding equity-indexed compensation expenses) for the year ended December 31, 2015 compared to the year ended December 31, 2014 was primarily due to increased salaries and benefits, partially offset by a $3 million favorable foreign exchange fluctuation impact.

Equity-indexed compensation expense. See "—Analysis of Operating Segments—Transportation Segment" for discussion of equity-indexed compensation expense for the periods presented.

Maintenance Capital. 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.

The increase in maintenance capital in 2015 over 2014 was primarily due to various tank and facility projects and timing of equipment replacements, as well as the impact from a change in classification of certain maintenance capital costs to our Transportation segment in the 2014 period.

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 purchased from suppliers and natural gas sales attributable to the activities performed by our 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, NGL sales volumes and waterborne cargos), (ii) the effects of competition on our lease gathering 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 and relative fluctuations in market-related indices.

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, 2016	2015	2014	Favorable/(Unfavorable) Variance 2016-2015 $	2016-2015 %	2015-2014 $	2015-2014 %
Revenues	$ 19,018	$ 21,945	$ 42,150	$ (2,927)	(13)%	$ (20,205)	(48)%
Purchases and related costs	(18,627)	(21,018)	(40,752)	2,391	11 %	19,734	48 %
Field operating costs [2]	(291)	(433)	(481)	142	33 %	48	10 %
Equity-indexed compensation expense - field operating costs	(1)	—	(2)	(1)	N/A	2	100 %
Segment general and administrative expenses [2] [3]	(93)	(102)	(105)	9	9 %	3	3 %
Equity-indexed compensation expense - general and administrative	(15)	(11)	(28)	(4)	(36)%	17	61 %
Adjustments [4] :							
(Gains)/losses from derivative activities net of inventory valuation adjustments	406	106	(243)	300	283 %	349	144 %
Long-term inventory costing adjustments	(58)	99	85	(157)	(159)%	14	16 %
Net (gain)/loss on foreign currency revaluation	10	(29)	9	39	134 %	(38)	(422)%
Equity-indexed compensation expense	10	11	18	(1)	(9)%	(7)	(39)%
Segment adjusted EBITDA	$ 359	$ 568	$ 651	$ (209)	(37)%	$ (83)	(13)%
Maintenance capital	$ 10	$ 8	$ 7	$ 2	25 %	$ 1	14 %
Segment adjusted EBITDA per barrel	$ 0.85	$ 1.33	$ 1.54	$ (0.48)	(36)%	$ (0.21)	(14)%

Average Daily Volumes (in thousands of barrels per day)	Year Ended December 31, 2016	2015	2014	Favorable (Unfavorable) Variance 2016-2015 Volume	2016-2015 %	2015-2014 Volume	2015-2014 %
Crude oil lease gathering purchases	894	943	949	(49)	(5)%	(6)	(1)%
NGL sales	259	223	208	36	16 %	15	7 %
Waterborne cargos	7	2	—	5	250 %	2	N/A
Supply and Logistics segment total volumes	1,160	1,168	1,157	(8)	(1)%	11	1 %

(1) Revenues and costs include intersegment amounts.

(2) Field operating costs and Segment general and administrative expenses exclude equity-indexed compensation expense, which is presented separately in the table above.

(3) 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.

(4) 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):

	NYMEX WTI Crude Oil Price	
During the Year Ended December 31,	**Low**	**High**
2016	$ 26	$ 54
2015	$ 35	$ 61
2014	$ 53	$ 107

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 decreased for the year ended December 31, 2016 compared to the year ended December 31, 2015 and the year ended December 31, 2015 compared to the same 2014 period primarily due to lower crude oil and NGL prices during the period.

Generally, we expect a base level of earnings from our Supply and Logistics segment from the assets employed by this segment. This base level may be optimized and enhanced when there is a high level of market volatility, favorable basis differentials and/or a steep contango or backwardated market structure. During certain transitional periods, such as the current extended period of lower crude oil prices, our ability to generate above base-level earnings is challenging, and taking into account the overcapacity of midstream assets and increased competition that currently exists in most crude oil producing regions, generating even baseline-level performance is challenging. Our NGL operations are also impacted by similar competitive pressures. In addition, 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 segment revenues, net of purchases and related costs, decreased by $536 million for the year ended December 31, 2016 compared to the year ended December 31, 2015 (of which $144 million was related to the mark-to-market impact of certain derivatives and long-term inventory costing adjustments). Revenues, net of purchases and related costs, decreased by $471 million for the year ended December 31, 2015 compared to the same 2014 period (of which $389 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 the year ended December 31, 2016 compared to the year ended December 31, 2015 primarily due to continued and intensifying competition, largely due to overbuilt infrastructure underwritten with volume commitments and the effect of such on differentials, as well as volume declines in certain areas, which negatively impacted our unit margins. See the "Market Overview and Outlook" section below for additional discussion of recent market conditions.

  Net revenues decreased for the year ended December 31, 2015 as compared to the year ended December 31, 2014 primarily due to (i) the compression of certain differentials during the 2015 period, which resulted in fewer opportunities to capture above-baseline margins as compared to 2014 and (ii) increased competition, largely due to overbuilt infrastructure in certain areas that has negatively impacted our lease gathering unit margins and volumes, most notably during the second half of 2015. However, such unfavorable results were partially offset by revenues from opportunities created by the contango market structure during 2015.

- NGL Operations — 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 are primarily reflected in our Facilities segment and (ii) higher supply costs driven by competition, which more than offset higher sales volumes.

  Net revenues increased for the year ended December 31, 2015 compared to the year ended December 31, 2014. The increase was primarily driven by higher margins due to the lower cost of inventory carried over from 2014 year end and higher sales volumes.

- Impact from Certain Derivative Activities, Net of Inventory Valuation Adjustments — The mark-to-market of certain of our derivative activities impacting 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), gains and losses on certain derivatives that are related to investing activities (such as the purchase of linefill) 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.

- 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.

- 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. In addition, the depreciation of CAD relative to USD resulted in lower net USD costs of approximately $15 million for 2016 compared to 2015 and $41 million for 2015 compared to 2014. Such costs are primarily associated with intercompany facility fees and are largely offset in our Facilities segment results.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) decreased for the year ended December 31, 2016 compared to the same 2015 period 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.

The decrease in field operating costs (excluding equity-indexed compensation expense) for the year ended December 31, 2015 compared to the year ended December 31, 2014 was primarily due to the decreased use of third-party trucking services as pipeline expansion projects were placed into service.

Segment General and Administrative Expenses. Segment general and administrative expenses (excluding equity-indexed compensation expense) decreased for the year ended December 31, 2016 compared to the same 2015 period due to cost reduction efforts.

Equity-indexed compensation expense. See "—Analysis of Operating Segments—Transportation Segment" for discussion of equity-indexed compensation expense for the periods presented.

Other Income and Expenses

Depreciation and Amortization

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 impairment losses 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.

Depreciation and amortization expense increased during the 2015 period over the comparable 2014 period primarily due to various capital expansion projects completed during 2015, partially offset by favorable foreign exchange fluctuation impacts.

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 for percentages):

		Average LIBOR	Weighted Average Interest Rate [1]
Interest expense for the year ended December 31, 2014	$ 348	0.1%	4.5%
Impact of issuance of senior notes	88		
Impact of retirement of senior notes	(9)		
Impact of capitalized interest	(9)		
Other	14		
Interest expense for the year ended December 31, 2015	$ 432	0.2%	4.5%
Impact of issuance of senior notes	34		
Impact of retirement of senior notes	(19)		
Impact of borrowings under credit facilities and commercial paper program	12		
Impact of capitalized interest	10		
Other	(2)		
Interest expense for the year ended December 31, 2016	$ 467	0.5%	4.5%

(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

Other income/(expense), net for the year ended December 31, 2016 was impacted by gains of $30 million related to the mark-to-market adjustment of our Preferred Distribution Rate Reset Option. See Note 12 to our Consolidated Financial Statements for additional information. Excluding such gains, other income/(expense), net in each of the years ended December 31, 2016, 2015 and 2014 was primarily comprised of foreign currency gains or losses related to revaluations of CAD-denominated interest receivables associated with our intercompany notes.

Income Tax Expense

Income tax expense decreased for the year ended December 31, 2016 compared to the year ended December 31, 2015 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.

The decrease in income tax expense for the year ended December 31, 2015 compared to the year ended December 31, 2014 was primarily due to the deferred income tax impact associated with fluctuations in the derivative mark-to-market valuation in our Canadian operations during the 2015 and 2014 periods. This benefit was partially offset by an Alberta, Canada provincial tax rate increase of 2% enacted during the second quarter of 2015, as well as higher current income tax expense resulting from increased year-over-year taxable earnings from our Canadian operations. The 2015 period was also favorably impacted by the depreciation of CAD relative to USD.

Market Overview and Outlook

For the last six years, crude oil markets have been fairly volatile, with significant swings in both prices and production levels coupled with relatively modest growth in global liquids demand. The period from 2011 through 2014 was generally characterized by (i) high commodity prices driving a significant increase in North American production volumes (3.7 million barrels per day, or 33%), including significantly increased production of light crudes and condensate, (ii) high levels of volatility in location and quality differentials, and (iii) high utilization of then existing pipeline and terminal infrastructure. These factors stimulated multiple industry initiatives to build new pipeline and terminal infrastructure, ultimately resulting in excess midstream capacity in the Permian, Eagle Ford, Williston, Midcontinent and DJ basins. Many of the new infrastructure projects constructed during this period are supported by long-term minimum volume commitments ("MVCs") whereby the shipper, often a producer with expectations of continued production or volume growth and the desire to secure associated takeaway capacity, agreed to ship and pay for certain stated volumes. The period of high commodity prices and increased production from 2011 through 2014 led to an oversupply of North American and global petroleum liquids, which resulted in a meaningful decrease in crude oil prices during the second half of 2014 and throughout 2015 and 2016 relative to the levels experienced during the first half of 2014. In turn, this resulted in a decrease in North American production levels in many areas as producers took rigs out of service and deferred completions at an increased rate. As a result, many of the producers and shippers that had previously entered into MVCs found themselves short of the volumes they needed to fulfill their MVCs, resulting in increased competition for the marginal uncommitted barrel. The combination of the slowdown in North American crude oil production growth and significant MVCs for new infrastructure created an environment for our business in which margins have compressed and differentials are less than transportation cost in some cases.

In 2016, the market remained oversupplied, but global demand growth began to outpace global supply growth as non-OPEC production declined. In November 2016, OPEC indicated a desire to return to its historical strategy of managing crude oil production levels. Joined by certain non-OPEC countries such as Russia and Mexico, OPEC and non-OPEC participants have targeted to cut output by approximately 1.8 million barrels per day in the first half of 2017. This decision drove a significant increase in crude oil prices during the fourth quarter of 2016. To the extent the production cut is successfully executed by the participating countries, accumulated inventories should begin to decline, prices should remain firm and potentially rise, ultimately leading to increased drilling and production activity levels. If the production cut is not executed, inventories could rise and prices could decline, ultimately leading to reduced drilling and production activity levels.

The recent increase in crude oil prices has led to increased rig activity in a few areas where we anticipate production levels to increase, most notably the Permian Basin and the STACK resource play in Oklahoma. If production growth resumes and pipeline utilization increases, differentials should improve and approach transportation cost on a regional basis. While we believe that challenging industry conditions will persist in the near term, especially given the uncertainty surrounding the degree to which the proposed production cut by OPEC and other non-OPEC countries is implemented, we anticipate improvements in market conditions and production growth in the lower 48 States during the latter half of 2017 and into 2018.

However, we can provide no assurance that the improvement in market conditions will be achieved or that we will not be negatively impacted by declining crude oil supply, lower commodity prices, reduced producer activity levels, competition for incremental volumes, reduced margins, low levels of volatility, challenging capital markets conditions or other related factors. Additionally, construction of additional infrastructure by us and our competitors could lead to even greater levels of excess takeaway capacity in certain areas for the near- to medium-term, which could further reduce unit margins in our various segments, and which could be exacerbated by declining levels of crude oil production. Finally, we cannot be certain that our expansion efforts will generate targeted returns or that any recently completed or future acquisition activities will be successful. See Item 1A. " Risk Factors — Risks Related to Our Business ."

Liquidity and Capital Resources

General

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 our credit facilities or 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 a program we initiated to evaluate potential sales of non-core assets and/or sales of partial interests in assets to strategic joint venture partners. 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 and other expenses and interest payments on outstanding debt, (ii) expansion and maintenance activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on our long-term debt and (v) distributions to our unitholders. We generally expect to fund our short-term cash requirements through cash flow generated from operating activities and/or borrowings under our commercial paper program or credit facilities. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions and refinancing our 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. As of December 31, 2016 , we had a working capital deficit of $392 million and approximately $2.4 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, 2016
Availability under senior unsecured revolving credit facility [(1)] [(2)]	$ 1,580
Availability under senior secured hedged inventory facility [(1)] [(2)]	597
Availability under senior unsecured 364-day revolving credit facility	1,000
Amounts outstanding under commercial paper program	(810)
Subtotal	2,367
Cash and cash equivalents	47
Total	$ 2,414

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

(2) Available capacity under the senior unsecured revolving credit facility and the senior secured hedged inventory facility was reduced by outstanding letters of credit of $20 million and $53 million, respectively.

We repaid $400 million of senior notes in January 2017, and we completed an approximate $1.215 billion acquisition in February 2017, both of which were initially funded with borrowings under our credit facilities and cash on hand. We received approximately $190 million of net proceeds from sales of our common units in January 2017, which sales were completed under our continuous offering program and pursuant to the Omnibus Agreement with AAP and PAGP. See further discussion in “Equity and Debt Financing Activities” and “ Acquisitions, Divestitures and Expansion Capital Expenditures ” below.

We believe that we have, and will continue to have, the ability to access the 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. Also, see Item 1A. “ Risk Factors ” for further discussion regarding such risks that may impact our liquidity and capital resources. Usage of the credit facilities, which provide the backstop for the commercial paper program, is subject to ongoing compliance with covenants. As of December 31, 2016 , we were in compliance with all such covenants.

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 storage and terminalling services provided 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 our credit facilities or 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 our credit facilities or 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 our credit facilities or 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, 2016 , 2015 and 2014 was approximately $726 million , $1.3 billion and $2.0 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 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.

During 2014, we decreased the volume of our crude oil inventory that we held. The decreased inventory levels were further impacted by lower prices for such inventory stored at the end of the year compared to prior year amounts. In addition, our margin balances fluctuated from a net cash outflow to a net cash inflow. A portion of the net proceeds received from the liquidation of such inventory and the positive cash flow associated with our margin balance activities were used to repay borrowings under our commercial paper program and favorably impacted cash flow from operating activities. These overall decreases were partially offset by an increase in the amount of NGL inventory stored at December 31, 2014 compared to prior year amounts, which was primarily financed through borrowings under our commercial paper program.

Credit Agreements, Commercial Paper Program and Indentures

At December 31, 2016 , we had four primary credit arrangements. These include a $1.6 billion senior unsecured revolving credit facility maturing in 2021, a $1.4 billion senior secured hedged inventory facility maturing in 2019 and a $1.0 billion, 364-day senior unsecured credit facility maturing in August 2017. Additionally, we have a $3.0 billion unsecured commercial paper program that is backstopped by our revolving credit facility and our hedged inventory facility. Our credit agreements (which impact our ability to access our commercial paper program because they provide the backstop that supports our short-term credit ratings) and the indentures governing our senior notes contain cross-default provisions. A default under our credit agreements would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with the provisions in our credit agreements, our ability to make distributions of available cash is not restricted. We were in compliance with the covenants contained in our credit agreements and indentures as of December 31, 2016 .

During the year ended December 31, 2016, we had net repayments on our credit facilities and commercial paper program of $759 million. The net repayments resulted primarily from cash flow from operating activities as well as cash received from our 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 our $175 million senior notes in August 2016, (iv) repayment of $642 million of borrowings that we 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 our credit facilities and commercial paper program of $931 million. These net borrowings resulted primarily from funding needs for (i) capital investments, (ii) repayment of senior notes that matured during 2015 and (iii) other general partnership purposes, and were partially offset by repayments from cash received from our debt and equity issuances.

Equity and Debt Financing Activities

Our financing activities primarily relate to funding expansion capital projects, acquisitions and refinancing of our 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 equity offerings, senior notes offerings and borrowings and repayments under our credit facilities or commercial paper program, as well as payment of distributions to our unitholders and general partner.

Registration Statements . We periodically access the capital markets for both equity and debt financing. We have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $2.0 billion of debt or equity securities (“Traditional Shelf”). All issuances of equity securities associated with our continuous offering program have been issued pursuant to the Traditional Shelf. At December 31, 2016 , we had approximately $1.2 billion of unsold securities available under the Traditional Shelf. We also have access to a universal shelf registration statement (“WKSI Shelf”), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. Our November 2016 senior notes issuance were conducted under our WKSI shelf. See “ Common Unit Issuances ” and “ Senior Notes ” below.

Common Unit Issuances . The following table summarizes our issuance of common units during the three years ended December 31, 2016 (net proceeds in millions):

Year	Type of Offering	Units Issued	Net Proceeds [1] [2]	
2016 Total	**Continuous Offering Program**	**26,278,288**	**$ 805**	[3]
2015	Continuous Offering Program	1,133,904	$ 59	[3]
2015	Underwritten Offering	21,000,000	1,062	[4]
2015 Total		**22,133,904**	**$ 1,121**	
2014 Total	**Continuous Offering Program**	**15,375,810**	**$ 866**	[3]

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

(2) For periods prior to the closing of the Simplification Transactions, amounts include our general partner’s proportionate capital contributions of $9 million , $22 million and $18 million during 2016 , 2015 and 2014 , respectively.

(3) We pay commissions to our sales agents in connection with common unit issuances under our Continuous Offering Program. We paid $8 million , $1 million and $9 million of such commissions during 2016 , 2015 and 2014 , respectively. The net proceeds from these offerings were used for general partnership purposes.

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

Subsequent to December 31, 2016, we sold an additional 4.0 million common units under our continuous offering program, generating proceeds of $129 million, net of $1 million of commissions to our sales agents.

PAGP Continuous Offering Program. On December 27, 2016, PAGP entered into an equity distribution agreement pursuant to which it may, from time to time though sales agents, sell Class A shares with an aggregate offering price of up to $500 million. PAGP did not issue any Class A shares prior to December 31, 2016. Subsequent to December 31, 2016, PAGP issued approximately 1.8 million Class A shares, generating proceeds of $60 million, net of $1 million of commissions to sales agents.

Pursuant to the Omnibus Agreement, PAGP has agreed to use the net proceeds from any public or private offering and sale of 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. The Omnibus Agreement also provides that immediately following such purchase and sale, AAP will use the net proceeds it receives from such sale of AAP units to purchase from us an equivalent number of our common units.

We used the net proceeds we received from the sale of such common units to AAP, and we intend to use any future proceeds, for general partnership purposes, which may include, among other things, repayment of indebtedness, acquisitions, capital expenditures and additions to working capital. Amounts repaid under our credit facilities or commercial paper program may be reborrowed to fund our ongoing expansion capital program, future acquisitions and investments or for general partnership purposes.

Preferred Unit Issuance . In January 2016, we 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 to us, after deducting offering expenses and the 2% transaction fee due to the purchasers and including our 2% general partner's proportionate contribution, of approximately $1.6 billion. We used the net proceeds for capital expenditures, repayment of debt and general partnership purposes. While our Series A preferred units are considered equity securities and are classified within partners' capital on our Consolidated Balance Sheet, the rating agencies only ascribe 50% equity credit with the remaining 50% considered debt for purposes of determining our credit ratings.

Our Series A preferred units rank senior to all classes or series of equity securities in us with respect to distribution rights. The holders of the Series A preferred units are entitled to receive quarterly distributions, subject to customary anti-dilution adjustments, of $0.525 per unit ($2.10 per unit annualized), which commenced with the quarter ending March 31, 2016. With respect to any quarter ending on or prior to December 31, 2017, we may elect to pay distributions on the preferred units in additional preferred units, in cash or in a combination of both.

After two years, the Series A preferred units are convertible at the purchasers' option into common units on a one-for-one basis, subject to certain conditions, and are convertible at our option in certain circumstances after three years. See Note 11 to our Consolidated Financial Statements for additional information regarding the Series A preferred units.

Senior Notes . During the last three years, we issued senior unsecured notes as summarized in the table below (in millions):

Year	Description	Maturity	Face Value	Gross Proceeds [1]	Net Proceeds [2]
2016	4.50% Senior Notes issued at 99.716% of face value [3]	December 2026	$ 750	$ 748	$ 741
2015	4.65% Senior Notes issued at 99.846% of face value [3]	October 2025	$ 1,000	$ 998	$ 990
2014	2.60% Senior Notes issued at 99.813% of face value [4]	December 2019	$ 500	$ 499	$ 495
2014	4.90% Senior Notes issued at 99.876% of face value [4]	February 2045	$ 650	$ 649	$ 643
2014	3.60% Senior Notes issued at 99.842% of face value [3]	November 2024	$ 750	$ 749	$ 743
2014	4.70% Senior Notes issued at 99.734% of face value [3]	June 2044	$ 700	$ 698	$ 691

(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) We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities or commercial paper program and for general partnership purposes.

(4) We used the net proceeds from this offering to repay outstanding borrowings under our commercial paper program (a portion of which was used to fund the acquisition of a 50% interest in BridgeTex). See Note 8 to our Consolidated Financial Statements for further discussion.

In January 2017, our $400 million, 6.13% senior notes matured and were repaid with cash on hand and proceeds from borrowings under our credit facilities and commercial paper program.

In August 2016, our $175 million, 5.88% senior notes matured and were repaid with cash on hand and proceeds from borrowings under our credit facilities and commercial paper program.

Our $150 million, 5.25% senior notes and $400 million, 3.95% senior notes matured in June 2015 and September 2015, respectively, and were repaid with borrowings under our commercial paper program.

Acquisitions, Divestitures and Expansion Capital Expenditures

In addition to our operating needs discussed above, we also use cash for our acquisition activities and expansion capital projects. Historically, we have financed these expenditures primarily with cash generated by operations and the financing activities discussed above. In the near term, we also intend to use proceeds from our asset sales program, as discussed further below. 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, 2016 , 2015 and 2014 , we paid cash of $282 million (net of cash acquired of $7 million), $105 million and $1,098 million , respectively, for acquisitions.

In February 2017, we acquired the Alpha Crude Connector gathering system for total consideration of $1.215 billion, subject to working capital and other adjustments. This acquisition was initially funded with borrowings under our credit facilities, which we intend to repay with proceeds from asset sales, equity issuances and retained cash flow. See Note 6 to our Consolidated Financial Statements for discussion of our acquisition activities.

Also in February 2017, we entered into a definitive agreement to form a 50/50 joint venture to acquire a crude oil pipeline located in the Southern Delaware Basin for $133 million; a majority of our 50% share of such amount is expected to be paid in common units issued to certain of the sellers at closing, which we expect to occur, subject to the satisfaction of customary closing conditions, during the first half of 2017.

2016-2017 Asset Sales Program . 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. We completed approximately $550 million of asset sales in 2016 (net of $85 million paid for a remaining interest in a pipeline that was subsequently sold), and $670 million of sales have closed or are expected to close during the first half of 2017, subject to customary closing conditions.

2017 Capital Projects . The majority of our 2017 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 2017 results, but will provide growth for 2018 and beyond. Our 2017 capital program includes the following projects as of February 2017 with the estimated cost for the entire year (in millions):

Projects	**2017**
Diamond Pipeline	$300
Permian Basin Area Systems [(1)]	120
Fort Saskatchewan Facility Projects	90
Cushing Terminal Expansions	30
Other Projects	260
Total Projected 2017 Expansion Capital Expenditures	$800

(1) Includes projected capital projects associated with our recently acquired Alpha Crude Connector gathering system.

Distributions to Our Unitholders

In accordance with our partnership agreement, after making distributions to holders of outstanding Series A preferred units, we distribute all of our available cash to our common unitholders of record within 45 days following the end of each quarter. 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.

Distributions to our Series A preferred unitholders. On February 14, 2017, we issued 1,287,773 additional Series A preferred units in lieu of paying a cash distribution of $34 million. See Note 11 to our Consolidated Financial Statements for additional information regarding our Series A preferred units.

Distributions to our unitholders. On February 14, 2017, we paid a quarterly distribution of $0.55 per common unit, which represents a year-over-year distribution decrease of approximately 21%. We believe this revised distribution level will significantly enhance our distribution coverage and credit profile. The total distribution of $371 million was paid to unitholders of record as of January 31, 2017. See Note 11 to our Consolidated Financial Statements for details of distributions paid during 2016, 2015 and 2014. Also, see Item 5. " Market for Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities — Cash Distribution Policy " for additional discussion regarding distributions.

Distributions to our general partner. Prior to the Simplification Transactions, our general partner was entitled, directly or indirectly, to receive 2% proportional distributions, as well as incentive distributions if the amount we distributed with respect to any quarter exceeded certain specified levels. See Note 11 to our Consolidated Financial Statements for discussion of the prior quarterly incentive distribution provisions and amounts paid to our general partner in 2016, 2015 and 2014.

We believe that we have sufficient liquid assets, cash flow from operating activities and borrowing capacity under our 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 nine 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. In addition, we enter into similar contractual obligations in conjunction with our natural gas operations. 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, 2016 (in millions):

	2017	2018	2019	2020	2021	2022 and Thereafter	Total
Long-term debt, including current maturities and related interest payments (1)	$ 1,128	$ 1,054	$ 1,270	$ 870	$ 940	$ 11,054	$ 16,316
Leases and rights-of-way easements (2)	195	165	140	118	97	404	1,119
Other obligations (3)	662	223	163	143	139	465	1,795
Subtotal	1,985	1,442	1,573	1,131	1,176	11,923	19,230
Crude oil, natural gas, NGL and other purchases (4)	5,068	2,626	2,120	1,492	1,283	4,377	16,966
Total	$ 7,053	$ 4,068	$ 3,693	$ 2,623	$ 2,459	$ 16,300	$ 36,196

(1) Includes debt service payments, interest payments due on senior notes, the commitment fee on assumed available capacity under our credit facilities, and long-term borrowings under our commercial paper program. Although there may be short-term borrowings under our credit facilities and 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 credit facilities or 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) surface rentals, (ii) office rent, (iii) pipeline assets and (iv) trucks, trailers and railcars. Includes capital and operating 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 $855 million associated with an agreement to transport crude oil on a pipeline that is owned by an equity method investee, in which we own a 50% interest. Our commitment to transport is supported by crude oil buy/sell agreements with third parties (including Oxy) with commensurate quantities.

(4) Amounts are primarily based on estimated volumes and market prices based on average activity during December 2016 . 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 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, 2016 and 2015 , we had outstanding letters of credit of approximately $73 million and $46 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. Certain of these entities are borrowers under credit facilities. We are neither a co-borrower nor a guarantor under any such facilities. 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, 2016 (unaudited, dollars in millions):

Entity	Type of Operation	Our Ownership Interest	Total Entity Assets	Total Cash and Restricted Cash	Total Entity Debt
Settoon Towing, LLC (“Settoon”) (1)	Barge Transportation Services	50%	$ 318	$ —	$ 201
BridgeTex Pipeline Company, LLC	Crude Oil Pipeline	50%	$ 920	$ 31	$ —
Caddo Pipeline LLC	Crude Oil Pipeline	50%	$ 125	$ 2	$ —
Cheyenne Pipeline LLC	Crude Oil Pipeline	50%	$ 60	$ 4	$ —
Diamond Pipeline LLC	Crude Oil Pipeline	50%	$ 300	$ —	$ —
Eagle Ford Pipeline LLC	Crude Oil Pipeline	50%	$ 776	$ 17	$ —
Eagle Ford Terminals Corpus Christi LLC	Crude Oil Terminal and Dock	50%	$ 105	$ 7	$ —
Frontier Aspen LLC	Crude Oil Pipeline	50%	$ 27	$ 5	$ —
STACK Pipeline LLC	Crude Oil Pipeline	50%	$ 34	$ 6	$ —
Saddlehorn Pipeline Company, LLC	Crude Oil Pipeline	40%	$ 587	$ 53	$ —
White Cliffs Pipeline, LLC	Crude Oil Pipeline	36%	$ 568	$ 5	$ —
Butte Pipe Line Company	Crude Oil Pipeline	22%	$ 41	$ 5	$ —

(1) In February 2017, Settoon signed a definitive agreement to sell its Liquid Bulk division that is expected to close in the first half of 2017, subject to customary closing conditions, including receipt of regulatory approvals. Settoon intends to use a portion of the proceeds from such sale to pay off all of its outstanding debt.

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 and sales and managing our anticipated base gas requirements. We manage these exposures with various instruments including exchange-traded futures, swaps and options.

- *NGL and other*

  We utilize NGL derivatives, primarily butane and propane 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, 2016 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	$ (111)	$ (96)	$ 97
Natural gas	8	$ 11	$ (11)
NGL and other	(185)	$ (68)	$ 68
Total fair value	$ (288)		

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 our senior notes are fixed rate notes and thus are not subject to interest rate risk. Our variable rate debt outstanding at December 31, 2016 , approximately $1.6 billion , is subject to interest rate re-sets that range from less than one week to two months. The average interest rate on variable rate debt that was outstanding during the year ended December 31, 2016 was 1.4%, based upon rates in effect during the year. The fair value of our interest rate derivatives was a liability of $50 million as of December 31, 2016 . A 10% increase in the forward LIBOR curve as of December 31, 2016 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, 2016 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 and, at times, a portion of our debt is denominated 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 a liability of $3 million as of December 31, 2016 . A 10% increase in the exchange rate (USD-to-CAD) would have resulted in a decrease of $22 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 $22 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 our Series A preferred units is an embedded derivative that must be bifurcated from the related host contract, our partnership agreement, and recorded at fair value in our Condensed Consolidated Balance Sheets. The valuation model utilized for this embedded derivative contains inputs including our common unit price, ten-year U.S. treasury rates and default probabilities to ultimately calculate the fair value of our Series A preferred units with and without the Preferred Distribution Rate Reset Option. The fair value of this embedded derivative was a liability of $32 million as of December 31, 2016 . A 10% increase in the fair value would have an impact of $3 million. A 10% decrease in the fair value would also have an impact of $3 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, 2016 , 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, 2016 . 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 2016 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 2016 that has not previously been reported.