BP PRUDHOE BAY ROYALTY TRUST
Form 10-K
March 01, 2019
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year ended December 31, 2018

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File Number 1-10243

BP PRUDHOE BAY ROYALTY TRUST

(Exact name of registrant as specified in its charter)

DELAWARE	**13-6943724**
State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

THE BANK OF NEW YORK MELLON

TRUST COMPANY, N.A., TRUSTEE

601 TRAVIS STREET, FLOOR 16

HOUSTON, TEXAS	**77002**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (713) 483-6020

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange on Which Registered**
UNITS OF BENEFICIAL INTEREST	**NEW YORK STOCK EXCHANGE**

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (17 CFR § 232.405) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company and emerging growth company in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer	Accelerated filer
Non-accelerated filer	Smaller reporting company
	Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act Yes No

The aggregate market value of Units held by nonaffiliates (computed by reference to the closing sale price in New York Stock Exchange transactions on June 29, 2018 (the last business day of the registrant s most recently completed second fiscal quarter)) was approximately $639,860,000.

As of March 1, 2019, 21,400,000 Units of Beneficial Interest were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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PART I

ITEM 1. BUSINESS

INTRODUCTION

BP Prudhoe Bay Royalty Trust (the Trust) was created as a Delaware business trust by the BP Prudhoe Bay Royalty Trust Agreement dated February 28, 1989 (the Trust Agreement) among The Standard Oil Company (Standard Oil), BP Exploration (Alaska) Inc. (BP Alaska), The Bank of New York Mellon (formerly named The Bank of New York), as trustee, and F. James Hutchinson, co-trustee (BNY Mellon Trust of Delaware, formerly named The Bank of New York (Delaware), successor co-trustee). BP Alaska and Standard Oil are wholly owned subsidiaries of BP p.l.c. (BP).

Effective as of December 15, 2010, The Bank of New York Mellon (BNYM) resigned as trustee under the Trust Agreement and BP Alaska appointed The Bank of New York Mellon Trust Company, N.A. (the Trust Company) to succeed BNYM as trustee. The Trust Company accepted its appointment and assumed all rights, titles, duties, powers and authority formerly held and exercised by BNYM under the Trust Agreement. The corporate trust office of the Trust Company (which we refer to hereafter as the Trustee) at which the affairs of the Trust are administered is located at 601 Travis Street, Floor 16, Houston, Texas 77002 and its telephone number at that address is (713) 483-6020.

The Trust electronically files annual reports on Form 10-K, quarterly reports on Form 10-Q and, when certain events require them, current reports on Form 8-K with the Securities and Exchange Commission (SEC). The public may read and copy any materials filed by the Trust with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers (including the Trust) that file electronically with the SEC. The address of the SEC s website is http://www.sec.gov.

The Trust does not maintain an Internet website, but certain information concerning the Trust and the Trust Units may be obtained from the BusinessWire website at the following page location: http://bpt.investorhq.businesswire.com. The Trustee will provide paper or electronic copies of the Trust s reports on Form 10-K, Form 10-Q and Form 8-K, and amendments to those reports, free of charge upon request as soon as reasonably practicable after the Trust files them with the SEC. Requests for copies of reports may be made by mail to: The Bank of New York Mellon Trust Company, N.A., 601 Travis Street, Floor 16, Houston, TX 77002, Attention: Global Corporate Trust Corporate Finance; by telephone to: (713) 483-6020; or by e-mail to: elaina.c.rodgers@bnymellon.com.

The information in this report relating to the Prudhoe Bay Unit, the calculation of royalty payments and certain other matters has been furnished to the Trustee by BP Alaska.

Forward-Looking Statements

Various sections of this report contain forward-looking statements (that is, statements anticipating future events or conditions and not statements of historical fact). Words such as anticipate, expect, believe, intend, plan or proj should, would, could, potentially, possibly or may, and other words that convey uncertainty of future events o outcomes are intended to identify forward-looking statements. Forward-looking statements in this report are subject to a number of risks and uncertainties beyond the control of the Trustee. These risks and uncertainties include such matters as future changes in oil prices, oil production levels, economic activity, domestic and international political events and developments, legislation and regulation, and certain changes in expenses of the Trust.

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The actual results, performance and prospects of the Trust could differ materially from those expressed or implied by forward-looking statements. Descriptions of some of the risks that could affect the future performance of the Trust appear in the following Item 1A, RISK FACTORS, and elsewhere in this report. There may be additional risks of which the Trustee is unaware or which are currently deemed immaterial.

In the light of these risks, uncertainties and assumptions, you should not rely unduly on any forward-looking statements. Forward-looking events and outcomes discussed in this report may not occur or may turn out differently. The Trustee undertakes no obligation to update forward-looking statements after the date of this report, except as required by law, and all such forward-looking statements in this report are qualified in their entirety by the preceding cautionary statements.

THE TRUST

Trust Property

The property of the Trust consists of an overriding royalty interest (the Royalty Interest) and cash and cash equivalents held by the Trustee from time to time. The Royalty Interest entitles the Trust to a royalty on 16.4246% of the lesser of (i) the first 90,000 barrels[1] of the average actual daily net production of crude oil and condensate per quarter from the working interest of BP Alaska as of February 28, 1989 in the Prudhoe Bay oil field located on the North Slope in Alaska or (ii) the average actual daily net production of crude oil and condensate per quarter from that working interest. The Prudhoe Bay field is one of four contiguous North Slope oil fields that are operated by BP Alaska and are known collectively as the Prudhoe Bay Unit. The Royalty Interest was conveyed to the Trust by an Overriding Royalty Conveyance dated February 27, 1989 from BP Alaska to Standard Oil and a Trust Conveyance dated February 28, 1989 from Standard Oil to the Trust. Copies of the Overriding Royalty Conveyance and the Trust Conveyance are filed with the SEC as exhibits to this report. The Overriding Royalty Conveyance and the Trust Conveyance are referred to collectively in this report as the Conveyance.

The Royalty Interest is a non-operational interest in minerals. The Trust does not have the right to take oil and gas in kind, nor does it have any right to take over operations or to share in any operating decision with respect to BP Alaska s working interest in the Prudhoe Bay field. BP Alaska is not obligated to continue to operate any well or maintain or attempt to maintain in force any portion of its working interest when, in its reasonable and prudent business judgment, the well or interest ceases to produce or is not capable of producing oil or gas in paying quantities.

Employees

The Trust has no employees. All administrative functions of the Trust are performed by the Trustee.

Duties and Powers of the Trustee

The duties of the Trustee are specified in the Trust Agreement and the laws of the State of Delaware. BNY Mellon Trust of Delaware has been appointed co-trustee in order to satisfy the Delaware Statutory Trust Act s requirement that the Trust have at least one trustee resident in, or which has its principal place of business in, Delaware. However, The Bank of New York Mellon Trust Company, N.A. alone is able to exercise the rights and powers granted to the Trustee in the Trust Agreement. A copy of the Trust Agreement is filed with the SEC as an exhibit to this report.

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The term barrel is a unit of measure of petroleum liquids equal to 42 United States gallons corrected to 60 degrees Fahrenheit temperature.

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The basic function of the Trustee is to collect income from the Royalty Interest, to pay all expenses, charges and obligations of the Trust from the Trust s income and assets, and to pay available cash to Unit holders. Because of the passive nature of the Trust s assets and the restrictions on the power of the Trustee to incur obligations, the only liabilities that the Trust normally incurs in the conduct of its operations are the Trustee s fees and routine administrative expenses, including accounting, legal and other professional fees.

The Trust Agreement grants the Trustee only the rights and powers necessary to achieve the purposes of the Trust. The Trust Agreement prohibits the Trust from engaging in any business or commercial activity or, with certain exceptions, any investment activity and from using any assets of the Trust to acquire any oil and gas lease, royalty or other mineral interest.

The Trustee is entitled to be indemnified out of the assets of the Trust for any liability or loss incurred by it in the performance of its duties unless the loss results from its negligence, bad faith or fraud or from expenses incurred in carrying out its duties that exceed the compensation and reimbursement to which it is entitled under the Trust Agreement.

Sales of Royalty Interest; Borrowings and Reserves

With certain exceptions, the Trustee may sell all or part of the Royalty Interest or an interest therein only if authorized to do so by vote of the holders of 60% of the Units outstanding. However, if the sale is made in order to pay specific liabilities of the Trust then due and involves a part, but not all or substantially all, of the Trust properties, the sale only needs to be approved by the vote of holders of a majority of the Units. Any sale of Trust properties must be for cash unless otherwise authorized by the Unit holders. The Trustee is obligated to distribute the available net proceeds of any such sale to the Unit holders after establishing reserves for liabilities of the Trust.

The Trustee has the power to borrow on behalf of the Trust or to sell Trust assets to pay liabilities of the Trust and to establish a reserve for the payment of liabilities without the consent of the Unit holders under the following circumstances:

The Trustee may borrow from a lender not affiliated with the Trustee if cash on hand is not sufficient to pay current liabilities and the Trustee has determined that it is not practical to pay such liabilities out of funds anticipated to be available in subsequent quarters and that, without such borrowing, the Trust property is subject to the risk of loss or diminution in value. To secure payment of its borrowings on behalf of the Trust, the Trustee is authorized to encumber the Trust s assets and to carve out and convey production payments. The borrowing must be on terms which (in the opinion of an investment banking firm or commercial banking firm selected by the Trustee) are commercially reasonable when compared to other available alternatives. No distributions to Unit holders may be made until the borrowings by the Trust have been repaid in full.

If the Trustee is unable to borrow to pay Trust liabilities, the Trustee may sell Trust assets if it determines that the failure to pay the liabilities at a later date will be contrary to the best interest of the Unit holders and that it is not practicable to submit the sale to a vote of the Unit holders. The sale must be made for cash at a price which (in the opinion of an investment banking firm or commercial banking firm selected by the Trustee) is at least equal to the fair market value of the interest sold and is made on commercially reasonable terms when compared to other available alternatives.

The Trustee has the right to establish a cash reserve for the payment of material liabilities of the Trust which may become due if it determines that it is not practical to pay such liabilities out of funds anticipated to be available in subsequent quarters and that, in the absence of a reserve, the Trust property is subject to the risk of loss or diminution in value or the Trustee is subject to the risk of personal liability for such liabilities.

In order for the Trustee to borrow, sell assets to pay Trust liabilities or establish a reserve for Trust liabilities, the Trustee must receive an unqualified written legal opinion that the contemplated action will not adversely affect the classification of the Trust as a grantor trust for federal income tax purposes or cause the income from the Trust to be treated as unrelated business taxable income for federal income tax purposes. If the Trustee is unable to obtain the required legal opinion, it still may proceed with the borrowing or sale, or establish the reserve, if it determines that the failure to do so will be materially detrimental to the Unit holders considered as a whole.

The Trustee maintains a $1,000,000 cash reserve to provide liquidity to the Trust during any periods in which the Trust does not receive a distribution from BP Alaska. On December 19, 2018, the Trust issued a press release to announce that the Trustee determined to gradually increase the Trustee s existing cash reserve for the payment of future expenses and liabilities of the Trust, as permitted by the Trust Agreement. The gradual increase in the cash reserve will begin with the distribution payable to Unit holders in April 2019. See Item 7 in Part II below.

Irrevocability; Amendment of the Trust Agreement

The Trust Agreement and the Trust are irrevocable. No person has the power to terminate, revoke or change the Trust Agreement except as described in the following paragraph and below under Termination of the Trust.

The Trust Agreement may be amended without a vote of the Unit holders to cure an ambiguity, to correct or supplement any provision of the Trust Agreement that may be inconsistent with any other provision or to make any other provision with respect to matters arising under the Trust Agreement that does not adversely affect the Unit holders. The Trust Agreement also may be amended with the approval of holders of a majority of the outstanding Units. However, no such amendment may alter the relative rights of Unit holders unless approved by the affirmative vote of holders of 100% of the outstanding Units, nor may any amendment reduce or delay the distributions to the Unit holders, alter the voting rights of Unit holders or the number of Units in the Trust, or make certain other changes, unless approved by the affirmative vote of holders of at least 80% of the outstanding Units and by the Trustee. The Trustee is required to consent to any amendment approved by the requisite vote of Unit holders unless the amendment affects the Trustee s rights, duties and immunities under the Trust Agreement. No amendment will be effective until the Trustee has received a ruling from the Internal Revenue Service or an opinion of counsel to the effect that such modification will not adversely affect the classification of the Trust as a grantor trust for federal income tax purposes or cause the income from the Trust to be treated as unrelated business taxable income for federal income tax purposes.

Termination of the Trust

The Trust will terminate if either (a) holders of at least 60% of the outstanding Units vote to terminate the Trust or (b) the net revenues from the Royalty Interest for two successive years are less than $1,000,000 per year (unless the net revenues during the two-year period have been materially and adversely affected by certain extraordinary events).

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Upon termination of the Trust, BP Alaska will have an option to purchase the Royalty Interest at a price equal to the greater of (i) the fair market value of the Trust property as set forth in an opinion of an investment banking firm, commercial banking firm or other entity qualified to give an opinion as to the fair market value of the assets of the Trust, or (ii) the number of outstanding Units multiplied by (a) the closing price of Units on the day of termination of the Trust on the stock exchange on which the Units are listed, or (b) if the Units are not listed on any stock exchange but are traded in the over-the-counter market, the closing bid price on the day of termination of the Trust as quoted on the NASDAQ Stock Market. The purchase must be for cash unless holders of 60% of the Units outstanding authorize the sale for non-cash consideration and the Trustee has received a ruling from the Internal Revenue Service or an opinion of counsel to the effect that such non-cash sale will not adversely affect the classification of the Trust as a grantor trust for federal income tax purposes or cause the income from the Trust to be treated as unrelated business taxable income for federal income tax purposes.

If BP Alaska does not exercise its option, the Trustee will sell the Trust property on terms and conditions approved by the vote of holders of 60% of the outstanding Units, unless the Trustee determines that it is not practicable to submit the matter to a vote of the Unit holders and the sale is made at a price at least equal to the fair market value of the Trust property as set forth in the opinion of the investment banking firm, commercial banking firm or other entity mentioned above and on terms and conditions deemed commercially reasonable by that firm.

The Trustee will distribute all available proceeds to the Unit holders after satisfying all existing liabilities of the Trust and establishing adequate reserves for the payment of contingent liabilities.

Unit holders do not have the right under the Trust Agreement to seek or secure any partition or distribution of the Royalty Interest or any other asset of the Trust or any accounting during the term of the Trust or during any period of liquidation and winding up.

Resignation or Removal of Trustee

The Trustee may resign at any time or be removed with or without cause by vote of the holders of a majority of the outstanding Units at a meeting called and held in accordance with the Trust Agreement. A successor trustee may be appointed by BP Alaska or, if the Trustee has been removed at a meeting of the Unit holders, the successor trustee may be appointed by the Unit holders at the meeting. Any successor trustee must be a corporation organized, doing business and authorized to exercise trust powers under the laws of the United States, any state thereof or the District of Columbia, or a national banking association domiciled in the United States, in either case having a combined capital, surplus and undivided profits of at least $50,000,000 and subject to supervision or examination by federal or state authorities. Unless the Trust already has a trustee that is a resident of or has a principal office in Delaware, any successor trustee must be a resident of Delaware or have a principal office in Delaware. No resignation or removal of the Trustee will become effective until a successor trustee has accepted appointment.

Voting Rights of Unit Holders

Unit holders possess certain voting rights, but their voting rights are not comparable to those of shareholders of a corporation. For example, there is no requirement for annual meetings of Unit holders or for periodic reelection of the Trustee.

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A meeting of the Unit holders may be called at any time to act with respect to any matter as to which the Trust Agreement authorizes the Unit holders to act. Any such meeting may be called by the Trustee in its discretion and will be called by the Trustee (i) as soon as practicable after receipt of a written request by BP Alaska or a written request that sets forth in reasonable detail the action proposed to be taken at the meeting and is signed by holders of at least 25% of the outstanding Units or (ii) when required by applicable laws or regulations or the New York Stock Exchange. The Trustee will give written notice of any meeting stating the time and place of the meeting and the matters to be acted on not more than 60 days nor fewer than 10 days before the meeting to all Unit holders of record on a date not more than 60 days before the meeting at their addresses shown on the records of the Trust. All meetings of Unit holders are required to be held in Manhattan, New York City. Unit holders are entitled to cast one vote on all matters coming before a meeting, in person or by proxy, for each Unit held on the record date for the meeting.

THE ROYALTY INTEREST

The Royalty Interest is a property right under Alaska law which burdens production, but there is no other security interest in the reserves or production revenues assigned to it. The royalty payable to the Trust for each calendar quarter is the sum of the amounts obtained by multiplying Royalty Production for each day in the calendar quarter by the Per Barrel Royalty for that day. The payment under the Royalty Interest for any calendar quarter may not be less than zero nor more than the aggregate value of the total production of oil and condensate from BP Alaska s working interest in the Prudhoe Bay Unit for the quarter, net of the State of Alaska royalty and less the value of any applicable payments made to affiliates of BP Alaska.

Royalty Production

The Royalty Production for each day in a calendar quarter is 16.4246% of the lesser of (i) the first 90,000 barrels of the actual average daily net production of crude oil and condensate for the quarter from the Prudhoe Bay (Permo-Triassic) Reservoir and saved and allocated to the oil and gas leases owned by BP Alaska in the Prudhoe Bay field as of February 28, 1989 (the 1989 Working Interests), or (ii) the actual average daily net production of crude oil and condensate for the quarter from the 1989 Working Interests. The Royalty Production is based on oil produced from the oil rim and condensate produced from the gas cap, but not on gas production or natural gas liquids production. The actual average daily net production of oil and condensate from the 1989 Working Interests for any calendar quarter is the total production of oil and condensate for the quarter, net of the State of Alaska royalty, divided by the number of days in the quarter.

Per Barrel Royalty

The Per Barrel Royalty for any day is the WTI Price for the day less the sum of (i) Chargeable Costs multiplied by the Cost Adjustment Factor and (ii) Production Taxes.

WTI Price

The WTI Price for any trading day is (i) the price (in dollars per barrel) for West Texas intermediate crude oil of standard quality having a specific gravity of 40 API degrees for delivery at Cushing, Oklahoma (West Texas Intermediate) quoted for that trading day by whichever of The Wall Street Journal, Reuters, or Platts Oilgram Price Report, in that order, publishes West Texas Intermediate price quotations for the trading day, or (ii) if the price of West Texas Intermediate is not published by one of those publications, the WTI Price will be the simple average of the daily mean prices (in dollars per barrel) quoted for West Texas Intermediate by one major oil company, one petroleum broker and one

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petroleum trading company designated by BP Alaska, in each case unaffiliated with BP and having substantial U.S. operations, until published price quotations are again available. If prices for West Texas Intermediate are not quoted so as to permit the calculation of the WTI Price, the price of West Texas Intermediate, for the purposes of calculating the WTI Price will be the price of another light sweet domestic crude oil of standard quality designated by BP Alaska and approved by the Trustee, with appropriate allowance for transportation costs to the Gulf coast (or another appropriate location) to equilibrate its price to the WTI Price. The WTI Price for any day which is not a trading day is the WTI Price for the preceding trading day.

Chargeable Costs

The Chargeable Costs per barrel of Royalty Production for each calendar year are fixed amounts specified in the Conveyance and do not necessarily represent BP Alaska s actual costs of production. Chargeable Costs per barrel were $16.90 during 2014, $17.00 during 2015, $17.10 during 2016, $17.20 during 2017 and $20.00 during 2018. Chargeable Costs for 2019 and subsequent years are shown in the following table:

Calendar year	Chargeable Costs per barrel
2019	23.75
2020	26.50

After 2020, Chargeable Costs increase at a uniform rate of $2.75 per barrel per year.

Cost Adjustment Factor

Pursuant to the Overriding Royalty Conveyance, [2] the Cost Adjustment Factor for a quarter was initially set as the ratio of the Consumer Price Index[3] published for the most recently past February, May, August or November to 121.1 (the Consumer Price Index for January 1989). The Overriding Royalty Conveyance provides, however, that if the average WTI Price for any calendar quarter falls to $18.00 or less[4], the Cost Adjustment Factor for that quarter will be the Cost Adjustment Factor for the immediately preceding quarter. If the average WTI Price returns to more than $18.00 for a later quarter, then for each subsequent quarter that the average WTI Price remains above $18.00, adjustments to the Cost Adjustment Factor resume, but with an adjustment to the formula that excludes changes in the Consumer Price Index during the period that adjustments to the Cost Adjustment Factor were suspended.[5]

2 The method for determining the Cost Adjustment Factor is set forth in Section 4.5 of the Overriding Royalty Conveyance.

3 The Consumer Price Index is the U.S. Consumer Price Index, all items and all urban consumers, U.S. city average (1982-84 equals 100), as first published, without seasonal adjustment, by the Bureau of Labor Statistics, Department of Labor, without regard to subsequent revisions or corrections.

4 The WTI Price was most recently at this level in the second quarter of 1999, where the applicable Cost Adjustment Factor and Consumer Price Index were 1.29737 and 1.662, respectively.

5 Pursuant to Section 4.5 of the Overriding Royalty Conveyance, the calculation of the Cost Adjustment Factor for each subsequent quarter that the WTI Price remains above $18.00 is the product of (x) the Cost Adjustment Factor for the most recently past calendar quarter in which the average WTI Price was equal to or less than $18.00 and (y) a fraction, the numerator of which is the Consumer Price Index published for the most recently past February, May, August or November, as the case may be, and the denominator of which is the Consumer Price Index published for the most recently past February, May, August or November during a quarter in which the average WTI Price was equal to or less than $18.00.

Production Taxes

Production Taxes are the sum of any severance taxes, excise taxes (including windfall profit tax, if any), sales taxes, value added taxes or other similar or direct taxes imposed upon the reserves or production, delivery or sale of Royalty Production, computed at defined statutory rates.

On April 14, 2013, Alaska s legislature passed an oil-tax reform bill amending Alaska s oil and gas production tax statutes, AS 43.55.10 *et seq.* (the Production Tax Statutes) with the aim of encouraging oil production and investment in Alaska s oil industry. On May 21, 2013, the Governor of Alaska signed the bill into law as chapter 10 of the 2013 Session laws of Alaska (the Act). Among significant changes, the Act eliminated the monthly progressivity tax rate implemented by certain amendments to the Production Tax Statutes in 2006 and 2007, increased the base rate from 25% to 35% and added a stair-step per-barrel tax credit for oil production. This tax credit is based on the gross value at the point of production per barrel of taxable oil and may not reduce a producer s tax liability below the minimum tax (which is a percentage, ranging from zero to 4%, of the gross value at the point of production of a producer s taxable production during the calendar year based on the average price per barrel for Alaska North Slope crude oil for sale on the United States West Coast for the year) under the Production Tax Statutes. These changes became effective on January 1, 2014.

On January 15, 2014, the Trustee executed a letter agreement with BP Alaska dated January 15, 2014 (the 2014 Letter Agreement) regarding the implementation of the Act with respect to the Trust. Pursuant to the 2014 Letter Agreement, Production Taxes for the Trust s Royalty Production will equal the tax for the relevant quarter, minus the allowable monthly stair-step per-barrel tax credits for the Royalty Production during that quarter. If there is a minimum tax -related limitation on the amount of the stair-step per-barrel tax credits that could otherwise be claimed for any quarter during the year, any difference between that limitation as preliminarily determined on a quarterly basis and the actual limitation for the entire year will be reflected in the payment to the Trust for the first quarter Royalty Production in the following year.

On July 6, 2015, BP Alaska and the Trustee signed a letter agreement (the 2014 Letter Agreement Amendment) amending the 2014 Letter Agreement to provide that if there is a minimum tax -related limitation on the amount of the stair-step per-barrel tax credits that could otherwise be claimed for any quarter during the year, any difference between that limitation as preliminarily determined on a quarterly basis and the actual limitation for the entire year will be reflected in the payment to the Trust for the fourth quarter Royalty Production payment for such year rather than in the payment to the Trust for the first quarter Royalty Production in the following year.

The 2014 Letter Agreement Amendment became effective immediately. Thus, for 2018 any difference between the limitation as preliminarily determined for the first through third quarters of 2018 and the actual limitation for 2018 will be reflected in the payment to the Trust for the fourth quarter of 2018, and not in the payment to the Trust for the first quarter of 2019.

Per Barrel Royalty Calculations

The following table shows how the above-described factors interacted during the past five years to produce the average Per Barrel Royalty paid during the calendar years indicated. Royalty revenues are generally received on the fifteenth day of the month following the end of the calendar quarter in which

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the related Royalty Production occurred. Revenues and expenses presented in the statement of cash earnings and distributions presented in Part II, Item 8 below are recorded on a modified cash basis and, as a result, royalty revenues and distributions shown in such statements for any calendar year are attributable to BP Alaska s operations during the twelve-month period ended September 30 of that year. Dollar amounts in the table have been rounded to two decimal places for presentation and do not reflect the precision of the actual calculations.

	Average WTI Price	Chargeable Costs	Cost Adjustment Factor	Adjusted Chargeable Costs	Production Taxes	Average Per Barrel Royalty
Calendar 2014:						
4th Qtr 2013	$ 97.40	$ 16.80	1.795	$ 30.15	$ 26.88	$ 40.33
1st Qtr 2014	98.58	16.90	1.808	30.55	17.50	50.52
2nd Qtr 2014	103.07	16.90	1.832	30.96	19.28	52.83
3rd Qtr 2014	97.31	16.90	1.831	30.95	16.60	49.75
Calendar 2015:						
4th Qtr 2014	$ 73.02	$ 16.90	1.818	$ 30.75	$ 6.88	$ 35.41
1st Qtr 2015	48.80	17.00	1.807	30.72	1.67	16.41
2nd Qtr 2015	57.80	17.00	1.831	31.13	2.02	24.65
3rd Qtr 2015	46.70	17.00	1.835	31.20	1.58	13.92
Calendar 2016:						
4th Qtr 2015	$ 42.15	$ 17.00	1.827	$ 31.07	$ 1.40	$ 9.68
1st Qtr 2016	33.73	17.10	1.826	31.22	1.06	1.45
2nd Qtr 2016	45.56	17.10	1.850	31.63	1.53	12.38
3rd Qtr 2016	44.99	17.10	1.855	31.71	1.51	11.81
Calendar 2017:						
4th Qtr 2016	$ 49.24	$ 17.10	1.858	$ 31.78	$ 1.68	$ 15.79
1st Qtr 2017	51.94	17.20	1.876	32.26	1.78	17.90
2nd Qtr 2017	48.32	17.20	1.884	32.41	1.63	14.27
3rd Qtr 2017	48.12	17.20	1.890	32.52	1.63	14.00
Calendar 2018:						
4th Qtr 2017	$ 55.48	$ 17.20	1.899	$ 32.67	$ 1.92	$ 20.89
1st Qtr 2018	62.96	20.00	1.917	38.34	2.21	22.38
2nd Qtr 2018	67.85	20.00	1.937	38.74	2.41	26.70
3rd Qtr 2018	69.60	20.00	1.942	38.83	2.81	27.96

THE UNITS

Units

Each Unit represents an equal undivided share of beneficial interest in the Trust. The Units do not represent an interest in or an obligation of BP Alaska, Standard Oil or any of their respective affiliates. Units are evidenced by transferable certificates issued by the Trustee. Each Unit entitles its holder to the same rights as the holder of any other Unit. The Trust has no other authorized or outstanding class of securities.

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Distributions of Income

BP Alaska makes quarterly payments to the Trust of the amounts due with respect to the Trust s Royalty Interest on the fifteenth day following the end of each calendar quarter or, if the fifteenth is not a business day, on the next succeeding business day (the Quarterly Record Date). The Trustee pays all expenses of the Trust for each quarter on the Quarterly Record Date to the extent possible, then distributes the excess, if any, of the cash received by the Trust over the Trust s expenses, net of any additions to or subtractions from the cash reserve established for the payment of estimated liabilities (the Quarterly Distribution), to the persons in whose names the Units were registered at the close of business on the Quarterly Record Date.

The Trust Agreement requires the Trustee to pay the Quarterly Distribution to Unit holders on the fifth day after the Trustee s receipt of the amount paid by BP Alaska. Cash balances held by the Trustee for distribution to Unit holders are required to be invested in United States government or agency obligations secured by the full faith and credit of the United States (Government Obligations) or, if Government Obligations that mature on the date of the distribution to Unit holders are not available, in repurchase agreements secured by Government Obligations with banks having capital, surplus and undivided profits of $100,000,000 or more (which may include The Bank of New York Mellon). If time does not permit the Trustee to invest collected funds in Government Obligations or repurchase agreements, the Trustee may invest funds overnight in a time deposit with a bank meeting the foregoing capital requirement (including The Bank of New York Mellon).

Reports to Unit Holders

After the end of each calendar year, the Trustee mails a report to the persons who held Units of record during the year containing information to enable them to make the calculations necessary for federal and Alaska income tax purposes, including the calculation of any depletion or other deduction which may be available to them for the calendar year. In addition, after the end of each calendar year the Trustee mails Unit holders an annual report containing a copy of this Form 10-K and certain other information required by the Trust Agreement.

Limited Liability of Unit Holders

The Trust Agreement provides that the Unit holders are, to the full extent permitted by Delaware law, entitled to the same limitation of personal liability extended to stockholders of private corporations for profit under Delaware law.

Possible Divestiture of Units

The Trust Agreement imposes no restrictions on nationality or other status of the persons eligible to hold Units. However, it provides that if at any time the Trust or the Trustee is named a party in any judicial or administrative proceeding seeking the cancellation or forfeiture of any property in which the Trust has an interest because of the nationality, or any other status, of any one or more Unit holders, the Trustee may require each holder whose nationality or other status is an issue in the proceeding to dispose of his Units to a party not of the nationality or other status at issue in the proceeding. If any holder fails to dispose of his Units within 30 days after receipt of notice from the Trustee to do so, the Trustee will redeem any Units not so transferred within 90 days after the end of the 30-day period specified in the notice for a cash price equal to the fair market value of the Units. Units redeemed by the Trustee will be cancelled.

The Trustee may cause the Trust to borrow any amount required to redeem the Units. If the purchase of Units from an ineligible holder by the Trustee would result in a non-exempt prohibited transaction under the Employee Retirement Income Security Act of 1970, or under the Internal Revenue Code of 1986, the Units subject to the Trustee s right of redemption will be purchased by BP Alaska or a designee of BP Alaska.

Issuance of Additional Units

The Trust Agreement provides that BP Alaska or an affiliate from time to time may assign to the Trust additional royalty interests meeting certain conditions and, upon satisfaction of various other conditions, the Trust may issue up to an additional 18,600,000 Units. BP Alaska has not conveyed any additional royalty interests to the Trust, and the Trust has not issued any additional Units.

THE BP SUPPORT AGREEMENT

BP agreed to provide financial support to BP Alaska in meeting its payment obligations to the Trust in a Support Agreement dated February 28, 1989 among BP, BP Alaska, Standard Oil and the Trust (the Support Agreement). Within 30 days after BP receives notice from the Trustee that the royalty payable with respect to the Royalty Interest or any other amount payable by BP Alaska or Standard Oil has not been paid to the Trustee, BP will cause BP Alaska and Standard Oil to satisfy their respective payment obligations to the Trust and the Trustee under the Trust Agreement and the Conveyance, including contributing to BP Alaska the funds necessary to make such payments. BP is required to make available to BP Alaska and Standard Oil such financial support as BP Alaska, Standard Oil or the Trustee may request in writing. Any Unit holder has the unconditional right to institute suit against BP to enforce BP s obligations under the Support Agreement.

Neither BP nor BP Alaska may transfer or assign its rights or obligations under the Support Agreement without the prior written consent of the Trustee, except that BP can arrange for its obligations to be performed by any of its affiliates so long as BP remains responsible for ensuring that its obligations are performed in a timely manner.

BP Alaska may sell or transfer all or part of its working interest in the Prudhoe Bay Unit, although such a transfer will not relieve BP of its responsibility to ensure that BP Alaska s payment obligations with respect to the Royalty Interest and under the Trust Agreement and the Conveyance are performed.

BP will be released from its obligation under the Support Agreement upon the sale or transfer of all or substantially all of BP Alaska s working interest in the Prudhoe Bay Unit if the transferee agrees in writing to assume and be bound by BP s obligation under the Support Agreement. The transferee s agreement to assume BP s obligations must be reasonably satisfactory to the Trustee and the transferee must be an entity having a rating of its unsecured, unsupported long-term debt of at least A3 from Moody s Investors Service, Inc., a rating of at least A- from Standard & Poor s, or an equivalent rating from at least one nationally-recognized statistical rating organization (after giving effect to the sale or transfer and the assumption of all of BP Alaska s obligations under the Conveyance and all of BP s obligations under the Support Agreement).

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THE PRUDHOE BAY UNIT AND FIELD

Prudhoe Bay Unit Operation and Ownership

Since several oil companies besides BP Alaska hold acreage within the Prudhoe Bay field, as well as several contiguous oil fields, the Prudhoe Bay Unit was established to optimize field development. Other owners of these fields include affiliates of Exxon Mobil Corporation, ConocoPhillips and Chevron Corporation. The Trust s Royalty Interest pertains only to production from the 1989 Working Interests in the Prudhoe Bay field and does not include production from the other oil fields included in the Prudhoe Bay Unit.

The operations of BP Alaska and the other working interest owners in the Prudhoe Bay Unit are governed by an agreement dated April 1, 1977 among the State of Alaska and the working interest owners establishing the Prudhoe Bay Unit (the Prudhoe Bay Unit Agreement) and an agreement dated April 1, 1977 among the working interest owners governing Prudhoe Bay Unit operations (the Prudhoe Bay Unit Operating Agreement).

The Prudhoe Bay Unit Operating Agreement specifies the allocation of production and costs to the working interest owners. It also defines operator responsibilities and voting requirements and is unusual in its establishment of separate participating areas for the gas cap and oil rim. Since July 1, 2000, BP Alaska has been the sole operator of the Prudhoe Bay Unit.

The ownership of the Prudhoe Bay Unit by participating area as of December 31, 2018 is shown in the following table:

	Oil rim	**Gas cap**
BP Alaska	26.36%(a)	26.36%(b)
Exxon Mobil	36.40	36.40
ConocoPhillips	36.08	36.08
Chevron	1.16	1.16
Total	100.00%	100.00%

(a) The Trust s share of oil production and condensate is computed based on BP Alaska s ownership interest in the oil rim participating area of 50.68% as of February 28, 1989. Subsequent decreases in BP Alaska s participation in oil rim ownership do not affect calculation of Royalty Production from the 1989 Working Interests and have not decreased the Trust s Royalty Interest.

(b) The Trust s share of condensate production is computed based on BP Alaska s ownership interest in the gas cap participating area of 13.84% as of February 28, 1989. Subsequent increases in BP Alaska s gas cap ownership do not affect calculation of Royalty Production from the 1989 Working Interests and have not increased the Trust s Royalty Interest. Under the terms of an Issues Resolution Agreement entered into by the Prudhoe Bay Unit owners in October 1990, produced condensate (defined as the Original Condensate Reserve in the agreement) from the gas cap participating area was allocated to that participating area until a cumulative limit of 1,175 million barrels was reached. This cumulative limit was reached in June 2014, and beginning at that time and continuing thereafter, the condensate is allocated to the oil rim participating area.

If BP Alaska fails to pay any costs and expenses chargeable to BP Alaska under the Prudhoe Bay Unit Operating Agreement and the production of oil and condensate is insufficient to pay such costs and expenses, the Royalty Interest is chargeable with a pro rata portion of such costs and expenses and is subject to the enforcement against it of liens granted to the operators of the Prudhoe Bay Unit. However, in the Conveyance BP Alaska agreed to pay all costs and expenses chargeable to it and to ensure that no such costs and expenses will be chargeable against the Royalty Interest. The Trust is not liable for any loss or liability incurred by BP Alaska or others attributable to BP Alaska s working interest in the Prudhoe Bay Unit or to the oil produced from it and BP Alaska has agreed to indemnify the Trust and hold it harmless against any such impositions.

BP Alaska has the right to amend or terminate the Prudhoe Bay Unit Agreement, the Prudhoe Bay Unit Operating Agreement and any leases or conveyances with respect to the 1989 Working Interests in the exercise of its reasonable and prudent business judgment without liability to the Trust. BP Alaska also has the right to sell or assign all or any part of the 1989 Working Interests, so long as the sale or assignment is expressly made subject to the Royalty Interest and the terms and provisions of the Conveyance.

The Prudhoe Bay Field

The Prudhoe Bay field is located on the North Slope of Alaska, 250 miles north of the Arctic Circle and 650 miles north of Anchorage. The Prudhoe Bay field extends approximately 12 miles by 27 miles and contains nearly 150,000 gross productive acres. Approximately 45% of the acreage within the field is subject to the Royalty Interest granted to the Trust by the Conveyance. The Prudhoe Bay field, which was discovered in 1968 by BP and others, has been in production since 1977 and is the largest producing oil field in North America. As of December 31, 2018, approximately 12.6 billion barrels of oil and condensate had been produced from the Prudhoe Bay field.

Field Geology

The principal hydrocarbon accumulations at Prudhoe Bay are in the Ivishak sandstone of the Sadlerochit Group at a depth of approximately 8,700 feet below sea level. The Ivishak is overlain by four minor reservoirs of varying extent which are designated the Put River, Eileen, Sag River and Shublik (PESS) formations. Underlying the Sadlerochit Group are the oil-bearing Lisburne and Endicott formations. The net production allocated to the Royalty Interest pertains only to the Ivishak and PESS formations, collectively known as the Prudhoe Bay (Permo-Triassic) Reservoir, and does not pertain to the Lisburne and Endicott formations.

The Ivishak sandstone was deposited, commencing some 250 million years ago, during the Permian and Triassic geologic periods. The sediments in the Ivishak are composed of sandstone, conglomerate and shale which were deposited by a massive braided river and delta system that flowed from an ancient mountain system to the north. Oil was trapped in the Ivishak by a combination of structural and stratigraphic trapping mechanisms.

Gross reservoir thickness is 550 feet, with a maximum oil column thickness of 425 feet. The original oil column is bounded on the top by a gas-oil contact, originally at 8,575 feet below sea level across the main field, and on the bottom by an oil-water contact at approximately 9,000 feet below sea level. A layer of heavy oil and tar overlays the oil-water contact in the main field and has an average thickness of around 40 feet.

Oil Characteristics

The oil produced from the Prudhoe Bay (Permo-Triassic) Reservoir is a medium grade, low sulfur crude with an average specific gravity of 27 API degrees. The gas cap composition is such that, upon surfacing, a liquid hydrocarbon phase, known as condensate, is formed.

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The Royalty Interest is based upon oil produced from the oil rim and condensate produced from the gas cap, but not upon gas production (which is currently uneconomic on a large scale) or natural gas liquids production stripped from gas produced.

Historical Production

Production from the Prudhoe Bay field began on June 19, 1977, with the completion of the Trans-Alaska Pipeline System (TAPS). As of December 31, 2018 there were 1048 active producing oil wells, 31 gas reinjection wells, 196 water injection wells and water and miscible gas injection wells in the Prudhoe Bay field. Production wells drilled in the field during the three years ended December 31, 2018 were: 33 in 2016, 23 in 2017 and 14 in 2018. These include new sidetrack completions in existing wells. No exploratory drilling activities were conducted in the field during the three-year period. Production from the Prudhoe Bay field reached a peak in 1988 and has declined steadily since then. The average well production rate was about 177 barrels per day in 2014, 170 barrels per day in 2015, 171 barrels per day in 2016, 178 barrels per day in 2017 and 166 barrels per day in 2018.

BP Alaska s share of the hydrocarbon liquids production from the Prudhoe Bay field includes oil, condensate and natural gas liquids. Using the production allocation procedures from the Prudhoe Bay Unit Operating Agreement, the Prudhoe Bay field s total production and the net share of oil and condensate (net of State of Alaska royalty) allocated to the 1989 Working Interests have been as follows during the past five years:

	Oil		Condensate	
Calendar year	Total field	Net to 1989 Working Interests	Total field	Net to 1989 Working Interests
	(thousand barrels per day)			
2014	184.4	81.8	19.4	2.3
2015	196.4	87.1	0.0(a)	0.0
2016	197.9	87.8	0.0(a)	0.0
2017	188.0	83.4	0.0(a)	0.0
2018	174.2	77.3	0.0(a)	0.0

(a) Having reached the cumulative condensate limit in June 2014, pursuant to the Issues Resolution Agreement all condensate produced from the Initial Participating Area (IPA) is now allocated to the Oil Rim IPA for accounting purposes.

Collection and Transportation of Prudhoe Bay Oil

Raw crude oil produced from individual production wells located at well pads is diverted to flowlines (pipelines). The flowlines transport the raw crude oil to one of six separation facilities (three on the western side of the Prudhoe Bay Unit and three on the eastern side) where the water and natural gas mixed with the raw crude are removed. The stabilized crude is then sent from the separation facilities through two 34-inch diameter transit lines, one from each half of the Prudhoe Bay Unit, to Pump Station 1, the starting point for TAPS.

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At Pump Station 1, Alyeska Pipeline Service Company, the operator of TAPS, meters the oil and pumps it in the 48-inch diameter pipeline to Valdez, almost 800 miles (1,288 km) to the south, where it is either loaded onto marine tankers or stored temporarily. It currently takes the oil about 16 days to make the trip from the Prudhoe Bay Unit to Valdez. TAPS has a mechanical capacity of 1.1 million barrels of oil a day. During 2018, TAPS averaged 509 thousand barrels per day.

Following a partial shutdown of the eastern side of the Prudhoe Bay Unit which lasted from August 7 until September 22, 2006, BP Alaska replaced approximately 16 miles of oil transit lines and has implemented new integrity management and corrosion monitoring practices that supplement or replace the practices that existed in 2006. BP Alaska states that its integrity management practices meet the requirements of 49 CFR 195.452 for pipeline integrity management in high consequence areas.

Reservoir Management

The Prudhoe Bay field is a complex, combination-drive reservoir, with widely varying reservoir properties. Reservoir management involves directing field activities and projects to maximize the economic value of reserves.

Several different oil recovery mechanisms are currently active in the Prudhoe Bay field, including pressure depletion, gravity drainage/gas cap expansion, water flooding and miscible gas flooding. Separate yet integrated reservoir management strategies have been developed for the areas affected by each of these recovery processes.

Reserve Estimates

Proved oil reserves attributable to the 1989 Working Interests at December 31, 2018 are those quantities of oil which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from 2019 forward from known reservoirs and under existing economic conditions, operating methods and government regulations. Estimates of proved reserves are inherently imprecise and subjective and are revised over time as additional data becomes available. Such revisions often may be substantial. BP Alaska s reserve estimates and production assumptions and projections are predicated upon a reasonable estimate of the allocation of hydrocarbon liquids between oil and condensate according to the procedures of the Prudhoe Bay Unit Operating Agreement. Oil and condensate are physically produced in a commingled stream of hydrocarbon liquids. The allocation of hydrocarbon liquids between the oil and condensate from the Prudhoe Bay field is a theoretical calculation performed in accordance with procedures specified in the Prudhoe Bay Unit Operating Agreement. Under the terms of an Issues Resolution Agreement entered into by the Prudhoe Bay Unit owners in October 1990 (the Issuers Resolution Agreement), the allocation procedures were adjusted to generally allocate condensate in a manner which approximates the anticipated decline in the production of oil until an agreed original condensate reserve of 1,175 million barrels has been allocated to the working interest owners.

By letter dated December 19, 2014, BP Alaska advised the Trustee that the portion of the hydrocarbon liquids produced from the initial participating areas of the Prudhoe Bay Unit being allocated as condensate from the gas cap participating area was found to have reached on June 8, 2014 the agreed original condensate reserve of 1,175 million barrels allocated to the working interest owners. As a result, the portion of hydrocarbon liquids previously allocated as condensate to the gas cap participating area will be allocated to the oil rim participating area. This event has had the effect of changing the calculation of the volume of Royalty Production subject to the Royalty Interest because 50.68% of hydrocarbon

liquids allocated to the oil rim participating area[6] are counted for the purpose of calculating such volume, but only 13.84% of the hydrocarbon liquids are allocated to the gas cap participating area for such purpose.[7] The end of the allocation to the gas cap participating area on June 8, 2014 meant that volumes of hydrocarbon liquids subject to the Royalty Interest for the second and third quarters of 2014 were greater than the volumes of Royalty Production initially reported by BP Alaska. The correction to the volumes of Royalty Production and the Royalty payments with respect to the Royalty Interest for such quarters were made in conjunction with the scheduled Royalty payment in January 2015 for the quarter ended December 31, 2014. See Note 6 of Notes to Financial Statements below.

There is no precise method of forecasting the allocation of reserve volumes to the Trust. The Royalty Interest is not a working interest and the Trust is not entitled to receive any specific volume of reserves from the 1989 Working Interests. The reserve volumes attributable to the 1989 Working Interests are estimated using an allocation of reserve volumes based on estimated future production and the average WTI Price, and assume no future movement in the Consumer Price Index and no changes to the procedure for calculating Production Taxes. The estimated reserve volumes attributable to the Trust will vary if different estimates of production, prices and other factors are used. Even if expected reservoir performance does not change, the estimated reserves, economic life, and future revenues attributable to the Trust may change significantly in the future. This may result from changes in the WTI Price or from changes in other prescribed variables utilized in calculations defined by the Overriding Royalty Conveyance.

The reserves attributable to the 1989 Working Interests constitute only a part of the overall reserves in the Prudhoe Bay Unit. BP Alaska has estimated that the proved reserves allocated to the Trust as of December 31, 2018 were 15.772 million barrels of oil and condensate, of which 15.638 million barrels are proved developed reserves[8] and 0.134 million barrels are proved undeveloped reserves[9]. Proved reserves attributable to the Trust were increased by approximately 6.702 million barrels during 2018 as a result of the increase in the West Texas Intermediate price, forecast revisions and capital activities including drilling and well treatments. Additional information regarding changes in estimated quantities of proved oil and condensate, proved developed reserves and proved undeveloped reserves is found below in Supplemental Reserve Information and Standardized Measure of Discounted Future Net Cash Flow Relating to Proved Reserves (Unaudited) following the Notes to Financial Statements.

In all cases, the volumes are being progressed as a part of an adopted development plan that calls for drilling of wells over a period of time. BP has a historical record of completing comparable projects. There were no contributions to proved undeveloped reserves from extensions or discoveries during 2018. Based on the 2018 twelve-month average WTI Price[10] of $65.56 per barrel, other economic parameters

6 See note (a) to the table of ownership of the Prudhoe Bay Unit by participating area as of December 31, 2015 above under the caption THE PRUDHOE BAY UNIT and FIELD Prudhoe Bay Unit Operation and Ownership .

7 See note (b) to the table of ownership of the Prudhoe Bay Unit by participating area as of December 31, 2016 above under the caption THE PRUDHOE BAY UNIT and FIELD Prudhoe Bay Unit Operation and Ownership .

8 Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

9 Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

10 The unweighted arithmetic average of the WTI Price on the first day of each month during the year.

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prescribed by the Conveyance, and utilizing procedures specified in Financial Accounting Standards Board Accounting Standards Codification (FASB ASC) 932, *Extractive Activities Oil and Gas*, BP Alaska calculated that as of December 31, 2018 production of oil and condensate from the proved reserves allocated to the 1989 Working Interests will result in undiscounted estimated future cash flow to the Trust of $154.662 million, with a net present value of estimated future cash flows at 10% discount of $138.541 million.

The internal controls applicable to the foregoing estimates of the reserves allocated to the Trust are those employed by BP, which provides the information to the Trustee. BP Alaska has advised the Trustee that BP s vice president of segment reserves is the petroleum engineer primarily responsible for overseeing the preparation of the reserves estimate. He has 30 years of diversified industry experience managing the governance and compliance of BP s reserves estimation since 2005. He is a past member of the Society of Petroleum Engineers Oil and Gas Reserves Committee, a sitting member of the American Association of Petroleum Geologists Committee on Resource Evaluation and current chair of the bureau of the United Nations Economic Commission for Europe Expert Group on Resource Classification. The Trust employs Miller and Lents, Ltd., an international oil and gas consulting firm, to conduct an annual review of BP Alaska s estimates of the proved reserves allocated to the Trust, estimated future net revenues to the Trust, and the remaining period of economic production from the Prudhoe Bay field attributable to the Trust. All Miller and Lents, Ltd. staff members assigned to the BP Prudhoe Bay Royalty Trust are licensed professional engineers. Work was supervised by a licensed professional engineer with more than 15 years of experience with the Trust. A copy of the February 25, 2019 report of Miller and Lents, Ltd. is filed as Exhibit 99 to this report.

BP Alaska has undertaken a program of field-wide infrastructure renewal, pipeline replacement, and mechanical improvements to wells. As a consequence of these activities and their required downtime, and the natural production declines discussed above under Historical Production, BP Alaska s net production of oil and condensate allocated to the Trust from proved reserves was less than 90,000 barrels per day on an annual basis in 2016, 2017 and 2018. BP Alaska anticipates that its average net production of oil and condensate allocated to the Trust from proved reserves will be below 90,000 barrels per day on an annual average basis most future years. The occurrence of major gas sales could accelerate the decline in net production, due to the consequent decline in reservoir pressure. See Item 1A, RISK FACTORS.

Based on the 2018 twelve-month average WTI Price of $65.56 per barrel, current Production Taxes, and the Chargeable Costs adjusted as prescribed by the Overriding Royalty Conveyance, it is estimated that royalty payments to the Trust will continue through the year 2022, and would be zero in the following year. Therefore, no proved reserves are currently attributed to the BP Prudhoe Bay Royalty Trust after that date. Even if expected reservoir performance does not change, the estimated reserves, economic life and future net revenues attributable to the Trust may change significantly in the future. This may result from sustained periods of change in the WTI Price, the Production Tax or from changes in other prescribed variables utilized in calculations as defined by the Overriding Royalty Conveyance.

BP Alaska is under no obligation to make investments in development projects which would add additional non-proved resources to proved reserves and cannot make such investments without the concurrence of the Prudhoe Bay Unit working interest owners. The Prudhoe Bay Unit working interest owners regularly assess the technical and economic attractiveness of implementing projects to increase Prudhoe Bay Unit proved reserves. See Item 1A, RISK FACTORS, below.

In the event of changes in BP Alaska s current assumptions, oil and condensate recoveries may be reduced from the current estimates, unless recovery projects other than those included in the current estimates are implemented.

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INDUSTRY CONDITIONS AND REGULATIONS

The production of oil and gas in Alaska is affected by many state and federal regulations with respect to allowable rates of production, marketing, environmental matters and pricing. Future regulations could change allowable rates of production or the manner in which oil and gas operations may be lawfully conducted.

In general, BP Alaska s oil and gas activities are subject to existing federal, state and local laws and regulations relating to health, safety, environmental quality and pollution control. BP Alaska believes that the equipment and facilities currently being used in its operations generally comply with the applicable legislation and regulations. During the past few years, numerous environmental laws and regulations have taken effect at the federal, state and local levels. Oil and gas operations are subject to extensive federal and state regulation and to interruption or termination by governmental authorities due to ecological and other considerations and in certain circumstances impose absolute liability upon lessees for the cost of cleaning up pollutants and for pollution damages resulting from their operations. Although BP Alaska has advised that the existence of legislation and regulation has had no material adverse effect on BP Alaska s current method of operations, the effect of future legislation and regulations cannot be predicted.

Since the end of 2006, the corrosion monitoring and mitigation practices for the oil transit lines in the Prudhoe Bay Unit have been monitored and reviewed by the U.S. Department of Transportation. The construction, testing, and commissioning of the new replacement oil transit lines have been inspected by DOT inspectors. The replacement lines have been constructed and are operated and maintained in accordance with the requirements of the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (the PIPES Act). The applicable requirements of the subsequent regulations of the PIPES Act began to be phased in in 2012. See THE PRUDHOE BAY UNIT AND FIELD Collection and Transportation of Prudhoe Bay Oil above.

CERTAIN TA X CONSIDERATIONS

The following is a summary of the principal tax consequences to Unit holders resulting from the ownership and disposition of Units. The laws and regulations affecting these matters are complex, and are subject to change by future legislation or regulations or new interpretations by the Internal Revenue Service, state taxing authorities or the courts. In addition, there may be differences of opinion as to the applicability or interpretation of present tax laws and regulations. BP Alaska and the Trust have not requested any rulings from the Internal Revenue Service with respect to the tax treatment of the Units, and no assurance can be given that the Internal Revenue Service would concur with the statements below.

Unit holders are urged to consult their tax advisors regarding the effects on their specific tax situations of owning and disposing of Units.

Federal Income Tax

Classification of the Trust

The following discussion assumes that the Trust is properly classified as a grantor trust under current law and is not an association taxable as a corporation.

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General Features of Grantor Trust Taxation

A grantor trust is not subject to tax, and its beneficiaries (the Unit holders in the case of the Trust) are considered for tax purposes to own the assets of the trust directly. The Trust pays no federal income tax but files an information return reporting all items of income or deduction. If a court were to hold that the Trust is an association taxable as a corporation, the Trust would incur substantial income tax liabilities in addition to its other expenses.

Taxation of Unit Holders

In computing his federal income tax liability, each Unit holder is required to take into account his share of all items of Trust income, gain, loss, deduction, credit and tax preference, based on the Unit holder s method of accounting. Consequently, it is possible that in any year a Unit holder s share of the taxable income of the Trust may exceed the cash actually distributed to him in that year. For example, if the Trustee should add to the reserve for the payment of Trust liabilities or repay money borrowed to satisfy debts of the Trust, the money used to replenish the reserve or to repay the loan is income to and must be reported by the Unit holder, even though the money was not distributed to the Unit holder.

The Trust makes quarterly distributions to the persons who held Units of record on each Quarterly Record Date. The terms of the Trust Agreement seek to assure to the extent practicable that income, expenses and deductions attributable to each distribution are reportable by the Unit holder who receives the distribution.

The Trust allocates income and deductions to Unit holders based on record ownership at Quarterly Record Dates. It is not known whether the Internal Revenue Service will accept the allocation based on this method.

Depletion Deductions

The owner of an economic interest in producing oil and gas properties is entitled to deduct an allowance for the greater of cost depletion or (if otherwise allowable) percentage depletion on each such property. A Unit holder s deduction for cost depletion in any year is calculated by multiplying the holder s adjusted tax basis in his Units (generally his cost less prior depletion deductions) by Royalty Production during the year and dividing that product by the sum of Royalty Production during the year and estimated remaining Royalty Production as of the end of the year. The allowance for percentage depletion generally does not apply to interests in proven oil and gas properties that were transferred after December 31, 1974 and prior to October 12, 1990. The Omnibus Budget Reconciliation Act of 1990 repealed this rule for transfers occurring on or after October 12, 1990. Unit holders who acquired their Units on or after that date may be permitted to deduct an allowance for percentage depletion if such deduction would otherwise exceed the allowable deduction for cost depletion. In order to take percentage depletion, a Unit holder must qualify for the independent producer exemption contained in section 613A(c) of the Internal Revenue Code of 1986. Percentage depletion is based on the Unit holder s gross income from the Trust rather than on his adjusted basis in his Units. Any deduction for cost depletion or percentage depletion allowable to a Unit holder reduces his adjusted basis in his Units for purposes of computing subsequent depletion or gain or loss on any subsequent disposition of Units.

Unit holders must maintain records of their adjusted basis in their Units, make adjustments for depletion deductions to such basis, and use the adjusted basis for the computation of gain or loss on the disposition of the Units.

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Taxation of Foreign Unit Holders

Generally, a holder of Units who is a nonresident alien individual or which is a foreign corporation (a Foreign Taxpayer) is subject to tax on the gross income produced by the Royalty Interest at a rate equal to 30% (or at a lower treaty rate, if applicable). This tax is withheld by the Trustee and remitted directly to the United States Treasury. A Foreign Taxpayer may elect to treat the income from the Royalty Interest as effectively connected with the conduct of a United States trade or business under Internal Revenue Code section 871 or section 882, or pursuant to any similar provisions of applicable treaties. If a Foreign Taxpayer makes this election, it is entitled to claim all deductions with respect to such income, but a United States federal income tax return must be filed to claim such deductions. This election once made is irrevocable unless an applicable treaty provides otherwise or unless the Secretary of the Treasury consents to a revocation.

Section 897 of the Internal Revenue Code and the Treasury Regulations thereunder treat the Trust as if it were a United States real property holding corporation. Foreign holders owning more than five percent of the outstanding Units are subject to United States federal income tax on the gain on the disposition of their Units. Foreign Unit holders owning less than five percent of the outstanding Units are not subject to United States federal income tax on the gain on the disposition of their Units, unless they have elected under Internal Revenue Code section 871 or section 882 to treat the income from the Royalty Interest as effectively connected with the conduct of a United States trade or business.

If a Foreign Taxpayer is a corporation which made an election under Internal Revenue Code section 882(d), the corporation would also be subject to a 30% tax under Internal Revenue Code section 884. This tax is imposed on U.S. branch profits of a foreign corporation that are not reinvested in the U.S. trade or business. This tax is in addition to the tax on effectively connected income. The branch profits tax may be either reduced or eliminated by treaty.

Sale of Units

Generally, a Unit holder will realize gain or loss on the sale or exchange of his Units measured by the difference between the amount realized on the sale or exchange and his adjusted basis for such Units. Gain on the sale of Units by a holder that is not a dealer with respect to such Units will generally be treated as capital gain. However, pursuant to Internal Revenue Code section 1254, certain depletion deductions claimed with respect to the Units must be recaptured as ordinary income upon sale or disposition of such interest.

Backup Withholding

A payor must withhold 24% of any reportable payment if the payee fails to furnish his taxpayer identification number (TIN) to the payor in the required manner or if the Secretary of the Treasury notifies the payor that the TIN furnished by the payee is incorrect. Unit holders will avoid backup withholding by furnishing their correct TINs to the Trustee in the form required by law.

Widely Held Fixed Investment Trusts

The Trustee assumes that some Trust Units are held by a middleman, as such term is broadly defined in the U.S. Treasury Regulations (which includes custodians, nominees, certain joint owners, and brokers holding an interest for a custodian in street name). Therefore, the Trustee considers the Trust to be a widely held fixed investment trust (WHFIT) for U.S. Federal income tax purposes. The Bank of New York Mellon Trust Company, N.A. is the representative of the Trust that will provide tax information in accordance with applicable U.S. Treasury Regulations governing the information reporting requirements of the Trust as a WHFIT. For information contact The Bank of New

York Mellon Trust Company, N.A., Global Corporate Trust Corporate Finance, 601 Travis Street, Floor 16, Houston, TX 77002, telephone number (713) 483-6020.

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State Income Taxes

Unit holders may be required to report their share of income from the Trust to their state of residence or commercial domicile. However, only corporate Unit holders will need to report their share of income to the State of Alaska. Alaska does not impose an income tax on individuals or estates and trusts. All Trust income is Alaska source income to corporate Unit holders and should be reported accordingly.

Foreign Account Tax Compliance Act

Pursuant to the Foreign Account Tax Compliance Act (commonly referred to as FATCA), distributions from the Trust to foreign financial institutions and certain other non-financial foreign entities may be subject to U.S. withholding taxes. Specifically, certain withholdable payments (including certain royalties, interest and other gains or income from U.S. sources) made to a foreign financial institution or non-financial foreign entity will generally be subject to the withholding tax unless the foreign financial institution or non-financial foreign entity complies with certain information reporting, withholding, identification, certification and related requirements imposed by FATCA. Foreign financial institutions and non-financial foreign entities located in jurisdictions that have an intergovernmental agreement with the United States governing FATCA may be subject to different rules. Foreign Unit holders are encouraged to consult their own tax advisors regarding the possible implications of these withholding provisions on their investment in Trust Units.

ITEM 1A. RISK FACTORS

Owners of Units are exposed to risks and uncertainties that are particular to their investment.

Royalty Production from the Prudhoe Bay field is projected to decline and will eventually cease.

The Prudhoe Bay field has been in production since 1977. Development of the field is largely completed and proved reserves are being depleted. Production of oil and condensate from the field has been declining during recent years and the decline is expected to continue. As discussed above under the caption THE PRUDHOE BAY UNIT and FIELD Reserve Estimates , Royalty payments to the Trust, based on calculations using a 2018 WTI Price of $65.56 per barrel, among other prescribed variables, are projected to cease after 2022.

Production estimates included in this report are based on economic conditions and production forecasts as of the end of 2018, and also depend on various assumptions, projections and estimates which are continually revised and updated by BP Alaska. These revisions could result in material changes to the projected declines in production. It is possible that economic production from the reserves allocated to the 1989 Working Interests could decline more quickly and end sooner than is currently projected.

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Royalty payments by BP Alaska to the Trust are unpredictable, because they depend on Cushing, Oklahoma WTI spot prices, which, like crude oil prices in general, are subject to volatility, and on the volume of production from the 1989 Working Interests, which may vary from quarter to quarter in the future.

WTI prices, like prices in the global crude oil market generally, are subject to periodic fluctuations and significant volatility. This was dramatically demonstrated by the precipitous decline in WTI Prices from more than $76 per barrel on October 3, 2018 to under $43 dollars per barrel on December 25, 2018. While some analysts had predicted that crude oil prices would exceed $100 per barrel in 2018 for the first time since 2014, WTI prices finished the year down by 25% at $45.41 per barrel and Brent crude, the international benchmark, finished the year at $50.57 per barrel, down by almost 20%. This was the first annual decline in WTI and Brent crude prices since 2015. At the beginning of the fourth quarter of 2018, crude oil prices were at four-year highs. The sudden drop in oil prices in the fourth quarter of 2018 ended a two and a half year recovery after global oil prices had declined more than 70% from June 2014 through the middle of February 2016. While oil prices are generally expected to rise in 2019, the economic and geopolitical factors that led to the fall in oil prices in the fourth quarter of 2018 may have a negative impact on the recovery of oil prices in 2019.

The reasons for the sudden decline in oil prices in the fourth quarter of 2018 were not generally anticipated earlier in the year. President Trump s decision in early May to withdraw the U.S. from the Iran nuclear agreement resulted in a greater than 6% rise in oil prices, as the withdrawal was expected to lead to the renewal of U.S. economic sanctions on Iran and adversely affecting Iran s oil industry. With global oil supplies declining at that time and an increased probability of further supply reductions due to limitations on Iran s oil exports, Saudi Arabia and Russia agreed in September 2018 to increase production to help contain rising oil prices in order to support demand.

However, by October 2018, certain events such as the sharp drop in the U.S. stock market due to disappointing third quarter earnings reports (particularly by the large FANG technology stocks (Facebook, Amazon, Netflix and Google parent Alphabet)), the continuing U.S.-China trade dispute and the prospect of continued increases in interest rates by the U.S. Federal Reserve Board contributed to concerns of a global economic slowdown, helping to depress crude oil prices. The strengthening of the U.S. dollar also weighed on oil prices by decreasing demand in emerging markets for crude oil, which is sold in dollars. Also, larger than expected increases in U.S. crude inventories in October helped alleviate concerns of a global oil supply shortage that had helped to boost oil prices earlier in the year. The increases in inventories suggested that global demand for oil would grow more slowly than anticipated earlier in the year.

While global demand for crude started to decrease, the rise in oil prices earlier in the year had led U.S. shale producers to increase production. According to the U.S. Energy Information Administration (EIA), a record high in U.S. daily production of 10.9 million barrels was reached in the first week of June. The EIA also estimated in its January 2019 Short-Term Energy Outlook (STEO) that total U.S. crude oil production averaged 10.9 million barrels per day in 2018, an increase of 1.6 million barrels per day compared to production in 2017. As a result, the U.S. became the world s leading producer of crude oil in 2018.

The combination of increasing supply and decreasing demand resulted in the largest drop in crude oil prices in October 2018 since July 2016. Moreover, when the U.S. sanctions on Iran were restored on November 5, 2018, eight major importers of Iranian crude oil were unexpectedly granted exemptions, contributing further to the downward pressure on crude oil prices by decreasing the amount of crude that had been expected to be withdrawn from the global market.

In response to this situation, OPEC and certain non-OPEC producers led by Russia agreed in December 2018 to reduce their output by 1.2 million barrels per day in an effort to decrease the expanding crude surplus in the market. Subsequently, after the 2018 fourth quarter decline, oil prices began to recover at the beginning of the first quarter of 2019.

With respect to 2019, EIA forecasts that total global oil production will exceed consumption for the first half of the year. The EIA forecasts that oil supplies will rise by about 1.4 million barrels per day in 2019, primarily as a result of increasing U.S. production. U.S. output is expected to average 12.4 million barrels per day, an increase from the 2018 record production of 10.9 million barrels per day. Although the EIA forecasts that demand will grow by approximately 1.5 million barrels per day, such growth is not expected to offset the anticipated increases in supply until the third quarter of 2019. As a result, oil prices could continue to be volatile in the coming year. Partially offsetting this increase in U.S. output will be the decrease in production agreed to by OPEC and the coalition of producers led by Russia. Also in December 2018, the Alberta government decided to impose production cuts of 325,000 barrels per day until the excess storage supply in Canada is reduced. More recently, the sanctions imposed by the U.S. on Petróleos de Venezuela SA (PDVSA), Venezuela s state-owned oil and natural gas company, in January of this year are expected to remove additional amounts of crude from the market. The sanctions prohibit U.S. firms from importing Venezuelan crude oil that was not already in transit at the time of the sanctions.

In its February 2019 STEO, EIA forecast that Brent spot prices will average $61 per barrel in 2019 and $62 per barrel in 2020. According to the February 2019 STEO, WTI crude oil prices will average about $8 per barrel lower than Brent prices during the first quarter of 2019 but gradually fall to $4 per barrel in the fourth quarter of 2019. This $4 per barrel discount of WTI to Brent is expected to continue through 2020. EIA anticipates that increases in crude oil production in the United States will be offset in part by decreased production elsewhere, particularly in OPEC. In its January 2019 STEO, the EIA forecast that global consumption will increase by 1.5 million barrels per day in 2019, with growth largely coming from China, the United States, and India. EIA expects that the substantial price declines in the fourth quarter of 2018 together with OPEC production cuts will help keep global crude supply and demand in balance. This balance is expected to keep prices at around current levels in the near term. However, EIA s supply and demand forecast for 2019 is subject to significant uncertainty. Actual results or changes in market expectations regarding supply and demand could cause significant price fluctuations in 2019.

The forecast that the spread between WTI and Brent prices will decrease by the fourth quarter of 2019 assumes that certain limitations on the capacity to transport crude oil from the Cushing, Oklahoma storage hub to the Gulf Coast will be alleviated after the middle of the year. At that point, EIA expects that new capacity to carry crude oil from West Texas to the Gulf Coast will go into operation and will reduce current distribution bottlenecks throughout Texas and Oklahoma. In prior periods, Cushing has occasionally become oversupplied due to new oil flows from Canada and the United States. Historically, this market had been reliant on high-cost rail and trucks to ship both crude oil stored at Cushing and production from Canada and the Bakken shale formation to the Gulf Coast. These constraints on transportation of crude oil out of the U.S. Midwest market, together with the great increase in production in North America and the decades-long U.S. ban on crude oil exports, had helped to weigh down WTI spot prices for several years and kept the price of WTI crude oil at a historic discount to globally traded waterborne crudes such as Brent. Prior to that period, WTI, which is generally a sweeter and lighter crude oil than Brent, had been more likely to trade at a premium to Brent.

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After diverging in 2011 to a high of around $30 per barrel, with Brent the more expensive oil, the spread between WTI and Brent gradually decreased as these transportation problems appeared to be largely resolved. For example, the direction of the Seaway crude oil pipeline was reversed in 2012 and pump station additions and modifications were subsequently made. In 2014 the Seaway Twin pipeline running parallel to the reversed Seaway pipeline was opened. Also in 2014, the Cushing MarketLink phase of the Keystone pipeline went into operation. This portion of the Keystone pipeline starts at Cushing, where American-produced oil is added to the pipeline s Canadian oil. The pipeline then runs south to terminals in Nederland, Texas near refineries located in the Port Arthur, Texas area. The Houston Lateral pipeline also began operating in 2017. This is a 47-mile pipeline transporting crude oil from the MarketLink pipeline in Liberty County, Texas, to refineries and terminals in the Houston area. Also, in December 2017, the Plains All American and Valero Diamond Pipeline went into operation. This pipeline, with a capacity of 200,000 barrel per day, connects Cushing to Valero s refinery in Memphis, Tennessee.

Despite this increase in pipeline capacity out of Cushing, the tremendous growth in U.S. production, could result in additional transportation bottlenecks at Cushing, helping to widen the gap between WTI and Brent prices. In November 2018, Plains All American Pipeline LP announced that the expanded Sunrise Pipeline oil system from the Permian basin to Cushing was placed into service. While this development is expected to provide relief from transportation constraints in the Permian basin, it will help increase the flow of crude oil to Cushing. The expanded Sunrise Pipeline currently transports approximately 300,000 to 350,000 barrels per day and can ultimately transport approximately 500,000 barrels per day from Midland to Colorado City and Wichita Falls, Texas, and provides connections to Cushing. Also, the Saddlehorn pipeline, completed in 2016, which runs from Carr, Colorado to Platteville, Colorado, where it links up with the Grand Mesa Oil Pipeline, is currently capable of transporting 190,000 barrels per day to storage facilities in Cushing. The Matador pipeline, which will run 38 miles from Adams County, Colorado to the Saddlehorn terminal in Platteville Colorado for ultimate delivery to Cushing, is also currently under development and is expected to be in service by late 2019. The Matador pipeline will have an initial capacity of 220,000 barrels per day.

It was expected that even more crude oil would flow into Cushing following the approval by the Trump administration in January 2017 of a permit allowing TransCanada to build the Keystone XL pipeline and the approval by the Nebraska Public Service Commission of a new route for the pipeline in November 2017. Nebraska was the only state that had not yet approved the route of the pipeline. However, on November 8, 2018, a U.S. federal district court judge in Montana ordered a temporary halt to construction of the Keystone XL pipeline and ordered the U.S. Department of State to conduct a supplemental environmental impact statement. This could lead to additional delays to the project. However, TransCanada forecasts that, if the project is ultimately completed, Keystone XL would eventually carry up to 830,000 barrels of oil per day. This could significantly increase the total amount of crude oil flowing into Cushing via the Keystone pipeline system. The first part of that system, which runs through North and South Dakota, Nebraska and Missouri, went into operation in 2010 and connects Hardisty, Alberta to the Wood River Refinery in Roxana, Illinois, and the Patoka Oil Terminal Hub north of Patoka, Illinois. The pipeline has a nominal capacity of 435,000 barrels per day. The second part of the Keystone system is a 291 mile-long pipeline connection running from Steele City, Nebraska south to Cushing, Oklahoma. This Keystone-Cushing pipeline, which opened in 2011, transports 100,000 barrels of crude oil per day to Cushing. The Keystone XL pipeline would enter the U.S. through Montana, where American-produced oil would be added to the pipeline, and would then connect with the existing Keystone pipeline at Steele City, Nebraska. This would increase the amount of oil in the Keystone system flowing east to Illinois refineries and south to Cushing.

While insufficient outgoing pipeline capacity capable of transporting the crude oil entering Cushing could, as in prior years, depress WTI prices, pipeline capacity out of Cushing continues to increase, with new projects expected to go into operation in the near future. Magellan Midstream Partners, L.P. and

Navigator Energy Services have proposed a pipeline project known as Voyager. This pipeline would be nearly 500 miles long and would link the companies terminals in Cushing and East Houston. Once the Voyager reaches Houston, the pipeline is expected to be able to link to refineries in the region as well as to crude oil export facilities. The Voyager, which would have an initial capacity of at least 250,000 barrels per day, would also link with the Saddlehorn pipeline and the Glass Mountain pipeline, which services Midcontinent basins, as well as with other connections within Cushing. Also, in August 2018, Tallgrass Energy, LP (Tallgrass) announced that it plans to develop a new crude oil pipeline, known as the Seahorse Pipeline, from Cushing to the refining complex located in St. James, Louisiana. The approximately 700 mile long pipeline is expected to transport up to 800,000 barrels of crude oil per day from Cushing to the Louisiana Gulf Coast. The pipeline is expected to start operations in the third quarter of 2021. The other potential project to help relieve Cushing bottlenecks is the Capline reversal project. Capline currently transports crude oil from St. James, Louisiana, to Patoka, Illinois. Although Capline does not connect to Cushing, it could divert crude oil that would otherwise flow through Cushing.

The spread between the Brent price and the price of U.S. domestic production has also been affected by the lifting of the U.S. ban on crude oil exports which was introduced in the 1970 s. This ban was lifted in December 2015 and provided an outlet for U.S. oil to help prevent inventories from building up, which could cause prices to decrease. The removal of the ban could also contribute to wider use of WTI as a global benchmark. For the week through November 30, 2018, the U.S. exported more oil than it imported for the first time in 75 years. The EIA forecasts in the February 2019 STEO that by the fourth quarter of 2020, the U.S. will be a net exporter of crude oil and petroleum products by approximately 1.1 million barrels per day.

If OPEC and non-OPEC nations continue to adhere to the production cuts agreed to in December 2018, U.S. producers may have an opportunity to gain access to additional international markets. This possibility of losing market share to the U.S. could jeopardize compliance with the agreed-upon production levels by OPEC and the other producing countries. However, in a recent development, it was reported in early February 2019 that OPEC was seeking to enter into a formal relationship with the group of 10 oil producing nations led by Russia.

The amount and value of reserves attributable to the Trust, the estimated life of the Trust, estimates of future net revenues and estimates of the present value of future net revenues fluctuate based on the WTI Price, among other factors. WTI Prices may be below the break-even point for daily royalty calculations.

As discussed above under THE ROYALTY INTEREST in Item 1, revenues to the Trust are calculated daily by BP Alaska using the WTI price, production tax, and other variables as prescribed by the Conveyance applicable on that specific day. On January 1, 2019 the break-even WTI price (at which all taxes and prescribed deductions are equal to the WTI price) was $47.69.[11] The quarterly royalty payment by BP Alaska to the Trust is the sum of the individual revenues calculated each day during the quarter. In the event that one or more daily calculations results in a negative amount, the total of such daily negative amounts during that calendar quarter would be subtracted from total daily positive amounts during such quarter to determine the royalty payment for such quarter, provided, that in no event will any quarterly royalty payment be less than zero.

[11] The fixed Chargeable Cost increases specified in the Conveyance will impact the break-even price in future years.

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The estimated future net revenues and present value of estimated future net revenues reported herein are calculated based on a single average WTI price, that being the average of 12 WTI values, each value representing the WTI price in effect on the first calendar day of the month for the 12 months prior to January 1, 2019. As a result, any single calculation of a calendar day will not reflect the value of the dividend paid to the Trust for any quarter, nor will it reflect the estimated future value of the Trust or the estimation of how long royalty payments to the Trust will continue.

Based on the 2018 twelve-month average WTI Price of $65.56 per barrel, current Production Taxes, and the Chargeable Costs adjusted as prescribed by the Overriding Royalty Conveyance, it is estimated that royalty payments to the Trust will continue through the year 2022, and would be zero in the following year. Therefore, no proved reserves are currently attributed to the BP Prudhoe Bay Royalty Trust after that date. Even if expected reservoir performance does not change, the estimated reserves, economic life and future net revenues attributable to the Trust may change significantly in the future as a result of sustained periods of change in the WTI Price, the Production Tax or from changes in other prescribed variables utilized in calculations as defined by the Overriding Royalty Conveyance. Such changes could result in the termination of royalty payments prior to 2022.

While energy price forecasts are highly uncertain, EIA forecasts that Brent crude oil spot prices will average approximately $61 per barrel in 2019 and WTI spot prices will average $55 per barrel in 2019. As discussed under THE PRUDHOE BAY UNIT AND FIELD Reserve Estimates , the amount and value of reserves attributable to the Trust and the estimated life of the Trust fluctuate based on changes to certain prescribed factors, including the WTI price. WTI prices at the level forecast by EIA should, subject to the effect of the other prescribed variables, result in positive royalty payments to the Trust, if such prices actually constitute the 2019 twelve-month average WTI Price (that is, the unweighted arithmetic average of the WTI price on the first day of each month during the year). If the actual 2019 twelve-month average WTI Price is lower than forecast, this could result, subject to the effect of the other prescribed variables, in substantial decreases in the value and the estimated life of the Trust as calculated for such periods compared to the 2018 calculations set forth under THE PRUDHOE BAY UNIT AND FIELD Reserve Estimates .

However, future domestic and international events and conditions may produce wide swings in crude oil prices over relatively short periods of time. Recent moves in crude oil prices have been affected by many factors. These include changes in demand due to variations in economic activity, increased efficiency, increased demand for other types of fuel, strong production growth, new supplies from tight and shale resources, whether OPEC and other oil producing nations have been willing to intervene to stabilize oversupplied crude oil markets by cutting production or to take other measures in order to preserve or expand market share, shifts in inventory management strategies by international oil companies, conservation measures by consumers, increasing effects of the oil futures market and other unpredictable political, geopolitical, psychological and economic factors, such as developments with respect to political unrest in Iran and the Iran nuclear deal, the continuing collapse of Venezuela s oil industry, tensions between North Korea and South Korea and the U.S., the strength or weakness of the U.S. dollar (the currency in which crude oil is quoted, with crude oil prices, like prices of other commodities priced in dollars, generally moving inversely to the value of the dollar), how the policies of the U.S. administration may influence oil production and markets, expectations for global economic growth, developments relating to the U.S.-China trade dispute, events relating to the departure of the United Kingdom from the European Union (Brexit), political turmoil in North Africa and the Middle East and ongoing tensions in other regions of the world and turmoil and volatility in global stock markets.

For additional information, see the history of WTI Prices since 1986 published by the U.S. Energy Information Administration at http://tonto.eia.doe.gov.

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It is increasingly likely that the Trust s revenues in future periods also will be affected by decreases in production from the 1989 Working Interests. BP Alaska s average net production of oil and condensate allocated to the Trust from proved reserves was less than 90,000 barrels per day on an annual basis during 2016, 2017 and 2018, and the Trustee has been advised that BP Alaska expects that average net production allocated to the Trust from the proved reserves will be less than 90,000 barrels a day on an annual basis in future years. Unit holders thus are subject to the risk that cash distributions with respect to their Units may vary widely from quarter to quarter.

Prudhoe Bay field oil production could be shut in partially or entirely from time to time as a result of damage to or failures of field pipelines or equipment.

In August 2006, BP Alaska shut down the eastern side of the Prudhoe Bay Unit following the discovery of unexpectedly severe corrosion and a small spill from the oil transit line on that side of the Unit. Earlier, in March of 2006, BP had to temporarily shut down and commence the replacement of a three-mile segment of transit line on the western side of the Prudhoe Bay Unit following discovery of a large oil spill.

BP Alaska completely replaced approximately 16 miles of transit lines on the eastern and western sides of the Prudhoe Bay Unit and has implemented federally-required corrosion monitoring practices. However, the discovery of additional defects in Prudhoe Bay Unit oil flowlines and transit lines, and damage to or failures of separation facilities or other critical equipment, could result in future shutdowns of oil production from all or portions of the Prudhoe Bay Unit and have an adverse effect on future royalty payments.

Oil production from the Prudhoe Bay Unit could be interrupted by damage to the Trans-Alaska Pipeline System from natural causes, accidents, deliberate attacks or declining oil flows.

The Trans-Alaska Pipeline System connects the North Slope oil fields to the southern port of Valdez, almost 800 miles away. It is the only way that oil can be transported from the North Slope to market. The pipeline system crosses three mountain ranges, many rivers and streams and thaw-sensitive permafrost. It is susceptible along its length to damage from earthquakes, forest fires and other natural disasters. The pipeline system also is vulnerable to failures of pipeline segments and pumping equipment, accidental damage and deliberate attacks. Recently, the pipeline has become susceptible to damage resulting from declining flows of oil from the North Slope. Slower flows cause the temperature of the oil in the pipeline to cool faster, increasing the rate of deposit of wax, which coats pipe walls, hides corrosion and clogs sensors on smart pigs sent through the pipeline to detect it. Even lower flow rates projected in the future may lead to internal damage caused by ice formation within the pipe and external damage from frost heaves under buried segments. Major upgrades to the pipeline may be required to counteract the effects of cooler oil temperature. If the pipeline or its pumping stations should suffer major damage from natural or man-made causes, production from the Prudhoe Bay Unit could be shut in until the pipeline system can be repaired and restarted. Royalty payments to the Trust could be halted or reduced by a material amount as a result of interruption to production from the Prudhoe Bay Unit.

In January 2011, TAPS was shut down over two periods of several days each as a result of the discovery of a leak of crude oil in the basement of a booster pump building at Pump Station No. 1. See THE PRUDHOE BAY UNIT AND FIELD Collection and Transportation of Prudhoe Bay Oil in Item 1 for additional information.

On November 30, 2018, TAPS was shut down for 7 hours as a precaution after a 7.0 magnitude earthquake struck the region. No damages to TAPS were reported and it was brought back online after Alyeska Pipeline Service Company, the operator of TAPS, determined it was operationally safe to restart the system.

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As noted above, without more crude oil to be transported by TAPS, slower flows and freezing temperatures could eventually force the closure of the pipeline, making it impossible to transport oil from the North Slope to market. In 2018, after two consecutive years of increase, the pipeline s average throughput decreased by approximately 18,000 barrels per day in 2018 compared to 2017. This amounted to a 3.4 percent decrease. The 2018 throughput was the pipeline s second lowest annual daily average after 2015. Before the 2016 increase, the last increase in pipeline throughput was in 2002, when the pipeline carried over one million barrels per day. The 2016 and 2017 increases have been attributed to a combination of factors, such as better than expected performance from newer oil fields west of Prudhoe Bay, such as ConocoPhillips CD-5 development on the North Slope in the Colville River Unit (part of the Alpine Field and the first commercial oil development on Alaska Native lands within the boundaries of the National Petroleum Reserve-Alaska (NPRA) as discussed below) and the ability of oil companies to produce oil from mature fields like Prudhoe Bay more efficiently. Nevertheless, throughput for the last three years has averaged only 518,169 barrels per day. The pipeline was designed to carry much higher volumes of oil. In 2011, a study by Alyeska raised questions as to whether TAPS could continue in operation below a throughput level of approximately 300,000 barrels per day. A 2018 update of the 2011 low flow study details steps Alyeska is taking or plans to take such as adding heat to maintain crude oil temperature within operating parameters to mitigate the problems associated with slower oil flow through the pipeline. The EIA, which has forecast continued declining production from the North Slope, has also noted that considerable investment could be required to keep TAPS operational if throughput goes below 350,000 barrels per day.

However, in potentially significant developments for Alaska and TAPS, recent discoveries in the North Slope could increase crude oil production by as much as 40 percent during the next eight years, according to data and information services provider IHS Markit. Among other discoveries, Caelus Energy LLC, a small energy exploration company, announced in October 2016 that it had discovered oil in Smith Bay on Alaska s northern coast. The company reported that the field could hold as much as 6 billion barrels of oil and that it expects to be able to recover between 1.8 to 2.4 billion barrels. However, due to the complexity and expense of the project and the length of the regulatory process, oil from the discovery is not expected to flow to TAPS until 2022. In March of 2017, a partnership between Spanish oil company Repsol and its U.S. partner, Armstrong Energy, announced a significant oil discovery in the Nanushuk formation located across the central and western portion of the North Slope. The partnership predicted that production could begin as soon as 2021 and could produce as much as 120,000 barrels of oil per day. According to the partnership, the discovery, located in a well known as Horseshoe, is 20 miles south of where Repsol-Armstrong had already found oil in 2014 and 2015 in a project known as the Pikka Unit. The Pikka project is already in early development and it is anticipated that first production will begin in 2021, with a possible production of nearly 120,000 barrels of oil per day. Also in January 2017, ConocoPhillips announced a new oil discovery, known as Willow, located in the Greater Mooses Tooth Unit on ConocoPhillips leases in the northeastern portion of NPRA. According to ConocoPhillips, Willow could produce up to 100,000 barrels of oil per day. Production at Willow is expected to begin in 2023. In addition, production at ConocoPhillip s CD-5 development reached 37,000 barrels of oil per day in 2018, more than originally projected. ConocoPhillips also announced in October 2018 that it had begun production at its Greater Mooses Tooth 1 field (GMT1), also located in the NPRA. The field is projected to eventually produce up to 38,000 barrels per day. In October 2018, the Bureau of Land Management and the U.S. Army Corps of Engineers issued a Joint Record of Decision approving ConocoPhillips Greater Mooses Tooth 2 project (GMT2). GMT2 is located about 8 miles west of GMT1 in the NPRA and is expected to produce 35,000 to 40,000 barrels per day during peak production. The Horseshoe, Willow, Smith Bay and GMT discoveries are all located in the Nanushuk formation or the related Torok formation. As a result of these discoveries, it has been projected that over the next five years, ConocoPhillips will be adding 100,000 barrels a day to TAPS.

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Another potential source of crude oil in Alaska lies in the 19 million acres of the Arctic National Wildlife Refuge (ANWR). It is estimated that a 1.5-million-acre part of the coastal plain of ANWR known as the 1002 area contains 11.8 billion barrels of potentially recoverable crude oil. A 40-year-old ban on energy development in the ANWR was removed when the Tax Cuts and Jobs Act (the TCJA) was enacted in December 2017. The TCJA includes a provision that permits oil exploration and drilling in the 1002 area. In addition, the Trump administration announced in January 2018 that it would allow new offshore oil and gas drilling in nearly all United States coastal waters, including the Arctic Ocean.

Production from the 1989 Working Interests may be interrupted or discontinued by BP Alaska.

BP Alaska has no obligation to continue production from the 1989 Working Interests or to maintain production at any level and may interrupt or discontinue production at any time. The Trust does not have the right to take over operation of the 1989 Working Interests or share in any operating decisions by BP Alaska concerning the Prudhoe Bay Unit. The operation of the Prudhoe Bay Unit is subject to normal operating hazards incident to the production and transportation of oil in Alaska. In the event of damage to the infrastructure, facilities and equipment in the Prudhoe Bay field which is covered by insurance, BP Alaska has no obligation to use insurance proceeds to repair such damage and may elect to retain such proceeds and close damaged areas to production.

Construction of a gas pipeline from the North Slope of Alaska could accelerate the decline in Royalty Production from the Prudhoe Bay field.

The construction of a natural gas pipeline to bring natural gas from the North Slope could make it economical to extract natural gas from the Prudhoe Bay field and transport it to market. Currently, natural gas released by pumping oil is reinjected into the ground, which helps to maintain reservoir pressure and facilitates extraction of oil from the field. Extraction of natural gas from the Prudhoe Bay field would lower reservoir pressure, although carbon dioxide stripped out of the gas could be reinjected and other methods could be employed to mitigate the reduction. The lowering of the reservoir pressure could accelerate the decline in production from the 1989 Working Interests and the time at which royalty payments to the Trust would cease. Since the Trust is not entitled to any royalty payments with respect to natural gas production from the 1989 Working Interests, the Unit holders would not realize any offsetting benefit from natural gas production from the Prudhoe Bay field.

Without a pipeline, extraction of natural gas from the Prudhoe Bay field on a large scale would not be economical. In October 2012, ExxonMobil, ConocoPhillips, BP and Calgary-based TransCanada Corporation (TransCanada) notified the Alaska Governor that they had agreed on a plan to combine what were once two competing natural gas pipeline projects destined for the continental U.S. into one project focused on export markets. This project contemplated building an 800-mile natural gas pipeline from the North Slope to a port on the southern coast of Alaska from which liquified natural gas (LNG) would be exported to Asia. It was contemplated that the project would also include natural gas processing facilities and a natural-gas export terminal.

In January 2014, it was announced that the state of Alaska would pursue becoming an equity partner in the Alaska natural gas pipeline project and that ExxonMobil, BP, ConocoPhillips, TransCanada, Alaska Gasline Development Corporation (AGDC), and Alaska s commissioners of natural resources and revenue had signed a heads of agreement (HOA) for the Alaska LNG Project. This established the commercial framework for the development of the natural gas pipeline from the North Slope to the south-central Alaska coast. The Nikiski area of the Kenai Peninsula was selected as the leading site for the LNG plant. In November 2015, AGDC purchased TransCanada s 25% interest in the project.

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In August 2016, ExxonMobil, BP and ConocoPhilips indicated that they did not currently wish to make further investments in the Alaska LNG project. This decision followed a report, commissioned by ExxonMobil, BP and AGDC, by an energy consultancy firm stating the project s competitiveness ranks poorly under current market conditions. At the end of 2016, it was announced that AGDC had concluded agreements with ExxonMobil, BP and ConocoPhillips to take over the leadership position in the Alaska LNG project.

In November 2017, Alaska state officials announced that AGDC, which is currently the sole owner of the Alaska LNG project, had signed a joint development agreement with Sinopec, one of the world s largest oil and gas companies, China Investment Corp., the world s third-largest sovereign wealth fund, and the state-owned commercial bank, Bank of China, to pursue the project. In January 2019, Alaska and three Chinese companies agreed to extend negotiations to conclude definitive agreements for the Alaska LNG project until June 30, 2019. In June 2017, it was announced that AGDC had signed an agreement with the Korea Gas Corp. to establish a cooperative framework for the development of Alaska s natural gas infrastructure.

The Alaska LNG project, which AGDC has stated may cost approximately $43 billion, is currently in the federal regulatory phase. AGDC expects a final environmental review to be completed by the Federal Energy Regulatory Commission (FERC) in December 2019 and a record of decision in March 2020. Construction of the project is currently expected to begin in 2020 with a goal of transporting natural gas by 2024. In May 2018, AGDC announced that BP Alaska and AGDC had agreed on the primary terms of a gas sales agreement to supply natural gas to the Alaska LNG project. In September 2018, AGDC also announced that it had agreed to terms and conditions for gas sales with ExxonMobil. Negotiations between ConocoPhillips and AGDC are ongoing.

The effect of any changes to the Alaska Production Tax Statutes on Per Barrel Royalty and Royalty Production from the Prudhoe Bay field is unpredictable.

As noted (see THE ROYALTY INTEREST Production Taxes in Item 1 above), Alaska s Production Tax Statutes affect the calculation of the Per Barrel Royalty. Among other changes to the Production Tax Statutes, the 2013 amendments added a stair-step per-barrel tax credit for oil production, provided that a producer s tax liability may not be reduced below the minimum tax . Since going into effect on January 1, 2014, the 2013 amendments had the effect of reducing Production Taxes imposed on Royalty Production. Moreover, as a result of the low oil price environment that began in mid-2014, Royalty Production has been subject to the minimum tax under the Production Tax Statutes since the first quarter of 2015. The reduction in Production Taxes has in part offset the reduction in royalty payments that resulted from declining WTI prices.

Any changes to the Production Tax Statutes in the future may also impact the amount of Production Taxes and, in turn, the amount of royalty payments. Whether or when any such changes may occur and the effect any such changes may have on the Per Barrel Royalty is unpredictable.

The Production Tax Statutes can also have an impact on Royalty Production from the Prudhoe Bay field. For example, the 2007 amendments to the Production Tax Statutes (see THE ROYALTY INTEREST Production Taxes in Item 1 above) may have accelerated the decline in production of oil and condensate from the Prudhoe Bay field to the extent that it caused BP Alaska and the other owners of working interests in the Prudhoe Bay Unit to reduce or defer investment in oil production infrastructure renewal, well development and implementation of new technology due to uncompetitive returns on investment in Alaska. The 2007 amendments, in addition to increasing the basic oil production tax rate and the progressivity factor, also eliminated or reduced many deductions and credits permitted under the 2006 amendments to the Production Tax Statutes. Due in part to the 2007 amendments, BP Alaska s

spending on production adding activity, adjusted for inflation, was flat to declining from 2008 through 2012. As noted under THE ROYALTY INTEREST Production Taxes in Item 1 above, the 2013 amendments to the Production Tax Statutes were intended to encourage oil production and investment in Alaska s oil industry by eliminating the monthly progressivity tax rate implemented by 2006 and 2007 amendments and adding a stair-step per-barrel tax credit for oil production. Due to the low oil price environment that has prevailed for much of the time since the 2013 amendments went into effect, and since the Prudhoe Bay field is a mature field, the impact of the 2013 amendments in terms of encouraging oil production and investment with respect to the Prudhoe Bay field is uncertain. However, it has been suggested that the 2013 amendments to the Production Tax Statutes provided the impetus for the series of recent Alaska oil discoveries discussed above.

There are potential conflicts of interest between BP Alaska and the Trust that could affect the royalties paid to Unit holders.

The interests of BP Alaska and the Trust with respect to the Prudhoe Bay Unit could at times be different. The Per Barrel Royalty that BP Alaska pays to the Trust is based on the WTI Price, Chargeable Costs and Production Taxes, all of which are amounts contractually defined in the Conveyance. The WTI Price does not necessarily correspond to the actual price realized by BP Alaska for crude oil produced from the 1989 Working Interests, and Chargeable Costs and Production Taxes may not bear any relation to BP Alaska s actual costs of production and tax expenses. The actual per barrel profit realized by BP Alaska on the Royalty Production may differ materially from the Per Barrel Royalty that it is required to pay to the Trust. It is possible under certain circumstances that the relationship between BP Alaska s actual per barrel revenues and costs could be such that BP Alaska might determine to interrupt or discontinue production in whole or in part from the 1989 Working Interests even though a Per Barrel Royalty might otherwise be payable to the Trust under the Conveyance.

ITEM 1B. UNRESOLVED STAFF COMMENTS

The Trust has not received any written comments from the staff of the Securities and Exchange Commission regarding its periodic or current reports under the Securities Exchange Act of 1934 (the Exchange Act) that remain unresolved.

ITEM 2. PROPERTIES

Reference is made to Item 1 for the information required by this item.

ITEM 3. LEGAL PROCEEDINGS

None

ITEM 4. MINE SAFETY DISCLOSURE

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT S UNITS, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF UNITS

The Units are listed and traded on the New York Stock Exchange under the symbol BPT. The following table shows the high and low sales prices per Unit on the New York Stock Exchange and the cash distributions paid per Unit, for each calendar quarter in the two years ended December 31, 2018.

	High	Low	Distributions Per Unit
2017:			
First Quarter	$ 32.95	$ 15.00	$ 0.994
Second Quarter	24.65	18.55	1.098
Third Quarter	22.45	18.75	0.833
Fourth Quarter	22.75	18.65	0.675
2018:			
First Quarter	$ 27.95	$ 19.25	$ 1.230
Second Quarter	31.80	20.85	1.275
Third Quarter	34.60	26.75	1.408
Fourth Quarter	37.23	17.00	1.380

As of February 14, 2019, 21,400,000 Units were outstanding and were held by 259 holders of record. No Units were purchased by the Trust or any affiliated purchaser during the year ended December 31, 2018.

Future payments of cash distributions are dependent on such factors as prevailing WTI Prices, the relationship of the rate of change in the WTI Price to the rate of change in the Consumer Price Index, the Chargeable Costs, the rates of Production Taxes prevailing from time to time, and the actual Royalty Production from the 1989 Working Interests. See THE ROYALTY INTEREST in Item 1.

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ITEM 6. SELECTED FINANCIAL DATA

The following table presents in summary form selected financial information regarding the Trust.

	Year ended December 31				
	2018	2017	2016	2015	2014
	(in thousands, except per Unit amounts)				
Royalty revenues	$ 114,369	$ 78,193	44,917	126,781	227,904
Interest income	34	11	2		
Trust administration expenses	(1,121)	$ (1,165)	(1,298)	(1,320)	(1,141)
Cash earnings	$ 113,282	$ 77,039	43,621	125,461	226,763
Cash distributions	$ 113,263	$ 77,031	43,619	125,461	226,763
Cash distributions per unit	$ 5.293	$ 3.600	2.038	5.863	10.596

	2018	2017	2016	2015	2014
Trust corpus	$ 691	$ 785	786	750	833
Total assets	$ 1,031	$ 1,012	1,004	1,002	1,002
Units outstanding	21,400,000	21,400,000	21,400,000	21,400,000	21,400,000

ITEM 7. TRUSTEE S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Liquidity and Capital Resources

The Trust is a passive entity. The Trustee s activities are limited to collecting and distributing the revenues from the Royalty Interest and paying liabilities and expenses of the Trust. Generally, the Trust has no source of liquidity and no capital resources other than the revenue attributable to the Royalty Interest that it receives from time to time. See the discussion under THE ROYALTY INTEREST in Item 1 for a description of the calculation of the Per Barrel Royalty, and the discussion under THE PRUDHOE BAY UNIT AND FIELD Reserve Estimates in Item 1 for information concerning the estimated future net revenues of the Trust. However, the Trust Agreement gives the Trustee power to borrow, establish a cash reserve, or dispose of all or part of the Trust property under limited circumstances. See the discussion under THE TRUST Sales of Royalty Interest; Borrowings and Reserves in Item 1.

Since 1999, the Trustee has maintained a $1,000,000 cash reserve to provide liquidity to the Trust during any future periods in which the Trust does not receive a distribution. As noted above under THE TRUST Sales of Royalty Interest; Borrowings and Reserves , on December 19, 2018, the Trust issued a press release to announce that the Trustee had determined to gradually increase the Trustee s existing cash reserve for the payment of future expenses and liabilities of the Trust, as permitted by the Trust

Agreement. Commencing with the distribution to Unit holders payable in April, 2019, the Trustee intends to withhold the greater of $33,750 or 0.17% of the funds otherwise available for distribution each quarter to gradually increase existing cash reserves by a total of approximately $270,000. The Trustee may increase or decrease the targeted amount at any time, and may increase or decrease the rate at which it is withholding funds to build the cash reserve at any time, without advance notice to the Unit holders. Cash held in reserve will be invested as required by the Trust Agreement. Any cash reserved in excess of the amount necessary to pay or provide for the payment of future known, anticipated or contingent expenses or liabilities eventually will be distributed to Unit holders, together with interest earned on the funds.

The Trustee will draw funds from the cash reserve account during any quarter in which the quarterly distribution received by the Trust does not exceed the liabilities and expenses of the Trust, and will replenish the reserve from future quarterly distributions, if any. The Trustee anticipates that it will keep this cash reserve program in place until termination of the Trust.

Amounts set aside for the cash reserve are invested by the Trustee in U.S. government or agency securities secured by the full faith and credit of the United States, or mutual funds investing in such securities. Interest income received by the Trust from the investment of the reserve fund is added to the distributions received from BP Alaska and paid to the Unit holders on each Quarterly Record Date.

Results of Operations

Relatively modest changes in oil prices significantly affect the Trust s revenues and results of operations. Crude oil prices are subject to significant changes in response to fluctuations in the domestic and world supply and demand and other market conditions as well as the world political situation as it affects OPEC and other producing countries. The effect of changing economic conditions on the demand and supply for energy throughout the world and future prices of oil cannot be accurately projected.

Royalty revenues are generally received on the Quarterly Record Date (generally the fifteenth day of the month) following the end of the calendar quarter in which the related Royalty Production occurred. The Trustee, to the extent possible, pays all expenses of the Trust for each quarter on the Quarterly Record Date on which the revenues for the quarter are received. For the statement of cash earnings and distributions, revenues and Trust expenses are recorded on a cash basis and, as a result, distributions to Unit holders in each calendar year ending December 31 are attributable to BP Alaska s operations during the twelve-month period ended on the preceding September 30.

When BP Alaska s average net production of oil and condensate per quarter from the 1989 Working Interests exceeds 90,000 barrels a day, the principal factors affecting the Trust s revenues and distributions to Unit holders are changes in WTI Prices, scheduled annual increases in Chargeable Costs, changes in the Consumer Price Index and changes in Production Taxes. However, it is likely that the Trust s revenues in future periods also will be affected by increases and decreases in production from the 1989 Working Interests. BP Alaska s net production of oil and condensate allocated to the Trust from proved reserves was less than 90,000 barrels per day on an annual basis during 2016, 2017 and 2018. The Trustee has been advised that BP Alaska expects that average net production allocated to the Trust from the proved reserves will be less than 90,000 barrels a day on an annual basis in future years.

BP Alaska estimates Royalty Production from the 1989 Working Interests for purposes of calculating quarterly royalty payments to the Trust because complete actual field production data for the preceding calendar quarter generally is not available by the Quarterly Record Date. To the extent that average net production from the 1989 Working Interests is below 90,000 barrels per day, calculation by BP Alaska of actual Royalty Production data may result in revisions of prior Royalty Production estimates. Revisions

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by BP Alaska of its Royalty Production calculations may result in quarterly royalty payments by BP Alaska which reflect adjustments for overpayments or underpayments of royalties with respect to prior quarters. Such adjustments, if material, may adversely affect certain Unit holders who buy or sell Units between the Quarterly Record Dates for the Quarterly Distributions affected. See Note 8 of Notes to Financial Statements in Item 8. Because the annual statement of cash earnings and distributions of the Trust is prepared on a modified cash basis, royalty revenues for the calendar year do not include the amounts of underpayments or overpayments affecting payments received during the fourth quarter of the year.

During the years 2017 and 2018 and the period of 2019 up to the date of this report, WTI Prices have been above the level necessary for the Trust to receive a Per Barrel Royalty. Whether the Trust will be entitled to future distributions during the remainder of 2019 will depend on WTI Prices prevailing during the remainder of the year.

As discussed above in Item 1A RISK FACTORS , it is possible that global oil prices could remain at current or lower levels for a significant period. As also discussed above in Item 1A RISK FACTORS , on January 1, 2019, the break-even WTI price (the price at which all taxes and prescribed deductions are equal to the WTI price) for the Trust to receive a positive Per Barrel Royalty with respect to a particular day s production was $47.69. From the beginning of the first quarter of 2019 through February 20, 2019, the WTI crude oil spot price fluctuated between a high of $57.11 per barrel on February 20, 2019 and a low of $46.31 per barrel on January 2, 2019. The WTI crude oil spot price on February 21, 2019 was $56.84 per barrel. The quarterly royalty payment by BP Alaska to the Trust is the sum of the individual revenues attributed to the Trust as calculated each day during the quarter. Any single calculation of a calendar day will not reflect the value of the dividend paid to the Trust for the quarter, nor will it reflect the estimated future value of the Trust. However, if a low oil price environment should occur for a protracted period, quarterly royalty payments could decline significantly, and could in fact be zero.

2018 compared to 2017

As explained in Note 2 of Notes to Financial Statements below, the financial statements of the Trust are prepared on a modified cash basis and differ from financial statements prepared in accordance with generally accepted accounting principles in that (a) revenues are recorded when received (generally within 15 days of the end of the preceding quarter) and distributions to Trust Unit holders are recorded when paid and (b) Trust expenses are recorded on an accrual basis. As a consequence, Trust royalty revenues for the fiscal year are based on Royalty Production during the twelve months ended September 30 of the fiscal year.

		Increase (decrease)		
	12 Months Ended 9/30/2018	**Amount**	**Percent**	**12 Months Ended 9/30/2017**
Average WTI Price	$ 63.95	$ 14.54	29.4	$ 49.41
Adjusted Chargeable Costs	$ 37.15	$ 4.9	15.2	$ 32.25
Average Production Taxes	$ 2.34	$ 0.66	39.2	$ 1.68
Average Per Barrel Royalty	$ 24.48	$ 8.99	58.0	$ 15.49
Average net royalty production (mb/d)	78.3	(6.5)	(7.7)	84.8

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Average WTI prices during the twelve months ended September 30, 2018 increased significantly compared to the preceding twelve-month period. Average monthly WTI prices during this period ranged from a low of $51.56 during the first month of the period in October 2017 to a high of $70.84 during July 2018. The increase in the Consumer Price Index used to calculate the Cost Adjustment Factor, as well as the scheduled increase in Chargeable Costs from $17.20 in calendar 2017 to $20.00 in calendar 2018, resulted in the increase in Adjusted Chargeable Costs during the twelve month ended September 30, 2018. The increase in the average Per Barrel Royalty for the period resulted primarily from the rise in WTI prices. This increase was partially offset by the increase in Production Taxes. Although the nearly 40 percent increase in Production Taxes resulted from the increase in WTI price between the two periods, Production Taxes remained historically low for the twelve months ended September 30, 2018 because Production Taxes for the first three quarters during the period were calculated on the basis of the minimum tax under the Act and the 2014 Letter Agreement. See Note 5 of Notes to Financial Statements in Item 8 below.

The decrease in the average net production from the 1989 Working Interests between the two periods was due to the naturally declining production rate from the Prudhoe Bay field and variance in the impacts of planned and unplanned downtime during the two reporting periods.

	Year Ended 12/31/2018	Increase (decrease) Amount	Percent	Year Ended 12/31/2017
		(Dollars in thousands)		
Royalty revenues	$ 114,369	$ 36,176	46.3	$ 78,193
Cash earnings	$ 113,282	$ 36,243	47.0	$ 77,039
Cash distributions	$ 113,263	$ 36,232	47.0	$ 77,031
Administrative expenses	$ 1,121	($ 44)	(3.8)	$ 1,165
Trust corpus at year end	$ 691	($ 94)	(12.0)	$ 785

The period-to-period increases in royalty revenues, cash earnings and cash distributions are due to the significantly higher average WTI Prices that prevailed during 2018 compared to 2017. The decrease in administrative expenses reflects lower overall costs of supplies and services and timing differences in accruals of expenses. The decrease in the Trust corpus reflects the increase in accrued expenses for the period.

2017 compared to 2016

	12 Months Ended 9/30/2017	Increase (decrease) Amount	Percent	12 Months Ended 9/30/2016
Average WTI Price	$ 49.41	$ 7.80	18.7	$ 41.61
Adjusted Chargeable Costs	$ 32.25	$ 0.82	2.6	$ 31.43
Average Production Taxes	$ 1.68	$ 0.31	22.6	$ 1.37
Average Per Barrel Royalty	$ 15.49	$ 6.68	75.8	$ 8.81
Average net royalty production (mb/d)	84.8	(4.2)	(4.7)	89.0

Average WTI prices during the twelve months ended September 30, 2017 increased significantly compared to the preceding twelve-month period. WTI prices during this period ranged from an average high price of $53.47 during February 2017 to an average price of $49.82 during the last month of the

period in September 2017. The lowest average monthly price for the period was $45.18 in June 2017. The increase in the Consumer Price Index used to calculate the Cost Adjustment Factor, as well as the scheduled increase in Chargeable Costs from $17.10 in calendar 2016 to $17.20 in calendar 2017, resulted in the modest increase in Adjusted Chargeable Costs during the twelve month ended September 30, 2017. The increase in the average Per Barrel Royalty for the period resulted primarily from the rise in WTI prices. This increase was partially offset by the increase in Production Taxes. Although the 22.6 percent increase in Production Taxes resulted from the increase in WTI price between the two periods, Production Taxes remained historically low for the twelve months ended September 30, 2017 because, as with each quarter since the second quarter of 2015, Production Taxes for each quarter during the period were calculated on the basis of the minimum tax under the Act and the 2014 Letter Agreement. See Note 5 of Notes to Financial Statements in Item 8 below.

The decrease in the average net production from the 1989 Working Interests between the two periods was due to the naturally declining production rate from the Prudhoe Bay field and variance in the impacts of planned and unplanned downtime during the two reporting periods.

	Year Ended 12/31/2017	**Increase (decrease) Amount**	**Percent**	**Year Ended 12/31/2016**
		(Dollars in thousands)		
Royalty revenues	$ 78,193	$ 33,276	74.1	$ 44,917
Cash earnings	$ 77,039	$ 33,418	76.6	$ 43,621
Cash distributions	$ 77,031	$ 33,412	76.6	$ 43,619
Administrative expenses	$ 1,165	($ 134)	(10.3)	$ 1,298
Trust corpus at year end	$ 785	($ 1)	(0.1)	$ 786

The period-to-period increases in royalty revenues, cash earnings and cash distributions are due to the significantly higher average WTI Prices that prevailed during 2017 compared to 2016. The decrease in administrative expenses reflects lower overall costs of supplies and services and timing differences in accruals of expenses.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Trust is a passive entity and except for the Trust s ability to borrow money as necessary to pay liabilities of the Trust that cannot be paid out of cash on hand, the Trust is prohibited from engaging in borrowing transactions. The Trust periodically holds short-term investments acquired with funds held by the Trust pending distribution to Unit holders and funds held in reserve for the payment of Trust expenses and liabilities. Because of the short-term nature of these investments and limitations on the types of investments which may be held by the Trust, the Trust is not subject to any material interest rate risk. The Trust does not engage in transactions in foreign currencies which could expose the Trust or Unit holders to any foreign currency related market risk or invest in derivative financial instruments. It has no foreign operations and holds no long-term debt instruments.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

BP PRUDHOE BAY ROYALTY TRUST

Index To Financial Statements

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Report of Independent Registered Public Accounting Firm

To the Trustee and Holders of Trust Units

BP Prudhoe Bay Royalty Trust:

Opinion on the Financial Statements

We have audited the accompanying statements of assets, liabilities, and trust corpus of BP Prudhoe Bay Royalty Trust (the Trust) as of December 31, 2018 and 2017, and the related statements of cash earnings and distributions and changes in trust corpus for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the financial statements). In our opinion, the financial statements present fairly, in all material respects, the assets, liabilities, and trust corpus of the Trust as of December 31, 2018 and 2017, and its cash earnings and distributions and changes in trust corpus for each of the years in the three-year period ended December 31, 2018, in conformity with the modified cash basis of accounting described in note 2.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Trust s internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 1, 2019 expressed an unqualified opinion on the effectiveness of the Trust s internal control over financial reporting.

Basis of Accounting

As described in note 2 to the financial statements, these financial statements were prepared on the modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of The Bank of New York Mellon Trust Company, N.A., as the Trust s trustee (the Trustee). Our responsibility is to express an opinion on these financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Trust in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by the Trustee, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

(signed) KPMG LLP

We have served as the Trust s auditor since 1989.

Dallas, Texas

March 1, 2019

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Report of Independent Registered Public Accounting Firm

To the Trustee and Holders of Trust Units

BP Prudhoe Bay Royalty Trust:

Opinion on Internal Control Over Financial Reporting

We have audited BP Prudhoe Bay Royalty Trust s (the Trust) internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the statements of assets, liabilities, and trust corpus of the Trust as of December 31, 2018 and 2017, and the related statements of cash earnings and distributions and changes in trust corpus for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the financial statements), and our report dated March 1, 2019 expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Bank of New York Mellon Trust Company, N.A., as the Trust s trustee (the Trustee) is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the Item 9A Internal Control Over Financial Reporting Management s Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Trust s internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Trust in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

The Trust s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the modified cash basis of accounting. The Trust s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Trust; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the modified cash basis of accounting, and that receipts and expenditures of the Trust are being made only in accordance with authorizations of the Trustee; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Trust s assets that could have a material effect on the financial statements.

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

(signed) KPMG LLP

Dallas, Texas

March 1, 2019

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BP Prudhoe Bay Royalty Trust

Statements of Assets, Liabilities and Trust Corpus

(Prepared on a modified basis of cash receipts and disbursements)

(In thousands, except unit data)

	December 31, 2018	December 31, 2017
Assets		
Cash and cash equivalents (Note 2)	$ 1,031	$ 1,012
Total assets	$ 1,031	$ 1,012
Liabilities and Trust Corpus		
Accrued expenses	$ 339	$ 227
Trust corpus (40,000,000 units of beneficial interest authorized, 21,400,000 units issued and outstanding)	692	785
Total liabilities and trust corpus	$ 1,031	$ 1,012

See accompanying notes to financial statements.

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BP Prudhoe Bay Royalty Trust

Statements of Cash Earnings and Distributions

(Prepared on a modified basis of cash receipts and disbursements)

(In thousands, except unit data)

	Year Ended December 31, 2018	2017	2016
Royalty revenues	$ 114,369	$ 78,193	$ 44,917
Interest income	34	11	2
Less: Trust administrative expenses	(1,121)	(1,165)	(1,298)
Cash earnings	$ 113,282	$ 77,039	$ 43,621
Cash distributions	$ 113,263	$ 77,031	$ 43,619
Cash distributions per unit	$ 5.293	$ 3.600	$ 2.038
Units outstanding	21,400,000	21,400,000	21,400,000

See accompanying notes to financial statements.

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BP Prudhoe Bay Royalty Trust

Statements of Changes in Trust Corpus

(Prepared on a modified basis of cash receipts and disbursements)

(In thousands)

	Year Ended December 31, 2018	2017	2016
Trust corpus at beginning of year	$ 785	$ 786	$ 750
Cash earnings	113,282	77,039	43,621
(Increase) decrease in accrued expenses	(112)	(9)	34
Cash distributions	(113,263)	(77,031)	(43,619)
Trust corpus at end of year	$ 692	$ 785	$ 786

See accompanying notes to financial statements.

BP Prudhoe Bay Royalty Trust

Notes to Financial Statements

(Prepared on a modified basis of cash receipts and disbursements)

December 31, 2018

(1) Formation of the Trust and Organization

BP Prudhoe Bay Royalty Trust (the Trust), a grantor trust, was created as a Delaware statutory trust pursuant to a Trust Agreement dated February 28, 1989 among the Standard Oil Company (Standard Oil), BP Exploration (Alaska) Inc. (BP Alaska), The Bank of New York Mellon, as trustee, and BNY Mellon Trust of Delaware (successor to The Bank of New York (Delaware)), as co-trustee. On December 15, 2010, The Bank of New York Mellon resigned as trustee and was replaced by The Bank of New York Mellon Trust Company, N.A., a national banking association, as successor trustee (the Trustee). Standard Oil and BP Alaska are indirect wholly owned subsidiaries of BP p.l.c. (BP).

On February 28, 1989, Standard Oil conveyed an overriding royalty interest (the Royalty Interest) to the Trust. The Trust was formed for the sole purpose of owning and administering the Royalty Interest. The Royalty Interest represents the right to receive, effective February 28, 1989, a per barrel royalty (the Per Barrel Royalty) of 16.4246% on the lesser of (a) the first 90,000 barrels of the average actual daily net production of oil and condensate per quarter or (b) the average actual daily net production of oil and condensate per quarter from BP Alaska s working interest as of February 28, 1989 in the Prudhoe Bay field, located on the North Slope of Alaska. Trust Unit holders will remain subject at all times to the risk that production will be interrupted or discontinued. BP has guaranteed the performance of BP Alaska of its payment obligations with respect to the Royalty Interest.

Effective January 1, 2000, BP Alaska and all other Prudhoe Bay working interest owners cross-assigned interests in the Prudhoe Bay field pursuant to the Prudhoe Bay Unit Alignment Agreement. BP Alaska retained all rights, obligations, and liabilities associated with the Trust.

The trustees of the Trust are The Bank of New York Mellon Trust Company, N.A. and BNY Mellon Trust of Delaware. BNY Mellon Trust of Delaware serves as co-trustee in order to satisfy certain requirements of the Delaware Statutory Trust Act. The Bank of New York Mellon Trust Company, N.A. alone is able to exercise the rights and powers granted to the Trustee in the Trust Agreement.

The Per Barrel Royalty in effect for any day is equal to the price of West Texas Intermediate crude oil (the WTI Price) for that day less scheduled Chargeable Costs (adjusted for inflation) and Production Taxes (based on statutory rates then in existence).

The Trust is passive, with the Trustee having only such powers as are necessary for the collection and distribution of revenues, the payment of Trust liabilities, and the protection of the Royalty Interest. The Trustee, subject to certain conditions, is obligated to establish cash reserves and borrow funds to pay liabilities of the Trust when they become due. The Trustee may sell Trust properties only (a) as authorized by a vote of the Trust unit holders, (b) when necessary to provide for the payment of specific liabilities of the Trust then due (subject to certain conditions) or (c) upon termination of the Trust. Each Trust Unit issued and outstanding represents an equal undivided share of beneficial interest in the Trust. Royalty payments are received by the Trust and distributed to Trust Unit holders, net of Trust expenses, in the month succeeding the end of each calendar quarter. The Trust will terminate (i) upon a vote of Trust unit holders of not less than 60% of the outstanding Trust units, or (ii) at such time the net revenues from the Royalty Interest for two successive years are less than $1,000,000 per year (unless the net revenues during such period are materially and adversely affected by certain events).

BP Prudhoe Bay Royalty Trust

Notes to Financial Statements

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In order to ensure the Trust has the ability to pay future expenses, the Trust established a cash reserve account which the Trustee believes is sufficient to pay approximately one year s current and expected liabilities and expenses of the Trust.

(2) Basis of Accounting

The financial statements of the Trust are prepared on a modified cash basis and reflect the Trust s assets, liabilities, corpus, earnings, and distributions, as follows:

a. Revenues are recorded when received (generally within 15 days of the end of the preceding quarter) and distributions to Trust unit holders are recorded when paid.

b. Trust expenses (which include accounting, engineering, legal, and other professional fees, trustees fees, and out-of-pocket expenses) are recorded on an accrual basis.

c. Cash reserves may be established by the Trustee for certain contingencies that would not be recorded under generally accepted accounting principles.

While these statements differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America, the modified cash basis of reporting revenues and distributions is considered to be the most meaningful because quarterly distributions to the Trust unit holders are based on net cash receipts. The accompanying modified cash basis financial statements contain all adjustments necessary to present fairly the assets, liabilities and corpus of the Trust as of December 31, 2018 and 2017, and the modified cash earning and distributions and changes in Trust corpus for the years ended December 31, 2018, 2017 and 2016. The adjustments are of a normal recurring nature and are, in the opinion of the Trustee, necessary to fairly present the results of operations.

As of December 31, 2018 and 2017, cash equivalents which represent the cash reserve consist of cash accounts and U.S. Treasury Bills with original maturities of ninety days or less.

Estimates and assumptions are required to be made regarding assets, liabilities and changes in Trust corpus resulting from operations when financial statements are prepared. Changes in the economic environment, financial markets and any other parameters used in determining these estimates could cause actual results to differ, and the difference could be material.

(3) Royalty Interest

At inception in February 1989, the Royalty Interest held by the Trust had a carrying value of $535,000,000. In accordance with generally accepted accounting principles, the Trust amortized the value of the Royalty Interest based on the units of production method. Such amortization was charged directly to the Trust corpus, and did not affect cash earnings. In addition, the Trust periodically evaluated impairment of the Royalty Interest by comparing the undiscounted cash flows expected to be realized from the Royalty Interest to the carrying value, pursuant to the Financial Accounting Standards Board Accounting Standards Codification (ASC) 360, *Property, Plant, and Equipment*. If the expected future undiscounted cash flows were less than the carrying value, the Trust recognized impairment losses for the difference between the carrying value and the estimated fair value of the Royalty Interest. By December 31, 2010, the Trust had recognized accumulated amortization of $359,473,000 and aggregate impairment write-downs of $175,527,000 reducing the carrying value of the Royalty Interest to zero.

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(4) Income Taxes

The Trust files its federal tax return as a grantor trust subject to the provisions of subpart E of Part I of Subchapter J of the Internal Revenue Code of 1986, as amended, rather than as an association taxable as a corporation. The Trust unit holders are treated as the owners of Trust income and corpus, and the entire taxable income of the Trust will be reported by the Trust unit holders on their respective tax returns.

If the Trust were determined to be an association taxable as a corporation, it would be treated as an entity taxable as a corporation on the taxable income from the Royalty Interest, the Trust unit holders would be treated as shareholders, and distributions to Trust unit holders would not be deductible in computing the Trust s tax liability as an association.

(5) Alaska Oil and Gas Production Tax

On April 14, 2013, Alaska s legislature passed an oil-tax reform bill amending Alaska s oil and gas production tax statutes, AS 43.55.10 *et seq.* (the Production Tax Statutes) with the aim of encouraging oil production and investment in Alaska s oil industry. On May 21, 2013, the Governor of Alaska signed the bill into law as chapter 10 of the 2013 Session laws of Alaska (the Act). Among significant changes, the Act eliminated the monthly progressivity tax rate implemented by certain amendments to the Production Tax Statutes in 2006 and 2007, increased the base rate from 25% to 35% and added a stair-step per-barrel tax credit for oil production. This tax credit is based on the gross value at the point of production per barrel of taxable oil and may not reduce a producer s tax liability below the minimum tax (which is a percentage, ranging from zero to 4%, of the gross value at the point of production of a producer s taxable production during the calendar year based on the average price per barrel for Alaska North Slope crude oil for sale on the United States West Coast for the year) under the Production Tax Statutes. These changes became effective on January 1, 2014.

On January 15, 2014, the Trustee executed a letter agreement with BP Alaska dated January 15, 2014 (the 2014 Letter Agreement) regarding the implementation of the Act with respect to the Trust. Pursuant to the 2014 Letter Agreement, Production Taxes for the Trust s Royalty Production will equal the tax for the relevant quarter, minus the allowable monthly stair-step per-barrel tax credits for the Royalty Production during that quarter. If there is a minimum tax -related limitation on the amount of the stair-step per-barrel tax credits that could otherwise be claimed for any quarter during the year, any difference between that limitation as preliminarily determined on a quarterly basis and the actual limitation for the entire year will be reflected in the payment to the Trust for the first quarter Royalty Production in the following year.

On July 6, 2015, BP Alaska and the Trustee signed a letter agreement (the 2014 Letter Agreement Amendment) amending the 2014 Letter Agreement to provide that if there is a minimum tax -related limitation on the amount of the stair-step per-barrel tax credits that could otherwise be claimed for any quarter during the year, any difference between that limitation as preliminarily determined on a quarterly basis and the actual limitation for the entire year will be reflected in the payment to the Trust for the fourth quarter Royalty Production payment for such year rather than in the payment to the Trust for the first quarter Royalty Production in the following year.

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(6) Royalty Revenue Adjustments

Certain royalty payments received by the Trust in 2018, 2017 and 2016 were adjusted by BP Alaska to compensate for underpayments or overpayments of the royalties due with respect to the quarters ended prior to the dates of such payments. Average net production of crude oil and condensate from the proved reserves allocated to the Trust was less than 90,000 barrels per day during certain quarters. Royalty payments by BP Alaska with respect to those quarters were based on estimates by BP Alaska of production levels because actual data was not available by the dates on which payments were required to be made to the Trust. Subsequent recalculation by BP Alaska of royalty payments due based on actual production data resulted in the payment adjustments shown in the table below (in thousands).

	2018 Payments Received			
	January	**April**	**July**	**October**
Royalty payment as calculated	$ 26,520	$ 27,610	$ 30,427	$ 29,305
Adjustment for underpayment (overpayment), plus accrued interest	19	1	65	422
Net payment received	$ 26,539	$ 27,611	$ 30,492	$ 29,727

	2017 Payments Received			
	January	**April**	**July**	**October**
Royalty payment as calculated	$ 21,475	$ 23,814	$ 18,230	$ 14,627
Adjustment for underpayment (overpayment), plus accrued interest	7			40
Net payment received	$ 21,482	$ 23,814	$ 18,230	$ 14,667

	2016 Payments Received			
	January	**April**	**July**	**October**
Royalty payment as calculated	$ 13,168	$ 1,951	$ 15,110	$ 14,582
Adjustment for underpayment (overpayment), plus accrued interest	(47)			153
Net payment received	$ 13,121	$ 1,951	$ 15,110	$ 14,735

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(7) Subsequent Event

In January 2019, the Trust received a payment of $21,758,699 from BP Alaska. This payment consisted of $21,360,475, representing the royalty payment due with respect to the Trust s Royalty Interest for the quarter ended December 31, 2018, plus $398,224, representing the amount of an underpayment by BP Alaska, including interest on the underpayment, of the royalty payment due with respect to the quarter ended September 30, 2018. On January 22, 2019, after deducting Trust administrative expenses, the Trustee distributed $21,462,621 to Unit holders of record on January 16, 2019.

Subsequent events have been evaluated through the date these financial statements are issued.

(8) Summary of Quarterly Results (Unaudited)

A summary of selected quarterly financial information for the years ended December 31, 2018, 2017, and 2016 is as follows (in thousands, except unit data):

	2018 Fiscal Quarter			
	First	**Second**	**Third**	**Fourth**
Royalty revenues	$ 26,539	$ 27,611	$ 30,492	$ 29,727
Interest income	6	11	8	9
Trust administrative expenses	(215)	(407)	(297)	(202)
Cash earnings	$ 26,330	$ 27,215	$ 30,203	$ 29,534
Cash distributions	$ 26,325	$ 27,282	$ 30,122	$ 29,534
Cash distributions per unit	$ 1.2302	$ 1.2748	$ 1.4076	$ 1.3800

	2017 Fiscal Quarter			
	First	**Second**	**Third**	**Fourth**
Royalty revenues	$ 21,482	$ 23,814	$ 18,230	$ 14,667
Interest income	2	3	3	3
Trust administrative expenses	(206)	(311)	(406)	(242)
Cash earnings	$ 21,278	$ 23,506	$ 17,827	$ 14,428
Cash distributions	$ 21,277	$ 23,504	$ 17,825	$ 14,425
Cash distributions per unit	$ 0.9943	$ 1.0983	$ 0.8329	$ 0.6745

2016 Fiscal Quarter

	First	Second	Third	Fourth
Royalty revenues	$ 13,121	$ 1,951	$ 15,110	$ 14,735
Interest income		1	1	
Trust administrative expenses	(241)	(410)	(450)	(197)
Cash earnings	$ 12,880	$ 1,542	$ 14,661	$ 14,538
Cash distributions	$ 12,880	$ 1,542	$ 14,660	$ 14,537
Cash distributions per unit	$ 0.6019	$ 0.0721	$ 0.6850	$ 0.6793

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(9) Supplemental Reserve Information and Standardized Measure of Discounted Future Net Cash Flow Relating to Proved Reserves (Unaudited)

Pursuant to Statement of FASB ASC 932, *Extractive Activities Oil and Gas*, the Trust is required to include in its financial statements supplementary information regarding estimates of quantities of proved reserves attributable to the Trust and future net cash flows. The following information in this note reflects the adoption of Securities Exchange Act Release No. 59192, *Modernization of Oil and Gas Reporting* which became effective for financial statements for fiscal years ending on or after December 31, 2009.

Estimates of proved reserves are inherently imprecise and subjective and are revised over time as additional data becomes available. Such revisions may often be substantial. Information regarding estimates of proved reserves attributable to the combined interests of BP Alaska and the Trust were based on reserve estimates prepared by BP Alaska. BP Alaska s reserve estimates are believed to be reasonable and consistent with presently known physical data concerning the size and character of the Prudhoe Bay field.

There is no precise method of allocating estimates of physical quantities of reserve volumes between BP Alaska and the Trust, since the Royalty Interest is not a working interest and the Trust does not own and is not entitled to receive any specific volume of reserves from the Prudhoe Bay field. Reserve volumes attributable to the Trust were estimated by allocating to the Trust its share of estimated future production from the field, based on the 12-month average WTI Price for 2018 ($65.56 per barrel), 2017 ($51.34 per barrel) and 2016 ($42.75 per barrel). Because the reserve volumes attributable to the Trust are estimated using an allocation of reserve volumes based on the estimated future production and on the current WTI Price, a change in the timing of estimated production or a change in the WTI price will result in a change in the Trust s estimated reserve volumes. Therefore, the estimated reserve volumes attributable to the Trust will vary if different production estimates and prices are used.

In addition to production estimates and prices, reserve volumes attributable to the Trust are affected by the amount of Chargeable Costs that will be deducted in determining the Per Barrel Royalty. Net proved reserves of oil and condensate attributable to the Trust as of December 31, 2018, 2017 and 2016, based on BP Alaska s latest reserve estimate at such times and the 12-month average WTI prices for 2018, 2017 and 2016, were estimated to be 15.772, 9.070, 9.376 million barrels, respectively (of which 15.638, 9.047 and 9.204 million barrels, respectively, are proved developed reserves). Under the provisions of FASB ASC 932, no consideration can be given to reserves not considered proved at the present time.

The standardized measure of discounted future net cash flow relating to proved reserves disclosure required by FASB ASC 932 assigns monetary amounts to proved reserves based on current prices. This discounted future net cash flow should not be construed as the current market value of the Royalty Interest. A market valuation determination would include, among other things, anticipated price changes and the value of additional reserves not considered proved at the present time or reserves that may be produced after the currently anticipated end of field life. At December 31, 2018, 2017 and 2016, the standardized measure of discounted future net cash flow relating to proved reserves attributable to the Trust (estimated in accordance with the provisions of FASB ASC 932), based on the 12-month average WTI Prices for 2018, 2017 and 2016 of $65.56, $51.34 and $42.75 per barrel, respectively, scheduled chargeable costs in future years and production taxes were as follows (in thousands):

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	December 31,		
	2018	2017	2016
Future cash inflows	$ 154,662	$ 73,823	$ 63,824
10% annual discount for estimated timing of cash flows	(16,121)	(5,147)	(4,638)
Standardized measure of discounted future net cash flow (a)	$ 138,541	$ 68,676	$ 59,186

(a) The following are the principal sources of the change in the standardized measure of discounted future net cash flows (in thousands):

	December 31,		
	2018	2017	2016
Net changes in prices and production costs	$ 176,825	$ 90,114	$ (123,825)
Net change in production taxes	(5,029)	(2,973)	5,972
Other	845	58	152
	172,641	87,199	(117,701)
Royalty revenues received (b)	(109,588)	(83,250)	(53,278)
Accretion of discount	6,812	5,541	15,668
Net increase (decrease) during the year	$ 69,865	$ 9,490	$ (155,311)

(b) For the purpose of this calculation, royalty income received for 2018, 2017 and 2016 includes the following (in thousands):

Period October 1, 2018 through December 31, 2018	$ 21,759
Period October 1, 2017 through December 31, 2017	$ 26,539
Period October 1, 2016 through December 31, 2016	$ 21,482

The above royalty income was received by the Trust in January 2019, 2018 and 2017, respectively.

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The changes in estimated quantities of proved oil and condensate were as follows:

Proved developed and undeveloped reserves (thousands of barrels) as of:

December 31, 2015	23,052
Revisions of previous estimates (1)	(8,517)
Production	(5,159)
December 31, 2016	9,376
Revisions of previous estimates (2)	4,617
Production	(4,923)
December 31, 2017	9,070
Revisions of previous estimates (3)	11,311
Production	(4,609)
December 31, 2018	15,772
Proved developed reserves (thousands of barrels) as of:	
December 31, 2016	9,204
December 31, 2017	9,047
December 31, 2018	15,638
Proved undeveloped reserves (thousands of barrels) as of:	
December 31, 2016	172
December 31, 2017	23
December 31, 2018	134

(1) The negative revision in year-end 2016 reserves reflects a decrease in the WTI Price from $50.28 per barrel for 2015 to $42.75 per barrel for 2016 using the 12-month average of the first-day-of-the-month price for each month in the years ended December 31, 2015 and 2016, respectively. Under the economic conditions and production forecast at year end 2014, the per-barrel royalty was forecast to be zero following the year 2028. Under the economic conditions and production forecast at year end 2015, the per-barrel royalty was forecast to be zero following the year 2020. Under the economic conditions and production forecast at year end 2016, the per-barrel royalty was forecast to be zero following the year 2018. This reduction in economic life results in a significant reduction in reserve volumes.

(2)

The positive revision in year-end 2017 reserves reflects an increase in the WTI Price from $42.75 per barrel for 2016 to $51.34 per barrel for 2017 using the 12-month average of the first-day-of-the-month price for each month in the years ended December 31, 2016 and 2017, respectively. Under the economic conditions and production forecast at year end 2014, the per-barrel royalty was forecast to be zero following the year 2028. Under the economic conditions and production forecast at year end 2015, the per-barrel royalty was forecast to be zero following the year 2020. Under the economic conditions and

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production forecast at year end 2016, the per-barrel royalty was forecast to be zero following the year 2018. Under the economic conditions and production forecast at year end 2017, the per-barrel royalty was forecast to be zero following the year 2019. This increase in economic life from year-end 2016 to year-end 2017 results in a positive revision in reserve volumes.

(3) The positive revision in year-end 2018 reserves reflects an increase in the WTI Price from $51.34 per barrel for 2017 to $65.56 per barrel for 2018 using the 12-month average of the first-day-of-the-month price for each month in the years ended December 31, 2017 and 2018, respectively. Under the economic conditions and production forecast at year end 2014, the per-barrel royalty was forecast to be zero following the year 2028. Under the economic conditions and production forecast at year end 2015, the per-barrel royalty was forecast to be zero following the year 2020. Under the economic conditions and production forecast at year end 2016, the per-barrel royalty was forecast to be zero following the year 2018. Under the economic conditions and production forecast at year end 2017, the per-barrel royalty was forecast to be zero following the year 2019. Under the economic conditions and production forecast at year end 2018, the per-barrel royalty was forecast to be zero following the year 2022. This increase in economic life from year-end 2017 to year-end 2018 results in a positive revision in reserve volumes.

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

There have been no changes in accountants and no disagreements with accountants on any matter of accounting principles or practices or financial statement disclosures during the two fiscal years ended December 31, 2018.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

The Trustee has disclosure controls and procedures (as defined in Rule 13a-15(e) and Rule 15d-15(e) under the Exchange Act) that are designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC s rules and forms. These controls and procedures include but are not limited to controls and procedures designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act is accumulated and communicated to the responsible trust officers of the Trustee to allow timely decisions regarding required disclosure.

Under the terms of the Trust Agreement and the Conveyance, BP Alaska has significant disclosure and reporting obligations to the Trust. BP Alaska is required to provide the Trust such information concerning the Royalty Interest as the Trustee may need and to which BP Alaska has access to permit the Trust to comply with any reporting or disclosure obligations of the Trust pursuant to applicable law and the requirements of any stock exchange on which the Units are issued. These reporting obligations include furnishing the Trust a report by February 28 of each year containing all information of a nature, of a standard and in a form consistent with the requirements of the SEC respecting the inclusion of reserve and reserve valuation information in filings under the Exchange Act and with applicable accounting rules. The report is required to set forth, among other things, BP Alaska s estimates of future net cash flows from proved reserves attributable to the Royalty Interest, the discounted present value of such proved reserves and the assumptions utilized in arriving at the estimates contained in the report.

In addition, the Conveyance gives the Trust certain rights to inspect the books and records of BP Alaska and discuss the affairs, finances and accounts of BP Alaska relating to the 1989 Working Interests with representatives of BP Alaska; it also requires BP Alaska to provide the Trust with such other information as the Trustee may reasonably request from time to time and to which BP Alaska has access.

The Trustee s disclosure controls and procedures include ensuring that the Trust receives the information and reports that BP Alaska is required to furnish to the Trust on a timely basis, that the appropriate responsible personnel of the Trustee examine such information and reports, and that information requested from and provided by BP Alaska is included in the reports that the Trust files or submits under the Exchange Act.

As of the end of calendar year 2018, the trust officers of the Trustee responsible for the administration of the Trust conducted an evaluation of the Trust s disclosure controls and procedures. Their evaluation considered, among other things, that the Trust Agreement and the Conveyance impose enforceable legal obligations on BP Alaska, and that BP Alaska has provided the information required by those agreements and other information requested by the Trustee from time to time on a timely basis. The officers concluded that the Trust s disclosure controls and procedures were effective, as of December 31, 2018.

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Internal Control Over Financial Reporting

Management s Annual Report on Internal Control Over Financial Reporting.

The Bank of New York Mellon Trust Company, N.A., as Trustee of the Trust, is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) promulgated under the Exchange Act. The Trust s internal control over financial reporting is defined as a process designed by or under the supervision of the Trustee to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Trust s financial statements for external reporting purposes in accordance with the modified cash basis of accounting. The Trust s internal control over financial reporting includes policies and procedures that pertain to maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with the modified cash basis of accounting, and that receipts and expenditures are being made only in accordance with authorizations of the Trustee; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Trust s assets that could have a material effect on the Trust s financial statements.

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

The Trustee conducted an evaluation of the effectiveness of the Trust s internal control over financial reporting based on the criteria established in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Based on the Trustee s evaluation under the COSO criteria, the Trustee concluded that the Trust s internal control over financial reporting was effective as of December 31, 2018.

The effectiveness of the Trust s internal control over financial reporting as of December 31, 2018 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report set forth in full above on page 42.

Changes in Internal Control Over Financial Reporting.

There has not been any change in the Trust s internal control over financial reporting identified in connection with the Trustee s evaluation of the Trust s internal control over financial reporting that occurred during the Trust s fourth fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Trust s internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Not applicable.

PAR T III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The Trust has no directors or executive officers. The Trust is administered by the Trustee under the authority granted it in the Trust Agreement. The Trust Agreement grants the Trustee only the rights and powers necessary to achieve the purposes of the Trust. See THE TRUST Duties and Powers of Trustee in Item 1.

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The Trustee may be removed with or without cause by vote of holders of a majority of the Units at a meeting called and held as provided in the Trust Agreement. At the meeting the Unit holders may appoint a successor trustee meeting the requirements set forth in the Trust Agreement. See THE TRUST Resignation or Removal of Trustee in Item 1.

The Trust has not adopted a code of ethics. The standards of conduct governing the Trustee are set forth in the Trust Agreement and Delaware law. Ethical standards applicable to the employees of the Trustee are set forth in the Code of Conduct which may be found at http://www.bnymellon.com/ethics.

There is no audit committee or committee performing comparable functions responsible for reviewing the audited financial statements of the Trust.

ITEM 11. EXECUTIVE COMPENSATION

The Trust has no directors, officers or employees to whom it pays compensation. The Trust is administered by employees of the Trustee in the ordinary course of their employment who receive no compensation specifically related to their services to the Trust.

Under the Trust Agreement, the Trustee is entitled to receive on each Quarterly Record Date a quarterly fee, currently consisting of the sum of (i) a quarterly administrative fee of $.0011 per Unit outstanding on the Quarterly Record Date plus (ii) $10.00 for each payment by wire transfer to a Unit holder. The administrative service fee is subject to increase in each calendar year by the proportionate increase, if any, during the preceding calendar year in the Consumer Price Index (as defined in the Conveyance; see THE ROYALTY INTEREST Cost Adjustment Factor in Item 1) during the preceding calendar year. The Trustee also bills the Trust for certain reimbursable expenses. There is no compensation committee or committee performing similar functions with authority to determine any compensation of the Trustee other than the fees and reimbursable expenses provided for in the Trust Agreement.

The compensation received by the Trustee from the Trust during the three fiscal years ended December 31, 2018 was as follows:

Year ended December 31,	Trustee s Fees	Transfer Agent and Registrar Fees
2016	238,011	
2017	234,716	