BP PRUDHOE BAY ROYALTY TRUST
Form 10-K
March 02, 2009

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

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

For the Fiscal Year ended December 31, 2008

OR

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

Commission File Number 1-10243

BP PRUDHOE BAY ROYALTY TRUST

(Exact name of registrant as specified in its charter)

DELAWARE	
State or other jurisdiction of incorporation or organization)	**13-6943724** (I.R.S. Employer Identification No.)
THE BANK OF NEW YORK MELLON, TRUSTEE 101 BARCLAY STREET NEW YORK, NEW YORK	**10286**
(Address of principal executive offices)	(Zip Code)

Registrant s telephone number, including area code: (212) 815-6908

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes þ No o

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 o No þ

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 þ No o

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

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

Large Accelerated filerþ Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company) Smaller reporting company o

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

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, 2008 (the last business day of the registrant s most recently completed second fiscal quarter) was approximately $2,211,904,000.

As of February 27, 2009, 21,400,000 Units of Beneficial Interest were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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PART I

ITEM 1. BUSINESS

INTRODUCTION

BP Prudhoe Bay Royalty Trust (the Trust) was created as a Delaware business trust by the BP Prudhoe Bay Royalty Trust Agreement dated February 28, 1989 (the Trust Agreement) among The Standard Oil Company (Standard Oil), BP Exploration (Alaska) Inc. (BP Alaska), The Bank of New York Mellon (formerly named The Bank of New York), as trustee (the Trustee), and F. James Hutchinson, co-trustee (BNY Mellon Trust of Delaware, formerly named The Bank of New York (Delaware), successor co-trustee). BP Alaska and Standard Oil are wholly owned subsidiaries of BP p.l.c. (BP). The Trustee s corporate trust offices are located at 101 Barclay Street, New York, New York 10286 and its telephone number is (212) 815-6908.

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

The Trust does not maintain an Internet website, but certain information concerning the Trust and the Trust Units may be obtained from the BusinessWire website at the following page location: http://www.businesswire.com/portal/site/home/news/company?vnsId=41701 . The Trustee will provide paper or electronic copies of the Trust s reports on Form 10-K, Form 10-Q and Form 8-K, and amendments to those reports, free of charge upon request as soon as reasonably practicable after the Trust files them with the SEC. Requests for copies of reports may be made by mail to: The Bank of New York Mellon, 101 Barclay Street, Floor 8W, New York, NY 10286, Attention: Mr. Geovanni Barris, Corporate Trust Department; by telephone to: (212) 815-6908; or by e-mail to: geovanni.barris@bnymellon.com.

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

Forward-Looking Statements

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

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

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

THE TRUST

Trust Property

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

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

Employees

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

Duties and Powers of the Trustee

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

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

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

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

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

Sales of Royalty Interest; Borrowings and Reserves

With certain exceptions, the Trustee may sell all or part of the Royalty Interest or an interest therein only if authorized to do so by vote of the holders of 70% of the Units outstanding if the sale is to be effected on or before December 31, 2010, or holders of 60% of the Units outstanding if the sale is to be effected after 2010. However, if the sale is made in order to pay specific liabilities of the Trust then due and involves a part, but not all or substantially all, of the Trust properties, the sale only needs to be approved by the vote of holders of a majority of the Units. Any sale of Trust properties must be for cash unless otherwise authorized by the Unit holders. The Trustee is obligated to distribute the available net proceeds of any such sale to the Unit holders after establishing reserves for liabilities of the Trust.

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

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

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

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

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

The Trustee maintains a $1,000,000 cash reserve to provide liquidity to the Trust during any periods in which the Trust does not receive a distribution from BP Alaska. See Item 7 in Part II below.

Irrevocability; Amendment of the Trust Agreement

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

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

Termination of the Trust

The Trust will terminate: (i) on or before December 31, 2010 if holders of at least 70% of the outstanding Units vote to terminate the Trust, or (ii) after December 31, 2010 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 commencing after 2010 are less than $1,000,000 per year (unless the net revenues during the two-year period have been materially and adversely affected by certain extraordinary events).

Upon termination of the Trust, BP Alaska will have an option to purchase the Royalty Interest at a price equal to the greater of (i) the fair market value of the Trust property as set forth in an opinion of an investment banking firm, commercial banking firm or other entity qualified to give an opinion as to the fair market value of the assets of the Trust, or (ii) the number of outstanding Units multiplied by (a) the closing price of Units on the day of termination of the Trust on the stock exchange on which the Units are listed, or (b) if the Units are not listed on any stock exchange but are traded in the over-the-counter market, the closing bid price on the day of termination of the Trust as quoted on the NASDAQ National Market System. The purchase must be for cash unless holders of 70% of the Units outstanding (60% if the decision to terminate the Trust is made after December 31, 2010) authorize the sale for non-cash consideration and the Trustee has received a ruling from the Internal Revenue Service or an opinion of counsel to the effect that such non-cash sale will not adversely affect the classification of the Trust as a grantor trust for federal income tax purposes or cause the income from the Trust to be treated as unrelated business taxable income for federal income tax purposes.

If BP Alaska does not exercise its option, the Trustee will sell the Trust property on terms and conditions approved by the vote of holders of 70% of the outstanding Units (60% if the sale is made after December 31, 2010), unless the Trustee determines that it is not practicable to submit the matter to a vote of the Unit holders and the sale is made at a price at least equal to the fair market value of the Trust property as set forth in the opinion of the investment banking firm, commercial banking firm or other entity mentioned above and on terms and conditions deemed commercially reasonable by that firm.

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

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

Resignation or Removal of Trustee

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

Voting Rights of Unit Holders

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

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

THE ROYALTY INTEREST

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

Royalty Production

The Royalty Production for each day in a calendar quarter is 16.4246% of the lesser of (i) the first 90,000 barrels of the actual average daily net production of crude oil and condensate for the quarter from the Prudhoe Bay (Permo-Triassic) Reservoir and saved and allocated to the oil and gas leases owned by BP Alaska in the Prudhoe Bay field as of February 28, 1989 (the BP Working Interests), or (ii) the actual average daily net production of crude oil and condensate for the quarter from the BP 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 BP Working Interests for any calendar quarter is the total production of oil and condensate for the quarter, net of the State of Alaska royalty, divided by the number of days in the quarter.

Per Barrel Royalty

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

WTI Price

The WTI Price for any trading day is (i) the price (in dollars per barrel) for West Texas intermediate crude oil of standard quality having a specific gravity of 40 API degrees for delivery at Cushing, Oklahoma (West Texas Intermediate) quoted for that trading day by whichever of The Wall Street Journal, Reuters, or Platts Oilgram Price Report, in that order, publishes West Texas Intermediate price quotations for the trading day, or (ii) if the price of West Texas Intermediate is not published by one of those publications, the WTI Price will be the simple average of the daily mean prices (in dollars per barrel) quoted for West Texas Intermediate by one major oil company, one petroleum broker and one petroleum trading company designated by BP Alaska, in each case unaffiliated with BP and having substantial U.S. operations, until published price quotations are again available. If prices for West Texas Intermediate are not quoted so as to permit the calculation of the WTI Price, the price of West Texas Intermediate, for the purposes of calculating the WTI Price will be the price of another light sweet domestic crude oil of standard quality designated by BP Alaska and approved by the Trustee, with appropriate allowance for transportation costs to the Gulf coast (or another appropriate location) to equilibrate its price to the WTI Price. The WTI Price for any day which is not a trading day is the WTI Price for the preceding trading day.

Chargeable Costs

The Chargeable Costs per barrel of Royalty Production for each calendar year are fixed amounts specified in the Conveyance and do not necessarily represent BP Alaska s actual costs of production. Chargeable Costs per barrel were $12.00 during 2004, $12.25 during 2005, $12.50 during 2006, $12.75 during 2007 and $13.00 during 2008. Chargeable Costs for 2009 and subsequent years are shown in the following table:

Calendar year	Chargeable Costs per barrel	Calendar year	Chargeable Costs per barrel
2009	$13.25	2015	$17.00
2010	14.50	2016	17.10
2011	16.60	2017	17.20
2012	16.70	2018	20.00
2013	16.80	2019	23.75
2014	16.90	2020	26.50

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

Cost Adjustment Factor

The Cost Adjustment Factor for a quarter is the ratio of the Consumer Price Index published for the most recently past February, May, August or November to 121.1 (the Consumer Price Index for January 1989). The Consumer Price Index is the U.S. Consumer Price Index, all items and all urban consumers, U.S. city average (1982-84 equals 100), as first published, without seasonal adjustment, by the Bureau of Labor Statistics, Department of Labor, without regard to subsequent revisions or corrections. 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, 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.

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.

Until August 2006, the Production Taxes payable with respect to the Royalty Production were (i) the Alaska Oil Production Tax (the Old Tax), which was levied at the flat rate of 15% of the gross value of oil at the point of production (the wellhead or field value) and which, as required by the Conveyance, was applied for the purpose of determining the Royalty Interest without regard to the economic limit factor (a formula designed to result in low tax rates for smaller low productive fields and higher tax rates for larger highly productive fields), and (ii) a surcharge of $0.03 per barrel of Royalty Production. The Conveyance provides that, in the case of taxes based upon wellhead or field value, the WTI Price less the product of $4.50 multiplied by the Cost Adjustment Factor is deemed to be the wellhead or field value.

Alaska adopted a new oil and gas production tax on August 20, 2006 (Chapter 2, Third Special Session Laws of Alaska 2006) (the 2006 Tax) which amended the Alaska oil and gas production tax statutes, AS 43.55.10 et seq. (the Production Tax Statutes) and replaced the Old Tax. Under the 2006 Tax, producers are taxed on the production tax value of taxable oil (gross value at the point of production for the calendar year less the producer s direct costs of exploring for, developing, or producing oil or gas deposits located within the producer s leases or properties in Alaska (Lease Expenditures) for the year) at a rate equal to the sum of 22.5% plus a progressivity rate determined by the average monthly production tax value of the oil produced. The progressivity portion of the 2006 Tax was equal to 0.25% times the amount by which the simple average for each calendar month of the daily production tax values per barrel of the oil produced during the month exceeded $40 per barrel. In addition, the 2006 Tax increased the surcharge on oil produced from leases or properties in Alaska from $0.03 to $0.04 per barrel.

On December 20, 2007, a bill (Chapter 1, Second Special Session Laws of Alaska 2007) (the 2007 Tax) took effect and further amended the Production Tax Statutes in certain respects. The 2007 Tax changed the basic tax rate from 22.5% to 25% and increased the progressivity rate. If the producer s average monthly production tax value per barrel is greater than $30 but not more than $92.50, the new progressivity tax rate is 0.4% times the amount by which the average monthly production tax value exceeds $30 per barrel. If the producer s average monthly production tax value per barrel is greater than $92.50, the progressivity tax rate is the sum of 25% and the product of 0.1% multiplied by the difference between the average monthly production tax value per barrel and $92.50, except that the sum may not exceed 50%.

In order to resolve uncertainties in the interpretation of the Conveyance resulting from adoption of the 2006 Tax, in October 2006 the Trustee entered into a letter agreement with BP Alaska (the 2006 Letter Agreement), a copy of which is incorporated by reference as Exhibit 4.5 to this report. The 2006 Letter Agreement sets forth principles agreed to by BP Alaska and the Trustee to resolve how the amount of tax chargeable against the Royalty Interest was to be determined under the Conveyance and the extent to which the retroactivity of the tax legislation was to be recognized for purposes of the Conveyance (the Consensus Principles). In December 2007, BP Alaska notified the Trustee that the adoption of the 2007 Tax made it necessary to modify the Consensus Principles to give effect to the new tax rates. After determining that the proposed changes to the Consensus Principles were consistent with the changes in tax rates effected by the 2007 Tax, on January 11, 2008 the Trustee executed a letter agreement dated December 21, 2007 with BP Alaska (the 2008 Letter Agreement) which supplements and amends the 2006 Letter Agreement and which is incorporated by reference as Exhibit 4.6 to this report.

Determination of Production Taxes

The following paragraphs describe how the Consensus Principles provide for the amount of Production Taxes (other than the $0.04 per barrel surcharge) to be determined under the 2006 Tax (from August 20, 2006 through December 19, 2007) and under the 2007 Tax (from December 20, 2007 and thereafter):

(a) The production tax value per barrel of oil for each day is determined by taking the WTI Price for that day and subtracting the product of the amount of the Chargeable Costs then in effect multiplied by the applicable Cost Adjustment Factor.

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(b) The tax rate for the progressivity portion of the tax equals:

2006 Tax	2007 Tax
(i) zero, if the simple average of the daily taxable values per barrel under (a) above for a calendar month is not greater than $40 per barrel; or	(i) zero, if the simple average of the daily taxable values per barrel under (a) above for a calendar month is not greater than $30 per barrel;
(ii) 0.25% times the amount by which the simple average for each calendar month of the daily production tax values per barrel of oil under (a) above, exceeds $40 per barrel.	(ii) 0.4% times the amount by which the simple average of the taxable values per barrel under (a) above for a calendar month exceeds $30 per barrel if that average is not greater than $92.50 per barrel; or
	(iii) the sum of 25% plus 0.1% times the amount by which the simple average of the taxable values per barrel under (a) above for a calendar month exceeds $92.50, except that such sum may not exceed 50%.

(c) The amount of Production Tax chargeable against the Royalty Interest equals the taxable value per barrel under (a) above times the Royalty Production under the Conveyance, times a rate equal to the sum of the progressivity rate determined under (b) above plus the following percentage:

2006 Tax	2007 Tax
22.5%	25%

Retroactivity of Tax

Although both the 2006 Tax and the 2007 Tax are retroactive (to April 1, 2006, in the case of the 2006 Tax; to July 1, 2007, in the case of the 2007 Tax), in the Consensus Principles the parties agreed that the 2006 Tax and 2007 Tax would not be applied retroactively to payments by BP Alaska with respect to the Royalty Interest. Production Taxes charged against the Royalty Interest were the amount of Old Tax as calculated under the Conveyance for oil production during the period from April 1 to August 19, 2006, inclusive. For oil produced on August 20, 2006 through December 19, 2007, the Production Taxes charged against the Royalty Interest were the amount of 2006 Tax, determined as described above, for that production, and for oil produced on December 20, 2007 and thereafter the Production Taxes charged against the Royalty Interest are the amount of 2007 Tax, determined as described above.

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Use of Inflation Adjusted Chargeable Costs under Consensus Principles

The 2006 Letter Agreement contains a discussion of the rationale for using inflation adjusted Chargeable Costs as a proxy for BP Alaska s actual Lease Expenditures for purposes of determining Production Taxes chargeable against the Royalty Interest. The 2006 Letter Agreement explains that under the 2006 Tax BP Alaska is required to use estimates of Lease Expenditures for purposes of its monthly reporting to the State of Alaska, and that actual Lease Expenditures are determined and reconciled to monthly estimates up to three months after the close of each fiscal year. The use of BP Alaska s estimated Lease Expenditures for purposes of calculating the Production Taxes applied to quarterly payments of the Royalty Interest could require regular adjustments to future royalty payments to compensate for over or under charges of Production Taxes to past royalty payments once actual Lease Expenditures were determined. These adjustments could create unfair benefits for certain Unit holders and unfair detriment to others. BP Alaska stated that inflation adjusted Chargeable Costs were expected to provide a reasonable, although not an exact, approximation of BP Alaska s Leasehold Expenditures and provide certainty to investors in the Trust Units. BP Alaska cautioned, however, that to the extent actual Lease Expenditures for a particular year are higher than adjusted Chargeable Costs for the year, the Trust Units may bear Production Taxes at a higher rate than the rate of tax applicable to BP Alaska s production for the year; conversely, if BP Alaska s Lease Expenditures for a year are less than adjusted Chargeable Costs for that year, Production Taxes charged against the Royalty Interest may be charged at a lower rate than the rate of tax applicable to BP Alaska s production.

In addition to changes in the rates of tax applicable to oil and gas production introduced by the 2007 Tax, the legislation authorizes the Alaska Department of Revenue (DOR) to interpret and apply the amendments to the Production Tax Statutes. The 2007 Tax allows DOR to limit deductible transportation costs for transportation by a regulated pipeline to something less than the tariff actually paid. Other amendments allow DOR to exclude by regulation certain categories of otherwise deductible lease expenditures, or a fixed percentage of them, from being deductible in determining the production tax value of taxable oil. In the 2008 Letter Agreement, BP Alaska indicated that, depending on what the new regulations provide, it may wish to amend the Consensus Principles so that something less than the full amount of Chargeable Costs is to be deducted under the Conveyance in determining the taxable value per barrel. Any such amendment would require the consent of the Trustee. If any such amendment should be proposed, the Trustee will evaluate the proposal to determine whether such amendment is consistent with the Conveyance and the interests of the Unit holders of the Trust and will make its decision accordingly.

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Per Barrel Royalty Calculations

The following table shows how the above-described factors interacted during the past five years to produce the average Per Barrel Royalty paid during the calendar years indicated. Royalty revenues are generally received on the fifteenth day of the month following the end of the calendar quarter in which the related Royalty Production occurred. Revenues and expenses presented in the statement of cash earnings and distributions presented in Part II, Item 8 below are recorded on a modified cash basis and, as a result, royalty revenues and distributions shown in such statements for any calendar year are attributable to BP Alaska s operations during the twelve-month period ended September 30 of that year.

	Average WTI Price	Chargeable Costs	Cost Adjustment Factor	Adjusted Chargeable Costs	Production Taxes(1)	Average Per Barrel Royalty
Calendar 2004:						
4th Qtr 2003	$ 31.23	$11.75	1.421	$16.69	$ 3.76	$10.78
1st Qtr 2004	35.18	12.00	1.434	17.20	4.34	13.64
2nd Qtr 2004	38.31	12.00	1.456	17.47	4.79	16.05
3rd Qtr 2004	43.78	12.00	1.459	17.51	5.61	20.66
Calendar 2005:						
4th Qtr 2004	48.35	12.00	1.471	17.65	6.29	24.41
1st Qtr 2005	49.70	12.25	1.477	18.09	6.49	25.12
2nd Qtr 2005	53.09	12.25	1.497	18.34	6.98	27.77
3rd Qtr 2005	63.03	12.25	1.512	18.53	8.46	36.04
Calendar 2006:						
4th Qtr 2005	60.01	12.25	1.521	18.63	8.01	33.37
1st Qtr 2006	63.36	12.50	1.530	19.13	8.50	35.73
2nd Qtr 2006	70.53	12.50	1.559	19.49	9.56	41.48
3rd Qtr 2006	70.64	12.50	1.570	19.63	10.68	40.34
Calendar 2007:						
4th Qtr 2006	60.17	12.50	1.552	19.39	9.31	31.46
1st Qtr 2007	58.17	12.75	1.567	19.98	8.66	29.54
2nd Qtr 2007	65.00	12.75	1.601	20.42	10.59	34.00
3rd Qtr 2007	75.29	12.75	1.601	20.42	14.45	40.42
Calendar 2008:						
4th Qtr 2007	90.93	12.75	1.618	20.63	22.29	48.01
1st Qtr 2008	97.78	13.00	1.630	21.19	33.58	43.01
2nd Qtr 2008	124.34	13.00	1.668	21.68	52.37	50.29
3rd Qtr 2008	118.69	13.00	1.687	21.93	48.18	48.58

(1) Production Taxes for the third quarter of 2006 and subsequent

quarters reflect the effect of the 2006 amendment of the Alaska oil and gas Production Tax Statutes. Production taxes for the first quarter of 2008 and subsequent periods reflect the application of the 2007 amendment of the Production Tax Statutes.

(2) Dollar amounts in the table have been rounded to two decimal places for presentation and do not reflect the precision of the actual calculations.

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THE UNITS

Units

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

Distributions of Income

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

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

Reports to Unit Holders

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

Limited Liability of Unit Holders

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

Possible Divestiture of Units

The Trust Agreement imposes no restrictions on nationality or other status of the persons eligible to hold Units. However, it provides that if at any time the Trust or the Trustee is named a party in any

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judicial or administrative proceeding seeking the cancellation or forfeiture of any property in which the Trust has an interest because of the nationality, or any other status, of any one or more Unit holders, the Trustee may require each holder whose nationality or other status is an issue in the proceeding to dispose of his Units to a party not of the nationality or other status at issue in the proceeding. If any holder fails to dispose of his Units within 30 days after receipt of notice from the Trustee to do so, the Trustee will redeem any Units not so transferred within 90 days after the end of the 30-day period specified in the notice for a cash price equal to the fair market value of the Units. Units redeemed by the Trustee will be cancelled.

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

Issuance of Additional Units

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

THE BP SUPPORT AGREEMENT

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

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

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

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

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from at least one nationally-recognized statistical rating organization (after giving effect to the sale or transfer and the assumption of all of BP Alaska s obligations under the Conveyance and all of BP s obligations under the Support Agreement).

THE PRUDHOE BAY UNIT AND FIELD

Prudhoe Bay Unit Operation and Ownership

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

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

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

The ownership of the Prudhoe Bay Unit by participating area as of December 31, 2008 is shown in the following table:

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

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

(b) The Trust s share of condensate production is computed based on BP Alaska s ownership interest in the gas cap participating area of 13.84% as of February 28, 1989. Subsequent increases in BP Alaska s gas cap ownership do not affect calculation of Royalty Production from the BP Working Interests and have not increased the Trust s Royalty Interest.

If BP Alaska fails to pay any costs and expenses chargeable to BP Alaska under the Prudhoe Bay Unit Operating Agreement and the production of oil and condensate is insufficient to pay such costs and expenses, the Royalty Interest is chargeable with a pro rata portion of such costs and expenses and is subject to the enforcement against it of liens granted to the operators of the Prudhoe Bay Unit. However,

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in the Conveyance BP Alaska agreed to pay all costs and expenses chargeable to it and to ensure that no such costs and expenses will be chargeable against the Royalty Interest. The Trust is not liable for any loss or liability incurred by BP Alaska or others attributable to BP Alaska s working interest in the Prudhoe Bay Unit or to the oil produced from it and BP Alaska has agreed to indemnify the Trust and hold it harmless against any such impositions.

BP Alaska has the right to amend or terminate the Prudhoe Bay Unit Agreement, the Prudhoe Bay Unit Operating Agreement and any leases or conveyances with respect to the BP Working Interests in the exercise of its reasonable and prudent business judgment without liability to the Trust. BP Alaska also has the right to sell or assign all or any part of the BP 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 productive acres. 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, 2008, approximately 11.1 billion barrels of oil and condensate had been produced from the Prudhoe Bay field.

Field Geology

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

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

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

Oil Characteristics

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

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

Historical Production

Production from the Prudhoe Bay field began on June 19, 1977, with the completion of the Trans-Alaska Pipeline System (TAPS). As of December 31, 2008 there were about 1,128 active producing oil wells, 34 gas reinjection wells, 88 water injection wells and 133 water and miscible gas injection wells in the Prudhoe Bay field. Production from the Prudhoe Bay field reached a peak in 1988 and has declined steadily since then. The average well production rate was about 317 barrels per day in 2004, 293 barrels per day in 2005, 223 barrels per day in 2006, 232 barrels per day in 2007 and 232 barrels per day in 2008. There was a temporary impact on production from the east side of the Prudhoe Bay Unit as a result of the August 2006 partial shutdown, as discussed in the last paragraph under the heading Collection and Transportation of Prudhoe Bay Oil, below

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

	Oil		**Condensate**	
Calendar year	**Total field**	**Net to BP Working Interests**	**Total field**	**Net to BP Working Interests**
		(thousand barrels per day)		
2004	243.4	107.9	109.0	13.2
2005	228.9	101.5	96.4	11.7
2006	173.9	77.1	76.7	9.3
2007 [(a)]	184.1	81.6	77.9	9.4
2008	192.7	85.4	69.4	8.4

(a) 2007 production figures reported in the Trust s Annual Report on Form 10-K for the year ended December 31, 2007 have been revised to reflect actual production for the year.

Collection and Transportation of Prudhoe Bay Oil

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

At Pump Station 1, Alyeska Pipeline Service Company, the operator of TAPS, meters the oil and pumps it in the 48-inch diameter pipeline to Valdez, almost 800 miles (1,287 km) to the south, where it is either loaded onto marine tankers or stored temporarily. It takes the oil about seven days to make the trip from the Prudhoe Bay Unit to Valdez. TAPS has a capacity of approximately 1.4 million barrels of oil per day.

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On August 7, 2006, BP announced that BP Alaska had begun a shutdown of the Prudhoe Bay Unit following the discovery of unexpectedly severe corrosion and a small spill from the oil transit line on the eastern side of the field. The decision followed the receipt several days earlier of data from a smart pig run completed in late July. Analysis of the data revealed 16 anomalies in 12 locations in the oil transit line. During follow up inspections of the anomalies, BP Alaska personnel discovered corrosion-related wall thinning which appeared to exceed criteria for continued operation and a leak and small spill estimated at four to five barrels. BP had previously announced plans to replace a three-mile segment of transit line on the western side of the Prudhoe Bay field following inspections conducted after a large spill caused by corrosion discovered in March 2006.

BP subsequently determined to shut down only the eastern side of the Prudhoe Bay Unit and continue production from the western side of the Unit. The partial shutdown of the field reduced average daily production to approximately half of normal output. On September 22, 2006, BP announced that it had received clearance from the U.S. Department of Transportation (DOT) to restart production in the eastern half of the Prudhoe Bay Unit. In December 2008 BP completed the replacement of approximately 16 miles of oil transit lines. BP Alaska has implemented new integrity management and corrosion monitoring practices that supplement or replace the practices that existed in 2006. BP Alaska s integrity management practices meet the requirement of 49 CFR 195.452 for pipeline integrity management in high consequence areas.

Reservoir Management

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

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

Reserve Estimates

Estimates of proved reserves are inherently imprecise and subjective and are revised over time as additional data become available. Such revisions often may be substantial. BP Alaska s reserve estimates and production assumptions and projections are predicated upon a reasonable estimate of the allocation of hydrocarbon liquids between oil and condensate according to the procedures of the Prudhoe Bay Unit Operating Agreement. Oil and condensate are physically produced in a commingled stream of hydrocarbon liquids. The allocation of hydrocarbon liquids between the oil and condensate from the Prudhoe Bay field is a theoretical calculation performed in accordance with procedures specified in the Prudhoe Bay Unit Operating Agreement. Due to the differences in percentages between oil and condensate, the overall share of oil and condensate production allocated to the BP Working Interests will vary over time according to the proportions of hydrocarbon liquid being allocated as condensate or as oil. Under the terms of an Issues Resolution Agreement entered into by the Prudhoe Bay Unit owners in October 1990, the allocation procedures have been 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.

An electronic device including magnetic flux leakage and ultrasonic thickness testing systems that is propelled through a pipeline to inspect the pipeline wall.

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The reserves attributable to the Trust s Royalty Interest constitute only a part of the overall reserves allocated to the BP Working Interests. BP Alaska has estimated that the net remaining proved reserves attributable to the Trust as of December 31, 2008 were 54.954 million barrels of oil and condensate, of which 46.096 million barrels are proved developed reserves and 8.858 million barrels are proved undeveloped reserves. Using procedures specified in Financial Accounting Standards Board Statement of Financial Accounting Standards No. 69, BP Alaska calculated that as of December 31, 2008 production of oil and condensate from the proved reserves allocated to the Trust s Royalty Interest will result in estimated future net revenues to the Trust of $632.47 million, with a present value of $418.57 million. (See Item 7 in Part II below for information concerning adoption by the SEC of revisions to its oil and gas reporting disclosures.) BP Alaska s estimates of proved reserves and the estimated future net revenues from the Prudhoe Bay Unit have been reviewed by Miller and Lents, Ltd., independent oil and gas consultants, as set forth in their report following this section.

BP Alaska has undertaken a program of field-wide infrastructure renewal, pipeline replacement, and mechanical improvements to wells. As a consequence of these activities and their required downtime, BP Alaska s net production of oil and condensate from proved reserves was less than 90,000 barrels per day on an annual basis in 2008. BP Alaska anticipates that its average net production of oil and condensate from proved reserves will be below 90,000 barrels per day on an annual average basis in 2009 and all future years. The occurrence of major gas sales could accelerate the decline in net production, due to the consequent decline in reservoir pressure. See Item 1A, RISK FACTORS. Based on the WTI Price of $44.60 per barrel on December 31, 2008, current Production Taxes, and the Chargeable Costs adjusted as prescribed by the Overriding Royalty Conveyance, it is estimated that royalty payments to the Trust will continue through the year 2020. BP Alaska expects continued economic production from the Prudhoe Bay field at a declining rate through 2049; however, for the economic conditions and production forecast as of December 31, 2008 the Per Barrel Royalty will be zero following the year 2020.

There is no precise method of forecasting the allocation of reserve volumes between BP Alaska and 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 BP Working Interests. Rather, reserve volumes attributable to the Trust at any given date are estimated by allocating to the Trust its share of estimated future production from the BP Working Interests based on WTI Prices and other economic parameters in effect on the date of the evaluation.

The following table shows the net remaining proved reserves of oil and condensate allocated to the BP Working Interests, the net proved reserves allocated to the Trust, and the WTI Prices on the dates indicated:

	Net Proved Reserves		
December 31	**BP Working Interests (a)**	**Trust (b)**	**WTI Price per barrel**
	(million barrels)		
2004	941.4	77.4	$43.46
2005	1,043.0	85.3	61.04
2006	912.1	81.1	61.06
2007	915.1	97.8	96.01
2008	791.4	55.0	44.60

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(a) Includes proved undeveloped reserves of 115.4 million barrels at December 31, 2004, 96.0 million barrels at December 31, 2005, 84.2 million barrels at December 31, 2006, 68.7 million barrels at December 31, 2007 and 63.6 million barrels at December 31, 2008.

(b) Includes proved undeveloped reserves of 9.1 million barrels at December 31, 2004, 12.3 million barrels at December 31, 2005, 12.1 million barrels at December 31, 2006, 10.9 million barrels at December 31, 2007 and 8.9 million barrels at December 31, 2008.

The reserve volumes attributable to the Trust are estimated using an allocation of reserve volumes based on estimated future production and the current WTI Price, and assume no future movement in the Consumer Price Index and no changes to the procedure for calculating Production Taxes. The estimated reserve volumes attributable to the Trust will vary if different estimates of production, prices and other factors are used. Even if expected reservoir performance does not change, the estimated reserves, economic life, and future revenues attributable to the Trust may change significantly in the future. This may result from changes in the WTI Price or from changes in other prescribed variables utilized in calculations defined by the Overriding Royalty Conveyance. See Note 11 (unaudited) of the Notes to Financial Statements in Item 8.

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

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

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INDEPENDENT OIL AND GAS CONSULTANTS REPORT

Miller and Lents, Ltd.
international oil and gas consultants
founded 1948

February 12, 2009

The Bank of New York Mellon
Corporate Trust Division
Trustee, BP Prudhoe Bay Royalty Trust
101 Barclay Street, 8 West
New York, New York 10286

Re: Estimates of Proved Reserves, Future Production Rates, and Future Net Revenues for the BP Prudhoe Bay Royalty Trust
As of December 31, 2008

Gentlemen:

This letter report is a summary of investigations performed in accordance with our 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 investigations included reviews of the estimates of Proved Reserves and production rate forecasts of oil and condensate made by BP Exploration (Alaska) Inc. attributable to the BP Prudhoe Bay Royalty Trust as of December 31, 2008. Additionally, we 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.

The estimates and calculations reviewed were summarized in the report prepared by BP Exploration (Alaska) Inc. and transmitted with a cover letter dated February 11, 2009 addressed to Mr. Geovanni Barris of The Bank of New York Mellon and signed by Mr. Lewis Westwick. Reviews were also performed by Miller and Lents, Ltd. during this year or in previous years of (1) the procedures for estimating and documenting Proved Reserves, (2) the estimates of in-place reservoir volumes, (3) the estimates of recovery factors and production profiles for the various areas, pay zones, projects, and recovery processes that are included in the estimates of Proved Reserves, (4) the production strategy and procedures for implementing that strategy, (5) the 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 on August 7, 1989, by BP Exploration (Alaska) Inc.

Proved Reserves were estimated by BP Exploration (Alaska) Inc. 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.

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Miller and Lents, Ltd.

The Bank of New York Mellon — February 12, 2009
Trustee, BP Prudhoe Bay Royalty Trust

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 which in turn depends upon the West Texas Intermediate Price, the Chargeable Costs, the Cost Adjustment Factor, and Production Taxes, all of which are defined in the Overriding Royalty Conveyance. Barrel as used herein means Stock Tank Barrel as defined in the Overriding Royalty Conveyance.

Our reviews do not constitute independent estimates of the reserves and annual production rate forecasts for the areas, pay zones, projects, and recovery processes examined. We relied upon the accuracy and completeness of information provided by BP Exploration (Alaska) Inc. with respect to pertinent ownership interests and various other historical, accounting, engineering, and geological data.

As a result of our cumulative reviews, based on the foregoing, we conclude that:

1. A large body of basic data and detailed analyses are available and were used in making the estimates. In our 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. 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 are in accordance with generally accepted geological and engineering practice in the petroleum industry.

3. Based on our 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 us.

4. The estimated net remaining Proved Reserves attributable to the BP Prudhoe Bay Royalty Trust as of December 31, 2008, of 54.954 million barrels of oil and condensate are, in the aggregate, reasonable. Of the 54.954 million barrels of total Proved Reserves, 46.096 million barrels are Proved Developed Reserves, and 8.858 million barrels are Proved Undeveloped Reserves.

5. Utilizing the specified procedures outlined in Financial Accounting Standards Board Statement of Financial Accounting Standards No. 69, BP Exploration (Alaska) Inc. calculated that as of December 31, 2008 production of the Proved Reserves will result in Estimated Future Net Revenues of $632.47 million and Present Value of Estimated Future Net Revenues of $418.57 million to the BP Prudhoe Bay Royalty Trust. These estimates are reasonable.

6. BP Exploration (Alaska) Inc. has undertaken a program of field-wide infrastructure renewal, pipeline replacement, and well mechanical improvements. As a consequence of these activities and their required downtime, BP Exploration (Alaska) Inc. s net production of oil and condensate from Proved Reserves was less than 90,000 barrels per

Miller and Lents, Ltd.

The Bank of New York Mellon February 12, 2009
Trustee, BP Prudhoe Bay Royalty Trust

day on an annual average basis in 2008. BP Exploration (Alaska) Inc. expects that its net production of oil and condensate from Proved Reserves will be less than 90,000 barrels per day on an average basis in all future years. The BP Exploration (Alaska) Inc. projection of its net production of oil and condensate under its forecast of downtime and operating efficiency is reasonable.

7. Production attributable to the BP Prudhoe Bay Royalty Trust will decline with the BP Exploration (Alaska) Inc. production. However, the Per Barrel Royalty will not have a positive value if the West Texas Intermediate Price is less than the sum per barrel Chargeable Costs and per barrel 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 regardless of BP Exploration (Alaska) Inc. s net production level.

8. Based on the West Texas Intermediate Price of $44.60 per barrel on December 31, 2008, current Production Taxes, and the Chargeable Costs adjusted as prescribed by the Overriding Royalty Conveyance, the projection that royalty payments will continue through the year 2020 is reasonable. BP Exploration (Alaska) Inc. expects continued economic production at a declining rate through the year 2049; however, for the economic conditions and production forecast as of December 31, 2008 the Per Barrel Royalty will be zero following the year 2020. Therefore, no reserves are currently attributed to the BP Prudhoe Bay Royalty Trust after that date.

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

Estimates of ultimate and remaining reserves and production scheduling depend upon assumptions regarding expansion or implementation of alternative projects or development programs and upon strategies for production optimization. BP Exploration (Alaska) Inc. 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 estimates of Proved Reserves includes only those projects or development programs that are deemed reasonably certain to be implemented, given current economic and regulatory conditions. 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. BP Exploration (Alaska) Inc. currently

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expects continued economic production from the reservoir at a declining rate through the year 2049. 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 and condensate production capacity.

In making its future production rate forecasts, BP Exploration (Alaska) Inc. 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. Oil and condensate recoveries are expected to be greater as a result of continued reinjection of produced gas than the recoveries would be if major volumes of produced gas were being sold. No major gas sale is assumed in the current estimates. If major gas sales are undertaken in the future, BP Exploration (Alaska) Inc. estimates that such sales would not actually commence until nine to eleven years in the future. In the event that major gas sales are initiated, ultimate oil and condensate recoveries may be reduced from the current estimates unless recovery projects other than those included in the current estimates are implemented.

Large volumes of natural gas liquids are likely to be produced and marketed in the future whether or not major gas sales become viable. Natural gas liquids 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 or natural gas liquids.

The evaluations presented in this report, with the exceptions of those parameters specified by others, reflect our informed judgments based on accepted standards of professional investigation but are subject to those generally recognized uncertainties associated with interpretation of geological, geophysical, and engineering information. Government policies and market conditions different from those reflected in this study or disruption of existing transportation routes or facilities may cause the total quantity of oil or condensate to be recovered, actual production rates, prices received, or operating and capital costs to vary from those reviewed in this report.

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Miller and Lents, Ltd., is an independent oil and gas consulting firm. None of the principals of this firm have any direct financial interests in BP Exploration (Alaska) Inc. or its parent or any related companies or in the BP Prudhoe Bay Royalty Trust. Our fee is not contingent upon the results of our work or report, and we have not performed other services for BP Exploration (Alaska) Inc. or the BP Prudhoe Bay Royalty Trust that would affect our objectivity.

Very truly yours,

MILLER AND LENTS, LTD.

By /s/ William P. Koza
William P. Koza, P.E.
Senior Consultant

By /s/ Carl D. Richard
Carl D. Richard, P.E.
Senior Vice President

WPK/eb

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INDUSTRY CONDITIONS AND REGULATIONS

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

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

Since the end of 2006, the corrosion monitoring and mitigation practices for oil transit lines in the Prudhoe Bay Unit have been monitored and reviewed by the U.S. Department of Transportation. The construction, testing, and commissioning of the new replacement oil transit lines have been inspected by DOT inspectors. The replacement lines have been constructed and are operated and maintained in accordance with the requirements of the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 even though the applicable requirements of the subsequent regulations are not phased in until 2012. See THE PRUDHOE BAY UNIT AND FIELD Collection and Transportation of Prudhoe Bay Oil above.

CERTAIN TAX CONSIDERATIONS

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

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

Federal Income Tax

Classification of the Trust

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

General Features of Grantor Trust Taxation

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

Taxation of Unit Holders

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

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

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

Depletion Deductions

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

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

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 28% 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 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, Corporate Trust Trustee Administration, 101 Barclay Street, New York, NY 10286, telephone number (212) 815-6908.

State Income Taxes

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

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ITEM 1A. RISK FACTORS

Owners of Units are exposed to risks and uncertainties that are particular to their investment. This Item describes several such risks and uncertainties, but not necessarily all of them.

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

The Prudhoe Bay field has been in production since 1977. Development of the field is largely completed and proved reserves are being depleted. Production of oil and condensate from the field has been declining during recent years and the decline is expected to continue. Royalty payments to the Trust are projected to cease after 2020. Production estimates included in this report are based on economic conditions and production forecasts as of the end of 2008, and also depend on various assumptions, projections and estimates which are continually revised and updated by BP Alaska. These revisions could result in material changes to the projected declines in production. It is possible that economic production from the reserves allocated to the BP Working Interests could decline more quickly and end sooner than is currently projected, especially if construction of a gas pipeline makes it economical to produce natural gas from the Prudhoe Bay field on a large scale, as discussed below.

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

During 2008 two competing plans for construction of a natural gas pipeline to bring natural gas from the North Slope to the U.S. market were launched and have reached the planning and project development stage.

Two subsidiaries of Calgary-based TransCanada Corporation (TransCanada) have been issued a license by the state of Alaska under the Alaska Gasline Inducement Act (AGIA) to construct a large-diameter natural gas pipeline from the North Slope. Under the license, the state will provide up to $500 million in matching funds and other incentives in exchange for TransCanada doing its best to secure customers for the pipeline, financing, and regulatory clearances from the Federal Energy Regulatory Commission (FERC) and Canadian authorities. Separately, BP and ConocoPhillips have combined resources to start a joint venture called Denali The Alaska Gas Pipeline, LLC (Denali) without support for the project from Alaska under the AGIA.

Both projects envision a gas treatment plant on Alaska s North Slope and a large-diameter pipeline through Alaska, and then into Canada through the Yukon Territory and British Columbia to the existing Alberta Storage Hub near Edmonton, Alberta. The Denali project also may include a 1,500-mile pipeline from Alberta to Chicago, if required.

In its February 9, 2009 semi-annual report to the U.S. Congress pursuant to section 1810 of the Energy Policy Act of 2005, FERC reported that progress had been made towards development of an Alaska natural gas pipeline during the reporting period and that both TransCanada and Denali are working towards conducting open seasons in 2010, during which the two competing consortia will seek customers to make long-term firm transportation commitments to the project. There is no assurance that either project will move from the development stage to licensing and construction of a pipeline. If either project is successful, gas could commence flowing from the North Slope to market in the lower 48 states by 2018.

Without a pipeline, extraction of natural gas from the Prudhoe Bay field on a large scale is not economical. 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. If a natural gas pipeline is constructed, it will make it economical to extract natural gas from the Prudhoe Bay field and transport it to the lower 48 states for sale. Extraction of natural gas from the Prudhoe Bay field will lower reservoir pressure, although carbon dioxide stripped out of the gas can be reinjected and other methods can be employed to mitigate the reduction. The lowering of the reservoir pressure may accelerate the decline in production from the BP Working Interests and the time at which royalty payments to the Trust will cease. Since the Trust is not entitled to any royalty payments with respect to natural gas production from the BP Working Interests, the Unit holders will not realize any offsetting benefit from natural gas production from the Prudhoe Bay field.

Royalty Production from the Prudhoe Bay field may be adversely affected by the recent change in the Alaska Production Tax Statutes.

The 2007 amendment of the Alaska Production Tax Statutes (see THE ROYALTY INTEREST Production Taxes in Item 1 above) may accelerate the decline in production of oil and condensate from the Prudhoe Bay field if BP Alaska and the other owners of working interests in the Prudhoe Bay Unit reduce or defer investment in oil production infrastructure renewal, well development and implementation of new technology. The 2007 amendment, in addition to increasing the basic oil production tax rate and the progressivity factor, also eliminates or reduces many deductions and credits permitted under the 2006 amendment. BP Alaska attributed a $100 million reduction, to $800 million, in its 2008 capital budget to the 2007 amendment. BP Alaska has budgeted approximately $1.2 billion in capital expenditures in Alaska for 2009, but approximately one-third of that amount will go to projects outside of the Prudhoe Bay field, and the company expects a 10 percent drop in drilling at Prudhoe Bay during 2009.

Royalty payments by BP Alaska to the Trust are unpredictable, because they depend on Cushing, Oklahoma WTI spot prices, which have been volatile in recent years, and on the volume of production from the BP Working Interests, which may vary from quarter to quarter in the future.

Even though WTI Prices have been rising generally in recent years, they nevertheless remain subject to significant periodic fluctuations. For additional information, see the monthly history of WTI Prices since 1986 published by the U.S. Energy Information Administration at http://tonto.eia.doe.gov/dnav/pet/hist/rwtcM.htm.

Recent moves in crude oil prices have been affected by many factors, including changes in demand by oil-consuming countries, the actions of OPEC to control production by members of the cartel, shifts in inventory management strategies by international oil companies, conservation measures by consumers, increasing effects of the oil futures market and other unpredictable political, psychological and economic factors including, most recently, the global economic recession. Future domestic and international events and conditions may produce wide swings in crude oil prices over relatively short periods of time.

It is increasingly likely that the Trust s revenues in future periods also will be affected by decreases in production from the BP Working Interests. BP Alaska s average net production of oil and condensate from proved reserves in the BP Working Interests was less than 90,000 barrels per day on an annual basis during 2008 and the Trustee has been advised that BP Alaska expects that average net production from the BP Working Interests will be less than 90,000 barrels a day on an annual basis in 2009 and future years. Unit holders thus are subject to the risk that cash distributions with respect to their Units may vary widely from quarter to quarter.

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

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

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

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

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. If the pipeline or its pumping stations should suffer major damage from natural or man-made causes, production from the Prudhoe Bay Unit could be shut in until the pipeline system can be repaired and restarted. Royalty payments to the Trust could be halted or reduced by a material amount as a result of interruption to production from the Prudhoe Bay Unit.

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

BP Alaska has no obligation to continue production from the BP 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 BP Working Interests or share in any operating decisions by BP Alaska concerning the Prudhoe Bay Unit. The operation of the Prudhoe Bay Unit is subject to normal operating hazards incident to the production and transportation of oil in Alaska. In the event of damage to the infrastructure, facilities and equipment in the Prudhoe Bay field which is covered by insurance, BP Alaska has no obligation to use insurance proceeds to repair such damage and may elect to retain such proceeds and close damaged areas to production.

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

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

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discontinue production in whole or in part from the BP 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. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of Unit holders during the fourth quarter ended December 31, 2008.

PART II

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

The Units are listed and traded on the New York Stock Exchange under the symbol BPT. The following table shows the high and low sales prices per Unit on the New York Stock Exchange and the cash distributions paid per Unit, for each calendar quarter in the two years ended December 31, 2008.

	High	Low	Distributions Per Unit
2007:			
First Quarter	$ 76.98	$54.80	$ 1.544
Second Quarter	72.50	63.50	1.545
Third Quarter	79.40	64.50	1.728
Fourth Quarter	80.20	69.20	2.282
2008:			
First Quarter	97.13	71.01	3.046
Second Quarter	103.49	88.51	2.670
Third Quarter	108.40	77.64	3.053
Fourth Quarter	95.47	58.08	2.937

As of February 24, 2009, 21,400,000 Units were outstanding and were held by 639 holders of record. No Units were purchased by the Trust or any affiliated purchaser during the year ended December 31, 2008.

Future payments of cash distributions are dependent on such factors as the prevailing WTI Price, the relationship of the rate of change in the WTI Price to the rate of change in the Consumer Price Index,

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the Chargeable Costs, the rates of Production Taxes prevailing from time to time, and the actual Royalty Production from the BP Working Interests. See THE ROYALTY INTEREST in Item 1.

ITEM 6. SELECTED FINANCIAL DATA

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

	Year ended December 31				
	2008	2007	2006	2005	2004
	(in thousands, except per Unit amounts)				
Royalty revenues	$252,298	177,318	184,864	152,978	82,682
Interest income	$ 33	81	75	37	11
Trust administration expenses	$ 1,797	1,687	1,057	1,097	976
Cash earnings	$250,534	175,712	183,882	151,918	81,717
Cash distributions	$250,525	175,713	183,883	151,908	81,702
Cash distributions per unit	$ 11.707	8.211	8.593	7.098	3.818

	December 31				
	2008	2007	2006	2005	2004
	(dollar amounts in thousands)				
Trust corpus	$ 4,757	6,592	8,853	10,876	12,881
Total assets	$ 5,035	7,035	9,044	11,054	13,052
Units outstanding	21,400,000	21,400,000	21,400,000	21,400,000	21,400,000

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

Liquidity and Capital Resources

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

Since 1999, the Trustee has maintained a $1,000,000 cash reserve to provide liquidity to the Trust during any future periods in which the Trust does not receive a distribution. The Trustee will draw funds from the cash reserve account during any quarter in which the quarterly distribution received by the Trust does not exceed the liabilities and expenses of the Trust, and will replenish the reserve from future quarterly distributions, if any. The Trustee anticipates that it will keep this cash reserve program in place until termination of the Trust.

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

Annual decreases in Trust corpus and total assets are the result of amortization of the Royalty Interest. See Notes 2 and 3 of Notes to Financial Statements in Item 8.

Results of Operations

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

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

When BP Alaska s average net production of oil and condensate per quarter from the BP Working Interests exceeds 90,000 barrels a day, the principal factors affecting the Trust s revenues and distributions to Unit holders are changes in WTI Prices, scheduled annual increases in Chargeable Costs, changes in the Consumer Price Index and changes in Production Taxes. However, it is likely that the Trust s revenues in future periods also will be affected by increases and decreases in production from the BP Working Interests. BP Alaska s net production of oil and condensate from proved reserves in the BP Working Interests was less than 90,000 barrels per day on an annual basis during 2007 and 2008. The Trustee has been advised that BP Alaska expects that average net production from the BP Working Interests will be less than 90,000 barrels a day on an annual basis in 2009 and future years.

BP Alaska estimates Royalty Production from the BP 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 BP Working Interests is below 90,000 barrels per day, calculation by BP Alaska of actual Royalty Production data may result in revisions of prior Royalty Production estimates. Revisions by BP Alaska of its Royalty Production calculations may result in quarterly royalty payments by BP Alaska which reflect adjustments for overpayments or underpayments of royalties with respect to prior quarters. Such adjustments, if material, may adversely affect certain Unit holders who buy or sell Units between the Quarterly Record Dates for the Quarterly Distributions affected. See Note 8 of Notes to Financial Statements in Item 8. Because the annual statement of cash earnings and distributions of the Trust is prepared on a modified cash basis, royalty revenues for the calendar year do not include the amounts of underpayments or overpayments affecting payments received during the fourth quarter of the year.

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During the years 2007 and 2008 and the period of 2009 up to the date of this report, WTI Prices have been above the level necessary for the Trust to receive a Per Barrel Royalty. Whether the Trust will be entitled to future distributions during the remainder of 2009 will depend on WTI Prices prevailing during the remainder of the year.

2008 compared to 2007

WTI Prices continued to rise rapidly during the fourth quarter of 2007 and throughout the first half of 2008, reaching a high of over $145 per barrel early in July 2008 before receding to an average of approximately $104 per barrel during September 2008. As a result of the increases in WTI Prices, average WTI Prices for the twelve months ended September 30, 2008 were 67% higher than during the preceding twelve-month period. Royalty revenues and cash earnings rose 42% and 43%, respectively, during the twelve months ended December 31, 2008 compared to the twelve months ended December 31, 2007, but the higher tax rates imposed by the 2007 Alaska oil and gas tax legislation (see THE ROYALTY INTEREST Production Taxes in Item 1), imposed a significant burden on Per Barrel Royalties. Production taxes charged against the average Per Barrel Royalty were approximately 264% higher with respect to the twelve months ended September 30, 2008 than during the twelve months ended September 30, 2007. Trust administrative expenses rose 6.5%, principally due to legal fees and expenses related litigation and other issues arising from the 2006 shutdown of the Prudhoe Bay field. See Note 7 of Notes to Financial Statements in Item 8.

2007 compared to 2006

WTI Prices receded during the fourth quarter of 2006 and first quarter of 2007 from the highs reached during the second and third quarters of 2006. As a consequence, in spite of average WTI Prices having risen to a high of $75.29 during the third quarter of 2007, average WTI Prices for the twelve months ended September 30, 2007 were 2.2% lower than during the preceding twelve-month period. Royalty revenues and cash earnings fell 4.1% and 4.4%, respectively, partly as a result of the overall decline in WTI Prices, but were affected to a greater degree by the higher tax rates imposed by the 2006 Alaska oil and gas tax legislation, which entered into the calculation of the Per Barrel Royalty commencing in the third quarter of 2006, as well as by a scheduled increase in Chargeable Costs from $12.50 to $12.75 per barrel beginning in the first quarter of 2007. Production taxes charged against the average Per Barrel Royalty were approximately 17% higher with respect to the twelve months ended September 30, 2007 than during the twelve months ended September 30, 2006. Cash earnings were affected by an increase of approximately 60% in Trust administrative expenses, principally due to legal fees and expenses incurred.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

BP PRUDHOE BAY ROYALTY TRUST

Index To Financial Statements

Report of Independent Registered Public Accounting Firm

Trustee and Holders of Trust Units of
BP Prudhoe Bay Royalty Trust:

We have audited the accompanying statements of assets, liabilities, and trust corpus of BP Prudhoe Bay Royalty Trust (the Trust) as of December 31, 2008 and 2007, and the related statements of cash earnings and distributions and changes in trust corpus for each of the years in the three year period ended December 31, 2008. These financial statements are the responsibility of The Bank of New York Mellon (formerly named The Bank of New York), as the Trust s trustee (the Trustee). Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by the Trustee, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities, and trust corpus of the Trust as of December 31, 2008 and 2007 and its cash earnings and distributions and changes in trust corpus for each of the years in the three year period ended December 31, 2008 in conformity with the modified cash basis of accounting described in note 2.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Trust s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 2, 2009 expressed an unqualified opinion on the effectiveness of the Trust s internal control over financial reporting.

KPMG LLP

Dallas, Texas
March 2, 2009

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BP Prudhoe Bay Royalty Trust
Statement of Assets, Liabilities and Trust Corpus
(Prepared on a modified basis of cash receipts and disbursements)
(In thousands, except unit data)

	December 31, 2008	December 31, 2007
Assets		
Royalty interest, net (Notes 1, 2 and 3)	$ 4,017	$ 6,026
Cash and cash equivalents (Note 2)	1,018	1,009
Total assets	$ 5,035	$ 7,035
Liabilities and Trust Corpus		
Accrued expenses	$ 278	$ 443
Trust corpus (40,000,000 units of beneficial interest authorized, 21,400,000 units issued and outstanding)	4,757	6,592
Total liabilities and trust corpus	$ 5,035	$ 7,035

See accompanying notes to financial statements.

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

	Year Ended December 31, 2008	2007	2006
Royalty revenues	$ 252,298	$ 177,318	$ 184,864
Interest income	33	81	75
Less: Trust administrative expenses	(1,797)	(1,687)	(1,057)
Cash earnings	$ 250,534	$ 175,712	$ 183,882
Cash distributions	$ 250,525	$ 175,713	$ 183,883
Cash distributions per unit	$ 11.707	$ 8.211	$ 8.593
Units outstanding	21,400,000	21,400,000	21,400,000

See accompanying notes to financial statements.

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BP Prudhoe Bay Royalty Trust
Statements of Changes in Trust Corpus
(Prepared on a modified basis of cash receipts and disbursements)
(In thousands)

	Year Ended December 31, 2008	2007	2006
Trust corpus at beginning of year	$ 6,592	$ 8,853	$ 10,876
Cash earnings	250,534	175,712	183,882
Decrease (increase) in accrued expenses	165	(252)	(13)
Cash distributions	(250,525)	(175,713)	(183,883)
Amortization of royalty interest	(2,009)	(2,008)	(2,009)
Trust corpus at end of year	$ 4,757	$ 6,592	$ 8,853

See accompanying notes to financial statements.

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BP Prudhoe Bay Royalty Trust
Notes to Financial Statements
(Prepared on a modified basis of cash receipts and disbursements)
December 31, 2008

(1) Formation of the Trust and Organization

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

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

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

The trustees of the Trust are The Bank of New York Mellon, a New York banking corporation, 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 alone is able to exercise the rights and powers granted to the Trustee in the Trust Agreement.

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

The Trust is passive, with the Trustee having only such powers as are necessary for the collection and distribution of revenues, the payment of Trust liabilities, and the protection of the Royalty Interest. The Trustee, subject to certain conditions, is obligated to establish cash reserves and borrow funds to pay liabilities of the Trust when they become due. The Trustee may sell Trust properties only (a) as authorized by a vote of the Trust unit holders, (b) when necessary to provide for the payment of specific liabilities of the Trust then due (subject to certain conditions) or (c) upon termination of the Trust. Each Trust Unit issued and outstanding represents an equal undivided share of beneficial interest in the Trust. Royalty payments are received by the Trust and distributed to Trust Unit holders, net of Trust expenses, in the month succeeding the end of each calendar quarter. The Trust will terminate upon the first to occur of the following events:

a. On or prior to December 31, 2010: upon a vote of Trust unit holders of not less than 70% of the outstanding Trust units.

b. After December 31, 2010: (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

BP Prudhoe Bay Royalty Trust
Notes to Financial Statements
(Prepared on a modified basis of cash receipts and disbursements)
December 31, 2008

successive years commencing after 2010 are less than $1,000,000 per year (unless the net revenues during such period are materially and adversely affected by certain events).

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

(2) Basis of Accounting

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

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

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

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

d. Amortization of the Royalty Interest is calculated based on the units of production method. Such amortization is charged directly to the Trust corpus, and does not affect cash earnings. The daily rate for amortization per net equivalent barrel of oil for the years ended December 31, 2008, 2007 and 2006 was $0.38, $0.38 and $0.41, respectively. The Trust evaluates 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 Statement of Financial Accounting Standards No. 144 *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS 144). If the expected future undiscounted cash flows are less than the carrying value, the Trust recognizes an impairment loss for the difference between the carrying value and the estimated fair value of the Royalty Interest.

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, 2008 and 2007, and the modified cash earning and distributions and changes in Trust corpus for the years ended December 31, 2008, 2007 and 2006. 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, 2008 and 2007, cash equivalents which represent the cash reserve consist of U.S. treasury bills with an initial term of less than three months.

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.

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BP Prudhoe Bay Royalty Trust
Notes to Financial Statements
(Prepared on a modified basis of cash receipts and disbursements)
December 31, 2008

(3) Royalty Interest

The Royalty Interest is comprised of the following at December 31, 2008 and 2007 (in thousands):

	December 31, 2008	December 31, 2007
Royalty Interest (at inception)	$ 535,000	$ 535,000
Less: Accumulated amortization	(357,465)	(355,456)
Impairment write-down	(173,518)	(173,518)
Balance, end of period	$ 4,017	$ 6,026

(4) Income Taxes

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

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

(5) Alaska Oil and Gas Production Tax

The Alaska oil and gas production tax statutes were amended by a bill (the 2006 Tax) which became effective on August 20, 2006. The 2006 Tax replaced an oil production tax levied at the flat rate of 15% of the gross value at the point of production (the wellhead or field value) of taxable oil produced from a producer s leases or properties in the State of Alaska. Under the 2006 Tax, producers were taxed on the production tax value of taxable oil (gross value at the point of production for the calendar year less the producer s direct costs of exploring for, developing, or producing oil or gas deposits located within the producer s leases or properties in Alaska for the year) at a rate equal to the sum of 22.5% plus a progressivity rate determined by the average monthly production tax value of the oil produced. The progressivity portion of the 2006 Tax was equal to 0.25% times the amount by which the simple average for each calendar month of the daily production tax values per barrel of the oil produced during the month exceeded $40 per barrel.

On December 20, 2007, a bill (the 2007 Tax) took effect which further amended the Alaska oil and gas production tax statutes in certain respects. The 2007 Tax changes the basic tax rate from 22.5% to 25% and increases the progressivity rate. If the producer s average monthly production tax value per barrel is greater than $30 but not more than $92.50, the new progressivity tax rate is 0.4% times the amount by which the average monthly production tax value exceeds $30 per barrel. If the producer s average monthly production tax value per barrel is greater than $92.50, the progressivity tax rate is the sum of 25% and the product of 0.1% multiplied by the difference between the average monthly production tax value per barrel and $92.50, except that the sum may not exceed 50%.

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BP Prudhoe Bay Royalty Trust
Notes to Financial Statements
(Prepared on a modified basis of cash receipts and disbursements)
December 31, 2008

The Trustee and BP Alaska entered into a letter agreement in October 2006 and an amendment thereto in January 2008 (the Letter Agreement) to resolve issues associated with the 2006 Tax and the 2007 Tax. The Letter Agreement modified the calculation of Production Taxes in the daily Per Barrel Royalty calculation effective as of August 20, 2006, in the case of the 2006 Tax, and effective December 20, 2007, in the case of the 2007 Tax. It also provides that the retroactivity provisions of the respective tax bills are not applicable to the Per Barrel Royalty calculation for periods prior to the effective dates of the 2006 Tax and the 2007 Tax.

(6) Partial Shutdown of Prudhoe Bay Oil Field

On August 7, 2006, BP announced that BP Alaska had commenced a shutdown of the Prudhoe Bay Field as a result of the discovery of unexpectedly severe corrosion and a small spill from an oil transit line in the Prudhoe Bay field. BP subsequently determined to shut down only the Eastern Operating Area of the field and continue production from the Western Operating Area. Clearance from the U.S. Department of Transportation to restart production in the Eastern Operating Area was received in September 2006.

(7) Litigation Contingency

The Trust has incurred, and may continue to incur legal and other expenses, in amounts which may be significant, as a result of litigation and other issues arising out of the August 2006 shutdown of the Prudhoe Bay field. Legal fees and expenses are the principal cause of the increases in Trust administrative expenses during 2007 and 2008.

(8) Royalty Revenue Adjustments

Certain of the royalty payments received by the Trust in 2007 and 2008 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 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:

	2007 Payments Received			
	January	**April**	**July**	**October**
Royalty payment as calculated	$ 41,470,000	$ 39,297,000	$ 44,164,111	$ 49,636,093
Adjustment for underpayment (overpayment), plus accrued interest	1,736,000	(47,000)		1,061,954
Net payment received	$ 43,206,000	$ 39,250,000	$ 44,164,111	$ 50,698,047

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BP Prudhoe Bay Royalty Trust
Notes to Financial Statements
(Prepared on a modified basis of cash receipts and disbursements)
December 31, 2008

	2008 Payments Received			
	January	April	July	October
Royalty payment as calculated	$ 65,284,449	$ 57,858,669	$ 66,030,352	$ 61,428,766
Adjustment for underpayment (overpayment), plus accrued interest	63,775			1,632,462
Net payment received	$ 65,348,224	$ 57,858,669	$ 66,030,352	$ 63,061,228

(9) Subsequent Event

In January 2009, the Trust received a payment of $35,279,522 from BP Alaska. This payment consisted of $34,480,780, representing the royalty payment due with respect to the Trust s Royalty Interest for the quarter ended December 31, 2008, plus $798,742, representing the amount of an underpayment by BP Alaska, including interest on the underpayment, of the royalty payment due with respect to the quarter ended September 30, 2008. See Note 8 above.

(10) Summary of Quarterly Results (Unaudited)

A summary of selected quarterly financial information for the years ended December 31, 2008, 2007, and 2006 is as follows (in thousands, except unit data):

	2008 Fiscal Quarter			
	First	Second	Third	Fourth
Royalty revenues	$ 65,348	$ 57,859	$ 66,030	$ 63,061
Interest income	19	7	3	4
Trust administrative expenses	(183)	(738)	(689)	(187)
Cash earnings	65,184	57,128	65,344	62,878
Cash distributions	65,182	57,137	65,344	62,862
Cash distributions per unit	3.0459	2.6699	3.0535	2.9375

	2007 Fiscal Quarter			
	First	Second	Third	Fourth
Royalty revenues	$ 43,206	$ 39,250	$ 44,164	$ 50,698
Interest income	20	20	21	20
Trust administrative expenses	(169)	(391)	(767)	(360)
Cash earnings	43,057	38,879	43,418	50,358
Cash distributions	43,059	38,879	43,415	50,360
Cash distributions per unit	2.0121	1.8168	2.0287	2.3533

2006 Fiscal Quarter

	First	Second	Third	Fourth
Royalty revenues	$ 45,383	$ 47,539	$ 55,797	$ 36,145
Interest income	14	18	22	21
Trust administrative expenses	(157)	(296)	(279)	(325)
Cash earnings	45,240	47,261	55,540	35,841
Cash distributions	45,246	47,258	55,538	35,841
Cash distributions per unit	2.1143	2.2083	2.5952	1.6748

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BP Prudhoe Bay Royalty Trust
Notes to Financial Statements
(Prepared on a modified basis of cash receipts and disbursements)
December 31, 2008

	Fiscal Year Ended		
	2008	**2007**	**2006**
Royalty revenues	$ 252,298	$ 177,318	$ 184,864
Interest income	33	81	75
Trust administrative expenses	(1,797)	(1,687)	(1,057)
Cash earnings	250,534	175,712	183,882
Cash distributions	250,525	175,713	183,883
Cash distributions per unit	11.7068	8.211	8.593

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

Pursuant to Statement of Financial Accounting Standards No. 69, *Disclosures About Oil and Gas Producing Activities* (FASB 69), 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.

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 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 WTI Price on December 31, 2008 ($44.60 per barrel), December 31, 2007 ($96.01 per barrel) and December 31, 2006 ($61.06 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, 2008, 2007 and 2006, based on BP Alaska s latest reserve estimate at such time and the WTI Prices on December 31, 2008, 2007 and 2006, were estimated to be 55, 98 and 81 million barrels, respectively (of which 46, 87 and 69 million barrels, respectively, are proved developed). Under the provisions of FASB 69, 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 69 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

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BP Prudhoe Bay Royalty Trust
Notes to Financial Statements
(Prepared on a modified basis of cash receipts and disbursements)
December 31, 2008

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, 2008, 2007 and 2006, 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 69), based on the WTI Prices on those dates of $44.60, $96.01 and $61.06, respectively, were as follows (in thousands):

	December 31, 2008	2007	2006
Future cash inflows	$ 632,470	$ 3,209,305	$ 1,855,225
10% annual discount for estimated timing of cash flows	(213,900)	(1,609,463)	(803,276)
Standardized measure of discounted future net cash flow (a)	$ 418,570	$ 1,599,842	$ 1,051,949

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

	December 31, 2008	2007	2006
Revisions of prior estimates	$ (17,490)	$ 64,461	$ (94,069)
Net changes in prices and production costs	(1,969,952)	1,364,445	6,635
Net change in production taxes	879,903	(778,644)	1,382
Other	168	1,608	(1,073)
	(1,107,371)	651,870	(87,125)
Royalty income received (b)	(233,885)	(209,172)	(191,604)
Accretion of discount	159,984	105,195	120,974
Net increase (decrease) during the year	$ (1,181,272)	$ 547,893	$ (157,755)

(b) For the purpose of this calculation, royalty income received for 2008, 2007 and 2006 includes the following:

Period October 1, 2008 through December 31, 2008	$35,280
Period October 1, 2007 through December 31, 2007	$65,182
Period October 1, 2006 through December 31, 2006	$43,206

The above royalty income was received by the Trust in January 2009, 2008 and 2007, respectively.

BP Prudhoe Bay Royalty Trust
Notes to Financial Statements
(Prepared on a modified basis of cash receipts and disbursements)
December 31, 2008

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, 2005	85,313
Revisions of previous estimates (1)	697
Production	(4,932)
December 31, 2006	81,078
Revisions of previous estimates (2)	21,970
Production	(5,249)
December 31, 2007	97,799
Revisions of previous estimates (3)	(37,988)
Production	(4,857)
December 31, 2008	54,954
Proved Developed Reserves (thousands of barrels) as of:	
December 31, 2006	69,024
December 31, 2007	86,869
December 31, 2008	46,096

(1) The positive revision in year-end 2006 reserves reflects an increase in the WTI Price from $61.04 per barrel at December 31, 2005 to $61.06 per barrel at December 31, 2006.

(2) The positive revision in year-end 2007 reserves reflects an increase in the WTI price from $61.06 per barrel at December 31, 2006 to $96.01

per barrel at December 31, 2007.

(3) The negative revision in year-end 2008 reserves reflects a decrease in the WTI price from $96.01 per barrel at December 31, 2007 to $44.60 per barrel at December 31, 2008.

In December 2008, the Securities and Exchange Commission released a final rule, Securities Exchange Act Release No. 59192, *Modernization of Oil and Gas Reporting*. The rule s new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. The new requirements also will allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (a) report on independence and qualifications of its reserves preparer or auditor; (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (c) report oil and gas reserves using an average price based upon the prior 12-month period rather than year-end prices. The new disclosure requirements are effective for financial statements for fiscal years ending on or after December 31, 2009. The effect of adopting the new reporting rules has not been determined, but it is not expected to have a significant effect on the Trust s financial position or results of operations.

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, 2008.

ITEM 9A. CONTROLS AND PROCEDURES

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 Securities Exchange Act of 1934, as amended (the Exchange Act) is recorded, processed, summarized and reported, within the time periods specified in the SEC s rules and forms. These controls and procedures include but are not limited to controls and procedures designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act is accumulated and communicated to the responsible trust officers of the Trustee to allow timely decisions regarding required disclosure.

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

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

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

As of the end of calendar 2008, the trust officers of the Trustee responsible for the administration of the Trust conducted an evaluation of the Trust s disclosure controls and procedures. Their evaluation considered, among other things, that the Trust Agreement and the Conveyance impose enforceable legal obligations on BP Alaska, and that BP Alaska has provided the information required by those agreements and other information requested by the Trustee from time to time on a timely basis. The officers concluded that the Trust s disclosure controls and procedures are effective.

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Internal Control Over Financial Reporting

Management s Annual Report on Internal Control Over Financial Reporting. The Bank of New York Mellon, 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 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* 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, 2008.

The Trustee s assessment of the effectiveness of the Trust s internal control over financial reporting as of December 31, 2008 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report set forth in full below.

Report of Independent Registered Public Accounting Firm

Trustee and Holders of Trust Units of
BP Prudhoe Bay Royalty Trust:

We have audited BP Prudhoe Bay Royalty Trust s (the Trust) internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Bank of New York Mellon (formerly named The Bank of New York), 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 effectiveness of the Trust s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 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.

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

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

In our opinion, BP Prudhoe Bay Royalty Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the statements of assets, liabilities, and trust corpus of BP Prudhoe Bay Royalty Trust as of December 31, 2008 and 2007, and the related statements of cash earnings and distributions and changes in trust corpus for each of the years in the three year period ended December 31, 2008, and our report dated March 2, 2009 expressed an unqualified opinion on those financial statements.

KPMG LLP

Dallas, Texas
March 2, 2009

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

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

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

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

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

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

ITEM 11. EXECUTIVE COMPENSATION

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

Under the Trust Agreement, the Trustee is entitled to receive on each Quarterly Record Date a quarterly fee, currently consisting of: (i) a quarterly administrative fee of $.0017 per Unit outstanding on the Quarterly Record Date plus $10.00 for each payment by wire transfer to a Unit holder and (ii) a transfer service fee of $2.42 per Unit holder account as of the Quarterly Record Date. Both the administrative service fee and the transfer service fee are subject to increase in each calendar year by the proportionate increase, if any, during the preceding calendar year in the Consumer Price Index (as defined in the Conveyance; see THE ROYALTY INTEREST Cost Adjustment Factor in Item 1) during the preceding calendar year. The Trustee also bills the Trust for certain reimbursable expenses. There is no compensation committee or committee performing similar functions with authority to determine any compensation of the Trustee other than the fees and reimbursable expenses provided for in the Trust Agreement.

The compensation received by the Trustee from the Trust during the three fiscal years ended December 31, 2008 was as follows:

Year ended December 31,	Trustee s Fees	Transfer Agent and Registrar Fees
2006	$147,081	$6,860
2007	172,235*	6,494
2008	155,432	6,391

* Includes $20,300 of extraordinary service fees.

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 February 27, 2009, 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 BP Alaska, Standard Oil, nor BP owns any Units. No Units are owned by The Bank of New York Mellon, as Trustee or in its individual capacity, or by BNY Mellon Trust of Delaware), as co-trustee or in its individual capacity.

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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 2008, or any currently proposed transaction in which a related person (as defined in Item 404 of Regulation S-K) had or will have a direct or indirect material interest, except for payment to the Trustee of the fees and reimbursement for expenses prescribed in the Trust Agreement. See Item 11 above.

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

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Fees for services performed by KPMG LLP for the years ended December 31, 2008 and 2007 are:

	2008	2007
Audit	$ 163,386	$ 135,000
Audit related	20,000	18,000
Tax	200,000	200,000
Other		
	$ 383,386	$ 353,000

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

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) FINANCIAL STATEMENTS

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

Report of Independent Registered Public Accounting Firm
Statements of Assets, Liabilities and Trust Corpus as of December 31, 2008 and 2007
Statements of Cash Earnings and Distributions for the years ended December 31, 2008, 2007 and 2006
Statements of Changes in Trust Corpus for the years ended December 31, 2008, 2007 and 2006
Notes to Financial Statements

(b) FINANCIAL STATEMENT SCHEDULES

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.

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(c) 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.
4.2	Overriding Royalty Conveyance dated February 27, 1989 between BP Exploration (Alaska) Inc. and The Standard Oil Company.
4.3	Trust Conveyance dated February 28, 1989 between The Standard Oil Company and BP Prudhoe Bay Royalty Trust.
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.
4.5	Letter agreement executed October 13, 2006 between BP Exploration (Alaska) Inc. and The Bank of New York, as Trustee.
4.6	Letter agreement executed January 11, 2008 between BP Exploration (Alaska) Inc. and The Bank of New York, as Trustee.
31	Rule 13a-14(a) certification.
32	Section 1350 certification.

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,
as Trustee

By: /s/ Geovanni Barris
Geovanni Barris
Vice President

March 2, 2009

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.

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INDEX TO EXHIBITS

Exhibit No.	Description
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 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).
31*	Rule 13a-14(a) certification.
32*	Section 1350 certification.

* Filed herewith.