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 18, 2015, the closing market price for our common units was $50.73 per unit and there were approximately 236,000 record holders and beneficial owners (held in street name). As of February 18, 2015, there were 376,241,697 common units outstanding.

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. In addition, our partnership agreement was amended to modify certain definitions related to target distribution amounts and minimum distribution amounts to reflect the unit split.

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]
2014			
4th Quarter	$ 59.75	$ 43.61	$ 0.6750
3rd Quarter	$ 61.09	$ 55.98	$ 0.6600
2nd Quarter	$ 60.05	$ 54.54	$ 0.6450
1st Quarter	$ 55.30	$ 49.25	$ 0.6300
2013			
4th Quarter	$ 53.74	$ 47.26	$ 0.6150
3rd Quarter	$ 57.72	$ 48.86	$ 0.6000
2nd Quarter	$ 59.52	$ 50.15	$ 0.5875
1st Quarter	$ 57.17	$ 45.95	$ 0.5750

(1) Cash distributions associated with 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.

Cash Distribution Policy

In accordance with our partnership agreement, we will distribute all of our available cash to our unitholders within 45 days following the end of each quarter in the manner described below. 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.

In addition to distributions on its 2% general partner interest, our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, our general partner is entitled, without duplication and except for the agreed upon adjustments discussed below, to 15% of amounts we distribute in excess of $0.2250 per unit, 25% of the amounts we distribute in excess of $0.2475 per unit and 50% of amounts we distribute in excess of $0.3375 per unit.

Although not required to do so, in response to past requests by our management in connection with our acquisition activities, our general partner has, from time to time, agreed to reduce the amounts due to it as incentive distributions. Such modifications were implemented with a view toward enhancing our competitiveness for such acquisitions and managing the overall cost of equity capital while achieving an appropriate balance between short-term and long-term accretion to our limited partners and the holders of our general partner interest and IDRs. During 2014 and 2013, our general partner's incentive distributions were reduced by approximately $23 million and $15 million, respectively. These reductions were agreed to in connection with our BP NGL Acquisition and the PNG Merger. In addition, our general partner has agreed to reduce the amount of its incentive distribution by $5.5 million per quarter during 2015, $5.0 million per quarter in 2016 and $3.75 million per quarter thereafter. See Note 3 to our Consolidated Financial Statements for further discussion of the BP NGL Acquisition. See Note 11 to our Consolidated Financial Statements for further discussion of the PNG Merger.

During 2014, we paid $473 million to our general partner, including $454 million of incentive distributions, net of reductions of approximately $23 million. Additionally, on February 13, 2015, we paid a quarterly distribution of $0.6750 per limited partner unit applicable to the fourth quarter of 2014, and in connection therewith, approximately $136 million was paid to our general partner, including approximately $131 million of incentive distributions, net of reductions of $5.5 million. See Item 13. "Certain Relationships and Related Transactions, and Director Independence—Our General Partner."

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."

Issuer Purchases of Equity Securities

We did not repurchase any of our common units during the fourth quarter of 2014, 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").

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Item 6. *Selected Financial Data*

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2014, 2013, 2012, 2011 and 2010 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." See Note 3 to our Consolidated Financial Statements for a discussion of our acquisitions.

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	(in millions, except per unit data)				
Statement of operations data:					
Total revenues	$ 43,464	$ 42,249	$ 37,797	$ 34,275	$ 25,893
Net income	$ 1,386	$ 1,391	$ 1,127	$ 994	$ 514
Net income attributable to PAA	$ 1,384	$ 1,361	$ 1,094	$ 966	$ 505
Per unit data:					
Basic net income per limited partner unit	$ 2.39	$ 2.82	$ 2.41	$ 2.46	$ 1.21
Diluted net income per limited partner unit	$ 2.38	$ 2.80	$ 2.40	$ 2.44	$ 1.20
Declared distributions per limited partner unit [1]	$ 2.55	$ 2.33	$ 2.11	$ 1.95	$ 1.88
Balance sheet data (at end of period):					
Total assets	$ 22,256	$ 20,360	$ 19,235	$ 15,381	$ 13,703
Long-term debt	$ 8,762	$ 6,715	$ 6,320	$ 4,520	$ 4,631
Total debt	$ 10,049	$ 7,828	$ 7,406	$ 5,199	$ 5,957
Partners' capital	$ 8,191	$ 7,703	$ 7,146	$ 5,974	$ 4,573
Other data:					
Net cash provided by operating activities	$ 2,004	$ 1,954	$ 1,240	$ 2,365	$ 259
Net cash used in investing activities	$ (3,296)	$ (1,653)	$ (3,392)	$ (2,020)	$ (851)
Net cash provided by/(used in) financing activities	$ 1,657	$ (281)	$ 2,151	$ (345)	$ 604
Capital expenditures:					
Acquisition capital	$ 1,099	$ 19	$ 2,286	$ 1,404	$ 407
Expansion capital	$ 2,026	$ 1,622	$ 1,185	$ 531	$ 355
Maintenance capital	$ 224	$ 176	$ 170	$ 120	$ 93

	Year Ended December 31,				
	2014	2013	2012	2011	2010
Volumes [2][3]					
Transportation segment (average daily volumes in thousands of barrels per day):					
Tariff activities	3,952	3,595	3,373	2,942	2,889
Trucking	127	117	106	105	97
Transportation segment total	4,079	3,712	3,479	3,047	2,986
Facilities segment:					
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	95	94	90	70	61
Rail load / unload volumes (average volumes in thousands of barrels per day)	231	221	—	—	—
Natural gas storage (average monthly working capacity in billions of cubic feet)	97	96	84	71	47
NGL fractionation (average volumes in thousands of barrels per day)	96	96	79	14	14
Facilities segment total (average monthly volumes in millions of barrels)	121	120	106	82	70
Supply and Logistics segment (average daily volumes in thousands of barrels per day):					
Crude oil lease gathering purchases	949	859	818	742	620
NGL sales	208	215	182	103	96
Waterborne cargos	—	4	3	21	68
Supply and Logistics segment total	1,157	1,078	1,003	866	784

(1) Represents cash distributions declared and paid during the year presented. Our general partner is entitled, directly or indirectly, to receive 2% proportional distributions, as well as incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. See Note 11 to our Consolidated Financial Statements for further discussion regarding our distributions.

(2) Volumes associated with acquisitions represent total volumes (attributable to our interest) for the number of days or months we actually owned the assets 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
    - Company Overview
    - Overview of Operating Results, Capital Investments and Other Significant Activities
- Acquisitions and Capital Projects
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements
- Results of Operations
- Outlook
- Liquidity and Capital Resources

Executive Summary

Company Overview

We own and operate midstream energy infrastructure and provide logistics services for crude oil, NGL, natural gas and refined products. The term NGL includes ethane and natural gasoline products as well as products commonly referred to as liquefied petroleum gas ("LPG") such as propane and butane. When used in this Form 10-K, NGL refers to all NGL products including LPG. 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

Primarily as a result of advances in drilling and completion techniques and their application to a number of large-scale shale and resource plays occurring contemporaneously with attractive crude oil and liquids prices, U.S. crude oil and liquids production over the last several years increased rapidly in multiple regions in the lower 48 states. Additionally, the crude oil market periodically experienced high levels of volatility in location and quality differentials as a result of the confluence of regional infrastructure constraints in North America, rapid and unexpected changes in crude oil qualities, international supply issues and regional downstream operating issues.

During 2013 and 2014, these market conditions had a positive impact on our profitability as our business strategy and asset base positioned us to capitalize on opportunities created by the volatile environment. In 2014, we recognized net income attributable to PAA of $1.384 billion as compared to net income attributable to PAA of $1.361 billion recognized in 2013. The year-over-year change in operating results was due to growth in our fee-based Transportation segment partially offset by less favorable results from our Supply and Logistics and Facilities segments (see further discussion of our segment operating results in the following sections). Net income attributable to PAA for 2014 was also impacted by:

- Higher depreciation and amortization expense and interest expense associated with our growing asset base and related financing activities;

- Increased income tax expense resulting from higher year-over-year earnings from our taxable Canadian operations; and

- Decreased net income attributable to noncontrolling interests due to our completion of the PNG Merger in 2013.

We have continued to invest in midstream infrastructure projects to address the need for additional pipeline takeaway capacity and to address associated logistical challenges, resulting in the execution of a $2.0 billion capital program during 2014. We also completed the acquisition of a 50% interest in BridgeTex in November 2014 for $1.088 billion. The majority of the capital spent in 2014 will contribute to growth in our fee-based Transportation and Facilities segments in future years. In addition, during the year, we paid $1.4 billion of cash distributions to our limited partners and general partner.

We funded our 2014 capital activities with the issuance of approximately 15.4 million common units under our continuous offering program for net proceeds of $866 million, and the completion of multiple senior notes offerings for net proceeds of approximately $2.6 billion.

During late 2014 and early 2015, crude oil and NGL prices decreased meaningfully, which resulted in significant reductions in the outlook for producer drilling activities in 2015. See "—Outlook" for a discussion of how such developments may impact our business.

Acquisitions and Capital Projects

We completed a number of acquisitions and capital projects in 2014, 2013 and 2012 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,		
	2014	**2013**	**2012**
Acquisition capital [1] [2]	$ 1,099	$ 19	$ 2,286
Expansion capital [3]	2,026	1,622	1,185
Maintenance capital [3]	224	176	170
	$ 3,349	$ 1,817	$ 3,641

(1) Includes our acquisition for $1.088 billion of a 50% interest in BridgeTex. We account for our interest in BridgeTex under the equity method of accounting. Acquisitions of initial investments in unconsolidated entities are included in "Acquisition capital." Additional subsequent investments in unconsolidated entities related to expansion projects of such entities are recognized in "Expansion capital."

(2) Excludes the PNG Merger completed on December 31, 2013, as we historically consolidated PNG into our financial statements for financial reporting purposes in accordance with GAAP. As consideration for the PNG Merger, we issued approximately 14.7 million PAA common units with a value of approximately $760 million. See Note 11 to our Consolidated Financial Statements for further discussion of the PNG Merger.

(3) 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. Businesses acquired impact our results of operations commencing on the closing date of each acquisition. Our acquisition and capital expansion activities are discussed further in "—Liquidity and Capital Resources" and in Note 3 to our Consolidated Financial Statements. Information regarding acquisitions completed in 2014, 2013 and 2012 is set forth in the table below (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
BridgeTex Acquisition (50% interest) [1]	11/14/2014	$ 1,088	Transportation
Other	Various	11	Facilities
2014 Total		$ 1,099	
2013 Total [2]	09/01/2013	$ 19	Transportation
BP NGL Acquisition [3]	04/01/2012	$ 1,633	Transportation, Facilities and Supply and Logistics
US Development Group Crude Oil Rail Terminals	12/13/2012	503	Facilities
Other	Various	150	Transportation, Facilities and Supply and Logistics
2012 Total		$ 2,286	

(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.

(2) Excludes the PNG Merger completed on December 31, 2013, as we historically consolidated PNG into our financial statements for financial reporting purposes in accordance with GAAP. As consideration for the PNG Merger, we issued approximately 14.7 million PAA common units with a value of approximately $760 million. See Note 11 to our Consolidated Financial Statements for further discussion of the PNG Merger.

(3) Total BP NGL Acquisition purchase price was approximately $1.683 billion. A cash deposit of $50 million was paid during 2011.

Expansion Capital Projects

Our 2014 projects primarily included the construction and expansion of pipeline systems and storage and terminal facilities. The following table summarizes our 2014, 2013 and 2012 projects (in millions):

Projects	2014	2013	2012
Permian Basin Area Projects [1]	$ 378	$ 59	$ 91
Cactus Pipeline [1]	350	64	—
Rail Terminal Projects [1] [4]	239	149	59
Fort Saskatchewan Facility Projects / NGL Line [1]	142	73	—
Eagle Ford JV Project [1] [3]	117	60	132
Western Oklahoma Pipeline	80	50	—
Mississippian Lime Pipeline	58	163	54
White Cliffs Expansion [5]	41	73	1
Line 63 Reactivation [1]	32	12	—
Diamond Pipeline [1]	29	3	—
Pascagoula Pipeline	26	125	13
St. James Terminal Expansions	25	51	46
Cushing Terminal Expansions [1]	13	38	31
Eagle Ford Area Projects [1] [2]	10	86	88
Rainbow II Pipeline	3	124	79
Other projects	483	492	591
Total	$ 2,026	$ 1,622	$ 1,185

(1) These projects will continue into 2015. See "—Liquidity and Capital Resources—Acquisitions, Capital Expenditures and Distributions Paid to Our Unitholders, General Partner and Noncontrolling Interests—2015 Capital Projects."

(2) Includes pipeline, tankage and condensate stabilization.

(3) Includes net expenditures associated with the formation of Eagle Ford Pipeline LLC in 2012, as well as subsequent contributions related to our 50% interest.

(4) Includes Bakersfield, CA; Carr, CO; Manitou, ND; Van Hook, ND; Yorktown, VA; and Kerrobert, Canada rail projects.

(5) Represents contributions related to our 35.7% investment interest in the White Cliffs Pipeline.

The overall increase in our expansion capital expenditures over the periods presented was primarily driven by our 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. A majority of the expansion capital spent in the years presented was invested in our fee-based Transportation and Facilities segments.

We expect to spend approximately $1.85 billion for expansion capital in 2015. See "—Liquidity and Capital Resources—Acquisitions, Capital Expenditures and Distributions Paid to Our Unitholders, General Partner and Noncontrolling Interests—2015 Capital Projects" 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 generally accepted accounting principles in the United States ("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 United States Securities and Exchange Commission ("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) purchase and sales accruals, (ii) fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (iii) fair value of derivatives, (iv) accruals and contingent liabilities, including our equity-indexed compensation plan accruals, (v) property and equipment and depreciation expense, (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:

Purchase and Sales Accruals. We routinely make accruals based on estimates for certain components of our revenues and cost of sales due to the timing of compiling billing information, receiving third-party information and reconciling our records with those of third parties. Where applicable, these accruals are based on nominated volumes expected to be purchased, transported and subsequently sold. Uncertainties involved in these estimates include levels of production at the wellhead, access to certain qualities of crude oil, pipeline capacities and delivery times, utilization of truck fleets to transport volumes to their destinations, weather, market conditions and other forces beyond our control. These estimates are generally associated with a portion of the last month of each reporting period. For the year ended December 31, 2014, we estimate that approximately 1% of annual revenues and cost of sales were recorded using sales and purchase estimates. Accordingly, a hypothetical variance of 10% from both of these estimates, either up or down in tandem, would impact annual revenues, cost of sales, operating income and net income attributable to PAA by less than 1% on an annual basis. Although the resolution of these uncertainties has not historically had a material impact on our reported results of operations or financial condition, because of the high volume, low margin nature of our business, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Variances from estimates are reflected in the period actual results become known, typically in the month following the estimate.

Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets. In accordance with Financial Accounting Standards Board ("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 our 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.

Impairment testing entails estimating future net cash flows relating to the asset, based on management's estimate of future revenues, future cash flows and market conditions including pricing, demand, competition, operating costs and other factors. Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer relationships, contracts and industry expertise, 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. 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. 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. We perform our goodwill impairment test annually (as of June 30) and when events or changes in circumstances indicate that the carrying value may not be recoverable. Through our annual testing of goodwill for potential impairment, which also includes a sensitivity analysis regarding the excess of our reporting unit's fair value over book value, we determined that the fair value of each reporting unit was substantially greater than its respective book value, and therefore goodwill was not considered impaired. See Note 7 to our Consolidated Financial Statements for a further discussion of goodwill.

Fair Value of Derivatives. Our derivatives that are not elected for the normal purchases and normal sales scope exception are reported at fair value as either assets or liabilities with changes in fair value recognized in either earnings or accumulated other comprehensive income / loss (“AOCI”). 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. 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. 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 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 including, but not limited to, environmental remediation and governmental penalties, asset retirement obligations, equity-indexed compensation plan accruals (as further discussed below), bonus accruals and potential legal claims. 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, and the possibility of existing legal claims giving rise to additional claims. 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 $15 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 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 $98 million, $116 million and $101 million in 2014, 2013 and 2012, 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 and Depreciation Expense. 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 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.

During 2014, 2013 and 2012, we recognized losses on impairments of long-lived assets of $10 million, $20 million and $168 million, respectively. The impairments recognized in 2014 and 2013 primarily related to assets that were taken out of service. These assets did not support spending the capital necessary to continue service and, in some instances, we utilized other assets to handle these activities. The impairments recognized in 2012 primarily related to our Pier 400 terminal project and the anticipated sale of certain refined products pipeline systems and related assets. See Note 6 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 $5 million in the aggregate over the years ended December 31, 2014, 2013 and 2012) 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 are valued at the lower of cost or market, with cost determined using an average cost method within specific inventory pools. At the end of each reporting period, we assess the carrying value of our inventory and 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 also 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, 2014, 2013 and 2012, we recorded charges of $289 million, $7 million and $128 million, respectively, related to the valuation adjustment of our crude oil, NGL and natural gas inventory due to declines in prices. See Note 5 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.

Results of Operations

Analysis of Operating Segments

We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates such segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 19 to our Consolidated Financial Statements for a definition of segment profit (including an explanation of why this is a performance measure) and a reconciliation of segment profit 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.

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

	Year Ended December 31,			Favorable/(Unfavorable) Variance			
				2014-2013		2013-2012	
	2014	2013	2012	$	%	$	%
Transportation segment profit	$ 925	$ 729	$ 710	$ 196	27%	$ 19	3%
Facilities segment profit	584	616	482	(32)	(5)%	134	28%
Supply and Logistics segment profit	782	822	753	(40)	(5)%	69	9%
Total segment profit	2,291	2,167	1,945	124	6%	222	11%
Depreciation and amortization	(392)	(375)	(482)	(17)	(5)%	107	22%
Interest expense, net	(340)	(303)	(288)	(37)	(12)%	(15)	(5)%
Other income/(expense), net	(2)	1	6	(3)	(300)%	(5)	(83)%
Income tax expense	(171)	(99)	(54)	(72)	(73)%	(45)	(83)%
Net income	1,386	1,391	1,127	(5)	—%	264	23%
Net income attributable to noncontrolling interests	(2)	(30)	(33)	28	93%	3	9%
Net income attributable to PAA	$ 1,384	$ 1,361	$ 1,094	$ 23	2%	$ 267	24%
Net income attributable to PAA:							
Basic net income per limited partner unit	$ 2.39	$ 2.82	$ 2.41	$ (0.43)	(15)%	$ 0.41	17%
Diluted net income per limited partner unit	$ 2.38	$ 2.80	$ 2.40	$ (0.42)	(15)%	$ 0.40	17%
Basic weighted average limited partner units outstanding	367	341	325	26	8%	16	5%
Diluted weighted average limited partner units outstanding	369	343	328	26	8%	15	5%

Non-GAAP Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses additional measures that are 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 adjusted earnings before interest, taxes, depreciation and amortization (“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 in conjunction with related GAAP financial measures, (i) provide additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and planning 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 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), (iii) inventory valuation 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. We have defined all such items hereinafter as “Selected Items Impacting Comparability.” These additional financial measures are reconciled to the most directly comparable measures 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 non-GAAP financial measures that are reconciled to the most directly comparable GAAP measures (in millions):

	Year Ended December 31,			Favorable/(Unfavorable) Variance			
				2014-2013		2013-2012	
	2014	2013	2012	$	%	$	%
Net income	$ 1,386	$ 1,391	$ 1,127	$ (5)	—%	$ 264	23%
Add:							
Interest expense, net	340	303	288	37	12%	15	5%
Income tax expense	171	99	54	72	73%	45	83%
Depreciation and amortization	392	375	482	17	5%	(107)	(22)%
EBITDA	$ 2,289	$ 2,168	$ 1,951	$ 121	6%	$ 217	11%
Selected Items Impacting Comparability of EBITDA							
Gains/(losses) from derivative activities net of inventory valuation adjustments [(1)]	$ 243	$ (59)	$ (74)	$ 302	512%	$ 15	20%
Long-term inventory valuation adjustments [(2)]	(85)	—	—	(85)	N/A	—	N/A
Equity-indexed compensation expense [(3)]	(56)	(63)	(59)	7	11%	(4)	(7)%
Net loss on foreign currency revaluation [(4)]	(13)	(1)	(7)	(12)	(1,200)%	6	86%
Significant acquisition-related expenses	—	—	(14)	—	N/A	14	100%
Other [(5)]	—	(1)	(2)	1	100%	1	50%
Selected Items Impacting Comparability of EBITDA	$ 89	$ (124)	$ (156)	$ 213	172%	$ 32	21%
EBITDA	$ 2,289	$ 2,168	$ 1,951	$ 121	6%	$ 217	11%
Selected Items Impacting Comparability of EBITDA	(89)	124	156	(213)	(172)%	(32)	(21)%
Adjusted EBITDA	$ 2,200	$ 2,292	$ 2,107	$ (92)	(4)%	$ 185	9%
Adjusted EBITDA	$ 2,200	$ 2,292	$ 2,107	$ (92)	(4)%	$ 185	9%
Interest expense, net	(340)	(303)	(288)	(37)	(12)%	(15)	(5)%
Maintenance capital [(6)]	(224)	(176)	(170)	(48)	(27)%	(6)	(4)%
Current income tax expense	(71)	(100)	(53)	29	29%	(47)	(89)%
Equity earnings in unconsolidated entities, net of distributions	(3)	(10)	2	7	70%	(12)	(600)%
Distributions to noncontrolling interests [(7)]	(3)	(38)	(48)	35	92%	10	21%
Implied DCF	$ 1,559	$ 1,665	$ 1,550	$ (106)	(6)%	$ 115	7%
Less: Distributions paid [(7)]	(1,469)	(1,215)	(1,017)				
DCF Excess/(Shortage) [(8)]	$ 90	$ 450	$ 533				

(1) 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. We also exclude the impact of corresponding inventory valuation adjustments, as applicable. See Note 12 to our Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities.

(2) We carry approximately 4 million barrels of 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) as a Selected Item Impacting Comparability of EBITDA. During the fourth quarter of 2014, crude oil and NGL prices decreased significantly resulting in an inventory valuation adjustment. See Note 5 to our Consolidated Financial Statements for additional inventory disclosures.

(3) 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 earnings 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 earnings per unit calculation 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.

(4) During 2014, 2013 and 2012, 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 selected items impacting comparability. See Note 12 to our Consolidated Financial Statements for further discussion regarding our currency exchange rate risk hedging activities.

(5) Includes other immaterial selected items impacting comparability.

(6) 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.

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

(8) Excess DCF is retained to establish reserves for future distributions, capital expenditures and other partnership purposes.

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 for the periods indicated:

Operating Results [1] **(in millions, except per barrel data)**	**Year Ended December 31, 2014**	**2013**	**2012**	**Favorable/(Unfavorable) Variance 2014-2013 $**	**%**	**2013-2012 $**	**%**
Revenues							
Tariff activities	$ 1,447	$ 1,293	$ 1,232	$ 154	12%	$ 61	5%
Trucking	208	205	184	3	1%	21	11%
Total transportation revenues	1,655	1,498	1,416	157	10%	82	6%
Costs and Expenses							
Trucking costs	(151)	(147)	(134)	(4)	(3)%	(13)	(10)%
Field operating costs [2]	(560)	(528)	(468)	(32)	(6)%	(60)	(13)%
Equity-indexed compensation expense - operations	(15)	(18)	(16)	3	17%	(2)	(13)%
Segment general and administrative expenses [2] [3]	(83)	(101)	(96)	18	18%	(5)	(5)%
Equity-indexed compensation expense - general and administrative	(29)	(39)	(30)	10	26%	(9)	(30)%
Equity earnings in unconsolidated entities	108	64	38	44	69%	26	68%
Segment profit	$ 925	$ 729	$ 710	$ 196	27%	$ 19	3%
Maintenance capital	$ 165	$ 123	$ 108	$ (42)	(34)%	$ (15)	(14)%
Segment profit per barrel	$ 0.62	$ 0.54	$ 0.56	$ 0.08	15%	$ (0.02)	(4)%

Average Daily Volumes (in thousands of barrels per day) [4]	Year Ended December 31,			Favorable/(Unfavorable) Variance 2014-2013		Favorable/(Unfavorable) Variance 2013-2012	
	2014	2013	2012	Volumes	%	Volumes	%
Tariff activities							
Crude Oil Pipelines							
All American	37	40	33	(3)	(8)%	7	21%
Bakken Area Systems	149	131	130	18	14%	1	1%
Basin / Mesa / Sunrise	733	718	696	15	2%	22	3%
BridgeTex	14	—	—	14	N/A	—	N/A
Capline	152	151	146	1	1%	5	3%
Eagle Ford Area Systems	227	102	23	125	123%	79	343%
Line 63 / Line 2000	122	113	128	9	8%	(15)	(12)%
Manito	47	46	57	1	2%	(11)	(19)%
Mid-Continent Area Systems	348	281	271	67	24%	10	4%
Permian Basin Area Systems	765	581	461	184	32%	120	26%
Rainbow	112	124	145	(12)	(10)%	(21)	(14)%
Rangeland	65	60	62	5	8%	(2)	(3)%
Salt Lake City Area Systems	136	131	149	5	4%	(18)	(12)%
South Saskatchewan	62	51	60	11	22%	(9)	(15)%
White Cliffs	30	23	18	7	30%	5	28%
Other	767	725	703	42	6%	22	3%
NGL Pipelines							
Co-Ed	58	56	44	2	4%	12	27%
Other	128	194	131	(66)	(34)%	63	48%
Refined Products Pipelines	—	68	116	(68)	(100)%	(48)	(41)%
Tariff activities total	3,952	3,595	3,373	357	10%	222	7%
Trucking	127	117	106	10	9%	11	10%
Transportation segment total	4,079	3,712	3,479	367	10%	233	7%

(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) Volumes associated with assets employed through acquisitions and capital expansion projects represent total volumes (attributable to our interest) for the number of days we employed the assets divided by the number of days in the period.

Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment profit generated by our tariff and other fee-related activities depends 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. Revenue from our pipeline capacity agreements generally reflects a negotiated amount.

The following is a discussion of items impacting Transportation segment profit and segment profit per barrel for the periods indicated.

Net Operating Revenues and Volumes. As noted in the table above, our total Transportation segment revenues, net of trucking costs, and volumes increased year-over-year for each comparative period presented. Our Transportation segment results were impacted by the following for the years ended December 31, 2014, 2013 and 2012:

- North American Crude Oil Production— During the years ended December 31, 2014 and 2013, the increase in North American crude oil production had a favorable impact on our results over the comparative periods presented. We experienced increased volumes and revenues on our existing pipeline systems, as well as incremental volumes and revenues from the expansion of certain of our pipelines systems, the construction of new pipelines and increased interconnectivity in the Permian Basin as a result of increased opportunities for midstream infrastructure development in production growth areas. For each of the comparative year-over-year periods presented, we experienced increased volumes, most notably on our Permian Basin Area Systems, Eagle Ford Area Systems (including the Eagle Ford pipeline) and certain pipelines included in our Mid-Continent Area Systems, as well as incremental revenue from increased pumpover movements at our Basin pipeline terminal. We estimate that the impact of increased production and related midstream infrastructure development increased our revenues by $95 million for the year ended December 31, 2014 over the year ended December 31, 2013 and $40 million for the year ended December 31, 2013 period over the year ended December 31, 2012.

- Loss Allowance Revenue — 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 revenues. The loss allowance revenue increased by $46 million for 2014 over 2013 and was primarily driven by higher volumes. The loss allowance revenue decreased by $23 million for 2013 compared to 2012 primarily due to a lower average realized price per barrel.

- Rate Changes — Revenues on our pipelines are impacted by various rate changes that occur during the period. These primarily include the indexing of rates on our FERC regulated pipelines, rate increases or decreases on our intrastate and Canadian pipelines or other negotiated rate changes. We estimate that the net impact of rate changes on our pipelines increased revenues by $40 million and $50 million during the year ended December 31, 2014 compared to 2013 and the year ended December 31, 2013 compared to 2012, respectively.

- Sale of Refined Products Pipelines — We sold certain refined products pipeline systems and related assets in July 2013 and November 2013. For the year ended December 31, 2013 compared to the year ended December 31, 2012, revenues and volumes on our refined products pipelines were lower by $15 million and 48,000 barrels per day, respectively, primarily due to the sale of such pipelines and related assets. As we did not own these assets during 2014, our revenues were lower by $28 million and volumes were lower by 68,000 barrels per day as compared to the year ended December 31, 2013.

- Foreign Exchange Impact — Revenues and expenses from our Canadian based subsidiaries, which use the Canadian dollar as their functional currency, are translated at the prevailing average exchange rates for each month. The average CAD to USD exchange rates for 2014, 2013 and 2012 were $1.10 CAD: $1.00 USD, $1.03 CAD: $1.00 USD, and $1.00 CAD: $1.00 USD, respectively. Therefore, we estimate that revenues from our Canadian pipeline systems and trucking operations were unfavorably impacted by $28 million for the year ended December 31, 2014 compared to the year ended December 31, 2013 and by $13 million for the year ended December 31, 2013 compared to the year ended December 31, 2012 due to the depreciation of the Canadian dollar relative to the U.S. dollar.

- BP NGL Acquisition Assets — We acquired pipelines through the BP NGL Acquisition completed on April 1, 2012. These assets contributed $27 million of additional tariff revenues for the year ended December 31, 2013 over the year ended December 31, 2012, which was primarily related to the benefit from a full period of ownership of these assets (as we only owned the assets for nine months of 2012). This increase excludes the unfavorable impacts on our Co-Ed pipeline related to (i) rate changes and (ii) weather-related downtime, as discussed below.

- Weather-Related Downtime — During the second and third quarters of 2013, our Rangeland, South Saskatchewan and Co-Ed pipelines in Canada were shut down due to high river flow rates and flooding in the surrounding area. We estimate that the downtime on these pipelines negatively impacted revenues and volumes by $15 million to $20 million and 15,000 to 20,000 barrels per day, respectively, for the year ended December 31, 2013. Similar weather-related downtime did not occur during the years ended December 31, 2014 or 2012 and, therefore, we experienced more favorable results in those periods as compared to the year ended December 31, 2013.

- Rail Impact — Volumes and revenues, primarily on our Manito and Rainbow pipelines and certain pipelines included in our Bakken Area Systems, were unfavorably impacted by producer decisions to deliver more crude oil to rail loading facilities in the area during the year ended December 31, 2013 compared to the year ended December 31, 2012. We estimate that volumes decreased by approximately 25,000 to 30,000 barrels per day and the impact to revenues was a decrease of $20 million over the comparative periods. During the year ended December 31, 2014, we did not experience the same decrease in volumes on these pipelines as compared to the prior period, and we also experienced favorable impacts on our South Saskatchewan pipeline related to producer decisions to deliver more crude oil via pipeline as opposed to using competing alternatives such as rail.

Additional noteworthy volume and revenue variances for the year ended December 31, 2014 compared to 2013 include (i) additional revenues of $12 million resulting from a reclassification of certain of our Canadian storage facilities from our Facilities segment to our Transportation segment during the second quarter of 2014 (ii) incremental volumes and revenues from our Pascagoula, Wascana and Bakken North pipelines, which were placed into service during the second quarter of 2014, (iii) decreased volumes and revenues on certain of our NGL pipelines due to (a) the discontinuation in the fourth quarter of 2013 of an agreement to transport volumes on a pipeline and (b) the impact of netting joint venture related volumes to our share on a pipeline during 2014, which did not affect revenues and (iv) decreased volumes on our Rainbow pipeline due to (a) lower producer volumes and (b) operational issues during September 2014; however, the unfavorable revenue impact of these decreases in volumes on Rainbow pipeline was offset by favorable revenue variances from an increase in tariff rates and the reclassification of a storage facility from our Facilities segment, the impacts of both of which are discussed above.

Additional noteworthy volume and revenue variances for the year ended December 31, 2013 compared to 2012 include (i) increased volumes and revenues on our All American pipeline due to higher production levels in 2013 coupled with lower maintenance activities at the production facilities in 2013 compared to 2012, (ii) decreases on the Salt Lake City Area Systems and our Line 63 and Line 2000 pipelines due to refinery maintenance issues and lower refinery demand for pipeline barrels; however, revenues on Line 63 pipeline were consistent with 2012 results due to movements on higher tariff segments and (iii) increased trucking activity due to increased demand for production transported to rail terminals and hauls from pipeline disruptions.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) increased during the year ended December 31, 2014 compared to the year ended December 31, 2013 primarily due to (i) a change in classification of $14 million of certain costs from General and administrative expenses, (ii) increased asset integrity spending, (iii) higher property tax expense due to capital expansion and (iv) higher utility costs associated with increased throughput volumes. The increase in operating costs for the comparative year ended periods was partially offset by a reduction in environmental remediation costs and an $11 million favorable impact of foreign exchange.

Field operating costs (excluding equity-indexed compensation expense) increased during the year ended December 31, 2013 compared to the year ended December 31, 2012 primarily due to (i) higher environmental response, remediation and related repair expenses associated with pipeline releases of $21 million, (ii) higher integrity management expenses associated with smart pigging and other integrity work, (iii) higher payroll costs, primarily due to the BP NGL Acquisition and increased headcount and (iv) $4 million of cost incurred associated with the testing of certain lines that we considered bringing back into service. Excluding the impacts of the environmental response and remediation expenses, field operating costs in general remained relatively consistent on a per barrel basis during the comparable annual periods.

General and Administrative Expenses. General and administrative expenses (excluding equity-indexed compensation expenses) decreased during the year ended December 31, 2014 over the year ended December 31, 2013 due to a change in classification of $14 million of certain costs to Field operating costs and a $5 million favorable impact of foreign exchange.

General and administrative expenses (excluding equity-indexed compensation expenses) increased during the year ended December 31, 2013 over the year ended December 31, 2012 due to the continued overall growth of the segment and legal fees incurred in connection with the sale of certain of our refined products pipelines in 2013.

Equity-Indexed Compensation Expenses. A majority of our equity-indexed compensation awards (including the AAP Management Units) contain performance conditions contingent upon achieving certain distribution levels. For awards with performance conditions (such as distribution targets), expense is accrued over the service period only if the performance condition is considered probable of occurring. When awards with performance conditions that were previously considered improbable become probable, we incur additional expense in the period that our probability assessment changes. This is necessary to bring the accrued liability associated with these awards up to the level it would have been if we had been accruing for these awards since the grant date. At December 31, 2014 and 2013, we determined that PAA distribution levels of $2.90 and $2.75 per unit, respectively, were probable of occurring. Furthermore, a change in unit price impacts the fair value of our liability-classified awards. See Note 16 to our Consolidated Financial Statements for additional information regarding our equity-indexed compensation plans.

On a consolidated basis, equity-indexed compensation expense decreased by approximately $18 million for the year ended December 31, 2014 over the year ended December 31, 2013 primarily due to the impact of the decrease in unit price during the year ended December 31, 2014 compared to the impact of the increase in unit price during the year ended December 31, 2013. Equity-indexed compensation expense increased by approximately $15 million for the year ended December 31, 2013 compared to the year ended December 31, 2012, primarily due to the following: (i) a more significant impact of the increase in unit price during the year ended December 31, 2013 compared to the impact of the increase during the year ended December 31, 2012, (ii) a greater number of units deemed probable of vesting for the year ended December 31, 2013 compared to the year ended December 31, 2012 and (iii) a higher average fair value per unit for those units deemed probable of vesting for the year ended December 31, 2013 compared to the year ended December 31, 2012.

Equity Earnings in Unconsolidated Entities. The favorable variance in equity earnings in unconsolidated entities for the year ended December 31, 2014 compared to the year ended December 31, 2013 was primarily driven by (i) increased throughput on the Eagle Ford pipeline as a result of increased crude oil production, as discussed above, (ii) increased throughput on the White Cliffs pipeline due to an expansion of the pipeline that was placed into service in July 2014, and (iii) earnings from our interest in BridgeTex, which we acquired in November 2014.

The favorable variance for the year ended December 31, 2013 compared to the year ended December 31, 2012 was largely due to (i) increased throughput on the Eagle Ford and White Cliffs pipelines as a result of increased production, as discussed above and (ii) increased capacity related to vessel additions and increased rates on services provided by Settoon Towing.

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 increase in maintenance capital in 2014 compared to 2013 is primarily due to pipeline replacement projects and increased investments in pipeline integrity. The increase in maintenance capital in 2013 compared to 2012 is primarily due to increased investments on pipeline integrity projects.

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 and processing arrangements.

The following tables set forth our operating results from our Facilities segment for the periods indicated:

Operating Results [1] (in millions, except per barrel data)	Year Ended December 31, 2014	2013	2012	Favorable/(Unfavorable) Variance 2014-2013 $	%	2013-2012 $	%
Revenues	$ 1,127	$ 1,075	$ 868	$ 52	5%	$ 207	24%
Natural gas sales [2]	—	302	230	(302)	(100)%	72	31%
Storage related costs (natural gas related)	(55)	(16)	(22)	(39)	(244)%	6	27%
Natural gas sales costs [2]	—	(296)	(216)	296	100%	(80)	(37)%
Field operating costs [3]	(404)	(362)	(289)	(42)	(12)%	(73)	(25)%
Equity-indexed compensation expense - operations	(4)	(2)	(2)	(2)	(100)%	—	—%
Segment general and administrative expenses [3] [4]	(60)	(63)	(64)	3	5%	1	2%
Equity-indexed compensation expense - general and administrative	(20)	(22)	(23)	2	9%	1	4%
Segment profit	$ 584	$ 616	$ 482	$ (32)	(5)%	$ 134	28%
Maintenance capital	$ 52	$ 38	$ 49	$ (14)	(37)%	$ 11	22%
Segment profit per barrel	$ 0.40	$ 0.43	$ 0.38	$ (0.03)	(7)%	$ 0.05	13%

Volumes (5)	Year Ended December 31, 2014	2013	2012	Favorable/(Unfavorable) Variance 2014-2013 Volumes	2014-2013 %	2013-2012 Volumes	2013-2012 %
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	95	94	90	1	1%	4	4%
Rail load / unload volumes (average volumes in thousands of barrels per day)	231	221	—	10	5%	221	N/A
Natural gas storage (average monthly working capacity in billions of cubic feet)	97	96	84	1	1%	12	14%
NGL fractionation (average volumes in thousands of barrels per day)	96	96	79	—	—%	17	22%
Facilities segment total (average monthly volumes in millions of barrels) (6)	121	120	106	1	1%	14	13%

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

(2) Effective January 1, 2014, our natural gas sales and costs, primarily attributable to the activities performed by our natural gas storage commercial optimization group, are reported in our Supply and Logistics segment.

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

(4) 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.

(5) Volumes associated with assets employed through acquisitions and capital expansion projects represent total volumes for the number of months we employed the assets divided by the number of months in the period.

(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 profit and segment profit per barrel for the periods indicated.

Net Operating Revenues and Volumes. As noted in the table above, our Facilities segment revenues, less storage related costs, and volumes increased year-over-year for each comparative period presented, albeit with a less significant increase for the year ended December 31, 2014 over the year ended December 31, 2013. Variances in net revenues and average monthly volumes between the comparative periods are discussed below:

- NGL Fractionation, NGL Storage and Natural Gas Processing Activities — Revenues increased by $31 million for the year ended December 31, 2014 over the year ended December 31, 2013 largely driven by higher facility fee revenues due to rate increases at certain of our storage and fractionation facilities, partially offset by lower physical processing gains. This increase in NGL revenues includes estimated unfavorable foreign currency impacts of $18 million due to the depreciation of the Canadian dollar relative to the U.S. dollar. The average CAD to USD exchange rate for the year ended December 31, 2014 was $1.10 CAD: $1.00 USD and $1.03 CAD: $1.00 USD for the year ended December 31, 2013.

  Our NGL fractionation plants, storage and processing facilities and related assets were primarily acquired through the BP NGL Acquisition completed in April 2012. These assets contributed $87 million of aggregate revenues for the year ended December 31, 2013 over the year ended December 31, 2012, primarily due to the benefit from a full period of ownership of these assets in 2013 (as we only owned the assets for nine months of 2012), as well as from physical processing gains recognized primarily at certain of our NGL fractionation facilities.

- Natural Gas Storage Operations — Net revenues decreased by $43 million for the year ended December 31, 2014 compared to the year ended December 31, 2013 primarily due to (i) less favorable storage rates on contracts that renewed or replaced expiring contracts, (ii) costs incurred to manage deliverability requirements in conjunction with the extended period of severe cold weather experienced during the first quarter of 2014 and (iii) lower hub services revenues due to limited market opportunities.

  Natural gas storage net revenues remained relatively consistent for the year ended December 31, 2013 compared to the year ended December 31, 2012 as less favorable storage rates largely offset incremental revenues from the expansions of our Pine Prairie and Southern Pines facilities.

- Rail Terminals — For the year ended December 31, 2014, revenues increased by $3 million over the year ended December 31, 2013 due to new rail terminals that came on line in the fourth quarter of 2013 and in 2014, substantially offset by the unfavorable impact of rail delays and lower volumes at certain of our existing rail terminals during 2014 and weather-related issues at certain of our terminals during the first quarter of 2014.

  Rail activities contributed $103 million to the increase in total revenues for the year ended December 31, 2013 over the year ended December 31, 2012 due to revenues from new terminals acquired through the USD Rail Terminal Acquisition completed in December 2012 and rail-related expansion projects placed into service during the latter portion of 2012 and 2013.

- Crude Oil Storage Activities — For the year ended December 31, 2014, revenues increased by $8 million over the year ended December 31, 2013 primarily due to increased throughput at our Cushing, Yorktown and Mobile/Ten Mile terminals and a 1.2 million barrel capacity expansion at our St. James terminal, partially offset by lower revenues from certain storage facilities in California and the East Coast due to underutilization resulting from decreased demand, as well decreased revenues of $12 million due to the reclassification of certain of our Canadian storage facilities to our Transportation segment during the second quarter of 2014.

  Revenues from our crude oil storage activities increased by $6 million for the year ended December 31, 2013 over the year ended December 31, 2012. Incremental revenues from expansion projects that were completed in phases at our Cushing, Patoka, St. James and Yorktown terminals were partially offset by decreased demand for storage at certain facilities in California and the East Coast.

- Condensate Processing Activities — Revenues increased by $8 million for the year ended December 31, 2014 compared to 2013 and by $5 million for the year ended December 31, 2013 compared to 2012 due to the benefit from the start-up and subsequent expansion of our Gardendale condensate processing facility.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expenses) increased during the year ended December 31, 2014 compared to the year ended December 31, 2013 due to (i) an increase in costs for rail activities, primarily due to new rail terminals that came online in the fourth quarter of 2013 and in 2014 as discussed above, (ii) a change in classification of $8 million of certain costs from General and administrative expenses, (iii) an increase in brine disposal costs associated with our NGL storage caverns, (iv) higher gas and power costs and (v) increased costs associated with the cancellation of certain capital projects. The effect of these increases was reduced by a $9 million favorable impact of foreign exchange.

Field operating costs (excluding equity-indexed compensation expenses) increased during the year ended December 31, 2013 compared to the year ended December 31, 2012 due to our growth through acquisitions, primarily the BP NGL and USD Rail Terminal Acquisitions. A portion of the increase was also related to additional costs for integrity and other maintenance, particularly on the assets that were part of the BP NGL Acquisition.

General and Administrative Expenses. General and administrative expenses (excluding equity-indexed compensation expenses) decreased during the year ended December 31, 2014 compared to the year ended December 31, 2013. These results reflect the net impact of a decrease due to a change in classification of $8 million of certain costs to Field operating costs during the 2014 period, partially offset by increased expenses resulting from overall growth in the segment.

Maintenance Capital. The increase in maintenance capital in 2014 from 2013 is primarily due to the timing of maintenance projects for tanks and other facility assets. The decrease in maintenance capital in 2013 from 2012 is primarily due to two major equipment replacement projects that occurred in 2012.

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, we expect our segment profit to increase or decrease directionally with (i) increases or decreases in our Supply and Logistics segment volumes (which consist of lease gathering crude oil purchase volumes, NGL sales volumes and waterborne cargos), (ii) demand for lease gathering services we provide producers 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. We do not anticipate that future changes in revenues resulting from variances in commodity prices will be a primary driver of segment profit.

The following tables set forth our operating results from our Supply and Logistics segment for the periods indicated:

Operating Results [1] [2]	Year Ended December 31,			Favorable/(Unfavorable) Variance			
				2014-2013		2013-2012	
(in millions, except per barrel data)	2014	2013	2012	$	%	$	%
Revenues	$ 42,150	$ 40,696	$ 36,440	$ 1,454	4%	$ 4,256	12%
Purchases and related costs [3]	(40,752)	(39,315)	(35,139)	(1,437)	(4)%	(4,176)	(12)%
Field operating costs [4]	(481)	(422)	(417)	(59)	(14)%	(5)	(1)%
Equity-indexed compensation expense - operations	(2)	(3)	(2)	1	33%	(1)	(50)%
Segment general and administrative expenses [4] [5]	(105)	(102)	(101)	(3)	(3)%	(1)	(1)%
Equity-indexed compensation expense - general and administrative	(28)	(32)	(28)	4	13%	(4)	(14)%
Segment profit	$ 782	$ 822	$ 753	$ (40)	(5)%	$ 69	9%
Maintenance capital	$ 7	$ 15	$ 13	$ 8	53%	$ (2)	(15)%
Segment profit per barrel	$ 1.85	$ 2.09	$ 2.05	$ (0.24)	(11)%	$ 0.04	2%

Average Daily Volumes	Year Ended December 31,			Favorable (Unfavorable) Variance			
				2014-2013		2013-2012	
(in thousands of barrels per day)	2014	2013	2012	Volume	%	Volume	%
Crude oil lease gathering purchases	949	859	818	90	10%	41	5%
NGL sales	208	215	182	(7)	(3)%	33	18%
Waterborne cargos	—	4	3	(4)	(100)%	1	33%
Supply and Logistics segment total	1,157	1,078	1,003	79	7%	75	7%

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(1) Revenues and costs include intersegment amounts.

(2) Prior to January 1, 2014, natural gas sales and costs attributable to the activities performed by our natural gas storage commercial optimization group were reported in our Facilities segment.

(3) Purchases and related costs include interest expense (related to hedged inventory purchases) of $12 million, $30 million and $12 million for the years ended December 31, 2014, 2013, and 2012, respectively.

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

(5) 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.

The following table presents the range of the NYMEX West Texas Intermediate benchmark price of crude oil during the periods indicated:

During the Year Ended December 31,	NYMEX WTI Crude Oil Price Low	NYMEX WTI Crude Oil Price High
2014	$ 53	$ 107
2013	$ 87	$ 111
2012	$ 77	$ 111

Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the sales and purchases, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those sales and purchases will not necessarily have a corresponding increase or decrease. The absolute amount of our revenues and purchases increased for the comparative periods presented, primarily resulting from higher crude oil volumes in the 2014 period and higher crude oil and NGL volumes in the 2013 period. The impact of the increase in volumes in 2014 was partially offset by lower crude oil prices relative to 2013, particularly in the fourth quarter.

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. Also, our NGL marketing 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 profit and segment profit per barrel for the periods indicated.

Net Operating Revenues and Volumes. Our Supply and Logistics segment revenues, net of purchases and related costs, increased year-over-year for each comparative period presented. The following summarizes the more significant items in the comparative periods:

- NGL Marketing Operations — Net revenues from our NGL marketing operations decreased for the year ended December 31, 2014 as compared to the year ended December 31, 2013. This decrease was driven by higher NGL purchases and related costs in the 2014 periods, primarily due to (i) a higher weighted average inventory cost, (ii) increased facility fees and (iii) a $10 million long-term inventory valuation adjustment. The long-term inventory valuation adjustment related to inventory necessary to meet our minimum 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. Additionally, NGL margins were further impacted by less favorable market conditions, most notably during (i) the second quarter of 2014, as market pricing was stronger in the comparable 2013 period due to heating requirements during a winter season that extended into the second quarter and greater petrochemical demand for propane and (ii) the fourth quarter of 2014, due to less demand for crop drying as compared to the 2013 period.

  Increased net revenues from our NGL marketing operations for the year ended December 31, 2013 as compared to the year ended December 31, 2012, were primarily due to more favorable market prices and higher demand related to (i) increases in export capacity in the U.S. that reduced overall product availability in the market, (ii) increased heating requirements during the extended winter season discussed above, (iii) heavy crop drying and (iv) petrochemical demand as well as more favorable supply contracts.

- Impact from Certain Derivative Activities, Net of Inventory Valuation Adjustments — The mark-to-market valuation of certain of our derivative activities impacted our net revenues as shown in the table below (in millions):

	Year Ended December 31, 2014	2013	2012	Variance 2014-2013	2013-2012
Gains/(losses) from certain derivative activities, net of inventory valuation adjustments [1]	$ 261	$ (59)	$ (75)	$ 320	$ 16

[1] Includes mark-to-market and other gains and losses resulting from certain derivative instruments that are related to underlying activities in future periods or the reversal of mark-to-market gains and losses from the prior period. These amounts are reduced by the net impact of inventory valuation adjustments attributable to inventory hedged by the related derivative and gains recognized in later periods on physical sales of inventory that was previously written

down. See Note 12 to our Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities.

- North American Crude Oil Production and Related Market Economics — The significant increase in crude oil and liquids-rich gas production growth in North America has created regional supply and demand imbalances due to the lack of sufficient infrastructure to support the movement of such production, which increased certain crude oil location differentials. The lack of existing pipeline takeaway capacity and associated logistical challenges created market conditions that provided opportunities to capture above-baseline margins in our supply and logistics crude oil activities over the last few years.

  Net revenues from our crude oil supply and logistics activities decreased for 2014 as compared to 2013. This decrease was driven by higher purchases and related costs, primarily due to a $75 million long-term inventory valuation adjustment. As also discussed in our NGL Marketing Operations section above, the long-term inventory valuation adjustment related to inventory necessary to meet our minimum 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. This unfavorable impact to the period was partially offset by favorable impacts from the widening of certain differentials, most notably in the second and third quarters of 2014 that allowed for more opportunities to capture above-baseline margins as compared to 2013.

  Net revenues from our crude oil supply and logistics activities also decreased for 2013 as compared to 2012. During the first quarter of 2013, the market conditions discussed above provided opportunities for increased margins. However, infrastructure additions in many of the impactful resource plays during the second and third quarters of 2013 began to relieve certain of the transportation constraints that had created opportunities for these favorable crude oil margins. Therefore, although we experienced higher crude oil lease gathering volumes in 2013 compared to 2012, we experienced fewer opportunities to capture favorable differentials from market dislocations.

  We believe the fundamentals of our business remain strong, as crude oil lease gathering purchases volumes in 2014 increased by 10% over 2013. However, as midstream infrastructure continues to be developed, we believe a normalization of margins will continue to occur as the logistics challenges are addressed. (See Items 1 and 2 “Business and Properties—Description of Segments and Associated Assets—Supply and Logistics Segment—Impact of Commodity Price Volatility and Dynamic Market Conditions on Our Business Model” included in Part I for further discussion regarding our business model, including diversification and utilization of our asset base among varying demand- and supply-driven markets.)

- Natural Gas Storage Commercial Optimization — Our natural gas storage commercial optimization activities for the year ended December 31, 2014 were 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.

Field Operating Costs. The increase in field operating costs (excluding equity-indexed compensation expenses) for the year ended December 31, 2014 over the year ended December 31, 2013 was primarily due to an increase in trucking costs associated with higher crude oil lease gathering purchases volumes and mark-to-market losses on fuel hedges.

Maintenance Capital. The decrease in maintenance capital in 2014 compared to 2013 was primarily due to reduced spending on trucking assets.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense includes losses on impairments of long-lived assets of approximately $10 million, $20 million and $168 million, for the 2014, 2013 and 2012 periods, respectively. The impairments recognized in 2014 and 2013 primarily related to assets that were taken out of service. These assets did not support spending the capital necessary to continue service and, in some instances, we utilized other assets to handle these activities. The impairments recognized in 2012 primarily related to our Pier 400 terminal project and the anticipated sale of certain refined products pipeline systems and related assets, which occurred in 2013. See Note 6 to our Consolidated Financial Statements for further discussion of asset impairments.

Excluding the impact of asset impairments, depreciation and amortization expense increased during the 2014 period over the comparable 2013 period primarily due to various recently completed capital expansion projects, as well as an acceleration of depreciation on certain pipeline assets to reflect a change in their estimated useful lives. These increases were partially offset by a reduction in amortization expense due to declining-balance amortization used for certain of our intangible assets acquired in recent years.

Excluding the impact of asset impairments, depreciation and amortization expense increased during the 2013 period over the comparable 2012 period primarily due to an increased amount of assets resulting from acquisition activities, as well as various capital expansion projects completed in recent years.

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 and included in purchases and related costs.

The following table summarizes the components impacting the interest expense variance for the years ended December 31, 2014 and 2013 (in millions, except for percentages):

		Average LIBOR Rate	Weighted Average Interest Rate [1]
Interest expense for the year ended December 31, 2012	$ 288	0.2%	5.2%
Impact of issuance of senior notes [2] [3]	47		
Impact of interest included in purchases and related costs [4]	(18)		
Impact of retirement of senior notes [5] [6]	(15)		
Impact of ineffective portion of terminated forward-starting swaps	(4)		
Other	5		
Interest expense for the year ended December 31, 2013	$ 303	0.2%	4.6%
Impact of issuance of senior notes [3] [7]	51		
Impact of interest included in purchases and related costs [4]	18		
Impact of retirement of senior notes [6]	(13)		
Impact of capitalized interest	(10)		
Other	(9)		
Interest expense for the year ended December 31, 2014	$ 340	0.1%	4.5%

(1) Excludes commitment and other fees.

(2) In March 2012, we completed the issuance of $750 million of 3.65% senior notes due 2022 and $500 million of 5.15% senior notes due 2042, and in December 2012, we completed the issuance of $400 million of 2.85% senior notes due 2023 and $350 million of 4.30% senior notes due 2043.

(3) In August 2013, we completed the issuance of $700 million of 3.85% senior notes due 2023.

(4) Interest costs attributable to borrowings for hedged inventory purchases are included in purchases and related costs in our Supply and Logistics segment profit as we consider interest on these borrowings a direct cost to storing the inventory. These costs were $12 million, $30 million and $12 million for the years ended December 31, 2014, 2013, and 2012, respectively.

(5) In September 2012, our $500 million, 4.25% senior notes matured.

(6) In December 2013, our $250 million, 5.63% senior notes matured.

(7) In April 2014, we completed the issuance of $700 million of 4.70% senior notes due 2044, in September 2014, we completed the issuance of $750 million of 3.60% senior notes due 2024 and in December 2014, we completed the issuance of $500 million of 2.60% senior notes due 2019 and $650 million of 4.90% senior notes due 2045.

Other Income/(Expense), Net

Other income/(expense), net in each of the years ended December 31, 2014, 2013 and 2012 was primarily comprised of foreign currency gains or losses related to revaluations of CAD-denominated interest receivables associated with our intercompany notes and the impact of related foreign currency hedges.

Income Tax Expense

Income tax expense increased for the year ended December 31, 2014 compared to the year ended December 31, 2013 primarily as a result of higher deferred income tax expense associated with derivative mark-to-market gains in our Canadian operations. The increased deferred income tax expense was partially offset by lower current income tax expense as a result of decreased year-over-year taxable earnings from our Canadian operations.

Income tax expense increased for year ended December 31, 2013 compared to the year ended December 31, 2012 primarily as a result of stronger performance from our existing Canadian operations and our operations related to the BP NGL Acquisition, both of which increased the proportion of earnings subject to Canadian federal and provincial taxes.

Outlook

Primarily as a result of advances in drilling and completion techniques and their application to a number of large-scale shale and resource plays occurring contemporaneously with attractive crude oil and liquids prices, U.S. crude oil and liquids production over the last several years has increased rapidly in multiple regions in the lower 48 states. This has been particularly true for light crudes and condensates. Similar resource development activities in Canada and ongoing oil sands development activities have also led to increased Canadian crude oil production. Additionally, the crude oil market has periodically experienced high levels of volatility in location and quality differentials as a result of the confluence of regional infrastructure constraints in North America, rapid and unexpected changes in crude oil qualities, international supply issues, and regional downstream operating issues. During 2013 and to a lesser degree 2014, these market conditions had a positive impact on our profitability as our business strategy and asset base positioned us to capitalize on opportunities created by the volatile environment.

However, over the last several years the combination of surging North American liquids production, relatively flat liquids production for the rest of the world and relatively modest growth in global liquids demand has led to a near to medium-term supply imbalance, which has further led to a significant and rapid reduction in petroleum prices and compression of basis differentials in a number of locations. While we believe that our business model and asset base have minimal direct exposure to petroleum prices, our performance is influenced by certain differentials and overall North American production levels, which in turn are impacted by major price movements. The meaningful decrease in crude oil prices during the second half of 2014 and early 2015 have led many producers, including producers that impact North American production levels, to significantly scale back capital programs for the next year or more. While we believe that the large North American resource base remains intact and will be developed, such production will likely take place at a slower pace and previously anticipated peak production levels will likely be reduced. This transitioning crude oil market may present challenges to our business model and asset base and may impact the rate of growth that we would have otherwise experienced over the next several years. In addition, increased competition and compressed differentials may drive lower unit margins in parts of our business, including our Supply and Logistics segment.

While we believe that these recent market developments should ultimately slow down crude oil supply growth and contribute toward bringing the markets back to equilibrium, there can be no assurance that such equilibrium will be achieved or that we will not be negatively impacted by declining crude oil supply, unfavorable volatility or challenging capital markets conditions. Additionally, construction of additional infrastructure by us and our competitors will likely continue to reduce existing infrastructure constraints, which could further reduce unit margins in our various segments, and underutilization of midstream assets resulting from continued production declines could have a similar unfavorable impact on unit margins. Finally, we cannot be certain that our expansion efforts will generate targeted returns or that any 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. 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 and general partner. 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, 2014, we had a working capital deficit of $576 million and approximately $2.6 billion of liquidity available to meet our ongoing operating, investing and financing needs as noted below (in millions):

	As of December 31, 2014
Availability under PAA senior unsecured revolving credit facility [1]	$ 1,591
Availability under PAA senior secured hedged inventory facility [1]	1,322
Amounts outstanding under PAA commercial paper program	(734)
Subtotal	2,179
Cash and cash equivalents	403
Total	$ 2,582

[1] Represents availability prior to giving effect to amounts outstanding under the PAA commercial paper program. Borrowings under the PAA commercial paper program reduce available capacity under the facility.

On January 16, 2015, we entered into a new $1.0 billion, 364-day senior unsecured credit agreement. Pursuant to the terms of the agreement, we have up to 364 days to draw on this facility and repay any loans thereunder.

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, 2014, 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 and/or the timing of settlement of our derivative activities. For example, gains and losses from settled instruments that qualify as effective cash flow hedges are deferred in AOCI, but may impact operating cash flow in the period settled. 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, 2014, 2013 and 2012 was approximately $2.0 billion, $1.95 billion and $1.24 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 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.

During 2013, we decreased the amount of our inventory, primarily due to the sale of crude oil inventory that had been stored during the contango market, as well as the sale of NGL inventory due to end users' increased demand for product used for heating and crop drying during the latter half of 2013. The net proceeds received from liquidation of such inventory during the year were used to repay borrowings under our credit facilities or commercial paper program and favorably impacted cash flow from operating activities. These decreases in inventory were partially offset by an increase in natural gas inventory whereby we retained more capacity for our own use. We primarily used borrowings under credit facilities to pay for the stored natural gas, which negatively impacted our cash flow from operating activities. Also, a significant portion of our 2013 natural gas sales occurred in December 2013, with cash collections on these sales occurring in January 2014.

During 2012, we increased the amount of our crude oil inventory, which was primarily financed through borrowings under our credit facilities. This resulted in a negative impact on our cash flow from operating activities for the period. During the year, we also increased the amount of our NGL inventory; however, these volumetric increases were offset by lower prices for such inventory stored at the end of the year compared to prior year amounts.

Credit Agreements, Commercial Paper Program and Indentures

At December 31, 2014, we had three primary credit arrangements. These include a $1.6 billion senior unsecured revolving credit facility maturing in 2019 and a $1.4 billion senior secured hedged inventory facility maturing in 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, 2014.

Additionally, in January 2015, we entered into a new $1.0 billion, 364-day senior unsecured credit agreement. See Note 10 to our Consolidated Financial Statements for additional discussion regarding our credit agreements, commercial paper program and senior notes.

Equity and Debt Financing Activities

Our financing activities primarily relate to funding acquisitions, expansion capital projects 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, 2014, we had approximately $613 million 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. During 2014, we issued four series of senior notes under the WKSI Shelf. See "Senior Notes" below.

Equity Offerings. The following table summarizes our issuance of common units in connection with marketed offerings or our Continuous Offering Program during the three years ended December 31, 2014 (net proceeds in millions):

Year	Type of Offering	Units Issued	Net Proceeds [1] [2]
2014 Total	Continuous Offering Program	15,375,810	$ 866[3]
2013 Total	Continuous Offering Program	8,644,807	$ 477[3]
2012	Continuous Offering Program	12,063,707	$ 524[3]
2012	Marketed Offering	11,500,000	455[4]
2012 Total		23,563,707	$ 979

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

(2) Amounts include our general partner's proportionate capital contributions of $18 million, $9 million and $20 million during 2014, 2013 and 2012, respectively.

(3) We pay commissions to our sales agents in connection with common unit issuances under our Continuous Offering Program. We paid $9 million, $5 million and $6 million of such commissions during 2014, 2013 and 2012, respectively. The net proceeds from these offerings were used for general partnership purposes.

(4) Offering was an underwritten transaction that required us to pay a gross spread. The net proceeds from such offering were used to fund a portion of the BP NGL Acquisition.

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]
2014	2.60% Senior Notes issued at 99.813% of face value [3]	December 2019	$ 500	$ 499	$ 495
2014	4.90% Senior Notes issued at 99.876% of face value [3]	February 2045	$ 650	$ 649	$ 643
2014	3.60% Senior Notes issued at 99.842% of face value [4]	November 2024	$ 750	$ 749	$ 743
2014	4.70% Senior Notes issued at 99.734% of face value [4]	June 2044	$ 700	$ 698	$ 691
2013	3.85% Senior Notes issued at 99.792% of face value [4]	October 2023	$ 700	$ 699	$ 693
2012	2.85% Senior Notes issued at 99.752% of face value [4]	January 2023	$ 400	$ 399	$ 396
2012	4.30% Senior Notes issued at 99.925% of face value [4]	January 2043	$ 350	$ 350	$ 346
2012	3.65% Senior Notes issued at 99.823% of face value [5]	June 2022	$ 750	$ 749	$ 742
2012	5.15% Senior Notes issued at 99.755% of face value [5]	June 2042	$ 500	$ 499	$ 494

(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 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.

(4) 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.

(5) We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities and for general partnership purposes. In addition, we used a portion of the proceeds to prefund the BP NGL Acquisition. See Note 3 to our Consolidated Financial Statements for a discussion of the BP NGL Acquisition.

In December 2013, our $250 million, 5.63% senior notes matured and were repaid with proceeds from our commercial paper program. In September 2012, our $500 million, 4.25% senior notes matured and were repaid with proceeds from our credit facilities.

Our $150 million, 5.25% senior notes will mature in June 2015, and our $400 million, 3.95% senior notes will mature in September 2015. We intend to use borrowings under our commercial paper program to repay these senior notes when they mature.

Acquisitions, Capital Expenditures and Distributions Paid to Our Unitholders, General Partner and Noncontrolling Interests

In addition to operating needs discussed above, we also use cash for our acquisition activities, capital projects and distributions paid to our unitholders, general partner and noncontrolling interests. We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by operations and the financing activities discussed above. 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. On November 14, 2014, we acquired a 50% interest in BridgeTex for $1.088 billion, including $13 million of working capital adjustments.

2015 Capital Projects. We expect the majority of funding for our 2015 capital program will be provided by borrowings under our commercial paper program as well as through our access to the capital markets for equity and debt as we deem necessary. Our capital program is highlighted by a large number of small-to-medium sized projects spread across multiple geographic regions/resource plays. We believe the diversity of our program mitigates the impact of delays, cost overruns or adverse market developments with respect to a particular project or geographic region/resource play. The majority of our 2015 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 2015 results, but will provide growth for 2016 and beyond. Our 2015 capital program includes the following projects as of February 2015 with the estimated cost for the entire year (in millions):

Projects	2015
Permian Basin Area Projects	$365
Fort Saskatchewan Facility Projects / NGL Line	290
Rail Terminal Projects (1)	240
Diamond Pipeline	165
Eagle Ford JV Project	85
Cactus Pipeline	85
Red River Pipeline (Cushing to Longview)	80
Cowboy Pipeline (Cheyenne to Carr)	50
Eagle Ford Area Projects	35
Line 63 Reactivation	30
Cushing Terminal Expansions	25
Other Projects	400
	$1,850
Potential Adjustments for Timing / Scope Refinement (2)	-$100 + $100
Total Projected Expansion Capital Expenditures	$1,750 - $1,950
Maintenance Capital Expenditures	$205 - $225

(1) Includes railcar purchases and projects located in or near St. James, LA and Kerrobert, Canada.

(2) Potential variation to current capital costs estimates may result from (i) changes to project design, (ii) final cost of materials and labor and (iii) timing of incurrence of costs due to uncontrollable factors such as permits, regulatory approvals and weather.

Distributions to our unitholders and general partner. We distribute 100% of our available cash within 45 days following the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. On February 13, 2015, we paid a quarterly distribution of $0.6750 per limited partner unit. This distribution represents a year-over-year distribution increase of approximately 9.8%. See Note 11 to our Consolidated Financial Statements for details of distributions paid. 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.

Although not required to do so, in response to past requests by our management in connection with our acquisition activities, our general partner has, from time to time, agreed to reduce the amounts due to it as incentive distributions. Such modifications were implemented with a view toward enhancing our competitiveness for such acquisitions and managing the overall cost of equity capital while achieving an appropriate balance between short-term and long-term accretion to our limited partners and the holders of our general partner interest and IDRs. Our general partner agreed to reduce the amount of its incentive distribution by $6.75 million for the distribution paid in February 2014, $5.5 million per quarter thereafter through November 2015, $5.0 million per quarter in 2016 and $3.75 million per quarter thereafter. These reductions were agreed to in connection with our BP NGL Acquisition and the PNG Merger. See Note 3 to our Consolidated Financial Statements for further discussion of the BP NGL Acquisition. See Note 11 to our Consolidated Financial Statements for further discussion of the PNG Merger. During 2014 and 2013, our general partner’s incentive distributions were reduced by approximately $23 million and $15 million, respectively.

Distributions to noncontrolling interests. We paid $3 million and $49 million for distributions to noncontrolling interests during the years ended December 31, 2014 and 2013, respectively. These amounts represent distributions paid on interests in PNG and SLC Pipeline LLC that were not owned by us. The decrease in amounts paid in 2014 is due to our completion of the PNG Merger on December 31, 2013, through which we purchased all of the noncontrolling interests in PNG. See Note 11 to our Consolidated Financial Statements for further discussion of the PNG Merger.

We believe that we have sufficient liquid assets, cash flow from operations 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 extending up to approximately ten years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between purchases on the one hand and sales and future delivery obligations on the other. 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, 2014 (in millions):

	2015	2016	2017	2018	2019	2020 and Thereafter	Total
Long-term debt, including current maturities and related interest payments (1)	$ 998	$ 604	$ 799	$ 972	$ 1,188	$ 10,605	$ 15,166
Leases (2)	162	151	127	102	78	373	993
Other obligations (3)	392	146	79	42	28	184	871
Subtotal	1,552	901	1,005	1,116	1,294	11,162	17,030
Crude oil, natural gas, NGL and other purchases (4)	6,617	4,457	3,303	1,991	1,304	3,968	21,640
Total	$ 8,169	$ 5,358	$ 4,308	$ 3,107	$ 2,598	$ 15,130	$ 38,670

(1) Includes debt service payments, interest payments due on senior notes and the commitment fee on assumed available capacity under the PAA revolving credit facilities. Although there may be short-term borrowings under the PAA revolving 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 facilities or commercial paper program) in the amounts above.

(2) Leases are primarily for (i) surface rentals, (ii) office rent, (iii) pipeline assets and (iv) trucks, trailers and railcars. Includes both capital and operating leases as defined by FASB guidance.

(3) Includes (i) other long-term liabilities, (ii) storage, processing and transportation agreements and (iii) commitments related to our capital expansion projects, including projected contributions for our share of the capital spending of our equity-method investments. Excludes a non-current liability of approximately $32 million related to derivative activity included in Crude oil, natural gas, NGL and other purchases.

(4) Amounts are primarily based on estimated volumes and market prices based on average activity during December 2014. 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 and construction activities. At December 31, 2014 and 2013, we had outstanding letters of credit of approximately $87 million and $41 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, 2014 (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	Barge Transportation Services	50%	$ 352	$ —	$ 247
BridgeTex Pipeline Company, LLC	Crude Oil Pipeline	50%	$ 888	$ 46	$ —
Eagle Ford Pipeline LLC	Crude Oil Pipeline	50%	$ 653	$ 11	$ —
White Cliffs Pipeline, LLC	Crude Oil Pipeline	36%	$ 540	$ 15	$ —
Butte Pipe Line Company	Crude Oil Pipeline	22%	$ 29	$ 3	$ —
Frontier Pipeline Company	Crude Oil Pipeline	22%	$ 25	$ 3	$ —

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 commodity 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.

Our policy is to (i) purchase only product for which we have a market, (ii) hedge our purchase and sales contracts so that price fluctuations do not materially affect our operating income and (iii) not acquire and hold physical inventory or other derivative instruments for the purpose of speculating on outright commodity price changes, as these activities could expose us to significant losses.

The fair value of our commodity derivatives and the change in fair value as of December 31, 2014 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	$ (64)	$ 35	$ (34)
Natural gas	(2)	$ (2)	$ 2
NGL and other	257	$ (23)	$ 23
Total fair value	$ 191		

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 debt issuances 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. The majority of our variable rate debt at December 31, 2014, $734 million, is subject to interest rate re-sets, which range up to three months. The average interest rate of 0.3% is based upon rates in effect during the year ended December 31, 2014. The fair value of our interest rate derivatives is a liability of $70 million as of December 31, 2014. A 10% increase in the forward LIBOR curve as of December 31, 2014 would result in an increase of $50 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of December 31, 2014 would result in a decrease of $50 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 is a liability of $12 million as of December 31, 2014. A 10% increase in the exchange rate (USD-to-CAD) would result in a decrease of $15 million to the fair value of our foreign currency derivatives. A 10% decrease in the exchange rate (USD-to-CAD) would result in an increase of $16 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.

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, 2014, 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, 2014. 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 2014 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 2014 that has not previously been reported.