

**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, 2022

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  
(State or other jurisdiction of  
incorporation or organization)

13-6943724  
(I.R.S. Employer  
Identification No.)

The Bank of New York Mellon Trust Company, N.A., Trustee  
601 Travis Street Floor 16  
Houston, Texas  
(Address of principal executive offices)

77002  
(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 Units of Beneficial Interest	Trading Symbol(s) BPT	Name of Each Exchange on Which Registered New York Stock Exchange
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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	<input type="checkbox"/>	Accelerated filer	<input checked="" type="checkbox"/>
Non-accelerated filer	<input type="checkbox"/>	Smaller reporting company	<input type="checkbox"/>
		Emerging growth company	<input type="checkbox"/>

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.

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements.

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b).

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, 2022 (the last business day of the registrant's most recently completed second fiscal quarter)) was approximately \$438,058,000.

As of March 16, 2023, 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**”), a grantor 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 1,500 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](http://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,” “estimates,” “expect,” “believe,” “intend,” “likely” “plan”, “predict” 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, changes in expenses of the Trust, cash reserve targets and the timing of the termination of the Trust, economic conditions, domestic and international political events and developments in major oil producing regions, especially in the Middle East and Russia, legislation and regulation, international hostilities, war, including, Russia’s war with Ukraine and the international responses thereto, including the imposition of international sanctions, developments in the COVID-19 pandemic, including the emergence of more contagious or virulent strains of the virus and the availability, uptake, and efficacy of vaccines.

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 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 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 and the Trust’s other reports 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 after satisfaction of all of the Trust's liabilities (including, without limitation, Administrative Expenses as defined below), and establishing or increasing reserves for the future liabilities of the Trust. 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 and those in connection with the eventual termination of the Trust 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 or a potential claim subsequent 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 and those of its agents and other professionals) incurred by it, individually or as Trustee, in the administration of the Trust and the Trust assets. See "ITEM 1. BUSINESS - THE BP SUPPORT AGREEMENT", for information about BP's agreement to provide financial support to the Trust.

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 cash reserve for the payment of liabilities of the Trust 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 cash 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.

#### **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 does not have a specific termination date. 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 satisfaction of all of the Trust's liabilities (including, without limitation, any Administrative Expenses), and establishing or increasing reserves for the future 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 (as described below) 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**,” or “**WTI**”) 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 \$20.00 during 2018, \$23.75 during 2019, \$26.50 during 2020, \$29.25 during 2021 and \$32.00 during 2022. After 2020, Chargeable Costs increase at a uniform rate of \$2.75 per barrel per year, resulting in Chargeable Costs of \$34.75 per barrel in 2023.

### **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 43.55.11 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”). The Production Tax Statutes were further amended through legislation enacted in 2014 and 2016. 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 for oil production from 25% to 35% of the annual production tax value of taxable oil, and added a stair-step per-barrel tax credit for oil production. The amount of the per barrel oil production tax credit varies based on the gross value at the point of production for each barrel of taxable oil. However, the production tax credit may not reduce a producer’s tax liability below a “minimum tax” amount. A producer’s minimum tax is computed by multiplying the gross value at the point of production of their taxable production during the calendar year by a percentage ranging from zero to 4%. The percentage used to compute the minimum tax varies based on the average price per barrel for Alaska North Slope crude oil for sale on the United States West Coast during the calendar year. The changes to the Production Tax Statutes under the Act 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 2022 and the actual limitation for 2022 is reflected in the payment to the Trust for the fourth quarter of 2022, and not in the payment to the Trust for the first quarter of 2023.

**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.

	<u>Average WTI Price</u>	<u>Chargeable Costs</u>	<u>Cost Adjustment Factor</u>	<u>Adjusted Chargeable Costs</u>	<u>Production Taxes</u>	<u>Average Per Barrel Royalty</u>
<b>Calendar 2018:</b>						
4 <sup>th</sup> Qtr. 2017	\$ 55.48	\$ 17.20	1.899	\$ 32.67	\$ 1.92	\$ 20.89
1 <sup>st</sup> Qtr. 2018	62.96	20.00	1.917	38.34	2.21	22.38
2 <sup>nd</sup> Qtr. 2018	67.85	20.00	1.937	38.74	2.41	26.70
3 <sup>rd</sup> Qtr. 2018	69.60	20.00	1.942	38.83	2.81	27.96
<b>Calendar 2019</b>						
4 <sup>th</sup> Qtr. 2018	\$ 58.82	\$ 20.00	1.941	\$ 38.81	\$ 2.04	\$ 17.94
1 <sup>st</sup> Qtr. 2019	54.87	23.75	1.946	46.23	1.88	6.77
2 <sup>nd</sup> Qtr. 2019	59.86	23.75	1.972	46.83	2.08	10.94
3 <sup>rd</sup> Qtr. 2019	56.33	23.75	1.976	46.92	1.94	7.48
<b>Calendar 2020</b>						
4 <sup>th</sup> Qtr. 2019	\$ 57.02	\$ 23.75	1.941	\$ 47.04	\$ 1.96	\$ 8.02
1 <sup>st</sup> Qtr. 2020	46.35	26.50	1.992	52.78	1.47	0
2 <sup>nd</sup> Qtr. 2020	28.42	26.50	1.974	52.32	0.57	0
3 <sup>rd</sup> Qtr. 2020	40.87	26.50	2.001	53.04	1.31	0
<b>Calendar 2021</b>						
4 <sup>th</sup> Qtr. 2020	\$ 42.67	\$ 26.50	2.004	\$ 53.10	\$ 1.39	\$ 0
1 <sup>st</sup> Qtr. 2021	57.87	29.25	2.025	59.24	1.99	0
2 <sup>nd</sup> Qtr. 2021	66.04	29.25	2.073	60.63	2.31	3.10
3 <sup>rd</sup> Qtr. 2021	70.64	29.25	2.106	61.61	2.49	6.54
<b>Calendar 2022</b>						
4 <sup>th</sup> Qtr. 2021	\$ 76.91	\$ 29.25	2.140	\$ 62.60	\$ 2.73	\$ 11.57
1 <sup>st</sup> Qtr. 2022	94.45	32.00	2.185	69.91	3.42	21.12
2 <sup>nd</sup> Qtr. 2022	108.70	32.00	2.251	72.02	7.21	29.74
3 <sup>rd</sup> Qtr. 2022	91.87	32.00	2.281	72.98	3.30	15.59

**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 agreed to 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 shall 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, 2022 is shown in the following table:

	<u>Oil rim</u>	<u>Gas cap</u>
HNS	26.36%(a)	26.36%(b)
Exxon Mobil	36.40	36.40
ConocoPhillips	36.08	36.08
Chevron	1.16	1.16
Total	<u>100.00%</u>	<u>100.00%</u>

- (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, 2022, approximately 12.8 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.

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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 overlies 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, 2022, there were 1,107 active producing oil wells, 39 gas reinjection wells, 321 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, 2022 were: 8 in 2020, 3 in 2021 and 20 in 2022. 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, 2022. Production from the Prudhoe Bay field reached a peak in 1988 and has declined steadily since then. The average well production rate was about 166 barrels per day in 2018, 163 barrels per day in 2019, 162 barrels per day in 2020, 159 barrels per day in 2021, and 157 barrels per day in 2022.

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 (thousand barrels per day)	Total field	Net to 1989 Working Interests
2018	174.2	77.3	0.0(a)	0.0(a)
2019	170.2	75.5	0.0(a)	0.0(a)
2020	167.0	74.0	0.0(a)	0.0(a)
2021	159.3	70.6	0.0(a)	0.0(a)
2022	156.6	69.5	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 (“**Alyeska**”), 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 2022, TAPS averaged 483,415 barrels per day, according to Alyeska.

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, 2022, are those quantities of oil which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from 2023 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 (\$93.67 per barrel for the 12-month period prior to December 31, 2022) 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.

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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. As a result of the 2022 SEC-defined 12-month average WTI Price of \$93.67, HNS estimated net remaining proved reserves attributable to the Trust as of December 31, 2022 are 8.232 million barrels of oil, of which 7.862 million barrels are proved developed reserves and 0.370 million 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. Additional information regarding 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 2022. Based on the 2022 12-month average WTI Price of \$93.67 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, 2022, production of oil and condensate from the proved reserves allocated to the 1989 Working Interests will result in estimated future net revenues to the Trust of \$61.169 million and a present value of future net revenues to the Trust of \$56.751 million. For the economic conditions and production forecast as of December 31, 2022, the per barrel royalty will be zero following the year 2024. Therefore, no reserves are currently attributed to the Trust after that date. 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 Reserves Manager, the technical person primarily responsible for overseeing the preparation of all of its reserve estimates. HNS’ Reserves Manager has over 20 years of reservoir and operations experience, holds a Bachelor of Science in Petroleum Engineering from Texas A&M 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 20 years of experience with the Trust. A copy of the February 24, 2023, 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 attributable to the Trust was less than 90,000 barrels per day on an annual basis in 2018, 2019, 2020, 2021, and 2022. HNS anticipates that its average net production of oil and condensate from proved reserves attributable to the Trust will be below 90,000 barrels per day on an annual average basis during future years. See “ITEM 1A. RISK FACTORS” for additional information.

Based on the 2022 twelve-month average WTI Price of \$93.67 per barrel, current Production Taxes, and the Chargeable Costs adjusted as prescribed by the Overriding Royalty Conveyance, HNS estimates that royalty payments to the Trust will continue through the year 2024 and would be zero the following year. Therefore, no

proved reserves are currently attributed to the BP Prudhoe Bay Royalty Trust after that date. Even if expected reservoir performance does not change, the estimated reserves, economic life and future net revenues attributable to the Trust may change significantly in the future. This may result from sustained periods of change in the WTI Price, the Production Tax or from changes in other prescribed variables utilized in calculations as defined by the Overriding Royalty Conveyance. 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. Assuming a WTI price of \$93.67 per barrel, which was the SEC-defined 12-month average in 2022, the projected value of the of the Production Taxes and Adjusted Chargeable Costs as prescribed by the Overriding Royalty Conveyance is \$83.03 per barrel in 2023 and \$89.34 per barrel in 2024 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” for additional information.

## **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 developments under the PIPES Act of 2020 and its implementing regulations. See “ITEM 1. BUSINESS - THE PRUDHOE BAY UNIT AND FIELD - COLLECTION AND TRANSPORTATION OF PRUDHOE BAY OIL” for additional information.

## **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 or the first quarter of 2021, and royalty payments may cease again in any future quarter.*

The Trust did not receive any Royalty Payments attributable to the four quarters during 2020 and the first quarter of 2021 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 approximately \$61 per barrel at the beginning of 2020 to below \$14 per barrel on April 22, 2020. During the period from January 2020 until May 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 7, 2023, that WTI prices will average approximately \$77.10 per barrel in 2023 and \$71.57 per barrel in 2024. Based on the 2022 twelve month average WTI Price of \$93.67 per barrel, the projected value of the Production Taxes and Adjusted Chargeable Costs as prescribed by the Conveyance is \$83.03 per barrel in 2023 and \$89.34 per barrel in 2024 and continues to increase thereafter.

The Trustee intends to retain in reserve at least \$6,000,000 and potentially more, in an amount sufficient to pay Administrative Expenses for at least two years plus anticipated expenses in connection with the termination of the Trust. To the extent necessary, the Trustee will deduct from any future Royalty Payments amounts sufficient to maintain the cash reserve at this level or at a level to be determined by the Trustee in the future without prior notice to the Unit holders. In order to comply with the Trust Agreement's termination process and requirements, the Trust is likely to incur significant additional expenditures. Accordingly, if the Trust receives Royalty Payments during 2023 or subsequent periods, the amount payable to Unit holders may be reduced by amounts used to replenish or add to the cash reserve. Increases in the rate of inflation may also increase Administrative Expenses and the expenses associated with the termination of the Trust, which may necessitate an increase in the level of the reserve. The Trustee will continue to review and reassess the adequacy of the cash reserve on an on-going basis based on the facts and circumstances at the time of such evaluations and may increase or decrease the targeted cash reserve or the rate at which it is withholding funds to replenish the cash reserve at any time, without advance notice to the Unit holders. See "ITEM 7. TRUSTEE'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – LIQUIDITY AND CAPITAL RESOURCES" for a discussion of the cash reserve.

*If net revenues are less than \$1,000,000 for two consecutive years, or if 60% of Unit holders vote in favor of termination, the Trust will terminate.*

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 any other 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. We cannot predict 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 2020, the oversupply of oil led to an unprecedented collapse in oil prices, forcing the contract futures price for 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 2020. 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 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. During 2022, WTI crude oil spot prices reached a high of \$123.70 on March 8, 2022 and increased to an average of \$94.97 a barrel for 2022. WTI prices, particularly in the first half of 2022, were elevated by a number of factors, such as the outbreak of the war in Ukraine, supply concerns, and increased demand following recovery from the COVID-19 pandemic. WTI prices generally decreased in the second half of the year, as concerns about a possible recession reduced demand.

While oil price forecasts are highly uncertain, the EIA forecast in its STEO dated March 7, 2023, that Brent crude oil spot prices will average approximately \$82.95 per barrel in 2023 and WTI crude oil spot prices will average approximately \$77.10 per barrel in 2023 and \$71.57 per barrel in 2024. According to the EIA forecast, it is expected that oil inventories will continue to build in 2023 and 2024, with a high demand for crude oil from refineries, with increasing global oil inventories resulting in decreasing crude oil prices beginning in the third quarter of 2023. We cannot predict future WTI prices or whether WTI prices will be at a level sufficient for the Trust to receive a positive Per Barrel Royalty in the future.

***COVID-19 caused substantial disruption in the oil industry and 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 resulted in significant economic contraction. The oil industry, in particular, was substantially disrupted, both domestically and internationally, by the COVID-19 pandemic, which caused significant changes in energy fuel supply and demand. Although WTI prices have recovered significantly, we cannot predict whether the COVID pandemic will continue to have a material adverse effect on WTI prices in the future.

***High rates of inflation as measured by the consumer price index will increase the Cost Adjustment Factor and decrease amounts available for Royalty Payments.***

The Per Barrel Royalty is the WTI Price for any particular day, less the sum of (i) Chargeable Costs multiplied by the Cost Adjustment Factor and (ii) Production Taxes. The Cost Adjustment Factor is a ratio that references the Consumer Price Index. The rate of inflation in the United States has increased sharply over the last two years, as reflected in increases in the Consumer Price Index. To the extent that the Consumer Price Index continues to rise, the Cost Adjustment Factor will also increase, which would decrease the future Per Barrel Royalty, negatively affecting the amount available, if any, for distribution to Unit holders.

**Risks Related to WTI Price**

***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 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, the continued effects of COVID-19 on the global economy, whether OPEC+ and other oil producing nations are willing to intervene to adjust oil prices, 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, particularly Russia’s war with Ukraine and the international responses thereto, including the imposition of sanctions, increased tensions between the U.S. and China and Iran, political unrest in Iran and developments with respect to the Iran nuclear deal, the 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, whether the U.S. government releases any of its oil reserves, 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, 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.

***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.***

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, 2023. As a result, any single calculation of a calendar day will not reflect the value of the royalty 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.

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. From the beginning of the first quarter of 2023 through March 6, 2023, the WTI crude oil spot price fluctuated between a high of \$81.62 per barrel on January 23, 2023, and a low of \$72.84 per barrel on January 4, 2023. The WTI crude oil spot price on March 6, 2023 was \$80.64 per barrel.

Based on the 2022 twelve-month average WTI Price of \$93.67 per barrel, current Production Taxes, and the Chargeable Costs adjusted as prescribed by the Overriding Royalty Conveyance, HNS estimates that royalty payments to the Trust will continue through the year 2024 and would be zero in the following year. Therefore, no proved reserves are currently attributed to the 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. For example, as described above, daily WTI crude oil spot prices since the beginning of 2023, through March 6, 2023, have been below the 2022 twelve-month average WTI Price.

***Government action, policies or regulations designed to discourage production of, reduce demand for, or promote alternatives to oil could impact the WTI Price, directly as intended or through unintended consequences.***

World-wide, governments are implementing policies intended to reduce greenhouse gas emissions by decreasing both the supply of and the demand for fossil fuels, including oil products, or promote alternatives. These actions include, among others, cap and trade programs, carbon taxes, trade tariffs, minimum renewable usage requirements, restrictive permitting, increased mileage and other efficiency standards, mandates for sales of electric vehicles, mandates for use of specific fuels or technologies, and other incentives or mandates designed to support transitioning to green energy sources. Political and other actors and their agents also increasingly seek to advance climate change objectives indirectly, such as by seeking to discourage or increase the cost of financing and investment in the oil industry. Depending on how policies are formulated and applied, such policies could decrease the demand for oil and the competitiveness of fossil fuels, which could materially negatively affect the WTI Price and the amount available, if any, for distribution to Unit holders.

## **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. The 2022 average WTI Price of \$93.67 per barrel, applicable under current SEC regulations, which 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, 2022, 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 after 2024. 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 Annual Report are based on economic conditions and production forecasts as of the end of 2022, 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.

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, 2020, 2021, and 2022, 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 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 2022, the pipeline's average throughput increased nearly 6,000 barrels daily over 2021. 2022 was the first year since 2017 that average daily throughput increased since 2017. Nevertheless, throughput for the last four years has averaged only 483,860 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 previously 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 forecasted in fall 2022 that Alaska North Slope oil production will increase to an average of 491,700 barrels per day in the fiscal year that ends June 30, 2023, which is up from the 476,500 barrels per day produced in fiscal 2022. Production is expected to increase to 503,700 barrels per day in 2024. The forecast anticipates that oil production declines will be potentially offset by incremental production from new developments, with several new fields in the planning and development process.

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 former Trump administration announced in January 2018 that it would allow new offshore oil and gas drilling in nearly all United States coastal waters, including the Arctic Ocean. 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.

***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. Historically, the reduction in Production Taxes has in part offset the reduction in royalty payments that resulted from declining WTI prices. During 2022, as a result of increased WTI Prices, the minimum tax did not apply, and higher taxes resulted in reduced royalty payments to the Trust.

Any changes to the Production Tax Statutes in the future may also impact Royalty Production and 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.

## **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 or the first quarter of 2021. Cash distributions on Trust units resumed in the second quarter of 2021 and continued in each of the four quarters of 2022, although there can be no assurance that cash distributions will be made in any future quarter. 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".

### ***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

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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 13, 2023, 21,400,000 Units were outstanding and were held by 200 holders of record. No Units were purchased by the Trust or any affiliated purchaser during the year ended December 31, 2022.

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 "ITEM 1. BUSINESS – THE ROYALTY INTEREST" for additional information.

### ITEM 6. [RESERVED]

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

#### Liquidity and Capital Resources

*Background.* 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 revenues attributable to the Royalty Interest that it receives from time to time. See the discussion in "ITEM 1. BUSINESS – THE ROYALTY INTEREST" for a description of the calculation of the Per Barrel Royalty, and the discussion in "ITEM 1. BUSINESS – THE PRUDHOE BAY UNIT AND FIELD – RESERVE ESTIMATES", 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 in "ITEM 1. BUSINESS – THE TRUST – SALES OF ROYALTY INTEREST; BORROWINGS AND RESERVES" for more information.

*Cash Reserve.* In July 1999, the Trustee established a cash reserve to provide liquidity to the Trust during future periods in which the Trust does not receive sufficient revenues from the Royalty Interest. The Trustee has drawn funds from the cash reserve account during the quarters in which the quarterly revenues received by the Trust did not exceed the liabilities and expenses of the Trust, and has replenished the reserve from deductions from quarterly distributions made to Unit holders during periods when the Trust received revenues from the Royalty Interest and Unit holders received distributions.

Due in part 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 revenues from the Royalty Interest attributable to the four quarters of 2020 or the first quarter of 2021. Consequently, the Trust was unable to make any additions to the funds on deposit in the cash reserve account since the January 2020 distribution made for revenues from the Royalty Interest attributable to the fourth quarter of 2019. In December 2020, the remaining funds on deposit in the cash reserve were insufficient to pay the Trustee's Administrative Expenses in 2020 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 unpaid expenses through December 18, 2020.

Following the receipt of the indemnity payment from HNS in December 2020, the Trust continued to accrue Administration Expenses but did not receive any revenues from the Royalty Interest until July 2021, when the Trust received a quarterly payment of approximately \$3.2 million attributable to the quarter ended June 30, 2021.

In July 2021, the Trust announced that the Trustee had determined to increase the Trustee's existing cash reserve by \$500 thousand, funding the full amount of the cash reserve from the Royalty Payment attributable to the second quarter of 2021. In October 2021, the Trust decided to increase the Trustee's existing cash reserve to \$6.0 million, which was fully funded from the Royalty Payment attributable to the third quarter of 2021.

The total amount added to the cash reserve takes into account that (i) the Trust had not received any revenues attributable to 2020 or the first quarter of 2021 and therefore had been unable to make any additions to the cash reserve for five quarters, (ii) the likelihood of future revenue from the Royalty Interest, (iii) the increase in Trust Administrative Expenses in 2020, (iv) the reset of the earliest potential termination date of the Trust, and (v) the expected expenses associated with the future termination of the Trust. The Trustee will continue to review and reassess the adequacy of the cash reserve on an on-going basis based on the facts and circumstances at the time of such evaluations and may increase or decrease the targeted cash reserve or the rate at which it is withholding funds to build the cash reserve at any time, without advance notice to the Unit holders. As previously disclosed by the Trust, the Trustee has increased and funded the cash reserve to a level it believes is sufficient to provide funding to pay the Administrative Expenses for a two-year period commencing when the sum of the net revenues from the Royalty Interest for two successive years are less than \$1.0 million per year, and to carry out an orderly termination of the Trust as set forth in Article IX of the Trust Agreement. Depending on the facts and circumstances at the time, the expenses of the termination process may include, without limitation, costs related to a professional evaluation of the value of the Royalty Interest, any and all other costs and expenses necessary to terminate the Trust, sell the Trust assets and provide for the orderly distribution of the remaining proceeds to the Unit holders, the costs of one or more consent solicitations of the Unit holders, legal fees and expenses, and all other professional services necessary to comply with the requirements of the Trust termination process.

Given the uncertainty with respect to the amount or timing of any future revenue from the Royalty Interest combined with the expenses of operating the Trust prior to termination and the limited ability to terminate the Trust in accordance with its terms, the Trustee has determined to withhold amounts necessary, when received by the Trust, to maintain the cash reserve at its current level of approximately \$6.0 million at this time. This cash reserve level assumes an orderly termination of the Trust sometime in the future based on current facts and circumstances, and as the receipt of additional Royalty Payments continues to reset that time line, the Trustee will re-evaluate the adequacy of the cash reserve balance and may increase or decrease it without notice to Unit holders. Accordingly, even if the Trust receives revenues from the Royalty Interest in any quarter during 2023 or beyond, it is possible that Unit holders will not receive a distribution on outstanding Units during such periods, because the Trust may need to withhold funds from any such revenue to first pay accrued Administrative Expenses and to replenish or add to the cash reserve, before distributing any funds to Unit holders. There can be no assurance that WTI prices will be at levels sufficient to result in revenues to the Trust in any future quarter. The Trustee intends to keep the cash reserve program in place until termination of the Trust.

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 accrued Administrative Expenses and 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.

*Other Sources of Liquidity.* In light of the Trust's cash shortfall in December 2020, the Trust began to explore the options available under the Trust Agreement to address the issue. These steps included efforts to obtain 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 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 potential lenders or potential purchasers of Trust assets, and to advise the Trust with respect to the timing of its potential termination pursuant to the Trust Agreement. The Trust was unsuccessful in its initial attempt to secure

a loan; however, because the Trust received additional revenues from the Royalty Interest such that the cash reserve is funded to the targeted level, a loan is no longer necessary, even if available on terms acceptable to the Trust. While these efforts are currently on hold, there can be no assurance in the future that the Trust will be able to secure a loan or arrange for the sale of Trust assets should it become necessary, or if it does secure a loan or arrange a sale, that any loan or sale would be on terms that are acceptable to the Trust.

*Termination of the Trust.* There is no set termination date for the Trust. 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 \$1.0 million per year. Net revenues to the Trust are calculated daily by HNS using the WTI Price, Production Taxes, and other variables as prescribed by the Overriding Royalty Conveyance applicable on that specific day. In 2020, the net revenues from the Royalty Interest were less than \$1.0 million. As a result, it was possible that the Trust could have terminated as early as sometime in 2022 under this provision of the Trust Agreement.

Since the beginning of 2022 through the end of the year, the WTI Price has fluctuated from a low of \$71.02 on from December 9 to December 12, 2022 to a high of \$123.70 on March 8, 2022, and exceeded the estimate of \$66.56 per barrel originally used to evaluate the likelihood of the Trust receiving Royalty Payments in 2022. Based on the 2022 SEC-defined twelve-month average WTI Price of \$93.67 per barrel (the unweighted average of first-day-of-the-month WTI Price over the period January through December of the respective year in accordance with SEC guidelines), WTI Prices, Production Taxes, and the Chargeable Costs adjusted as prescribed by the Overriding Royalty Conveyance, HNS has estimated that production of the proved reserves would result in no Royalty Payments to the Trust following the year 2024.

Although the Trust received net revenues attributable to each of the four quarters of 2022, there can be no assurance that WTI Prices will remain at levels sufficient to result in Royalty Payments to the Trust in any future quarter. Given the uncertainty around the continued regular receipt of net revenues from the Royalty Interest combined with the expenses of operating the Trust and the fees, costs and expenses related to the limited ability to terminate the Trust in accordance with its terms, the Trustee may explore options to terminate the trust in future. These options may include seeking consent of the Unit holders for an early termination of the Trust, among other things. A time line for termination cannot be accurately predicted.

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.

## **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, particularly the invasion of Ukraine by Russia, 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

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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, 2020, 2021, and 2022. 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 "ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA – NOTES TO FINANCIAL STATEMENTS – NOTE 8. ROYALTY REVENUE ADJUSTMENTS". 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.

The "break-even" (the price at which all taxes and prescribed deductions are equal to the WTI Price) WTI Price changes over time primarily as a result of changes in the Cost Adjustment Factor, which is based on the Consumer Price Index published for the most recently past February, May, August or November and Production Taxes, as Chargeable Costs remain constant for the calendar year. Additionally, as WTI Prices change, so do the Production Taxes and prescribed deductions, potentially increasing or decreasing the "break-even" WTI Price. 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.

From the beginning of the first quarter of 2023 through March 6, 2023, the WTI crude oil spot price fluctuated between a high of \$81.62 per barrel on January 23, 2023, and a low of \$72.84 per barrel on January 4, 2023. The WTI crude oil spot price on March 6, 2023 was \$80.46 per barrel.

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.

## 2022 Compared to 2021

	12 Months Ended 9/30/2022	Increase (decrease)		12 Months Ended 9/30/2021
		Amount (Dollars per barrel)	Percent	
Average WTI Price	\$ 92.97	\$33.69	56.8	\$ 59.28
Adjusted Chargeable Costs	\$ 69.36	\$10.72	18.3	\$ 58.64
Average Production Taxes	\$ 4.17	\$ 2.13	104.4	\$ 2.04
Average Per Barrel Royalty	\$ 19.44	\$20.84	N/A	\$ (1.40)
Average net royalty production (mb/d)	69.83	(1.65)	(2.3)	71.48

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Average WTI prices during the twelve months ended September 30, 2022, increased by 56.8 percent compared to the preceding twelve-month period. Average monthly WTI prices during this period ranged from a high of \$123.70 during the month of March 2022 to a low of \$65.57 during the month of December 2021. The increase in the Consumer Price Index used to calculate the Cost Adjustment Factor, as well as the scheduled increase in Chargeable Costs from \$29.95 in calendar 2021 to \$32.00 in calendar 2022, resulted in the 18.3 percent increase in Adjusted Chargeable Costs during the twelve months ended September 30, 2022. The increase in the Average Per Barrel Royalty for the 2022 period resulted primarily from the increase in WTI prices, reduced by the increase in Adjusted Chargeable Costs. Average Production Taxes increased 104.4 percent as a result of the increase in the WTI Price for part of 2022 and an increase in the Consumer Price Index used to calculate the Cost Adjustment Factor. HNS has informed the Trustee that the minimum tax did not apply due to the taxable value of the oil produced. As a result, Average Production Taxes in 2022 were not calculated on the basis of the minimum tax under Alaska law and the 2014 Letter Agreement Amendment. This is the first time this has occurred since the second quarter of 2015. The average net production from the 1989 Working Interest declined by 2.3 percent. This decrease was due to the naturally declining production rate from the Prudhoe Bay field. "ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA – NOTES TO FINANCIAL STATEMENTS – NOTE 7. ALASKA OIL AND GAS PRODUCTION TAX".

	Year Ended 12/31/2022	Increase (decrease)		Year Ended 12/31/2021
		Amount (Dollars in thousands)	Percent	
Royalty revenues	\$ 82,283	\$72,866	773.8	\$ 9,417
Cash earnings	\$ 80,888	\$73,077	935.6	\$ 7,811
Cash distributions	\$ 80,823	\$78,816	3927.1	\$ 2,007
Administrative expenses	\$ 1,464	\$ (141)	(8.8)	\$ 1,605
Trust corpus at year end	\$ 5,787	\$ 149	2.6	\$ 5,638

The increase in royalty revenues, cash earnings and cash distributions for the twelve months ended December 31, 2022 as compared to the same period in 2021 resulted from the increase in the Average WTI Price, offset by an the increase in Adjusted Chargeable Costs and average Production Taxes and a decline in average net production that prevailed during the twelve months ended December 31, 2022 as compared to same period in 2021. The decrease in Administrative Expenses paid during the twelve months ended December 31, 2022, reflects the resumption of the payment of Trust expenses in July 2021 following the prior cessation of royalty revenue. The increase in the Trust corpus is primarily due to an increase in cash and cash equivalents and a reduction in accrued expenses.

**2021 Compared to 2020**

	12 Months Ended 9/30/2021	Increase (decrease)		12 Months Ended 9/30/2020
		Amount (Dollars per barrel)	Percent	
Average WTI Price	\$ 59.28	\$16.08	37.2	\$ 43.20
Adjusted Chargeable Costs	\$ 58.64	\$ 7.35	14.3	\$ 51.29
Average Production Taxes	\$ 2.04	\$ 0.71	53.3	\$ 1.3399
Average Per Barrel Royalty	\$ (1.40)	\$ 8.02	85.1	\$ (9.42)
Average net royalty production (mb/d)	71.48	(2.95)	(4.0)	74.43

Average WTI prices during the twelve months ended September 30, 2021, increased by 37.2 percent compared to the preceding twelve-month period. Average monthly WTI prices during this period ranged from a high of \$72.82 during the month of July 2021 to a low of \$39.44 during the month of October 2020. The increase in the Consumer Price Index used to calculate the Cost Adjustment Factor, as well as the scheduled increase in

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Chargeable Costs from \$26.50 in calendar 2020 to \$29.25 in calendar 2021, resulted in the 14.3 percent increase in Adjusted Chargeable Costs during the twelve months ended September 30, 2021. The increase in the Average Per Barrel Royalty for the 2021 period resulted primarily from the increase in WTI prices, reduced by 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. The average net production from the 1989 Working Interest for the two reporting periods declined by 4.0%. This decrease was due to the naturally declining production rate from the Prudhoe Bay field. See “ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA – NOTES TO FINANCIAL STATEMENTS – NOTE 7. ALASKA OIL AND GAS PRODUCTION TAX”.

	Year Ended 12/31/2021	Increase (decrease)		Year Ended 12/31/2020
		Amount	Percent	
(Dollars in thousands)				
Royalty revenues	\$ 9,417	\$ 148	1.6	\$ 9,269
Cash earnings	\$ 7,811	\$ (315)	(3.9)	\$ 8,126
Cash distributions	\$ 2,007	\$(7,072)	(77.9)	\$ 9,079
Administrative expenses	\$ 1,605	\$ (87)	(5.1)	\$ 1,692
Trust corpus at year end	\$ 5,638	\$ 5,579	9,455.9	\$ 59

In the second quarter of 2021, the Trust resumed receiving royalty revenue following a cessation of royalty revenue for the five previous quarters. This resumption of royalty revenues was due to a significant increase in WTI prices after WTI prices had fallen to historic lows. Royalty revenues for the year ended December 31, 2021 increased by 1.6 percent as compared to royalty revenues for the prior year. Royalty revenues were negatively affected by increases in the Adjusted Chargeable Costs and the decline in net production that continued in 2021. The period-to-period declines in cash earnings and cash distributions are primarily due to the significantly lower average WTI prices that prevailed during 2020 compared to 2021. Cash distributions were also negatively impacted by deductions used to fund the cash reserve, which had been almost completely depleted during 2020 due to the lack of royalty revenues. Administrative expenses decreased slightly as a result of timing differences in payment of expenses. The increase in the Trust corpus reflects the impacts of cash earnings exceeding cash distributions as amounts were retained to increase the cash reserve amount to \$6,000,000 during 2021.

**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. The Trust 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

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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, 2022 and 2021, 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, 2022 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, 2022 and 2021, and its cash earnings and distributions and changes in trust corpus for each of the years in the three-year period ended December 31, 2022, 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, 2022, based 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, 2023 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.

### *Basis for Opinion*

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

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

### *Critical Audit Matters*

Critical audit matters are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the Trustee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. We determined that there are no critical audit matters.

/s/KPMG LLP

We have served as the Company's auditor since 1989

Dallas, Texas  
March 16, 2023

**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, 2022, 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, 2022, 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, 2022 and 2021, 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, 2022, and the related notes (collectively, the financial statements), and our report dated March 16, 2023 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 generally accepted accounting principles. 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, 2023

**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, 2022	December 31, 2021
<b>Assets</b>		
Cash and cash equivalents (Note 3)	\$ 132	\$ 6,002
Security held to maturity (Note 4)	5,935	—
<b>Total Assets</b>	<b>\$ 6,067</b>	<b>\$ 6,002</b>
<b>Liabilities and Trust Corpus</b>		
Accrued expenses	\$ 280	\$ 364
<b>Total Liabilities</b>	<b>280</b>	<b>364</b>
Trust Corpus (40,000,000 units of beneficial interest authorized, 21,400,000 units issued and outstanding)	5,787	5,638
<b>Total Liabilities and Trust Corpus</b>	<b>\$ 6,067</b>	<b>\$ 6,002</b>

See accompanying notes to financial statements.

**BP Prudhoe Bay Royalty Trust**  
**Statements of Cash Earnings and Distributions**  
**(Prepared on a modified cash basis)**  
**(In thousands, except unit data)**

	<u>Year Ended December 31,</u>		
	<u>2022</u>	<u>2021</u>	<u>2020</u>
Royalty revenues	\$ 82,283	\$ 9,417	\$ 9,269
Interest income (expense)	69	(1)	11
HNS expense reimbursement (Note 2)	—	—	538
Less: Trust administrative expenses	(1,464)	(1,605)	(1,692)
Cash earnings	<u>\$ 80,888</u>	<u>\$ 7,811</u>	<u>\$ 8,126</u>
Cash distributions	<u>\$ 80,823</u>	<u>\$ 2,007</u>	<u>\$ 9,079</u>
Cash distributions per unit	<u>\$ 3.7768</u>	<u>\$ 0.0938</u>	<u>\$ 0.4242</u>
Units outstanding	<u>21,400,000</u>	<u>21,400,000</u>	<u>21,400,000</u>

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)**

	<b>Year Ended December 31,</b>		
	<b>2022</b>	<b>2021</b>	<b>2020</b>
Trust corpus at beginning of year	\$ 5,638	\$ 59	\$ 898
Cash earnings	80,888	7,811	8,126
Decrease (increase) in accrued expenses	84	(225)	114
Cash distributions	(80,823)	(2,007)	(9,079)
Trust corpus at end of year	<u>\$ 5,787</u>	<u>\$ 5,638</u>	<u>\$ 59</u>

See accompanying notes to financial statements.

**BP Prudhoe Bay Royalty Trust**  
**Notes to Financial Statements**  
**(Prepared on a modified cash basis)**  
**December 31, 2022**

**(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”).

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 HNS’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 “break-even” price is calculated after the close of a quarter in accordance with the terms of the Overriding Royalty Conveyance. The “break-even” WTI Price changes over time primarily as a result of changes in the Cost Adjustment Factor, which is based on the Consumer Price Index published for the most recently past February, May, August or November, and Production Taxes, as Chargeable Costs remain constant for the calendar year. Additionally, as WTI Prices change, so do the Production Taxes and prescribed deductions, potentially increasing or decreasing the “break-even” WTI Price. The actual “break-even” price is calculated and provided by HNS.

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).

## **(2) Liquidity**

In July 1999, the Trustee established a cash reserve to provide liquidity to the Trust during future periods in which the Trust does not receive revenues from the Royalty Interest. The Trustee has drawn funds from the cash reserve account during the quarters in which the quarterly revenues received by the Trust did not exceed the liabilities and expenses of the Trust, and has replenished or otherwise added to the reserve from deductions from quarterly distributions made to Unit holders during periods when the Trust received revenues from the Royalty Interest and Unit holders received distributions.

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 further 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 Payments attributable to the four quarters of 2020 or the first quarter of 2021. Therefore, the Trust was unable to make quarterly deductions to make any additions to the funds on deposit in the cash reserve since the January 2020 distribution made for Royalty Payments attributable to the fourth quarter of 2019. In December 2020, the remaining funds on deposit in the cash reserve were insufficient to pay the Trustee’s fees and administrative fees, expenses, charges and costs, including accounting, engineering, legal, financial advisory, and other professional fees incurred in connection with the Trust (“Administrative Expenses”) in 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 and at that time there was no reasonable likelihood that the Trust would receive any future Royalty Payments. 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 those 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, if necessary, and in such case, the Trustee will continue to review its options under the Trust Agreement and Support Agreement, including obtaining a loan for the Trust, selling a portion of the Trust assets, or selling all of the Trust assets, or enforcing such indemnity, if necessary, should the available amounts in the cash reserve be insufficient to pay the Administrative Expenses of the Trust and the fees, costs and expenses related to an orderly termination of the Trust.

During 2021, the Trustee evaluated the adequacy of the cash reserve, the likelihood of the continued and regular receipts of revenues from the Royalty Interest in 2021 and beyond and the anticipated timing of termination of the Trust, and has determined to further increase the cash reserve to approximately \$6,000,000. After not receiving Royalty Payments attributable to the four quarters of 2020 and the first quarter of 2021, the Trust has received royalty payments for all quarters beginning with the second quarter 2021 through the quarter ended December 31, 2022. As a result, the Trustee transferred an additional \$4,229,980 to the reserve in October 2021.

Although the Trust received net revenues attributable to the quarters ended June 30, September 30, and December 31, 2021 and all four quarters of 2022, there can be no assurance that WTI Prices will remain at levels sufficient to result in Royalty Payments to the Trust in any future quarter.

The Trustee intends to continue to evaluate the adequacy of the cash reserve and may, at any time without notice to the Unit holders, increase or decrease the amount of the cash reserve due to the facts and circumstances prevailing from time to time. At this time, the Trustee believes the cash reserve, is sufficient to pay Trust fees and expenses for the next 12 months.

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.

In light of the Trust's cash shortfall in December 2020, the Trust began to explore the options available under the Trust Agreement to address the issue. These steps included efforts to obtain a loan for the Trust, sell a portion of the Trust assets, or sell all of the Trust assets and taking the necessary steps to terminate the Trust. The Trustee 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 potential lenders or potential purchasers of Trust assets, and to advise the Trust with respect to the timing of its potential termination pursuant to the Trust Agreement. To date, the Trust has not been successful in securing a loan, however, to the extent that the Trust receives additional revenue from the Royalty Interests, and the cash reserve is fully funded to a targeted level, a loan may no longer be necessary, even if available. Due to the uncertainty of future Royalty Payments to the Trust and the need to plan for its eventual orderly termination, there can be no assurance that the Trust would be able to secure a loan or arrange for the sale of Trust assets should it become necessary, or if it does, that any loan or sale would be on terms that are acceptable to the Trust.

### **(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, 2022 and 2021, and the modified basis of cash earnings and distributions and changes in Trust corpus for the years ended December 31, 2022, 2021 and 2020. 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, 2022 and 2021 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.

**(4) Security Held to Maturity**

At December 31, 2022, the security held to maturity consists of a United States Treasury Bill with a book value of \$5,935,000 and a market value of \$5,968,000, maturing on April 20, 2023.

**(5) 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.

**(6) 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.

**(7) 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.

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.

**(8) Royalty Revenue Adjustments**

Certain of the royalty payments received by the Trust in 2022, 2021, and 2020 were adjusted by BP Alaska to compensate for underpayments or overpayments of the royalties due with respect to the quarters ended prior to the dates of such payments. Average net production of crude oil and condensate from the proved reserves allocated to the Trust was less than 90,000 barrels per day during certain quarters. Royalty payments by BP Alaska with respect to those quarters were based on estimates by BP Alaska of production levels because actual data was not available by the dates on which payments were required to be made to the Trust. Subsequent recalculation by BP Alaska of royalty payments due based on actual production data resulted in the payment adjustments shown in the table below (in thousands).

	2022 Payments Received			
	January	April	July	October
Royalty payment as calculated	\$12,467	\$23,053	\$30,334	\$15,536
Adjustment for underpayment (overpayment), plus accrued interest	334	761	7	(210)
Net payment received	\$12,801	\$23,814	\$30,341	\$15,326

  

	2021 Payments Received			
	January	April	July	October
Royalty payment as calculated	\$ —	\$ —	\$ 3,272	\$ 6,149
Adjustment for underpayment (overpayment), plus accrued interest	—	—	(69)	(4)
Net payment received	\$ —	\$ —	\$ 3,203	\$ 6,145

  

	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	\$ —	\$ —	\$ —

**(9) Subsequent Event**

In January 2023, the Trust received a cash distribution of \$6,639,508 from HNS. This payment consisted of \$6,613,299, representing the Royalty Payment due with respect to the Trust’s Royalty Interest for the quarter ended December 31, 2022, plus \$26,209 representing the amount of an underpayment by HNS, including interest on the underpayment, of the Royalty Payment due with respect to the quarter ended September 30, 2022. On January 23, 2023, after deducting Administrative Expenses of \$279,859, the Trustee distributed \$6,364,996 to Unit holders of record on January 17, 2023.

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

**(10) Summary of Quarterly Results (Unaudited)**

A summary of selected quarterly financial information for the years ended December 31, 2022, 2021, and 2020 is as follows (in thousands, except unit data):

	2022 Fiscal Quarter			
	First	Second	Third	Fourth
Royalty revenues	\$ 12,801	\$ 23,814	\$ 30,341	\$ 15,326
Interest income	—	3	4	61
Trust administrative expenses	(364)	(541)	(276)	(283)
Cash earnings (loss)	\$ 12,437	\$ 23,276	\$ 30,069	\$ 15,104
Cash distributions	\$ 12,437	\$ 23,273	\$ 30,066	\$ 15,047
Cash distributions per unit	\$ 0.5812	\$ 1.0875	\$ 1.4050	\$ 0.7031

  

	2021 Fiscal Quarter			
	First	Second	Third	Fourth
Royalty revenues	\$ —	\$ —	\$ 3,272	\$ 6,145
Interest income	(1)	—	(1)	1
Trust administrative expenses	(75)	—	(1,100)	(430)
Cash earnings (loss)	\$ (76)	\$ —	\$ 2,171	\$ 5,716
Cash distributions	\$ —	\$ —	\$ 521	\$ 1,486
Cash distributions per unit	\$ —	\$ —	\$ .0244	\$ .0694

  

	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	\$ —	\$ —	\$ —

**(11) 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 2022 (\$93.67 per barrel), 2021 (\$66.56 per barrel), and 2020 (\$39.57 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, 2022, 2021, and 2020, based on BP Alaska's latest reserve estimate at such times and the 12-month average WTI price for 2022, 2021 and 2020, were estimated to be 8.232, 0, and 0 million barrels, respectively (of which 7.862, 0, and 0 million barrels, respectively, are proved developed reserves). Under the provisions of FASB ASC 932, no consideration can be given to reserves not considered proved at the present time.

The standardized measure of discounted future net cash flow relating to proved reserves disclosure required by FASB ASC 932 assigns monetary amounts to proved reserves based on current prices. This discounted future net cash flow should not be construed as the current market value of the Royalty Interest. A market valuation determination would include, among other things, anticipated price changes and the value of additional reserves not considered proved at the present time or reserves that may be produced after the currently anticipated end of field life. At December 31, 2022, 2021 and 2020, the standardized measure of discounted future net cash flow relating to proved reserves attributable to the Trust (estimated in accordance with the provisions of FASB ASC 932), based on the 12-month average WTI Price for 2022, 2021, and 2020 of \$93.67, \$66.56, and \$39.57 per barrel, respectively, were as follows (in thousands):

	December 31,		
	2022	2021	2020
Future cash inflows	\$61,169	\$—	\$—
10% annual discount for estimated timing of cash flows	4,418	—	—
Standardized measure of discounted future net cash flows (a)	<u>\$56,751</u>	<u>\$—</u>	<u>\$—</u>

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

	December 31,		
	2022	2021	2020
Net changes in prices and production costs	\$128,772	\$—	\$(69,163)
Net change in production taxes	—	—	2,729
Other	557	—	(25)
	129,329	—	(66,459)
Royalty income received (b)	(76,122)	—	60,943
Accretion of discount	3,544	—	—
Net increase (decrease) during the year	<u>\$ 56,751</u>	<u>\$—</u>	<u>\$ (5,516)</u>

(b) For the purpose of this calculation, royalty income received for 2022, 2021 and 2020 includes the following:

Period October 1, 2022 through December 31, 2022	\$ 6,640
Period October 1, 2021 through December 31, 2021	\$ 12,801
Period October 1, 2020 through December 31, 2020	\$ —

The above royalty income was received by the Trust in January 2023, 2022, and 2021, respectively.

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, 2019	4,465
Revisions of previous estimates (1)	(16)
Production	(4,449)
December 31, 2020	—
Revisions of previous estimates	—
Production	—
December 31, 2021	—
Revisions of previous estimates (2)	12,401
Production	(4,169)
December 31, 2022	8,232
Revisions of previous estimates	—
Production	—
Proved developed reserves (thousands of barrels) as of:	
December 31, 2020	—
December 31, 2021	—
December 31, 2022	7,862
Proved undeveloped reserves (thousands of barrels) as of:	
December 31, 2020	—
December 31, 2021	—
December 31, 2022	370

- (1) 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 royalty 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.
- (2) The positive revision in year-end 2022 reserves reflects an increase in the WTI price from \$66.56 per barrel for 2021 to \$93.67 per barrel for 2022 using the 12-month average of the first-day-of-the-month price for each month in the years ended December 31, 2022 and 2021, 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 royalty was forecast to be zero following the year 2020. Under the economic conditions and production forecast at year end 2021, the

per-barrel loyalty was forecast to be zero following the year 2021. Under the economic conditions and production forecast at year end 2022, the per-barrel loyalty was forecast to be zero following the year 2024. This increase in economic life from year-end 2021 to year-end 2022 results in a positive 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, 2022.

**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 2022, 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, 2022.

**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, 2022.

The effectiveness of the Trust's internal control over financial reporting as of December 31, 2022 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report set forth in full in “ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA - REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM - OPINION ON INTERNAL CONTROL OVER FINANCIAL REPORTING”.

#### **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.

#### **ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS**

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 “ITEM 1. BUSINESS - THE TRUST – DUTIES AND POWERS OF THE TRUSTEE” for additional information.

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 “ITEM 1. BUSINESS - THE TRUST – RESIGNATION OR REMOVAL OF TRUSTEE” for additional information.

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 “ITEM 1. BUSINESS – THE ROYALTY INTEREST – COST ADJUSTMENT FACTOR” for additional information) 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 was as follows:

<u>Year ended December 31,</u>	<u>Trustee's Fees</u>	<u>Transfer Agent and Registrar Fees</u>
2020	\$213,378	—
2021	\$229,149	—
2022	\$215,538	—

**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 15, 2023, 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 2022, 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. EXECUTIVE COMPENSATION” for additional information.

The Trust has no independent directors. See “ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE” for additional information.

**ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES**

Fees for services performed by KPMG LLP for the years ended December 31, 2022 and 2021 are:

	2022	2021
Audit	\$ 196,500	\$ 174,000
Audit related	24,500	22,000
Tax	221,000	272,000
	<u>\$ 442,000</u>	<u>\$ 468,000</u>

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, 2022 and 2021

Statements of Cash Earnings and Distributions for the years ended December 31, 2022, 2021 and 2020

Statements of Changes in Trust Corpus for the years ended December 31, 2022, 2021 and 2020

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\* [Certification of the Trustee Pursuant to Securities Exchange Act Rules 13a-14\(a\), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.](#)

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32**	<a href="#">Certification of the Trustee Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002</a>
99*	<a href="#">Report of Miller and Lents, Ltd., dated February 24, 2023.</a>
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 “ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA – NOTES TO FINANCIAL STATEMENTS - NOTE 3. BASIS OF ACCOUNTING”.

\* Filed herewith.

\*\* This certification is being furnished solely to accompany this annual report pursuant to 18 U.S.C. Section 1350, and is not being filed for purposes of Section 18 of the Securities Exchange Act of 1934 and is not to be incorporated by reference into any filing of the registrant, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

(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, 2023

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.

**CERTIFICATION OF THE TRUSTEE PURSUANT TO RULE 13A-14(A) UNDER THE SECURITIES EXCHANGE ACT OF 1934, AS  
ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

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, 2023

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

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

**CERTIFICATION OF THE TRUSTEE PURSUANT TO SECTION 18 U.S.C. SECTION 1350  
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

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, 2022 (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, 2023

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, 2022*

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

FEBRUARY 24, 2023





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February 24, 2023

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, 2022

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, 2022. 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 24, 2023.

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 February 24, 2023, addressed to Ms. Elaina Rodgers of BNY Mellon Trust Company, N.A. and signed by Mr. Matt Scholin. 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. The estimated net remaining proved reserves attributable to the BP Prudhoe Bay Royalty Trust as of December 31, 2022, of 8.232 million barrels of oil are, in the aggregate, reasonable. Of the 8.232 million barrels of total proved reserves, 7.862 million barrels are proved developed reserves, and 0.370 million barrels are proved undeveloped reserves.
4. The 2022 average West Texas Intermediate Price of \$93.67 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, 2022. 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, 2022, production of the proved reserves will result in estimated future net revenues of \$61.169 million and present value of estimated future net revenues of \$56.751 million 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 2022. 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. However, the Per Barrel Royalty will not have a positive 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 such circumstances, average daily production attributable to the BP Prudhoe Bay Royalty Trust will 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 \$93.67 per barrel and Production Taxes and Adjusted Chargeable Costs as prescribed by the Overriding Royalty Conveyance, the projection that royalty payments will continue through the year 2024 is reasonable. For the economic conditions and production forecast as of December 31, 2022, the Per Barrel Royalty will be zero following the year 2024. Therefore, no reserves are currently attributed to the BP Prudhoe Bay Royalty Trust after that date. 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.

The current estimated proved undeveloped reserves are part of ongoing development activities for which Hilcorp North Slope, LLC has a historical track record of completing comparable projects. Net proved undeveloped reserves attributable to the BP Prudhoe Bay Royalty Trust were increased by approximately 0.370 million barrels during 2022 as a result of a higher WTI Price. In all cases, the volumes are being progressed as part of an adopted development plan that calls for drilling of wells over a period of time given the magnitude of development. There were no contributions to proved undeveloped reserves from extensions or discoveries during 2022.

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.

In making its future production forecasts, Hilcorp North Slope, LLC provided for anticipated downtime and planned facilities upsets. Although allowances for unplanned upsets are also considered in the estimates, the studies do not provide for any impediments to crude oil production as a consequence of major disruptions.

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 20 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, 2022.

Very truly yours,

MILLER AND LENTS, LTD.  
Texas Registered Engineering Firm No. F-1442

By /s/ Jennifer A. Godbold  
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Senior Vice President



By /s/ Robert J. Oberst  
Robert J. Oberst, P.E.  
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