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, 2020

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 registration 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)**

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

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

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
UNITS OF BENEFICIAL INTEREST	BPT	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 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," "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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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 30, 2020 (the last business day of the registrant's most recently completed second fiscal quarter)) was approximately $71,262,000.

As of March 3, 2021, 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 as of 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) ("**BNYM**"), as trustee, and F. James Hutchinson, co-trustee (BNY Mellon Trust of Delaware, formerly named The Bank of New York (Delaware), successor co-trustee). At the time of the execution of the Trust, BP Alaska and Standard Oil were wholly-owned subsidiaries of BP p.l.c. ("**BP**").

On August 27, 2019, BP announced that it had agreed to sell BP Alaska and its other assets and operations in Alaska for total consideration of $5.6 billion to Hilcorp Alaska, LLC and its affiliates, which are affiliates of Houston-based Hilcorp Energy Company (collectively "**Hilcorp**"). On June 30, 2020, Hilcorp completed its acquisition of BP's entire upstream business in Alaska, including BP's interest in BP Alaska, which owned all of BP's upstream oil and gas interest in Alaska (including oil and gas leases in the Prudhoe Bay field), and on December 18, 2020, an affiliate of Hilcorp completed its acquisition of BP's midstream business in Alaska. On July 1, 2020, BP Alaska, a Delaware corporation, converted to a Delaware limited liability company and changed its name to Hilcorp North Slope, LLC, a wholly-owned subsidiary of Hilcorp Alaska, LLC. Hilcorp and its affiliates employ approximately 1,400 full-time employees in Alaska. Under the terms of the Trust Agreement, HNS is the successor to BP Alaska. For purposes of this Annual Report on Form 10-K, "**HNS**" means (i) at all times prior to June 30, 2020, BP Alaska, and (ii) at all times after and including June 30, 2020, Hilcorp North Slope, LLC (formerly known as BP Alaska).

On December 15, 2010, 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 maintains an Internet website at https://bpt.q4web.com/home/default.aspx. The Trust's Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K, as well as any amendments to those reports, are available free of charge through the Trust's website as soon as reasonably practicable after it files them with, or furnishes them to, the SEC. The SEC maintains a website at www.sec.gov that contains reports, proxy statements and other information regarding SEC registrants, including the Trust. Information contained on, or that can be accessed through, the Trust's website is not incorporated by reference into this Annual Report on Form 10-K, and you should not consider information on the Trust's website to be part of this Annual Report on Form 10-K. The Trust has included its website address as an inactive textual reference only.

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 HNS, and the Trustee is entitled to rely on the accuracy of such information in accordance with the Trust Agreement.

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) within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "**Exchange Act**"). Words such as "anticipate," "expect," "believe," "intend," "plan" or "project," and "should," "would," "could," "potentially," "possibly" or "may," and other words that convey uncertainty of future events or 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, production charges and costs, economic activity, domestic and international political events and developments, legislation and regulation, COVID-19, and certain changes in expenses of the Trust.

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 (the term "barrel" is a unit of measure of petroleum liquids equal to 42 United States gallons corrected to 60 degrees Fahrenheit temperature) of the actual average daily net production of crude oil and condensate per quarter from the working interest of BP Alaska (as predecessor to HNS) as of February 28, 1989, in the Prudhoe Bay oil field located on the North Slope in Alaska or (ii) the actual average 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 HNS 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 (as predecessor to HNS) 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-operating 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 HNS's working interest in the Prudhoe Bay field. HNS 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.

Human Capital

The Trust has no employees. All administrative functions of the Trust are performed by the Trustee, in accordance with the terms of the Trust.

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.

The basic function of the Trustee is to collect income from the Royalty Interest, to perform all necessary filing and reporting obligations of the Trust, to pay all fees, expenses, costs, 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 include, without limitation, the Trustee's fees and administrative fees, expenses, charges and costs, including accounting, engineering, legal, financial advisory, and other professional fees ("**Administrative Expenses**").

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 a fee for its services and to be reimbursed for Administrative Expenses from the Royalty Payments, and the cash reserve, and other sources available to the Trustee, including indemnification and sale of Trust assets. The Trustee may also be reimbursed for liabilities of the Trust through a loan in accordance with Section 6.06 of the Trust Agreement, or a sale of assets in accordance with Section 6.02 of the Trust Agreement, in each case under limited circumstances and subject to specified conditions, if the Royalty Payments or the cash reserve are insufficient to reimburse the Trustee for any liability or loss incurred by it in the performance of its duties. The Trust Agreement also provides that the Trustee, subject to certain exceptions, shall be indemnified by, and is entitled to receive reimbursement from (i) HNS (1) whenever the assets of the Trust are insufficient or not permitted by applicable law to provide such indemnity and (2) after the termination of the Trust to the extent that the Trustee did not have actual knowledge, or should not have reasonably known, of a potential claim against the Trustee for which a reserve could have been established and used to satisfy such claim prior to the final distribution of assets of the Trust upon its termination or to the extent any such reserve was insufficient and (ii) the assets of the Trust during any other period, against and from any and all liability, expense, claim, damage or loss (including reasonable legal fees and expenses) incurred by it, individually or as Trustee, in the administration of the Trust and the Trust assets.

HNS has also agreed to indemnify the Trustee, individually and as Trustee, and the Trust against certain liabilities under the federal securities laws.

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. Under certain circumstances, such as a sale of assets, the Trustee may sell all or part of the Royalty Interest or an interest therein without a vote of the Unit holders. 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 assets, the sale only needs to be approved by the vote of holders of a majority of the Units outstanding. Any sale of Trust assets 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 satisfaction of the Trust's outstanding and unpaid liabilities (which would include, without limitation, any fees, costs, expenses, charges and Administrative Expenses), and establishing or increasing reserves for the future 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 for fair market value and 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.

In order to ensure that the Trust had the ability to pay future expenses, the Trust established a cash reserve account in July 1999. The cash reserve account has been funded from periodic deductions from the Royalty Payments. These deductions were intended to result in an available cash balance in the cash reserve account sufficient to pay approximately one year's current and expected liabilities and Administrative Expenses of the Trust. In December 2018, the Trustee decided to gradually increase the Trustee's existing cash reserve for the payment of future Administrative Expenses and liabilities of the Trust, as permitted by the Trust Agreement. The gradual increase in the cash reserve began with the distribution payable to Unit holders in April 2019. The Trust did not receive any Royalty Payments attributable to 2020 for the four quarters during 2020 and as a result, the Trust has been unable to make a quarterly deduction to replenish the funds on deposit in the cash reserve account since the January 2020 distribution made for Royalty Payments attributed to the fourth quarter of 2019. In December 2020, the remaining funds on deposit in the cash reserve were insufficient to pay the current Administrative Expenses. On December 28, 2020, the Trust received an indemnity payment from HNS under Section 7.02 of the Trust Agreement in the amount of $537,835, representing the Trust's current unpaid Administrative Expenses through December 18, 2020. Although HNS agreed to make an indemnity payment to reimburse the Trust for current Administrative Expenses incurred by the Trustee on behalf of the Trust through December 18, 2020, there can be no assurance that HNS will make any further indemnification payments and in such case, the Trustee will continue to review its options under the Trust Agreement and Support Agreement to enforce such indemnity, if necessary, or otherwise obtain funds to pay the Trusts' Administrative Expenses.

At December 31, 2020, the cash balance of the cash reserve account was $188,579. The Trust anticipates incurring additional Administrative Expenses in excess of the cash balance of the reserve fund. The Trust is exploring all of the options available under the Trust Agreement to address the Trust's continuing operational shortfall. These steps may include obtaining a loan for the Trust, selling a portion of the Trust assets, or selling all of the Trust assets and taking the necessary steps to terminate the Trust. The Trustee has engaged a firm with expertise in the oil industry to provide financial advisory, investment banking, valuation, and consulting services to assist the Trust in identifying a potential lender or potential purchaser of Trust assets, and to advise the Trust with respect to the timing of its potential termination pursuant to the Trust Agreement. There can be no assurance that the Trust will be able to secure a loan or arrange for the sale of Trust assets, or if it can, that the loan or sale will be on terms that are acceptable to the Trust. 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 Units outstanding 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 a "force majeure" event). As used in the Trust Agreement, "force majeure" means, without limitation: (i) acts of God; strikes, lockouts or other industrial disturbances; acts of public enemies; orders or restraints of any kind of the government of the United States or of the State of Alaska or any of their departments, agencies, political subdivisions or officials, or any civil or military authority; insurrections; civil disturbances; riots; epidemics; sabotage; war, whether or not declared; landslides; lightning; earthquakes; fires; hurricanes; winds; tornados; storms; droughts; floods; arrests; restraint of government and people; explosions; breakage, malfunction or accident to facilities, machinery, transmission pipes or canals; partial or entire failure of utilities; shortages of labor, materials, supplies or transportation; or (ii) any other cause, circumstance or event (other than depletion of the petroleum reservoir in which the Trust has an interest) not reasonably within the control of HNS.

Upon termination of the Trust, HNS 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 HNS 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 is obligated to distribute the available net proceeds of any such sale to the Unit holders after establishing reserves for liabilities of the Trust.

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 HNS 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.

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 HNS 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 Units outstanding 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 the Borough of 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.

For more information regarding the Trust, see a copy of the Trust Agreement which has been filed with the SEC as an Exhibit 4.1 to this report.

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 HNS'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 HNS.

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 HNS (as successor to 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 petroleum trading company designated by HNS, in each case unaffiliated with HNS 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 HNS 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 HNS's actual costs of production. Chargeable Costs per barrel were $17.10 during 2016, $17.20 during 2017, $20.00 during 2018, $23.75 during 2019, and $26.50 during 2020. 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, the "**Cost Adjustment Factor**" for a quarter was initially set as the ratio of the Consumer Price Index published for the most recently past February, May, August or November, as the case may be, to 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, 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.

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 (as predecessor to HNS) 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 (as predecessor to HNS) 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.

As a result of the 2014 Letter Agreement Amendment, any difference between the limitation as preliminarily determined for the first through third quarters of 2020 and the actual limitation for 2020 is reflected in the payment to the Trust for the fourth quarter of 2020, and not in the payment to the Trust for the first quarter of 2021.

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, if any, 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 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 HNS'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 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	45.03	17.10	1.855	31.71	1.51	11.81

	Average WTI Price	Chargeable Costs	Cost Adjustment Factor	Adjusted Chargeable Costs	Production Taxes	Average Per Barrel Royalty
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
Calendar 2019						
4th Qtr. 2018	$ 58.82	$ 20.00	1.941	$ 38.81	$ 2.04	$ 17.94
1st Qtr. 2019	54.87	23.75	1.946	46.23	1.88	6.77
2nd Qtr. 2019	59.86	23.75	1.972	46.83	2.08	10.94
3rd Qtr. 2019	56.33	23.75	1.976	46.92	1.94	7.48
Calendar 2020						
4th Qtr. 2019	$ 57.02	$ 23.75	1.941	$ 47.04	$ 1.96	$ 8.02
1st Qtr. 2020	46.35	26.50	1.992	52.78	1.47	0
2nd Qtr. 2020	28.42	26.50	2.001	52.32	0.57	0
3rd Qtr. 2020	40.87	26.50	2.004	53.04	1.31	0

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 HNS, 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.

Distributions of Income

HNS 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 HNS. 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 provides 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 provides 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 HNS or a designee of HNS.

Issuance of Additional Units

The Trust Agreement provides that HNS 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. HNS (as successor to 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 (as predecessor to HNS) 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 HNS or Standard Oil has not been paid to the Trustee (including without limitation, the obligation to make payments as indemnification), BP will cause HNS 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 HNS the funds necessary to make such payments. BP is required to make available to HNS and Standard Oil such financial support as HNS, 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 HNS 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.

HNS 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 HNS'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 HNS'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 HNS's obligations under the Conveyance and all of BP's obligations under the Support Agreement). BP's obligations under the Support Agreement remain in effect following the completion Hilcorp's acquisition of BP's interest in BP Alaska.

For more information regarding the Support Agreement, see a copy of the Support Agreement which has been filed with the SEC as an Exhibit 4.4 to this report.

THE PRUDHOE BAY UNIT AND FIELD

Prudhoe Bay Unit Operation and Ownership

Since several oil companies besides HNS 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 HNS 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. BP Alaska served as the sole operator of the Prudhoe Bay Unit until June 30, 2020, when Hilcorp completed its acquisition of BP Alaska, converted it to a limited liability company, and changed its name to HNS.

The ownership of the Prudhoe Bay Unit by participating area as of December 31, 2020 is shown in the following table:

	Oil rim	Gas cap
HNS	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 HNS's (as successor to BP Alaska) ownership interest in the oil rim participating area of 50.68% as of February 28, 1989. Subsequent decreases in HNS'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 HNS's (as successor to BP Alaska) ownership interest in the gas cap participating area of 13.84% as of February 28, 1989. Subsequent increases in HNS'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 HNS fails to pay any costs and expenses chargeable to HNS 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, HNS 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 HNS or others attributable to HNS's working interest in the Prudhoe Bay Unit or to the oil produced from it, and HNS has agreed to indemnify the Trust and hold it harmless against any such impositions.

HNS 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. HNS 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, 2020, approximately 12.7 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.

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, 2020, there were 980 active producing oil wells, 35 gas reinjection wells, 311 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, 2020 were: 14 in 2018, 25 in 2019, and 8 in 2020. These include new sidetrack completions in existing wells. No exploratory drilling activities were conducted in the field during the three-year period ended December 31, 2020. Production from the Prudhoe Bay field reached a peak in 1988 and has declined steadily since then. The average well production rate was about 171 barrels per day in 2016, 178 barrels per day in 2017, 166 barrels per day in 2018, 163 barrels per day in 2019, and 162 barrels per day in 2020.

HNS'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:

Calendar year	Oil		Condensate	
	Total field	Net to 1989 Working Interests	Total field	Net to 1989 Working Interests
	(thousand barrels per day)			
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
2019	170.2	75.5	0.0(a)	0.0
2020	167.0	74.0	0.0(a)	0.0(a)

(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 transit lines, one from each half of the Prudhoe Bay Unit, to Pump Station 1, the starting point for TAPS.

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 20 days to make the trip from the Prudhoe Bay Unit to Valdez. TAPS has a mechanical capacity of 2.1 million barrels of oil a day. During 2020, TAPS averaged 479,554 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 implemented new integrity management and corrosion monitoring practices that supplemented or replaced the practices that existed in 2006.

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, 2020, are those quantities of oil which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from 2021 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. HNS'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.

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 unweighted arithmetic average of the WTI Price on the first day of each month during the year ($39.57 per barrel for the 12-month period prior to December 31, 2020) in accordance with SEC regulations, 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. HNS has estimated that the proved reserves allocated to the Trust as of December 31, 2020 were 0 barrels of oil and condensate, of which 0 barrels are proved developed reserves and 0 barrels are proved undeveloped reserves. 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. 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. Proved reserves attributable to the Trust were decreased by approximately 4.465 million barrels during 2020 as a result of the decrease in the WTI Price. 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. There were no contributions to proved undeveloped reserves from extensions or discoveries during 2020.

Based on the 2020 12-month average WTI Price of $39.57 per barrel (the unweighted arithmetic average of the WTI Price on the first day of each month during the year), other economic parameters prescribed by the Conveyance, and utilizing procedures specified in Financial Accounting Standards Board Accounting Standards Codification ("**FASB ASC**") 932, *Extractive Activities – Oil and Gas*, HNS calculated that as of December 31, 2020, production of oil and condensate from the proved reserves allocated to the 1989 Working Interests will result in undiscounted estimated future cash flows to the Trust of $0, with a net present value of estimated future cash flows at 10% discount of $0. In the event of changes in HNS's current assumptions, including price, oil and condensate recoveries may be changed from the current estimates.

The internal controls applicable to the foregoing estimates of the reserves allocated to the Trust are those employed by HNS, which provides the information to the Trustee. HNS has advised the Trustee that its reserves process is managed by its Chief Reservoir Engineer, the technical person primarily responsible for overseeing the preparation of all of its reserve estimates. He has over 20 years of reservoir and operations experience, holds a Bachelor of Science in Petroleum Engineering from Texas A&M University and a Master of Science in Petroleum Engineering from Stanford University, is a Licensed Professional Engineer in the State of Texas, and is a member of the SPE. The Trust employs Miller and Lents, Ltd., an international oil and gas consulting firm, to conduct an annual review of HNS'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 26, 2021, report of Miller and Lents, Ltd. is filed as Exhibit 99 to this report.

HNS'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 2018, 2019 and 2020. HNS 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 during future years. See Item 1A, "RISK FACTORS."

Based on the 2020 twelve-month average WTI Price of $39.57 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 be zero in 2021. 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. In order for the Trust to have associated reserves and future net revenues, the twelve-month average WTI Price per barrel must exceed the Production Taxes and Adjusted Chargeable Costs as prescribed by the Overriding Royalty Conveyance in future years. Assuming a WTI price of $39.57 per barrel, which was the SEC-defined 12-month average in 2020, the projected value of the of the Production Taxes and Adjusted Chargeable Costs as prescribed by the Overriding Royalty Conveyance is $59.87 per barrel in 2021 and $65.38 per barrel in 2022 and continues to increase thereafter.

HNS 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.

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, HNS'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. HNS 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 HNS has advised the Trustee that the existence of legislation and regulation has had no material adverse effect on HNS'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 ("**DOT**"). 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. The PIPES Act was most recently amended in December 2020. The PIPES Act of 2020 strengthens the Pipeline and Hazardous Materials Safety Administration's safety authority and includes provisions that advance the safe transportation of energy and other hazardous materials. The Prudhoe Bay Unit is monitoring the status of the new PIPES Act of 2020 in anticipation of new implementing regulations that may be promulgated under the current administration. See "THE PRUDHOE BAY UNIT AND FIELD – Collection and Transportation of Prudhoe Bay Oil" above.

CERTAIN TAX 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. HNS 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.

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. In 2020 certain indemnity payments were made by HNS to the Trust to reimburse it for Administrative Expenses incurred in accordance with the Trust Agreement because the Trust did not receive any Royalty Payments attributable to the four quarters during 2020, as described in Item 7 in Part II below. For federal income tax purposes, the receipt of the indemnity payments and the expenses paid with those indemnity payments will not be treated as income or deductions of the Trust or of any Unit holder.

The Trust makes quarterly distributions, to the extent available, 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.

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.

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 currently 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

The Trust's operations and financial results are subject to various risk and uncertainties, including those described below, any of which could adversely affect the Trust's operations, results, financial condition and prospects. In such an event, the market price of the Units could decline, and you may lose all or part of your investment. Additional risks and uncertainties not presently known to the Trust or that the Trust currently deems immaterial may also adversely affect the Trust. You should carefully consider the risk described below and the other information in this Annual Report on Form 10-K, including the Trust's audited financial statements and the related notes thereto, and "The Trustee's Discussion and Analysis of Financial Condition and Results of Operations."

Risks Related To Royalty Payments

There were no royalty payments to unit holders for the 2020 fiscal year and there may not be any royalty payments to unit holders in the 2021 fiscal year.

The Trust did not receive any Royalty Payments attributable to the four quarters during 2020 due to, among other things, a significant decline in WTI prices. The determination of Royalty Payments is based in part on the WTI price, and is calculated as an average over the relevant quarter, lessening the effect of price swings through the period. WTI prices fell from around $61 per barrel at the beginning of 2020 to below $14 per barrel on April 22, 2020. During the period from January 2020 to January 2021, WTI prices remained below the price required to exceed the "break even" WTI price (the price at which all taxes and prescribed deductions are equal to the WTI price) in order for the Trust to receive a positive Per Barrel Royalty with respect to a particular day's production. Additionally, as WTI prices change, so do the taxes and prescribed deductions, potentially increasing or decreasing the "break even" WTI price. While future oil prices cannot be accurately projected, the U.S. Energy Information Administration ("**EIA**") forecasts in its Short-Term Energy Outlook ("**STEO**"), released on March 9, 2021, that WTI prices will average approximately $57.24 per barrel in 2021 and $54.75 in 2022. Should this forecast of WTI prices prevail, the Trust will not receive a positive Per Barrel Royalty with respect to any day's production during 2021 and Unit holders will not receive Royalty Payments during 2021 or 2022. The projected value of the Production Taxes and Chargeable Costs as prescribed by the Conveyance is $60.72 per barrel in 2021 and $66.46 in 2022, and continues to increase thereafter.

Although the Trust does not expect to receive a positive Per Barrel Royalty for any day's production during 2021, the Trustee expects to retain in reserve future Royalty Payments, if any, made in fiscal 2021 or subsequent periods for future Administrative Expenses of at least $1,270,000 and potentially more in an amount sufficient to pay Administrative Expenses for at least one year plus anticipated expenses in connection with the termination of the Trust. In order to comply with the Trust Agreement's termination process and requirements, the Trust is likely to incur significant additional expenditures. Accordingly, even if the Trust receives Royalty Payments during 2021 or 2022, it is not currently anticipated that Unit holders will receive Royalty Payments on outstanding Units during such periods.

The Trust does not have adequate cash to pay its expenses and is exploring options either to obtain financing or to sell Trust assets.

In order to ensure that the Trust had the ability to pay all future Administrative Expenses, the Trust previously established a cash reserve account. The cash reserve account has been funded from periodic deductions from Royalty Payments. These deductions were intended to result in an available cash balance in the cash reserve account sufficient to pay the Administrative Expenses of the Trust for one year. Because the Trust did not receive any Royalty Payments attributable to the four quarters during 2020, the Trust has been unable to make a quarterly deduction to replenish the funds on deposit in the cash reserve account since the January 2020 distribution made for Royalty Payments attributed to the fourth quarter of 2019. In December 2020, the remaining funds on deposit in the cash reserve were insufficient to pay the current Administrative Expenses and the Trustee made a demand for indemnity and reimbursement of

Administrative Expenses upon HNS in accordance with the Trust Agreement in the amount of $537,835, representing the Trust's current unpaid Administrative Expenses through December 18, 2020. On December 28, 2020, HNS paid the requested funds to the Trustee and the Trustee applied those funds to the Trust's current unpaid expenses in accordance with the Trust Agreement. Although HNS agreed to make an indemnity payment to reimburse the Trust for current Administrative Expenses incurred by the Trustee on behalf of the Trust through December 18, 2021, there can be no assurance that HNS will make any further indemnification payments and in such case, the Trustee will continue to review its options under the Trust Agreement and Support Agreement to enforce such indemnity, if necessary, or otherwise obtain funds to pay the Trusts' Administrative Expenses.

At December 31, 2020, the cash balance of the cash reserve account was $188,579. The Trust anticipates incurring additional Administrative Expenses in excess of the cash balance of the reserve fund. The Trust is exploring all options available under the Trust Agreement to address the Trust's continuing operational shortfall. These steps may include obtaining a loan for the Trust, selling a portion of the Trust assets, or selling all of the Trust assets and taking the necessary steps to terminate the Trust. Such financings or sales in accordance with the Trust Agreement do not require the vote of Unitholders, provided certain conditions are satisfied. The Trustee has engaged a firm with expertise in the oil industry to provide financial advisory, investment banking, valuation, and consulting services to assist the Trust in identifying a potential lender or potential purchaser of Trust assets, and to advise the Trust with respect to the timing of its potential termination pursuant to the Trust Agreement. There can be no assurance that the Trust will be able to secure a loan or arrange for the sale of all or a portion of Trust assets, or if it can, that the loan or sale of assets will be on terms that are acceptable to the Trust. In addition, in the absence of more favorable third-party financing, an affiliate of HNS may elect to offer loan financing to the Trust in lieu of making indemnity payments. Such loan financings or asset sales may limit funds available from future Royalty Payments or the future amount of Royalty Payments payable on Trust assets. The uncertainty surrounding receipt of future royalties necessary for the Trust to avoid termination, coupled with the Trust's current liquidity position, raises substantial doubt regarding the Trust's ability to continue as a going concern.

Net revenues for 2020 to the Trust were less than $1,000,000 and estimated net revenues to the Trust for 2021 are expected to be less than $1,000,000, which will result in the 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 an event constituting a "force majeure" as defined in the Trust Agreement). Upon termination of the Trust, HNS 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, or (ii) the market value of the outstanding Units based on the closing price of Units on the New York Stock Exchange on the day of termination of the Trust. If HNS 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 and upon conditions deemed commercially reasonable. After the payment of all Administrative Expenses and after establishing reserves for liabilities of the Trust, the Trustee is obligated to distribute the available net proceeds of any such sale to the Unit holders.

Pursuant to the terms of the Trust Agreement, if net revenues during such two-year period have been materially and adversely impacted by an event constituting "force majeure", the termination of the Trust may be delayed. As used in the Trust Agreement, "force majeure" means, without limitation: (i) acts of God; strikes, lockouts or other industrial disturbances; acts of public enemies; orders or restraints of any kind of the government of the United States or of the State of Alaska or any of their departments, agencies, political subdivisions or officials, or any civil or military authority; insurrections; civil disturbances; riots; epidemics; sabotage; war, whether or not declared; landslides; lightning; earthquakes; fires; hurricanes; winds; tornados; storms; droughts; floods; arrests; restraint of government and people; explosions; breakage, malfunction or accident to facilities, machinery, transmission pipes or canals; partial or entire failure of utilities; shortages of labor, materials, supplies or transportation; or (ii) any other cause, circumstance or event (other than depletion of the petroleum reservoir in which the Trust has an interest) not reasonably within the control of HNS. If delayed, the Trust would incur additional liabilities. Also, the process required by the Trust Agreement to effect a sale of assets and to terminate the Trust will cause the Trust to incur additional liabilities, including without limitation, additional Administrative Expenses. Any such additional liabilities would reduce proceeds available for distribution to Unit holders from the sale of Trust assets made in connection with a Trust termination. The Trustee has engaged a firm with expertise in the oil industry to provide financial advisory, investment banking, valuation, and consulting services to assist the Trust in identifying a potential lender or potential purchaser of Trust assets, and to advise the Trust with respect to the timing of its potential termination pursuant to the Trust Agreement. There can be no assurance as to the timing of an eventual termination of the Trust.

Royalty payments by HNS to the Trust are unpredictable because such payments depend on Cushing, Oklahoma WTI spot prices, which, like crude oil prices in general, are subject to volatility.

WTI prices, like prices in the global crude oil market generally, are subject to periodic fluctuations and significant volatility. The impact of the COVID-19 pandemic had a significant impact on the oil industry in 2020, forcing U.S. oil prices to go negative for the first time on record. Worldwide demand for oil fell rapidly as governments closed businesses and restricted travel due to the COVID-19 pandemic and oil producers were faced with a glut of crude oil, which made it difficult for them to find space to store the oversupply. In April, the oversupply of oil led to an unprecedented collapse in oil prices, forcing the contract futures price for West Texas Intermediate (WTI) to plummet from $18 a barrel to around $(37) a barrel. Brent crude oil prices also tumbled, closing at $9.12 a barrel on April 21, 2020 down from $70 a barrel at the beginning of the year. Several other factors contributed to 2020's volatility. An oil price war between Russia and Saudi Arabia erupted in March 2020 when the two nations failed to reach a consensus on oil production levels. By the summer of 2020, oil prices began to rebound as nations emerged from lockdown and OPEC agreed to significant cuts in crude oil production. By year's end, optimism over the possible rollout of multiple COVID-19 vaccines buoyed the market; in November, Brent crude oil spot prices increased to an average of $43 a barrel and WTI crude oil spot prices increased to an average of $42.30. From the beginning of the first quarter of 2021 through March 8, 2021, the WTI crude oil spot price fluctuated between a high of $66.09 per barrel on March 5, 2021, and a low of $47.62 per barrel on January 4, 2021. The WTI crude oil spot price on March 8, 2021 was $65.05 per barrel.

COVID-19 has caused substantial disruption in the oil industry and has had a negative impact on WTI prices and the receipt of Royalty Payments by the Trust.

In December 2019, a novel strain of coronavirus, SARS-CoV-2 (severe acute respiratory syndrome coronavirus 2), surfaced in Wuhan, China, and has since spread to other countries, including the United States. In March 2020, the World Health Organization characterized the disease caused by the virus—COVID-19—as a pandemic. The pandemic resulted in governments around the world implementing stringent measures to help control the spread of the virus, including quarantines, "shelter in place" and "stay at home" orders, travel restrictions, business curtailments and other measures. While governments and central banks in several parts of the world have enacted fiscal and monetary stimulus measures to counteract the impact of COVID-19, the pandemic has resulted in significant economic contraction. The oil industry, in particular, was substantially disrupted, both domestically and internationally, by the COVID-19 pandemic, which has caused significant changes in energy fuel supply and demand. As a result, WTI prices fell from around $63 per barrel at the beginning of 2020 to below $8.91 per barrel on April 21, 2020. Although WTI prices have recovered significantly since then, they have remained below the price required to reach the "break even" WTI price (the price at which all Production Taxes and prescribed deductions for Chargeable Costs are equal to the WTI price) in order for the Trust to receive a positive Per Barrel Royalty with respect to a particular day's production.

Risks Related to WTI Price

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.

Revenues to the Trust are calculated daily by HNS using the WTI price, production tax, and other variables as prescribed by the Conveyance applicable on that specific day. The “break-even” WTI price (at which all Production Taxes and prescribed deductions for Chargeable Costs are equal to the WTI price) is projected to be approximately $60.72 per barrel in 2021 and $66.46 per barrel in 2022, and will continue to increase thereafter. The quarterly Royalty Payment by HNS 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.

The estimated future net revenues and present value of estimated future net revenues reported in this Annual Report 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, 2021. 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 2020 twelve-month average WTI Price of $39.57 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 would be zero in 2021. 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.

While energy price forecasts are highly uncertain, the EIA forecast in its STEO dated March 9, 2021, that Brent crude oil spot prices will average approximately $60.67 per barrel in 2021 and WTI spot prices will average $57.24 per barrel in 2021 and $54.75 in 2022. EIA’s forecast of declining crude oil prices and a more balanced oil market reflect global oil supply surpassing oil demand during the second half of 2021. Although EIA expects inventories to fall by 1.2 million barrels per day in the first half of 2021, increases in global oil supply will contribute to inventories rising by almost 0.4 million barrels per day in the second half of 2021 and a mostly balanced market in 2022. However, the forecast depends heavily on future production decisions by OPEC+, the responsiveness of U.S. tight oil production to higher oil prices, and the pace of oil demand growth, among other factors.

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 will not, subject to the effect of the other prescribed variables, result in positive royalty payments to the Trust in 2021, if such prices actually constitute the 2021 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).

Crude oil prices can be highly volatile as a result of many factors that are outside of the control of the Trust.

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 the effects of COVID-19 on the global economy, 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, and the success of such intervention, 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 increased tensions between the U.S. and Iran, political unrest in Iran and developments with respect to 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 Libya threatening that country's oil production and exports, ongoing tensions in other regions of the world and turmoil and volatility in global stock markets.

For additional information, historical WTI Prices are available from the U.S. Energy Information Administration.

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 have been, and are expected to continue to 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 HNS using the WTI price, production tax, and other variables as prescribed by the Conveyance applicable on that specific day. The fixed Chargeable Cost increases specified in the Conveyance have impacted and will continue to impact "break-even" prices. The quarterly royalty payment by HNS 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.

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, 2021. 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 2020 twelve-month average WTI Price of $39.57 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 would be zero in 2021. 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.

While energy price forecasts are highly uncertain, EIA, forecasts that WTI spot prices will average $57.24 per barrel in 2021. 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. Since the "break-even" WTI price (at which all Production Taxes and prescribed deductions for Chargeable Costs are equal to the

WTI price) is projected to be approximately $60.72 per barrel in 2021, WTI prices at the level forecasted by EIA will not, subject to the effect of the other prescribed variables, result in positive royalty payments to the Trust in 2021, if such prices actually constitute the 2021 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). From the beginning of the first quarter of 2021 through March 8, 2021, the WTI crude oil spot price fluctuated between a high of $66.09 per barrel on March 5, 2021, and a low of $47.62 per barrel on January 4, 2021. The WTI crude oil spot price on March 8, 2021 was $65.05 per barrel. The quarterly royalty payment by HNS 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.

Risks Related to Oil Production

Future Royalty Production from the Prudhoe Bay field is projected to decline and will eventually cease. Volume of production from the 1989 Working Interests varies from quarter to quarter and the decline in production has negatively affected the Trust's revenues.

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 2020 WTI Price of $39.57 per barrel, among other prescribed variables, are projected to be $0 in 2021 and beyond. The reduction in oil price, in addition to the annual increase in Chargeable Costs as adjusted upward by the Cost Adjustment Factor, are the primary drivers of the projected cessation of royalty payments during and after 2021. Even if the Trust receives Royalty Payments in future periods, such Royalty Payments may not continue based on projected production declines.

Production estimates included in this report are based on economic conditions and production forecasts as of the end of 2020, and also depend on various assumptions, projections and estimates which are continually revised and updated by HNS. These revisions could result in material changes to the projected declines in production.

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.

HNS'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 2018, 2019 and 2020, and the Trustee has been advised that HNS 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.

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

HNS 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 HNS 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, HNS has no obligation to use insurance proceeds to repair such damage and may elect to retain such proceeds and close damaged areas to production.

The impact that the sale of BP's Alaska assets to Hilcorp Alaska, LLC may have on the 1989 Working Interests is difficult to determine.

On August 27, 2019, BP announced that it had agreed to sell BP Alaska and its other assets and operations in Alaska for total consideration of $5.6 billion to Hilcorp Alaska, LLC and its affiliates, which are affiliates of Hilcorp. On June 30, 2020, Hilcorp completed its acquisition of BP's entire upstream business in Alaska, including BP's interest in BP Alaska, which owned all of BP's upstream oil and gas interest in Alaska (including oil and gas leases in the Prudhoe Bay field), and on December 18, 2020, an affiliate of Hilcorp completed its acquisition of BP's midstream business in Alaska. On July 1, 2020, BP Alaska, a Delaware corporation, converted to a Delaware limited liability company and changed its name to Hilcorp North Slope, LLC, a wholly-owned subsidiary of Hilcorp Alaska, LLC.

Hilcorp is one of the largest privately held oil and natural gas exploration and production companies in the U.S. and is currently the largest private oil and gas operator in Alaska. Hilcorp has been operating in Alaska since 2012. In 2014, the company purchased BP's interests in the Endicott and North Star fields and half of BP's interests in the Milne Point and Liberty fields. Because Hilcorp is closely held there is less information publicly available regarding its finances than there is for publicly owned entities such as Exxon Mobil, BP and ConocoPhillips, that have been major North Slope producers.

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 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. In both 2011 and 2018, TAPS was shut down temporarily – in one case because of a leak and in the other because of an earthquake. 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.

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 2019, the pipeline's average throughput decreased by approximately 18,000 barrels per day compared to 2018. This amounted to a 3.7 percent decrease. The 2019 throughput was the pipeline's lowest annual daily average. 2019 was the second consecutive year of decreased throughput following two consecutive years of increases in 2016 and 2017. Nevertheless, throughput for the last three years has averaged only 509,001 barrels per day. The pipeline was designed to carry much higher volumes of oil and while Alyeska is taking or plans to take steps 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.

Alaska's Department of Revenue has also forecast that Alaska North Slope oil production will decline to an average of 492,000 barrels per day in the fiscal year that ends June 30, 2020, which is down from the 494,900 barrels per day produced in fiscal 2019. Production is expected to decline further through 2024 before subsequently increasing to 494,500 barrels per day by 2029, as recent discoveries in the North Slope begin production. New North Slope discoveries in 2016, 2017 and 2018 could add as much as 360,000 barrels per day of oil production.

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. An administration plan to hold an oil and gas lease sale in the ANWR before the end of 2019 did not take place because of certain procedural delays. The Trump administration also 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. However, in March 2019, a U.S. District Court judge for the District of Alaska ruled that the executive order that removed the ban on oil and gas drilling in the Arctic Ocean and parts of the North Atlantic coast was unlawful. In addition, President Biden signed an executive order placing a temporary moratorium on oil and gas activity in the ANWR on January 20, 2021, one day after the Trump administration had issued nine oil and gas leases in the refuge's coastal plain. The order places a temporary moratorium on all activities of the Federal Government relating to the implementation of the Coastal Plain Oil and Gas Leasing Program, as established by the Record of Decision signed August 17, 2020, in the ANWR, pending a review of the program and, as appropriate and consistent with applicable law, a new, comprehensive analysis of the potential environmental impacts of the oil and gas program.

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.

It has long been considered that 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 liquefied natural gas (“LNG”) would be exported to Asia. It was contemplated that the project would also include natural gas processing facilities.

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. 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. The Alaska LNG project received construction authorization from federal authorities in May 2020, according to publicly-available information.

Unlike the Alaska LNG project, which contemplates gas from the North Slope being liquefied 800 miles away on the south coast of Alaska, and inspired by Russia’s Yamal LNG, a new company, Qilak LNG, would forego transporting gas via hundreds of miles of pipeline and proposes, instead, to ship LNG from production capacity to be constructed on the North Slope directly to Asian markets on ice-breaking tankers from Point Thomson. A feasibility study was scheduled to begin in 2020 with a final investment decision (FID) possible in 2021 or 2022. It is anticipated that shipments of LNG could start in the mid-2020s.

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.

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 HNS 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, HNS'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.

Risks Related to the Units

The market price for the Trust units may not reflect the value of the assets held by the Trust.

The public trading price for the Trust units has historically been tied to the recent and expected levels of cash distributions on the Trust units. However, no cash distribution were made for the 2020 fiscal year and none are expected for the 2021 fiscal year. The amounts available for distributions by the Trust vary in response to numerous factors outside the control of the Trust or HNS, including prevailing WTI Prices. The market price of the Trust units is not necessarily indicative of the value that the Trust would realize if the assets were sold to a third party buyer. In addition, the market price is not necessarily reflective of the fact that, since the assets of the Trust are depleting assets, a portion of each cash distribution paid on the Trust units should be considered by investors as a return of capital, with the remainder being considered as a return on investment. There is no guarantee that distributions made to a Unit holder over the life of these depleting assets will equal or exceed the purchase price paid by the Unit holder.

Trust Unit holders have limited voting rights and have limited ability to enforce the Trust's rights against HNS or any other operator of the underlying assets and limited rights and limited ability to assert any claims against the Trustee.

The voting rights of a Trust unitholder are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of Trust unitholders or for an annual or other periodic re-election of the Trustee.

The Trust Agreement and related trust law permit the Trustee and the Trust to sue HNS or any other operator of the underlying properties to compel them to fulfill the terms of the Conveyance and to enforce the obligations of HNS (as successor to BP Alaska) under the Support Agreement. If the Trustee does not take appropriate action to enforce provisions of the Conveyance, the Trust Agreement limits and conditions the rights of the Unit holders to assert any claims against the Trustee. These rights are limited and are set forth in Article VII of the Trust Agreement. Unit holders may enforce certain obligations of HNS (as successor to BP Alaska) under the Support Agreement. Unit holders may be limited in their right or ability to sue HNS or any other operator of the underlying properties. In addition, the rights of ultimate beneficial holders of Units may be limited by the Trust Agreement, which confers rights upon Unit "Holders," which term includes only those holders as show by the records of the Trustee pursuant to Article III of the Trust Agreement.

Financial information of the Trust is not prepared in accordance with U.S. GAAP.

The financial statements of the Trust are prepared on a modified cash basis of accounting, which is a comprehensive basis of accounting other than U.S. generally accepted accounting principles, or U.S. GAAP. Although this basis of accounting is permitted for royalty trusts by the Securities and Exchange Commission, the financial statements of the Trust differ from U.S. GAAP financial statements because net profits income is not accrued in the month of production, expenses are not recognized when incurred and cash reserves may be established for certain contingencies that would not be recorded in U.S. GAAP financial statements. See Item 8 – *Financial Statements and Supplementary Data* – Notes to Financial Statements – Note 3 Basis of Accounting for additional information.

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

The interests of HNS and the Trust with respect to the Prudhoe Bay Unit could at times be different. The Per Barrel Royalty that HNS 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 HNS for crude oil produced from the 1989 Working Interests, and Chargeable Costs and Production Taxes may not bear any relation to HNS's actual costs of production and tax expenses. The actual per barrel profit realized by HNS 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 HNS's actual per barrel revenues and costs could be such that continued operations may be uneconomic, and, to the extent permitted under the Conveyance and applicable law, HNS 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 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.

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.

As of March 3, 2021, 21,400,000 Units were outstanding and were held by 226 holders of record. No Units were purchased by the Trust or any affiliated purchaser during the year ended December 31, 2020.

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.

ITEM 6. SELECTED FINANCIAL DATA

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

	2020	2019	2018	2017	2016
Royalty revenues	$ 9,269	$48,972	$114,369	$78,193	$44,917
Interest income	$ 11	$ 35	$ 34	$ 11	$ 2
Trust administration expenses	$ (1,692)	$ (1,085)	$ (1,121)	$ (1,165)	$ (1,298)
Cash earnings	$ 8,126	$47,922	$113,282	$77,039	$43,621
Cash distributions	$ 9,079	$47,802	$113,263	$77,031	$43,619
Cash distributions per unit	$0.4242	$ 2.234	$ 5.293	$ 3.600	$ 2.038

	2020	2019	2018	2017	2016
Trust corpus	$ 59	$ 898	$ 692	$ 785	$ 786
Total assets	$ 266	$ 1,151	$ 1,031	$ 1,012	$ 1,004
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.

In July 1999, the Trustee established a cash reserve to provide liquidity to the Trust during any future periods in which the Trust does not receive a distribution from HNS. The Trustee draws 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 replenishes the reserve from future quarterly distributions, if any. 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. The Trustee anticipates that it will keep this cash reserve program in place, to the extent that it receives a distribution from HNS, until termination of the Trust. In December 2018, the Trust announced 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 began withholding the greater of $33,750 or 0.17% of the funds otherwise available for distribution each quarter to gradually increase existing cash reserves.

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. Any 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.

A novel strain of coronavirus, SARS-CoV-2 (severe acute respiratory syndrome coronavirus 2), surfaced in late 2019 and has since spread around the world. In March 2020, the World Health Organization characterized the disease caused by the virus—COVID-19—as a pandemic. Due to the economic impacts of the COVID-19 pandemic, the markets experienced a decline in oil prices in response to oil demand concerns and global storage considerations. As a result of, among other things, lower oil prices and the increase in Chargeable Costs, the Trust received no Royalty Payment for the quarters ended March 31, June 30, and September 30, 2020 and, as discussed in Note 8 to the financial statements, did not receive a Royalty Payment in January 2021 for the quarter ended December 31, 2020 given oil prices were below the "break-even" WTI price of $54.34 during such periods. The 2020 12-month average WTI Price was $39.57 per barrel.

Because the Trust did not receive any Royalty Payments attributable to the four quarters during 2020, the Trust has been unable to make a quarterly deduction to replenish the funds on deposit in the cash reserve account since the January 2020 distribution made for Royalty Payments attributed to the fourth quarter of 2019. In December 2020, the remaining funds on deposit in the cash reserve were insufficient to pay the current Administrative Expenses and the Trustee made a demand for indemnity and reimbursement of expenses upon HNS in accordance with the Trust Agreement in the amount of $537,835, representing the Trust's current unpaid expenses through December 18, 2020. On December 28, 2020, HNS paid the requested funds to the Trustee and the Trustee applied those funds to the Trust's current unpaid Administrative Expenses in accordance with the Trust Agreement. Although HNS agreed to make an indemnity payment to reimburse the Trust for current Administrative Expenses incurred by the Trustee on behalf of the Trust through December 18, 2020, there can be no assurance that HNS will make any further indemnification payments and in such case, the Trustee will continue to review its options under the Trust Agreement and Support Agreement to enforce such indemnity, if necessary, or otherwise obtain funds to pay the Trusts' Administrative Expenses.

At December 31, 2020, the cash balance of the cash reserve account was $188,579. The Trust anticipates incurring additional Administrative Expenses in excess of the cash balance of the reserve fund. The Trust is exploring the options available under the Trust Agreement to address the Trust's continuing operational shortfall. These steps may include obtaining a loan for the Trust, selling a portion of the Trust assets, or selling all of the Trust assets and taking the necessary steps to terminate the Trust. The Trustee has engaged a firm with expertise in the oil industry to provide financial advisory, investment banking, valuation, and consulting services to assist the Trust in identifying a potential lender or potential purchaser of Trust assets, and to advise the Trust with respect to the timing of its potential termination pursuant to the Trust Agreement. There can be no assurance that the Trust will be able to secure a loan or arrange for the sale of Trust assets, or if it can that the loan or sale will be on terms that are acceptable to the Trust.

Although the Trust did not receive Royalty Payments attributable to any quarter in 2020, in part due to the decline in WTI prices, the increase in Chargeable Costs and the payment of Production Taxes, coupled with decreased Royalty Production from the Prudhoe Bay Field, significantly reduce the likelihood of any material Royalty Payments to Unit holders in the first or second quarter of 2021, notwithstanding the current upward trend in the WTI Price.

The Trustee expects to retain in reserve future Royalty Payments, if any, made in fiscal 2021 or subsequent periods for future Administrative Expenses of at least $1,270,000 and potentially more in an amount sufficient to pay Trust fees and expenses for at least one year plus anticipated expenses in connection with the termination of the Trust. In order to comply with the Trust Agreement's termination process and requirements, the Trust is likely to incur significant additional expenditures. Accordingly, even if the Trust receives Royalty Payments during 2021 or 2022, it is not currently anticipated that Unit holders will receive Royalty Payments on outstanding Units during such periods.

If the Trust does not receive any additional Royalty Payments in 2021 or thereafter, or obtain alternative funding, the Trust's ability to meet its obligations would be adversely affected, which raises substantial doubt about its ability to continue as a going concern. As noted above, as a general matter, the Trust is expected to terminate at such time the net revenues from the Royalty Interest for two successive years are less than $1,000,000 per year.

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 HNS's operations during the twelve-month period ended on the preceding September 30.

When HNS'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. HNS'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 2018, 2019 and 2020. The Trustee has been advised that HNS 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.

HNS 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 HNS of actual Royalty Production data may result in revisions of prior Royalty Production estimates. Revisions by HNS of its Royalty Production calculations may result in quarterly royalty payments by HNS 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 7 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 2018 and 2019, WTI Prices were above the level necessary for the Trust to receive a Per Barrel Royalty. However, during, 2020 WTI Prices were below 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 2021 will depend on, among other things, WTI Prices prevailing during the remainder of the year.

As also discussed above in Item 1A "RISK FACTORS", on January 1, 2021, 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 $60.72. From the beginning of the first quarter of 2021 through March 8, 2021, the WTI crude oil spot price fluctuated between a high of $66.09 per barrel on March 5, 2021, and a low of $47.62 per barrel on January 4, 2021. The WTI crude oil spot price on March 8, 2021 was $65.05 per barrel. The quarterly royalty payment by HNS 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 are likely to be insignificant or be zero.

As explained in Note 3 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.

2020 Compared to 2019

	12 Months Ended 9/30/2020	Increase (decrease) Amount	Increase (decrease) Percent	12 Months Ended 9/30/2019
		(Dollars per barrel)		
Average WTI Price	$ 43.20	$(14.28)	(24.8)	$ 57.48
Adjusted Chargeable Costs	$ 51.29	$ 6.59	14.7	$ 44.70
Average Production Taxes	$ 1.33	$ (0.66)	(33.2)	$ 1.99
Average Per Barrel Royalty	$ (9.42)	$(20.21)	(187.3)	$ 10.79
Average net royalty production (mb/d)	74.43	0.63	0.9	73.8

Average WTI prices during the twelve months ended September 30, 2020, decreased by approximately 24.8 percent compared to the preceding twelve-month period. Average monthly WTI prices during this period ranged from a high of $59.84 during the December 2019 to a low of $18.20 during April 2020. The increase in the Consumer Price Index used to calculate the Cost Adjustment Factor, as well as the scheduled increase in Chargeable Costs from $23.75 in calendar 2019 to $26.50 in calendar 2020, resulted in the 15 percent increase in Adjusted Chargeable Costs during the twelve months ended September 30, 2020. The decrease in the average Per Barrel Royalty for the period resulted primarily from the decrease in WTI prices and the increase in Adjusted Chargeable Costs. As provided in the Trust Agreement, the payment with respect to the Royalty Interest for any calendar quarter may not be less than zero. See Note 6 of Notes to Financial Statements in Item 8 below.

	Year Ended 12/31/2020	Increase (decrease) Amount	Increase (decrease) Percent	Year Ended 12/31/2019
		(Dollars in thousands)		
Royalty revenues	$ 9,269	$(39,703)	(81.1)	$ 48,972
Cash earnings	$ 8,126	$(39,796)	(83.0)	$ 47,922
Cash distributions	$ 9,079	$(38,723)	(81.0)	$ 47,802
Administrative expenses	$ (1,692)	$ (607)	55.9	$ (1,085)
Trust corpus at year end	$ 59	$ (839)	(93.4)	$ 898

The period-to-period decreases in royalty revenues, cash earnings and cash distributions are due to the substantial decline in the average Per Barrel Royalty as a result of the lower average WTI Price, the increase in Adjusted Chargeable Costs and the decline in average net production that prevailed during 2020 compared to 2019. The increase in administrative expenses reflects an increase in overall expenses relating to the Trust’s efforts to address the diminished amount of cash available to fund expenses and lack of royalty revenues attributable to the 2020 calendar year, including an increase in professional fees, and timing differences in accruals of expenses. The decrease in the Trust corpus reflects the increase in accrued expenses for the period and significant decline in revenue.

2019 Compared to 2018

	12 Months Ended 9/30/2019	Increase (decrease) Amount	Percent	12 Months Ended 9/30/2018
		(Dollars per barrel)		
Average WTI Price	$ 57.48	$ (6.49)	(10.1)	$ 63.97
Adjusted Chargeable Costs	$ 44.70	$ 7.55	20.3	$ 37.15
Average Production Taxes	$ 1.99	$ (0.35)	(15.0)	$ 2.34
Average Per Barrel Royalty	$ 10.79	$(13.69)	(55.9)	$ 24.48
Average net royalty production (mb/d)	73.8	(4.5)	(5.7)	78.3

Average WTI prices during the twelve months ended September 30, 2019 decreased by approximately 10 percent compared to the preceding twelve-month period. Average monthly WTI prices during this period ranged from a high of $70.72 during the first month of the period in October 2018 to a low of $48.82 at the end of December 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 $20.00 in calendar 2018 to $23.75 in calendar 2019, resulted in the 20 percent increase in Adjusted Chargeable Costs during the twelve months ended September 30, 2019. The decrease in the average Per Barrel Royalty for the period resulted primarily from the decrease in WTI prices and the increase in Adjusted Chargeable Costs. This decrease was modestly offset by the decline in Production Taxes, which remained historically low for the twelve months ended September 30, 2019 because Production Taxes during the period were calculated on the basis of the minimum tax under the Act and the 2014 Letter Agreement. See Note 6 of Notes to Financial Statements in Item 8 below.

	Year Ended 12/31/2019	Increase (decrease) Amount	Percent	Year Ended 12/31/2018
		(Dollars in thousands)		
Royalty revenues	$ 48,972	$(63,397)	(57.2)	$ 114,369
Cash earnings	$ 47,922	$(65,360)	(57.7)	$ 113,282
Cash distributions	$ 47,802	$(65,461)	(57.8)	$ 113,263
Administrative expenses	$ (1,085)	$ (36)	(3.2)	$ 1,121
Trust corpus at year end	$ 898	$ 206	29.8	$ 692

The period-to-period decreases in royalty revenues, cash earnings and cash distributions are due to the substantial decline in the average Per Barrel Royalty as a result of the lower average WTI Price, the increase in Adjusted Chargeable Costs and the decline in average net production that prevailed during 2019 compared to 2018. The decrease in administrative expenses reflects lower overall costs of supplies and services and timing differences in accruals of expenses. The increase in the Trust corpus reflects the decrease in accrued expenses for the period.

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 the 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, 2020 and 2019, 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, 2020, 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, 2020 and 2019, and its cash earnings and distributions and changes in trust corpus for each of the years in the three-year period ended December 31, 2020, in conformity with the modified cash basis of accounting described in note 3 to the financial statements.

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, 2020, 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 16, 2021 expressed an unqualified opinion on the effectiveness of the Trust's internal control over financial reporting.

Basis of Accounting

As described in note 3 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.

Going Concern

The accompanying financial statements have been prepared assuming that the Trust will continue as a going concern. As discussed in note 2 to the financial statements, the Trust has not received any royalty payments attributable to any quarter in 2020 and it is uncertain whether the Trust will receive future royalties necessary for the Trust to avoid termination, which raise substantial doubt about its ability to continue as a going concern. The Bank of New York Mellon Trust Company, N.A.'s, as the Trust's trustee (the Trustee) plans in regard to these matters are also described in note 2. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Basis for Opinion

These financial statements are the responsibility of 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 Company 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 management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the Trustee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of a critical audit matter does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Going Concern Assessment

As discussed in note 2 to the financial statements, the Trust prepared its financial statements on a going concern basis. Due to lower oil prices throughout 2020, the Trust received no royalty payments attributable to the four quarters of the year ended December 31, 2020 and has not been able to replenish the funds on deposit in the cash reserve account since January 2020. The Trust believes that the uncertainty surrounding the receipt of future royalties, coupled with the Trust’s liquidity position as of December 31, 2020, raises substantial doubt regarding the Trust’s ability to continue as a going concern.

We identified the evaluation of the Trust’s assessment of its ability to continue as a going concern and related disclosures as a critical audit matter. Evaluating the termination provisions within the Trust Agreement required challenging auditor judgment given the degree of uncertainty associated with future oil prices. Further, assessing the liquidity requirements of the Trust and its options to obtain additional funding required challenging auditor judgment and effort.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the Trust’s assessment and disclosure of going concern uncertainties. This included controls related to the review of termination provisions within the Trust Agreement, liquidity requirements of the Trust, and the adequacy of disclosures. We read the Trust Agreement to obtain an understanding of the termination provisions and the provisions by which the Trustee may obtain a loan, sell assets, or be indemnified and reimbursed for expenses. To assess the impact of future oil prices on the termination provisions within the Trust Agreement, we compared the break-even oil price necessary during the quarterly production periods of 2021 for the Trust to receive royalty payments, as determined in accordance with the Trust Agreement, to publicly available prices. We compared the Trust’s cash balance as of December 31, 2020 to forecasts of obligations for a period of one year from the date of issuance of the financial statements. We evaluated the Trust’s assessment of its options to obtain additional funding by considering relevant provisions of the Trust Agreement and discussions with the Trustee and external legal counsel. In addition, we assessed the adequacy of the Trust’s disclosures related to the going concern assessment.

/s/ KPMG LLP

We have served as the Trust’s auditor since 1989.

Dallas, Texas
March 16, 2021

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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, 2020, 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, 2020, 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, 2020 and 2019, 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, 2020, and the related notes (collectively, the financial statements), and our report dated March 16, 2021 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 accompanying *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

A 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. A 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.

/s/ KPMG LLP

Dallas, Texas
March 16, 2021

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BP Prudhoe Bay Royalty Trust

Statement of Assets, Liabilities and Trust Corpus
(Prepared on a modified cash basis)

(In thousands, except unit data)

	December 31, 2020	December 31, 2019
Assets		
Cash and cash equivalents (Note 3)	$ 266	$ 1,151
Total Assets	$ 266	$ 1,151
Liabilities and Trust Corpus		
Accrued expenses	$ 139	$ 253
Royalty deposit liability (Note 8)	68	—
Total Liabilities	207	253
Trust Corpus (40,000,000 units of beneficial interest authorized, 21,400,000 units issued and outstanding)	59	898
Total Liabilities and Trust Corpus	$ 266	$ 1,151

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 cash basis)

(In thousands, except unit data)

	Year Ended December 31,		
	2020	2019	2018
Royalty revenues	$ 9,269	$ 48,972	$ 114,369
Interest income	11	35	34
HNS expense reimbursement (Note 2)	538	—	—
Less: Trust administrative expenses	(1,692)	(1,085)	(1,121)
Cash earnings	$ 8,126	$ 47,922	$ 113,282
Cash distributions	$ 9,079	$ 47,802	$ 113,263
Cash distributions per unit	$ 0.4242	$ 2.234	$ 5.293
Units outstanding	21,400,000	21,400,000	21,400,000

See accompanying notes to financial statements.

BP Prudhoe Bay Royalty Trust

Statements of Changes in Trust Corpus
(Prepared on a modified cash basis)

(In thousands)

	Year Ended December 31,		
	2020	2019	2018
Trust corpus at beginning of year	$ 898	$ 692	$ 785
Cash earnings	8,126	47,922	113,282
Decrease (increase) in accrued expenses	114	86	(112)
Cash distributions	(9,079)	(47,802)	(113,263)
Trust corpus at end of year	$ 59	$ 898	$ 692

See accompanying notes to financial statements.

(1) Formation of the Trust and Organization

BP Prudhoe Bay Royalty Trust (the "Trust"), a grantor trust, was created as a Delaware business trust pursuant to a Trust Agreement dated February 28, 1989 (the "Trust Agreement") among The Standard Oil Company ("Standard Oil"), BP Exploration (Alaska) Inc. ("BP Alaska")(now known as Hilcorp North Slope, LLC ("HNS")), 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, 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 interests as of February 28, 1989 in the Prudhoe Bay field situated on the North Slope of Alaska (the "1989 Working Interests"). Trust Unit holders are subject to the risk that production will be interrupted or discontinued or fall, on average, below 90,000 barrels per day in any quarter. BP has guaranteed the performance of BP Alaska of its payment obligations with respect to the Royalty Interest and that guarantee remains in place with respect to the performance of HNS of such payment obligations.

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, a Delaware banking corporation. 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
(Prepared on a modified cash basis)
December 31, 2020

(2) Impact of COVID-19 Pandemic and Going Concern

A novel strain of coronavirus, SARS-CoV-2 (severe acute respiratory syndrome coronavirus 2), surfaced in late 2019 and has since spread around the world. In March 2020, the World Health Organization characterized the disease caused by the virus—COVID-19—as a pandemic. Due to the economic impacts of the COVID-19 pandemic, the markets have experienced a decline in oil prices in response to oil demand concerns and global storage considerations. As a result of lower oil prices, the Trust received no royalty payment for the quarters ended March 31, June 30, and September 30, 2020 and, as discussed in Note 8 to these financial statements, did not receive a royalty payment in January 2021 for the quarter ended December 31, 2020.

As provided in the Trust Agreement, the quarterly royalty payment by HNS to the Trust is the sum of the individual revenues attributed to the Trust as calculated each day during the quarter. The amount of such revenues is obtained by multiplying Royalty Production for each day in the calendar quarter by the Per Barrel Royalty for that day. Pursuant to the Trust Agreement, 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. On January 1, 2020, 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 $54.34. As a result of the decline in oil prices, the daily WTI price has been below the “break-even” point for each day after January 23, 2020, resulting in a negative value for the payment calculation for each of the four quarters of 2020. However, as provided in the Trust Agreement, the payment with respect to the Royalty Interest for any calendar quarter may not be less than zero.

If oil prices remain below the “break-even” WTI price of $60.72 per barrel necessary for the Trust to receive a positive Per Barrel Royalty in each calendar quarter of 2021, the Trust’s operations will continue to be adversely impacted. As noted above, as a general matter, the Trust is expected to terminate at such time the net revenues from the Royalty Interest for two successive years are less than $1,000,000 per year.

In order to ensure that the Trust has the ability to pay future expenses, the Trust established a cash reserve account in July 1999. The cash reserve account was funded from periodic deductions from the royalty payments. These deductions were intended to result in an available cash balance in the cash reserve account that would be sufficient to pay approximately one year’s current and expected liabilities and expenses of the Trust.

As previously disclosed, the Trust has not received any royalty payments attributable to the four quarters of 2020. As a result, the Trust has not been able to replenish the funds on deposit in the cash reserve account since January 2020.

Pursuant to Section 7.02 of the Trust Agreement, the Trustee, on December 18, 2020, notified HNS in writing that available assets in the trust created under the Trust Agreement were insufficient to pay current expenses that had been incurred on behalf of the Trust relating to the Trustee’s administration of the Trust. Pursuant to the indemnity provisions contained in Section 7.02 of the Trust Agreement, the Trustee made a demand for indemnity and reimbursement of expenses upon HNS in the amount of $537,835, representing the Trust’s unpaid expenses through December 18, 2020. HNS paid the requested funds to the Trustee on December 28, 2020, and the Trustee applied those funds to the Trust’s unpaid expenses in accordance with the Trust Agreement. Although HNS agreed to make an indemnity payment to reimburse the Trust for current administrative expenses incurred by the Trustee on behalf of the Trust through December 18, 2020, there can be no assurance that HNS will make any further indemnification payments and in such case, the Trustee will continue to review its options under the Trust Agreement and Support Agreement to enforce such indemnity, if necessary.

The Trustee anticipates incurring significant additional expenses relating to continued compliance with the Trust's Securities and Exchange Act and tax reporting requirements through 2021. The Trustee is currently exploring with HNS the options available to the Trust under the Trust Agreement to address the Trust's continuing operational funding shortfall. These steps may include obtaining a loan for the Trust, selling a portion of the Trust assets, or selling all of the Trust assets and taking the necessary steps to terminate the Trust. In addition, the Trustee intends to increase the amount of the cash reserve, in the event that royalty payments are available to the Trust in the future. There can be no assurance that the Trust will be able to secure a loan or arrange for the sale of Trust assets, or that the loan or sale will be on terms that are acceptable to the Trust.

The Trust prepared its financial statements on a going concern basis. The uncertainty surrounding the receipt of future royalties necessary for the Trust to avoid termination, coupled with the Trust's current liquidity position, raises substantial doubt regarding the Trust's ability to continue as a going concern for a period of one year from the date the financial statements are issued.

(3) 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, 2020 and 2019, and the modified basis of cash earnings and distributions and changes in Trust corpus for the years ended December 31, 2020, 2019 and 2018. 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, 2020 and 2019 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.

BP Prudhoe Bay Royalty Trust
Notes to Financial Statements
(Prepared on a modified cash basis)
December 31, 2020

(4) 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.

(5) 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.

(6) Alaska Oil and Gas Production Tax

On April 14, 2013, Alaska's legislature passed an oil-tax reform bill aimed at encouraging oil production and investment in Alaska's oil industry. On May 21, 2013, the Governor 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 the 2006 Amendments and ACES, 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.

BP Prudhoe Bay Royalty Trust
Notes to Financial Statements
(Prepared on a modified cash basis)
December 31, 2020

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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(7) Royalty Revenue Adjustments

Certain of the royalty payments received by the Trust in 2020, 2019, and 2018 were adjusted by BP Alaska (as predecessor to HNS) 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).

	2020 Payments Received			
	January	April	July	October
Royalty payment as calculated	$ 9,321	$ —	$ —	$ —
Adjustment for underpayment (overpayment), plus accrued interest	16	—	—	—
Net payment received	$ 9,337	$ —	$ —	$ —

	2019 Payments Received			
	January	April	July	October
Royalty payment as calculated	$ 21,361	$ 7,732	$ 12,152	$ 7,291
Adjustment for underpayment (overpayment), plus accrued interest	398	16	12	10
Net payment received	$ 21,759	$ 7,748	$ 12,164	$ 7,301

	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

Due to a slight over estimation of the December 2019 production volume included in the 2019 fourth quarter royalty payment calculation, there was an overpayment by BP Alaska of $68,001, including interest through December 31, 2020, with respect to the 2019 fourth quarter royalty payment. This overpayment would be recovered by HNS in one or more future quarters with a sufficient positive royalty payment. In the event that there are no future, or insufficient, positive payments, it is expected that HNS would explore other options it may have under the Trust Agreement, the Conveyance or otherwise to recover the amount of the 2019 fourth quarter overpayment.

BP Prudhoe Bay Royalty Trust
Notes to Financial Statements
(Prepared on a modified cash basis)
December 31, 2020

(8) Subsequent Event

There was no royalty payment received by the Trust in January 2021 for the quarter ended December 31, 2020.

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

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BP Prudhoe Bay Royalty Trust
Notes to Financial Statements
(Prepared on a modified cash basis)
December 31, 2020

(9) Summary of Quarterly Results (Unaudited)

A summary of selected quarterly financial information for the years ended December 31, 2020, 2019, and 2018 is as follows (in thousands, except unit data):

	2020 Fiscal Quarter			
	First	Second	Third	Fourth
Royalty revenues	$ 9,337	$ (67)	$ —	$ (1)
Interest income	7	4	—	—
HNS expense reimbursement	—	—	—	538
Trust administrative expenses	(253)	(689)	(288)	(462)
Cash earnings (loss)	$ 9,091	$ (752)	$ (288)	$ 75
Cash distributions	$ 9,078	$ —	$ —	$ —
Cash distributions per unit	$ 0.4242	$ —	$ —	$ —

	2019 Fiscal Quarter			
	First	Second	Third	Fourth
Royalty revenues	$ 21,759	$ 7,748	$ 12,164	$ 7,301
Interest income	9	10	8	8
Trust administrative expenses	(326)	(312)	(341)	(106)
Cash earnings	$ 21,442	$ 7,446	$ 11,831	$ 7,203
Cash distributions	$ 21,463	$ 7,381	$ 11,793	$ 7,165
Cash distributions per unit	$ 1.0029	$ 0.3449	$ 0.5511	$ 0.3348

	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

BP Prudhoe Bay Royalty Trust
Notes to Financial Statements
(Prepared on a modified cash basis)
December 31, 2020

(10) Supplemental Reserve Information and Standardized Measure of Discounted Future Net Cash Flows 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 2020 ($39.57 per barrel), 2019 ($55.69 per barrel), and 2018 ($65.56 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, 2020, 2019, and 2018, based on BP Alaska's latest reserve estimate at such times and the 12-month average WTI price for 2020, 2019 and 2018, were estimated to be 0, 4.465, and 15.772 million barrels, respectively (of which 0, 4.394, and 15.638 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 flows 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 flows 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, 2020, 2019 and 2018, the standardized measure of discounted future net cash flows relating to proved reserves attributable to

BP Prudhoe Bay Royalty Trust
Notes to Financial Statements
(Prepared on a modified cash basis)
December 31, 2020

(10) Supplemental Reserve Information and Standardized Measure of Discounted Future Net Cash Flow Relating to Proved Reserves (Unaudited) (Cont'd)

the Trust (estimated in accordance with the provisions of FASB ASC 932), based on the 12-month average WTI Price for 2020, 2019, and 2018 of $39.57, $55.69, and $65.56 per barrel, respectively, were as follows (in thousands):

	December 31, 2020	2019	2018
Future cash inflows	$ —	$ 5,785	$ 154,662
10% annual discount for estimated timing of cash flows	—	(269)	(16,121)
Standardized measure of discounted future net cash flows (a)	$ —	$ 5,516	$ 138,541

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

	December 31, 2020	2019	2018
Net changes in prices and production costs	$(69,163)	$(109,850)	$ 176,825
Net change in production taxes	2,729	5,437	(5,029)
Other	(25)	52	845
	(66,459)	(104,361)	172,641
Royalty income received (b)(c)	60,943	(36,550)	(109,588)
Accretion of discount	—	7,886	6,812
Net increase (decrease) during the year	$ (5,516)	$(133,025)	$ 69,865

(b) For the purpose of this calculation, royalty income received for 2020, 2019 and 2018 includes the following:

Period October 1, 2020 through December 31, 2020	$ —
Period October 1, 2019 through December 31, 2019	$ 9,337
Period October 1, 2018 through December 31, 2018	$21,759

The above royalty income was received by the Trust in January 2021, 2020, and 2019, respectively.

(c) 2019 and 2018 amounts represent royalty income received. In 2020, the calculated royalty income was negative. As the royalty calculation was less than zero, no royalty payment was received in 2020.

BP Prudhoe Bay Royalty Trust
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(Prepared on a modified cash basis)
December 31, 2020

(10) Supplemental Reserve Information and Standardized Measure of Discounted Future Net Cash Flow Relating to Proved Reserves (Unaudited) (Cont'd)

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, 2017	9,070
Revisions of previous estimates (1)	11,311
Production	(4,609)
December 31, 2018	15,772
Revisions of previous estimates (2)	(6,916)
Production	(4,391)
December 31, 2019	4,465
Revisions of previous estimates (3)	(16)
Production	(4,449)
December 31, 2020	—
Proved developed reserves (thousands of barrels) as of:	
December 31, 2018	15,638
December 31, 2019	4,394
December 31, 2020	—
Proved undeveloped reserves (thousands of barrels) as of:	
December 31, 2018	134
December 31, 2019	71
December 31, 2020	—

BP Prudhoe Bay Royalty Trust
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(Prepared on a modified cash basis)
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(1) 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 2018. 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.

(2) The negative revision in year-end 2019 reserves reflects a decrease in the WTI price from $65.56 per barrel for 2018 to $55.69 per barrel for 2019 using the 12-month average of the first-day-of-the-month price for each month in the years ended December 31, 2018 and 2019, respectively. Under the economic conditions and production forecast at year end 2014, the per-barrel royalty was forecast to be zero following the year 2018. 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. Under the economic conditions and production forecast at year end 2019, the per-barrel royalty was forecast to be zero following the year 2020. This decrease in economic life from year-end 2018 to year-end 2019 results in a negative revision in reserve volumes.

(3) The negative revision in year-end 2020 reserves reflects a decrease in the WTI price from $55.69 per barrel for 2019 to $39.57 per barrel for 2020 using the 12-month average of the first-day-of-the-month price for each month in the years ended December 31, 2019 and 2020, respectively. Under the economic conditions and production forecast at year end 2014, the per-barrel royalty was forecast to be zero following the year 2018. 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. Under the economic conditions and production forecast at year end 2019, the per-barrel royalty was forecast to be zero following the year 2020. Under the economic conditions and production forecast at year end 2020, the per-barrel loyalty was forecast to be zero following the year 2020. This decrease in economic life from year-end 2019 to year-end 2020 results in a negative revision in reserve volumes.

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, 2020.

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, HNS has significant disclosure and reporting obligations to the Trust. HNS is required to provide the Trust such information concerning the Royalty Interest as the Trustee may need and to which HNS 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, HNS’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 HNS and discuss the affairs, finances and accounts of HNS relating to the 1989 Working Interests with representatives of HNS; it also requires HNS to provide the Trust with such other information as the Trustee may reasonably request from time to time and to which HNS has access.

The Trustee’s disclosure controls and procedures include ensuring that the Trust receives the information and reports that HNS 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 HNS is included in the reports that the Trust files or submits under the Exchange Act.

As of the end of calendar year 2020, 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 HNS, and that HNS 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, 2020.

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, 2020.

The effectiveness of the Trust's internal control over financial reporting as of December 31, 2020 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report set forth in full on page 44.

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.

PART 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.

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, 2020 was as follows:

Year ended December 31,	Trustee’s Fees	Transfer Agent and Registrar Fees
2018	$223,755	—
2019	$213,378	—
2020	$213,378	—

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

Securities Authorized for Issuance under Equity Compensation Plans

No Units are authorized for issuance under any form of equity compensation plan.

Unit Ownership of Certain Beneficial Owners

As of March 3, 2021, there were no persons known to the Trustee to be the beneficial owners of more than five percent of the Units.

Unit Ownership of Management

Neither HNS, Hilcorp, Standard Oil, nor BP owns any Units. No Units are owned by The Bank of New York Mellon Trust Company, N.A., as Trustee or in its individual capacity, or by BNY Mellon Trust of Delaware, as co-trustee or in its individual capacity.

Changes in Control

The Trustee knows of no arrangement, including the pledge of Units, the operation of which may at a subsequent date result in a change in control of the Trust.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

There has been no transaction by the Trust since the beginning of 2020, or any currently proposed transaction in which a related person (as defined in Item 404 of Regulation S-K) had or will have a direct or indirect material interest, except for payment to the Trustee of the fees and reimbursement for expenses prescribed in the Trust Agreement. See Item 11 above.

The Trust has no independent directors. See Item 10 above.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Fees for services performed by KPMG LLP for the years ended December 31, 2020 and 2019 are:

	2020	2019
Audit	$140,000	$196,500
Audit related	10,000	24,500
Tax	221,000	221,000
Other	—	—
	$371,000	$442,000

The Trust has no audit committee, and as a consequence, has no audit committee pre-approval policy with respect to fees paid to KPMG LLP.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents filed as part of this report.

The following financial statements of the Trust are included in Part II, Item 8:

Reports of Independent Registered Public Accounting Firm

Statements of Assets, Liabilities and Trust Corpus as of December 31, 2020 and 2019

Statements of Cash Earnings and Distributions for the years ended December 31, 2020, 2019 and 2018

Statements of Changes in Trust Corpus for the years ended December 31, 2020, 2019 and 2018
Notes to Financial Statements

(b) Description of Exhibits

4.1 BP Prudhoe Bay Royalty Trust Agreement dated February 28, 1989 among The Standard Oil Company, BP Exploration (Alaska) Inc., The Bank of New York Trustee, and F. James Hutchinson, Co-Trustee. Incorporated by reference to the correspondingly numbered exhibit to the Registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 2006 (File No. 1-10243).

4.2 Overriding Royalty Conveyance dated February 27, 1989 between BP Exploration (Alaska) Inc. and The Standard Oil Company. Incorporated by reference to the correspondingly numbered exhibit to the Registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 2006 (File No. 1-10243).

4.3 Trust Conveyance dated February 28, 1989 between The Standard Oil Company and BP Prudhoe Bay Royalty Trust. Incorporated by reference to the correspondingly numbered exhibit to the Registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 2006 (File No. 1-10243).

4.4 Support Agreement dated as of February 28, 1989, as amended May 8, 1989, among The British Petroleum Company p.l.c., BP Exploration (Alaska) Inc., The Standard Oil Company and BP Prudhoe Bay Royalty Trust. Incorporated by reference to the correspondingly numbered exhibit to the Registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 2006 (File No. 1-10243).

4.5 Letter agreement executed October 13, 2006 between BP Exploration (Alaska) Inc. and The Bank of New York, as Trustee. Incorporated by reference to the correspondingly numbered exhibit to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 1-10243).

4.6	Letter agreement executed January 11, 2008 between BP Exploration (Alaska) Inc. and The Bank of New York, as Trustee. Incorporated by reference to the correspondingly numbered exhibit to the Registrant's Current Report on Form 8-K dated January 11, 2008 (File No. 1-10243).
10.1	Settlement Agreement, dated May 8, 2009, among BP Exploration (Alaska) Inc., The Bank of New York Mellon, as Trustee, and BNY Mellon Trust Company of Delaware, as Co-Trustee. Incorporated by reference to the correspondingly numbered exhibit to the Registrant's Current Report on Form 8-K dated May 8, 2009 (File No. 1-10243).
10.2	Agreement of Resignation, Appointment and Acceptance dated as of December 15, 2010 among BP Exploration (Alaska) Inc., The Bank of New York Mellon and The Bank of New York Mellon Trust Company, N.A. Incorporated by reference to the correspondingly numbered exhibit to the Registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 2010 (File No. 1-10243).
31*	Rule 13a-14(a) certification.
32*	Section 1350 certification.
99*	Report of Miller and Lents, Ltd., dated February 26, 2021.
101	Explanatory note: An Interactive Data File is not submitted with this filing pursuant to Item 601(101) of Regulation S-K, because the Trust does not prepare its financial statements in accordance with generally accepted accounting principles as used in the United States. See Note 2 of Notes to Financial Statements in Part II, Item 8.

* Filed herewith.

(c) All financial statement schedules have been omitted because they are either not applicable, not required or the information is set forth in the financial statements or notes thereto.

ITEM 16. FORM 10-K SUMMARY.

None.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BP PRUDHOE BAY ROYALTY TRUST

By: THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A., as Trustee

By: /s/Elaina C. Rodgers
Elaina C. Rodgers
Vice President

March 16, 2021

The Registrant is a trust and has no officers, directors, or persons performing similar functions. No additional signatures are available and none have been provided.

EXHIBIT 31

CERTIFICATION

The undersigned, Elaina C. Rodgers, certifies that:

1. I have reviewed this annual report on Form 10-K of BP Prudhoe Bay Royalty Trust, for which The Bank of New York Mellon Trust Company, N.A. acts as Trustee;

2. Based on my knowledge, this report does not contain any untrue statement of material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, cash earnings and distributions and changes in the Trust corpus of the registrant as of, and for, the periods presented in this report;

4. I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act rules 13a-15(f) and 15d-15(f)) for the registrant and I have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under my supervision, to ensure that material information relating to the registrant is made known to me by others within that entity, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under my supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report my conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. I have disclosed, based on my most recent evaluation of internal control over financial reporting, to the registrant's auditors:

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves persons who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2021

By: /s/ Elaina C. Rodgers
Elaina C. Rodgers
Vice President

The Bank of New York Mellon Trust Company, N.A.

EXHIBIT 32

CERTIFICATION PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002, 18 U.S.C. SECTION 1350

The undersigned, Elaina C. Rodgers, is an authorized officer of The Bank of New York Mellon Trust Company, N.A., the trustee of BP Prudhoe Bay Royalty Trust (the “**registrant**”).

This statement is being furnished in connection with the filing by the registrant of the registrant’s annual report on Form 10-K for the fiscal year ended December 31, 2020 (the “**Report**”).

By execution of this statement, the undersigned certifies that:

(A) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and

(B) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the registrant as of the dates and for the periods covered by the Report.

Date: March 16, 2021

By: /s/ Elaina C. Rodgers
Elaina C. Rodgers
Vice President
The Bank of New York Mellon Trust Company, N.A.

Estimates of Proved Reserves, Future Production Rates, and Future Net Revenues for THE BP PRUDHOE BAY ROYALTY TRUST

As of December 31, 2020

Miller and Lents
909 Fannin Street, Suite 1300
Houston, Texas 77010 USA

FEBRUARY 26, 2021

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713.651.9455
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February 26, 2021

Ms. Elaina Rodgers, Vice President
Trustee, BP Prudhoe Bay Royalty Trust
BNY Mellon Trust Company, N.A.
US Client and Business Development
601 Travis, Floor 16
Houston, Texas 77002

Re: Estimates of Proved Reserves,
Future Production Rates, and
Future Net Revenues for the
BP Prudhoe Bay Royalty Trust
As of December 31, 2020

Dear Ms. Rodgers:

This letter report is a summary of investigations performed in accordance with the Miller and Lents, Ltd. (M&L) engagement by you as described in Section 4.8(d) of the Overriding Royalty Conveyance dated February 27, 1989, between BP Exploration (Alaska) Inc. and The Standard Oil Company. The purpose of M&L's review was to determine that the procedures and methods used by Hilcorp North Slope, LLC are effective and in accordance with the definitions contained in the Securities and Exchange Commission Regulation S-X, Rule 4-10(a). The investigations included reviews of the estimates of proved reserves and production rate forecasts of oil and condensate made by Hilcorp North Slope, LLC attributable to the BP Prudhoe Bay Royalty Trust as of December 31, 2020. Additionally, M&L reviewed calculations of the resulting estimated future net revenues and present value of estimated future net revenues attributable to the BP Prudhoe Bay Royalty Trust. M&L's review covers 100 percent of reserves and future revenues attributable to the BP Prudhoe Bay Royalty Trust. This report was completed on February 26, 2021.

Under the terms of an Issues Resolution Agreement entered into by the Prudhoe Bay Unit owners in October 1990, produced condensate from the Gas Cap Initial Participating Area (Gas Cap IPA) was allocated to the Gas Cap IPA until a cumulative limit of 1,175 million barrels was reached. This cumulative limit was reached in June 2014. Beginning at that time and continuing thereafter, that condensate is allocated to the Oil Rim Initial Participating Area (Oil Rim IPA). Therefore, references herein to oil production include condensate production allocated to the Oil Rim IPA.

The estimates and calculations reviewed were summarized in the report prepared by Hilcorp North Slope, LLC and transmitted with a cover letter dated March 2, 2021, addressed to Ms. Elaina Rodgers of BNY Mellon Trust Company, N.A. and signed by Ms. Colleen Elkins. Reviews were also performed by M&L during this year or in previous years of the (1) procedures for estimating and documenting proved reserves; (2) estimates of in-place reservoir volumes; (3) estimates of recovery factors and production profiles for the various areas, pay zones, projects, and recovery processes that are included in the estimate of proved reserves; (4) production strategy and procedures for implementing that strategy; (5) sufficiency of the data available for making estimates of proved reserves and production profiles; and (6) pertinent provisions of the Prudhoe Bay Unit Operating Agreement, the Issues Resolution Agreement, the Overriding Royalty Conveyance, the Trust Conveyance, the BP Prudhoe Bay Royalty Trust Agreement, and other related documents referenced in the Form F-3 Registration Statement filed with the Securities and Exchange Commission (SEC) on August 7, 1989 by BP Exploration (Alaska) Inc.

Proved reserves were estimated by Hilcorp North Slope, LLC in accordance with the definitions contained in Securities and Exchange Commission Regulation S-X, Rule 4-10(a). Estimated future net revenues and present value of estimated future net revenues are not intended and should not be interpreted to represent fair market values for the estimated reserves.

The Prudhoe Bay (Permo-Triassic) Reservoir is defined in the Prudhoe Bay Unit Operating Agreement. The Prudhoe Bay Unit is an oil and gas unit situated on the North Slope of Alaska. The BP Prudhoe Bay Royalty Trust is entitled to a royalty payment on 16.4246 percent of the first 90,000 barrels of the actual average daily net production of oil and condensate for each calendar quarter from the BP Exploration (Alaska) Inc. Working Interest as defined in the Overriding Royalty Conveyance. The payment amount depends upon the Per Barrel Royalty that in turn depends upon the West Texas Intermediate Price (WTI Price), the Chargeable Costs, the Cost Adjustment Factor, and Production Taxes, all of which are defined in the Overriding Royalty Conveyance. Changes to the Production Tax beginning January 1, 2014, were legislated by the State of Alaska and are incorporated herein. “Barrel” as used herein means stock tank barrel as defined in the Overriding Royalty Conveyance.

Payments received by the BP Prudhoe Bay Royalty Trust are based exclusively on a percentage of the first 90,000 barrels of the average actual daily net production of crude oil from the leases subject to the Overriding Royalty Conveyance. There is no relationship between any delivery commitments of Hilcorp North Slope, LLC and the other owners of the Working Interests in the Prudhoe Bay Field and the BP Prudhoe Bay Royalty Trust’s entitlement to the prescribed royalty payments. The BP Prudhoe Bay Royalty Trust does not directly or indirectly own any working interests in wells, operations, or acreage.

M&L’s reviews do not constitute independent estimates of the reserves and annual production rate forecasts for the areas, pay zones, projects, and recovery processes examined. M&L relied upon the accuracy and completeness of information provided by Hilcorp North Slope, LLC and historically by BP Exploration (Alaska) Inc. with respect to pertinent ownership interests and various other historical, accounting, engineering, and geological data. M&L employed all methods, procedures, and assumptions considered necessary in utilizing the data provided to prepare this report.

As a result of M&L’s cumulative reviews, based on the foregoing, M&L concludes that:

1. A large body of basic data and detailed analyses are available and were used in making the estimates. In M&L’s judgment, the quantity and quality of currently available data on reservoir boundaries, original fluid contacts, and reservoir rock and fluid properties are sufficient to indicate that any future revisions to the estimates of total original in-place volumes should be minor. Furthermore, the data and analyses on recovery factors and future production rates are sufficient to support the proved reserves estimates.
2. Proved reserves were estimated generally by using full-field three-dimensional reservoir simulation, well-established historical production performance trends, and/or other geologic and engineering studies. Where sufficient localized performance data did not exist, reserves were estimated by volumetric calculations, simulations, or by analogy to similar producing areas of the field. The methods and procedures employed to accumulate and evaluate the necessary information and to estimate, document, and reconcile reserves, annual production rate forecasts, and future net revenues are effective and appropriate.

   Based on M&L’s limited independent tests of the computations of reserves, production flowstreams, and future net revenues, such computations were performed in accordance with the methods and procedures described to M&L and conform to the relevant SEC definitions.

3. As a result of the 2020 SEC-defined 12-month average West Texas Intermediate Price, the estimated net remaining proved reserves attributable to the BP Prudhoe Bay Royalty Trust as of December 31, 2020 are zero.

4. The 2020 average West Texas Intermediate Price of $39.57 per barrel, applicable under current SEC regulations, represents the 12-month average of the first-day-of-the-month price for each month within the 12-month period prior to December 31, 2020. Based on this price, other economic parameters as prescribed by the Overriding Royalty Conveyance, and utilizing the specified procedures outlined in Financial Accounting Standards Board Accounting Standards Codification 932, Extractive Activities – Oil and Gas, Hilcorp North Slope, LLC calculated that as of December 31, 2020, production of the proved reserves will result in estimated future net revenues and present value of estimated future net revenues of $0 to the BP Prudhoe Bay Royalty Trust. These estimates are reasonable.

5. As a consequence of the natural production decline and the downtime required for ongoing infrastructure and other improvements, Hilcorp North Slope, LLC's net production of oil from proved reserves attributable to the BP Prudhoe Bay Royalty Trust was less than 90,000 barrels per day on an annual average basis in 2020. Hilcorp North Slope, LLC expects that the net production of oil from proved reserves attributable to the BP Prudhoe Bay Royalty Trust will be less than 90,000 barrels per day on an average basis during future years. The Hilcorp North Slope, LLC projection of the future net production of oil is reasonable.

6. Production attributable to the BP Prudhoe Bay Royalty Trust will decline with the Hilcorp North Slope, LLC production. The Per Barrel Royalty will continue to have no value if the West Texas Intermediate Price is less than the sum of the Chargeable Costs and Production Taxes, appropriately adjusted in accordance with the Overriding Royalty Conveyance. Under these circumstances, average daily production attributable to the BP Prudhoe Bay Royalty Trust will continue to have no value and therefore will not contribute to the reserves attributable to the BP Prudhoe Bay Royalty Trust regardless of Hilcorp North Slope, LLC's net production level.

7. Based on the SEC-defined 12-month average West Texas Intermediate Price of $39.57 per barrel and Production Taxes and Adjusted Chargeable Costs as prescribed by the Overriding Royalty Conveyance, the projection that royalty payments will continue to be zero is reasonable. Therefore, no reserves are currently attributed to the BP Prudhoe Bay Royalty Trust. In order for the BP Prudhoe Bay Royalty Trust to have associated reserves and future net revenues, the SEC-defined 12-month average West Texas Intermediate Price of $39.57 per barrel must exceed the Production Taxes and Adjusted Chargeable Costs as prescribed by the Overriding Royalty Conveyance in future years. The projected value of the Production Taxes and Adjusted Chargeable Costs as prescribed by the Overriding Royalty Conveyance is $59.87 per barrel in 2021 and is $65.38 per barrel in 2022 and continues to increase thereafter. Currently, the cessation of production date forecasted by Hilcorp North Slope, LLC exceeds the life of the BP Prudhoe Bay Royalty Trust.

8. Even if expected reservoir performance does not change, the estimated reserves, economic life, and future net revenues attributable to the BP Prudhoe Bay Royalty Trust may change significantly in the future. This may result from sustained periods of change in the West Texas Intermediate Price, the Production Tax, or from changes in other prescribed variables utilized in calculations defined by the Overriding Royalty Conveyance.

Estimates of ultimate and remaining reserves and production forecasts depend upon assumptions regarding expansion or implementation of alternative projects or development programs and upon strategies for production optimization. Hilcorp North Slope, LLC has continual reservoir management, surveillance, and planning efforts dedicated to (1) gathering new information, (2) improving the accuracy of its reserves and production capacity estimates, (3) recognizing and exploiting new opportunities, (4) anticipating potential problems and taking corrective actions, and (5) identifying, selecting, and implementing optimum recovery program and cost reduction alternatives. Given this significant effort and ever-changing economic conditions, estimates of reserves and production profiles will change periodically.

Future projects, development programs, or operating strategies different from those assumed in the current estimates may change future estimates and affect recoveries. However, because several complementary and alternative projects are being considered for recovery of the remaining oil in the reservoir, a decision not to implement a currently planned project may allow scope expansion or implementation of another project, thereby increasing the overall likelihood of recovering the reserves.

Future production rates will be controlled by facilities' limitations and upsets, well downtime, and the effectiveness of programs to optimize production and costs. Additional drilling, workovers, facilities modifications, new recovery projects, and programs for production enhancement and optimization are expected to mitigate but not eliminate the decline in gross oil production capacity.

Under current economic conditions, gas from the Alaskan North Slope, except for minor volumes, cannot be marketed commercially. As a result of continued reinjection of produced gas, oil recovery is expected to be greater than the recovery would be if major volumes of produced gas were being sold. No major gas sale is assumed in the current estimates. In the event that major gas sales are initiated, likely to supply a liquefied natural gas (LNG) project under consideration, ultimate oil recovery may be reduced from the current estimate unless recovery projects other than those included in the current estimate are implemented.

Large volumes of natural gas liquids (NGLs) are likely to be produced and marketed in the future whether or not major gas sales become viable. NGL reserves are not included in the estimates cited herein. The BP Prudhoe Bay Royalty Trust is not entitled to royalty payments from production or sales of natural gas, LNG, or NGLs.

The evaluations presented in this report, with the exceptions of those parameters specified by others, reflect M&L's informed judgments and are subject to the inherent uncertainties associated with interpretation of geological, geophysical, and engineering information. These uncertainties include, but are not limited to the (1) utilization of analogous or indirect data and (2) application of professional judgment. At this time, M&L and Hilcorp North Slope, LLC are not aware of any existing or pending federal or state regulations that would materially affect the ability of Hilcorp North Slope, LLC to recover the estimated reserves in the Prudhoe Bay Field. Government policies and market conditions different from those reflected in this study or disruption of existing transportation routes or facilities may cause (1) the total quantity of oil or condensate to be recovered, (2) actual production rates, (3) prices received, (4) operating and capital costs, or (5) Production Taxes to vary from those reviewed in this report. Minor precision inconsistencies may exist in the report due to truncation or rounding of aggregated values.

Miller and Lents, Ltd. was founded in 1948, offering services and expertise in many phases of the oil and gas industry. The firm is registered with the Texas Board of Professional Engineers. Assigned staff members include licensed professional engineers with over 25 years of diversified experience. Work was supervised by a licensed professional engineer with more than 15 years of experience with the BP Prudhoe Bay Royalty Trust.

Miller and Lents, Ltd. is an independent oil and gas consulting firm. No director, officer, or key employee of Miller and Lents, Ltd. has any financial ownership in the BP Prudhoe Bay Royalty Trust, Hilcorp North Slope, LLC, or its parent or any related companies. Compensation for this report is not contingent upon the results and M&L has not performed other services for Hilcorp North Slope, LLC or the BP Prudhoe Bay Royalty Trust that would affect its objectivity. Miller and Lents, Ltd. hereby grants consent for use of this letter, in its entirety, in the BP Prudhoe Bay Royalty Trust's SEC Form 10-K annual report filing for the fiscal year ended December 31, 2020.

Very truly yours,

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