BP PRUDHOE BAY ROYALTY TRUST
Form 10-K/A
April 23, 2004

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

Amendment No. 1

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

For the Fiscal Year ended December 31, 2003

OR

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

Commission File Number 1-10243

BP PRUDHOE BAY ROYALTY TRUST

(Exact name of registrant as specified in its charter)

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

Registrant s telephone number, including area code: (212) 815-2492

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

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. (X)

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes (X) No ( )

The aggregate market value of Units held by nonaffiliates (computed by reference to the closing sale price in New York Stock Exchange Composite Transactions on June 30, 2003 (the last business day of the registrant s most recently completed second fiscal quarter) was approximately $404,246,000.

As of March 24, 2004, 21,400,000 Units of Beneficial Interest were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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EXPLANATORY NOTE

This amendment to the Annual Report on Form 10-K of BP Prudhoe Bay Royalty Trust for the fiscal year ended December 31, 2003 is being filed solely for the purpose of supplementing the narrative under the heading Results of Operations 2003 compared to 2002 in Item 7 of Part II by adding an explanation of the increase in Trust administrative expenses from 2002 to 2003. This amendment does not modify or update any other information in the report.

PART I

ITEM 1. BUSINESS

INTRODUCTION

BP Prudhoe Bay Royalty Trust (the Trust), a grantor trust, was created as a Delaware business trust pursuant to 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. (the Company), The Bank of New York, as trustee (the Trustee), and F. James Hutchinson, co-trustee (The Bank of New York (Delaware), successor co-trustee). The Trustee s corporate trust offices are located at 101 Barclay Street, New York, New York 10286 and its telephone number is (212) 815-2492. The Company and Standard Oil are wholly owned subsidiaries of BP p.l.c. (BP).

Upon creation of the Trust, the Company conveyed to Standard Oil, and Standard Oil, in turn, conveyed to the Trust an overriding royalty interest (the Royalty Interest), which entitles the Trust to a royalty on 16.4246 percent of the first 90,000 Barrels* of the average actual daily net production of oil and condensate per quarter from the working interest of the Company as of February 28, 1989 in the Prudhoe Bay Unit located on the North Slope in Alaska (see THE PRUDHOE BAY UNIT below). The Royalty Interest is free of any exploration and development expenditures.

The only assets of the Trust are the Royalty Interest assigned to the Trust and cash or cash equivalents held by the Trustee from time to time as reserves or for distribution (the Trust Estate). The Trust is a passive entity, and the Trustee has been given only such powers as are necessary for the collection and distribution of revenues from the Royalty Interest and the payment of Trust liabilities and expenses. The beneficial interest in the Trust is divided into equal undivided units (the Units). The Units are not an interest in or an obligation of the Company, Standard Oil or BP. The Delaware Trust Act, under which the Trust was formed, entitles holders of the Units to the same limitation of personal liability as stockholders of a Delaware corporation.

The Company shares control of the operation of the Prudhoe Bay Unit with other working interest owners. The operations of the Company and the other working interest owners are governed by an agreement dated April 1, 1977 among the State of Alaska and such 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 Company has no obligation to continue production from the Prudhoe Bay Unit or to maintain production at any level and may interrupt or discontinue production at any time. 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 Prudhoe Bay Unit which is covered by insurance, the Company has no obligation to use insurance proceeds to repair such damage and may elect to retain such proceeds and close damaged areas to production.

The Trustee has no responsibility for the operation of the Prudhoe Bay Unit or authority over the Company, Standard Oil or BP. The information in this report relating to the Prudhoe Bay Unit, the

* As used in the overriding royalty conveyance and this report, (a) the term Barrel is a unit of measure equal to 42 United States gallons corrected to 60 degrees Fahrenheit temperature and with deductions for sediment and water content, and (b) the term Stock Tank Barrel or STB refers to a Barrel of stabilized oil or condensate at a temperature of 60 degrees Fahrenheit and sea-level atmospheric pressure (14.7 pounds per square inch absolute).

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calculation of the royalty payments and certain other matters has been furnished to the Trustee by the Company.

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 450 Fifth Street, N.W., 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 web site is http://www.sec.gov.

The Trust does not have an Internet web site from which information concerning the Trust may be obtained; however the Trust will make available free of charge upon request paper or electronic copies of its reports on Form 10-K, Form 10-Q and Form 8-K, and amendments to those reports, as soon as reasonably practicable after the Trust electronically files such material with the SEC. Requests for copies of reports should be made, if by mail, to: The Bank of New York, 101 Barclay Street, New York, NY 10286, Attention: Mr. Remo Reale, Corporate Trust Department; if by telephone, to: (212) 815-2492; and, if by e-mail, to: rreale@bankofny.com. See THE UNITS Reports to Unit Holders below for additional information.

THE TRUST

Duties and Limited Powers of Trustee

The duties of the Trustee are as specified in the Trust Agreement and by the laws of the State of Delaware. The discussion of terms of the Trust Agreement contained herein do not purport to be complete and are qualified in their entirety by reference to the Trust Agreement itself, which is filed as an exhibit to this report and is available upon request from the Trustee.

The basic function of the Trustee is to collect income from the Royalty Interest, to pay from the Trust s income and assets all expenses, charges and obligations of the Trust, and to pay available cash to holders of Units. The Bank of New York (Delaware) has been appointed co-trustee in order to satisfy certain requirements of the Delaware Trust Act, but The Bank of New York alone is able to exercise the rights and powers granted to the Trustee in the Trust Agreement.

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

The Trustee has the right to establish a cash reserve for the payment of material liabilities of the Trust which may become due. Such reserve can only be set up when the Trustee has determined that it is not practical to pay such liabilities in a subsequent quarter out of funds anticipated to be available and that, in the absence of such reserve, the Trust Estate 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. Furthermore, the Trustee must receive an unqualified written opinion of counsel to the effect that such reserve 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 unless the Trustee is unable to obtain such opinion and determines that the failure to establish such reserve will

be materially detrimental to the Unit holders considered as a whole or will subject the Trustee to the risk of personal liability for such liabilities.

The Trustee has a limited power to borrow on behalf of the Trust on a secured or unsecured basis. Such borrowing may be effected if at any time the amount of cash on hand is not sufficient to pay liabilities of the Trust then due. The Trustee can only borrow from an entity not affiliated with the Trustee. Certain other conditions must also be satisfied, including that the Trustee must determine that it is not practical to pay such liabilities in a subsequent quarter out of funds anticipated to be available and the Trust Estate is subject to the risk of loss or diminution in value. The borrowing must be effected pursuant to terms which (in the opinion of an investment banking firm or commercial banking firm) are commercially reasonable when compared to other available alternatives and the Trustee must receive an unqualified written opinion of counsel to the effect that such borrowing 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, unless the Trustee is unable to obtain such opinion and determines that the failure to effect such borrowing will be materially detrimental to the Unit Holders considered as a whole. To secure payment of borrowings by the Trust, the Trustee is authorized to mortgage, pledge, grant security interests in or otherwise encumber the Trust Estate or any portion thereof (including the Royalty Interest), and to carve out and convey production payments. The borrowing itself and the pledges or other encumbrances to secure borrowings are permitted without a vote of Unit holders. In the event of such borrowings, no further Trust distributions may be made until the indebtedness created by such borrowings has been paid in full.

The Trustee may sell Trust properties only as authorized by the affirmative vote of the holders of Units representing 70 percent of the Units outstanding, provided, however, that if such sale is effected in order to provide for the payment of specific liabilities of the Trust then due and involves a part, but not all or substantially all, of the Trust Estate, such sale shall be approved by the affirmative vote of a majority of the holders of the Units.

The Trustee may also sell the Trust Estate, or a portion thereof, for cash if such sale is effected in order to provide for the payment of specific liabilities of the Trust then due, cash on hand is insufficient and the Trustee is unable to effect a borrowing by the Trust. The Trustee must also determine that the failure to pay such liabilities at a later date will be contrary to the best interest of the holders of Units and that it is not practicable to submit the sale to a vote of the Unit holders. The sale must be effected at a price which (in the opinion of an investment banking firm or commercial banking firm) is at least equal to the fair market value of the interest sold and is effected pursuant to commercially reasonable terms when compared to other available alternatives. The Trustee must receive an unqualified written opinion of counsel to the effect that the 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 unless the Trustee is unable to obtain such opinion and determines that the failure to effect such sale will be materially detrimental to the Unit Holders considered as a whole. Finally, the Trustee may sell the Trust Estate upon termination of the Trust.

Any sale of Trust properties must be for cash unless otherwise authorized by the holders of Units. 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.

Except in certain circumstances, the Trustee is entitled to be indemnified out of the assets of the Trust for any liability, expense, claim, damage or other loss incurred by it in the performance of its duties unless such loss results from its negligence, bad faith or fraud or from its expenses in carrying out such duties exceeding the compensation and reimbursement it is entitled to under the Trust Agreement.

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Employees

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

Property of the Trust

Except for cash and cash equivalents held by the Trustee from time to time, the property of the Trust consists exclusively of the Royalty Interest. The Royalty Interest was conveyed to the Trust pursuant to an Overriding Royalty Conveyance dated February 27, 1989 between the Company and Standard Oil and a Trust Conveyance dated February 28, 1989 between Standard Oil and the Trust. The Overriding Royalty Conveyance and the Trust Conveyance are referred to collectively herein as the Conveyance. For a description of the terms of the Royalty Interest, see THE ROYALTY INTEREST below. The discussion of the terms of the Conveyance herein is qualified in its entirety by reference to the relevant provisions of the Overriding Royalty Conveyance and the Trust Conveyance which are filed with the Securities and Exchange Commission as exhibits to this report.

The interest conveyed to the Trust by the Conveyance is an overriding royalty interest consisting of the right to receive a Per Barrel Royalty for each Barrel of Royalty Production. The meaning of these terms is more fully described below under THE ROYALTY INTEREST. The Trust does not have the right to take oil and gas in kind.

The Royalty Interest constitutes a non-operational interest in minerals. The Trust has no right to take over operations or to share in any operating decision whatsoever with respect to the Company s working interest in the Prudhoe Bay Unit. The Company is not obligated to continue to operate any well or maintain in force or attempt to maintain in force any portion of its working interest in the Prudhoe Bay Unit when, in its reasonable and prudent business judgment, such well or interest ceases to produce or is not capable of producing oil or gas in paying quantities.

Under the terms of the Prudhoe Bay Unit Operating Agreement, if the Company fails to pay any costs and expenses chargeable to the Company under the Prudhoe Bay Unit Operating Agreement and the production of oil and condensate is insufficient to pay such costs and expenses, the Royalty Interest is chargeable with a pro rata portion of such costs and expenses and is subject to the enforcement against it of liens granted to the operators of the Prudhoe Bay Unit. However, in the Conveyance the Company agreed to pay timely 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 expense, claim, damage, loss or liability incurred by the Company or others attributable to the Company s working interest in the Prudhoe Bay Unit or to the oil produced from it, and the Company has agreed to indemnify the Trust and hold it harmless against any such impositions.

The Company 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 its working interest in the exercise of its reasonable and prudent business judgment without liability to the Trust. The Company also has the right to sell or assign all or any part of its working interest in the Prudhoe Bay Unit, so long as the sale or assignment is expressly made subject to the Royalty Interest and the terms and provisions of the Conveyance.

Amendment of the Trust Agreement

The Trust Agreement may be amended without a vote of the holders of Units to cure an ambiguity, to correct or supplement any provision of the Trust Agreement that may be inconsistent with any other such provision or to make any other provision with respect to matters arising under the Trust Agreement that do not adversely affect the holders of Units. The Trust Agreement may also be amended with the approval of a majority of the outstanding Units at a meeting of holders of Units. However, no such amendment may alter the relative rights of Unit holders, unless approved by the affirmative vote of holders of 100 percent of the outstanding Units and by the Trustee, or reduce or delay the distributions to the holders of Units or effect certain other changes unless approved by the affirmative vote of holders of at least 80 percent of the outstanding Units and by the Trustee. 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.

Resignation or Removal of Trustee

The Trustee may resign at any time or be removed with or without cause by the holders of a majority of the outstanding Units. Its successor must be a corporation organized and doing business under the laws of the United States, any state thereof or the District of Columbia, authorized under such laws to exercise trust powers, 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 the State of Delaware, then any successor trustee will be such a resident or have such a principal office. No resignation or removal of the Trustee shall become effective until a successor trustee shall have accepted appointment.

Liabilities and Contingent Reserves

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 incurred by the Trust are routine administrative expenses, such as Trustee s fees, and accounting, legal and other professional fees.

As discussed above, the Trustee may establish a cash reserve for the payment of material liabilities of the Trust which may become due, if the Trustee has determined that it is not practical to pay such liabilities out of funds anticipated to be available for subsequent quarterly distributions and that, in the absence of such a reserve, the trust estate is subject to the risk of loss or diminution in value or The Bank of New York is subject to the risk of personal liability for such liabilities. The Trustee is obligated to borrow funds required to pay liabilities of the Trust when due, and to pledge or otherwise encumber the Trust s assets, if it determines that the cash on hand is insufficient to pay such liabilities and that it is not practical to pay such liabilities out of funds anticipated to be available for subsequent quarterly distributions. Borrowings must be repaid in full before any further distributions are made to holders of Units. As previously described, certain other necessary conditions must also be satisfied prior to the establishment of a cash reserve or the Trust s borrowing of funds.

Termination of the Trust

The Trust is irrevocable and the Company has no power to terminate the Trust. The Trust will terminate: (a) on or prior to December 31, 2010 upon a vote of holders of not less than 70 percent of the outstanding Units, or (b) after December 31, 2010 either (i) at such time as 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 such period have been materially and adversely affected by an event constituting force majeure, or (ii) upon a vote of holders of not less than 60 percent of the outstanding Units.

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Upon termination of the Trust, the Company will have an option to purchase the Royalty Interest (for cash unless holders representing 70 percent of the Units outstanding (60 percent 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) at a price equal to the greater of (i) the fair market value of the Trust Estate 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. If the Units are neither listed nor traded in the over-the-counter market, the price will be the fair market value of the trust estate as set forth in the opinion mentioned above.

If the Company does not exercise its option, the Trustee will sell the Trust properties pursuant to procedures or material terms and conditions approved by the vote of holders of 70 percent of the outstanding Units (60 percent if the sale is made after December 31, 2010), unless the Trustee determines that it is not practicable to submit such procedures or terms to a vote of the holders of Units, and the sale is effected at a price which is at least equal to the fair market value of the trust estate as set forth in the opinion mentioned above and pursuant to terms and conditions deemed commercially reasonable by the investment banking firm, commercial banking firm or other entity rendering such opinion.

After satisfying all existing liabilities and establishing adequate reserves for the payment of contingent liabilities, the Trustee will distribute all available proceeds to the holders of Units.

In the Trust Agreement, holders of Units have waived the right to seek or secure any portion 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.

Voting Rights of Holders of Units

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

A meeting of the holders of Units may be called at any time to act with respect to any matter which the holders of Units are authorized to act pursuant to the Trust Agreement. Any such meeting may be called by the Trustee in its discretion and will be called (i) as soon as practicable after receipt of a written request by the Company or (ii) as soon as practicable after receipt of a written request that sets forth in reasonable detail the action proposed to be taken at such meeting and is signed by holders of Units owning not less than 25 percent of the then outstanding Units or (iii) as may be required by applicable laws or regulations of the New York Stock Exchange. All such meetings are required to take place in the Borough of Manhattan, The City of New York.

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 to which the Royalty Interest is entitled. The royalty payable to the Trust under the Royalty Interest for each calendar quarter is the sum of the

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product of (i) the Royalty Production and (ii) the Per Barrel Royalty for each day in the quarter. 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 the Company s working interest in the Prudhoe Bay Unit for such calendar quarter, net of the State of Alaska royalty and less the value of any applicable payments made to affiliates of the Company.

Royalty Production

The Royalty Production for each day in a calendar quarter is 16.4246 percent of the first 90,000 Barrels of the actual average daily net production of oil and condensate for such quarter from the Prudhoe Bay (Permo-Triassic) Reservoir and allocated to the oil and gas leases owned by the Company in the Prudhoe Bay Unit as of February 28, 1989 or as modified thereafter by any redetermination provided under the terms of the Prudhoe Bay Unit Operating Agreement and the Prudhoe Bay Unit Agreement (the Subject Leases). 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 Subject Leases for any calendar quarter is the total production of oil and condensate for such quarter, net of the State of Alaska royalty, divided by the number of days in such quarter.

Per Barrel Royalty

The Per Barrel Royalty in effect for any day is an amount equal to the WTI Price for such day less the sum of (i) the product of the Chargeable Costs multiplied by the Cost Adjustment Factor and (ii) Production Taxes. Based on the WTI Price on December 31, 2003, current Production Taxes and Chargeable Costs adjusted in accordance with the Conveyance, the Company estimates that Per Barrel Royalty payments will continue through the year 2018.

WTI Price

The WTI Price for any trading day means (i) the latest price (expressed in dollars per Barrel) for West Texas intermediate crude oil of standard quality having a specific gravity of 40 degrees API for delivery at Cushing, Oklahoma (West Texas Crude), quoted for such trading day by the Dow Jones International Petroleum Report (which is published in The Wall Street Journal) or if the Dow Jones International Petroleum Report does not publish such quotes, then such price as quoted by Reuters, or if Reuters does not publish such quotes, then such price as quoted in Platt s Oilgram Price Report, or (ii) if for any reason such publications do not publish the price of West Texas Crude, then the WTI Price will mean, until the price quotations described in (i) are again available, the simple average of the daily mean prices (expressed in dollars per Barrel) quoted for West Texas Crude by one major oil company, one petroleum broker and one petroleum trading company, in each case unaffiliated with BP and having substantial U.S. operations. Such major oil company, petroleum broker and petroleum trading company will be designated by the Company from time to time. In the event that prices for West Texas Crude are not quoted so as to permit the calculation of the WTI Price, West Texas Crude, for the purposes of calculating the WTI Price will mean such other light sweet domestic crude oil of standard quality as is designated by the Company and approved by the Trustee in the exercise of its reasonable judgment, with appropriate allowance for transportation costs to the Gulf Coast (or other appropriate location) to equilibrate such 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.

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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 the Company s actual costs of production. Chargeable Costs per Barrel for the five calendar years ended December 31, 2003 were: $9.80 during 1999; $10.00 during 2000; $10.75 during 2001; $11.25 during 2002; and $11.75 during 2003. Chargeable Costs for the calendar year ending December 31, 2004 and subsequent years are shown in the following table:

For the Year Ending December 31	Chargeable Costs Per Barrel	For the Year Ending December 31	Chargeable Costs Per Barrel
2004	$12.00	2013	$16.80
2005	12.25	2014	16.90
2006	12.50	2015	17.00
2007	12.75	2016	17.10
2008	13.00	2017	17.20
2009	13.25	2018	20.00
2010	14.50	2019	23.75
2011	16.60	2020	26.50
2012	16.70		

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

Chargeable Costs will be reduced by up to $1.20 per Barrel in 2006 and subsequent years if, between January 1, 2001 and December 31, 2005, either (a) an additional 400,000,000 STB of proved reserves (before taking into account any production therefrom) have not been added to proved reserves allocated to the Subject Leases (including, for the purpose of this calculation, a credit equal to the number of STB of proved reserves in excess of 300,000,000 added to the Company s reserves after December 31, 1987 and before January 1, 2001), or (b) an additional 100,000,000 STB of proved reserves (before taking into account any production therefrom) have not been added to the reserves allocated to the Subject Leases, without allowing any credit for additions prior to January 1, 2001. In general, proved reserves for purposes of this determination consist of the Company s estimate (determined to be reasonable by independent petroleum engineers) of the quantities of crude oil and condensate that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years under existing economic and operating conditions from the Prudhoe Bay (Permo-Triassic Reservoir) in the Prudhoe Bay Unit. See THE PRUDHOE BAY UNIT - Reserve Estimates below.

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As of December 31, 1987, the proved reserves of crude oil and condensate allocated to the Subject Leases were 2,035.6 million STB. Since that date, the Company has made the additions (and deductions) to its estimates of proved reserves allocated to the Subject Leases (before taking into account any production from such additions) as shown in the following table:

Year Ended December 31	Additions to Proved Reserves Annual	Additions to Proved Reserves Cumulative
	(Million STB)	
1988	42.3	42.3
1989	45.5	87.8
1990	24.0	111.8
1991	115.8	227.6
1992	144.3	371.9
1993	206.2	578.1
1994	89.9	668.0
1995	92.2	760.2
1996	(21.0)	739.2
1997	(1.5)	737.7
1998	(0.5)	737.2
1999	0.0	737.2
2000	57.3	794.5
2001	20.5	815.0
2002	0.0	815.0
2003	0.0	815.0

Additional drilling, workovers, facilities modifications, new recovery projects and programs for production enhancement and optimization may mitigate, but not eliminate the recent decline in gross oil and condensate production capacity. However, significant downward revisions of proved reserve estimates could result in a reduction of Chargeable Costs being required as described above in the year 2006 and thereafter.

Cost Adjustment Factor

The Cost Adjustment Factor is the ratio of (i) the Consumer Price Index published for the most recently past February, May, August or November, as the case may be, to (ii) 121.1 (the Consumer Price Index for January 1989), except that (a) if for any calendar quarter the average WTI Price is $18.00 or less, then the Cost Adjustment Factor for that quarter will be the Cost Adjustment Factor for the immediately preceding quarter, and (b) the Cost Adjustment Factor for any calendar quarter in which the average WTI Price exceeds $18.00, after a calendar quarter during which the average WTI Price is equal to or less than $18.00, and for each following calendar quarter in which the average WTI Price is greater than $18.00, will be the product of (x) the Cost Adjustment Factor for the most recently past calendar quarter in which the average WTI Price is equal to or less than $18.00 and (y) a fraction, the numerator of which will be the Consumer Price Index published for the most recently past February, May, August or November, as the case may be, and the denominator of which will be the Consumer Price Index published for the most recently past February, May, August or November during a quarter in which the average WTI Price is equal to or less than $18.00. 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.

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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. Such taxes are computed at defined statutory rates. In the case of taxes based upon wellhead or field value, the Conveyance provides that the WTI Price less the product of $4.50 and the Cost Adjustment factor will be deemed to be the wellhead or field value. At the present time, the Production Taxes payable with respect to the Royalty Production are the Alaska Oil and Gas Properties Production Tax (Alaska Production Tax). For the purposes of the Royalty Interest, the Alaska Production Tax is computed without regard to the economic limit factor, if any, as the greater of the percentage of value amount (based on the statutory rate and the wellhead value as defined above) and the cents per Barrel amount. As of the date of this report, the statutory rate for the purpose of calculating the percentage of value amount is 15 percent. A surcharge to the Alaska Production Tax increased Production Taxes by $0.05 per Barrel of net production effective July 1, 1989. Due to the spill response fund reaching $50 million in 1995, $0.02 per Barrel of the surcharge has been indefinitely suspended. In the event the balance of the spill response fund falls below $50 million, the $0.02 per Barrel surcharge will be reinstated until the fund balance again reaches $50 million. The remaining $0.03 per Barrel surcharge is not affected by the fund s balance and will continue to be imposed at all times.

Per Barrel Royalty Calculations

The following table shows how the above-described factors interacted during each of the past five years to produce the Per Barrel Royalty paid for each of the calendar quarters indicated. The Per Barrel Royalty with respect to each calendar quarter is paid to the Trust on the fifteenth day of the month following the end of the quarter. See THE UNITS - Distributions of Income below.

	Average WTI Price	Chargeable Costs	Cost Adjustment Factor	Adjusted Chargeable Costs	Production Taxes	Per Barrel Royalty
1999:						
1st Qtr	$13.08	$ 9.80	1.280	$12.54	$1.13	$ 0.00
2nd Qtr	17.44	9.80	1.280	12.54	1.79	3.11
3rd Qtr	21.71	9.80	1.287	12.61	2.42	6.68
4th Qtr	24.60	9.80	1.296	12.70	2.84	9.05
2000:						
1st Qtr	28.86	10.00	1.307	13.07	3.48	12.31
2nd Qtr	28.87	10.00	1.319	13.19	3.47	12.21
3rd Qtr	31.63	10.00	1.330	13.30	3.88	14.45
4th Qtr	31.98	10.00	1.341	13.41	3.92	14.66
2001:						
1st Qtr	28.83	10.75	1.354	14.55	3.44	10.84
2nd Qtr	27.92	10.75	1.368	14.71	3.29	9.92
3rd Qtr	26.82	10.75	1.367	14.69	3.13	9.00
4th Qtr	20.41	10.75	1.366	14.68	2.17	3.56

	Average WTI Price	Chargeable Costs	Cost Adjustment Factor	Adjusted Chargeable Costs	Production Taxes	Per Barrel Royalty
2002:						
1st Qtr	$21.67	$11.25	1.369	$15.40	$2.36	$ 3.91
2nd Qtr	26.28	11.25	1.384	15.57	3.04	7.67
3rd Qtr	28.33	11.25	1.391	15.65	3.34	9.34
4th Qtr	28.25	11.25	1.396	15.70	3.33	9.22
2003:						
1st Qtr	34.08	11.75	1.410	16.57	4.19	13.32
2nd Qtr	29.07	11.75	1.413	16.60	3.44	9.03
3rd Qtr	30.30	11.75	1.421	16.70	3.62	9.98
4th Qtr	31.23	11.75	1.421	16.69	3.76	10.78

Potential Conflicts of Interest

The interests of the Company and the Trust with respect to the Prudhoe Bay Unit could at times be different. In particular, because the Per Barrel Royalty is based on the WTI Price and Chargeable Costs rather than the Company s actual price realized and actual costs, the actual per Barrel profit received by the Company on the Royalty Production could differ from the Per Barrel Royalty to be paid to the Trust. It is possible, for example, that the relationship between the Company s actual per Barrel revenues and costs could be such that the Company may determine to interrupt or discontinue production in whole or in part even though a Per Barrel Royalty may otherwise have been payable to the Trust pursuant to the Royalty Interest. This potential conflict of interest could affect the royalties paid to Unit holders, although the Company will be subject to the terms of the Prudhoe Bay Unit Operating Agreement.

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 the Company, 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 equity securities.

Distributions of Income

The Company 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, to the extent possible, pays all expenses of the Trust for each quarter on the Quarterly Record Date. The Trustee then distributes an amount equal to the excess, if any, of the cash received by the Trust from the Royalty Interests over the expenses and payments of liabilities of the Trust, subject to adjustments for changes made by the Trustee in any cash reserve established for the payments of estimated liabilities of the Trust (the Quarterly Distribution) to the persons in whose names the Units were registered at the close of business on the immediately preceding Quarterly Record Date.

The Trust Agreement provides that the Trustee shall pay the Quarterly Distribution on the fifth day after the Trustee s receipt of the amount paid by the Company on the Quarterly Record Date, and that collected cash balances being held by the Trustee for distribution shall be invested in obligations issued or unconditionally guaranteed by the United States or any agency or instrumentality thereof and secured by the full faith and credit of the United States (Government Obligations) or, if Government Obligations with a maturity date on the date of the distribution to Unit holders are not available, in repurchase agreements with banks having capital, surplus and undivided profits of $100,000,000 or more (which may include The Bank of New York) secured by Government Obligations. If time does not permit the Trustee to invest collected funds in investments of the type described in the preceding sentence, the Trustee may invest such funds overnight in a time deposit with a bank meeting the foregoing requirement (including The Bank of New York).

Reports to Unit Holders

Within 90 days after the end of each calendar year, the Trustee mails to the holders of record of Units at any time during the calendar year a report 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 to holders of Units an annual report containing audited financial statements of the Trust, a letter of the independent petroleum engineers engaged by the Trust setting forth a summary of such firm s determinations regarding the Company s estimates of proved reserves and other related matters, and certain other information required by the Trust Agreement.

Following the end of each quarter, the Trustee mails Unit holders a quarterly report showing the assets and liabilities, receipts and disbursements and income and expenses of the Trust and the Royalty Production for such quarter.

Limited Liability of Unit Holders

The Trust Agreement provides that the holders of Units 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, the Trust Agreement provides that if at any time the Trust or the Trustee is named a party in any judicial or administrative proceeding seeking the cancellation or forfeiture of any property in which the Trust has an interest because of the nationality, or any other status, of any one or more holders, the following procedures will be applicable:

(i) The Trustee will give written notice of the existence of such proceedings to each holder whose nationality or other status is an issue in the proceeding. The notice will contain a reasonable summary of such proceeding and will constitute a demand to each such holder that he dispose of his Units within 30 days to a party not of the nationality or other status at issue in the proceeding described in the notice.

(ii) If any holder fails to dispose of his Units in accordance with such notice, the Trustee will redeem, at any time during the 90-day period following the termination of the 30-day period specified in the notice, any Unit not so transferred for a cash price per Unit equal to the closing price of the Units on the stock exchange on which the Units are then listed or, in the

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absence of any such listing, the closing bid price on the NASDAQ National Market System if the Units are so quoted or, if not, the mean between the closing bid and asked prices for the Units in the over-the-counter market, in either case as of the last business day prior to the expiration of the 30-day period stated in the notice. If the Units are neither listed nor traded in the over-the-counter market, the price will be the fair market value of the Units as determined by a recognized firm of investment bankers or other competent advisor or expert.

Units redeemed by the Trustee will be cancelled. The Trustee may, in its sole discretion, 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 ERISA, or under the Internal Revenue Code of 1986, the Units subject to the Trustee s right of redemption will be purchased by the Company or a designee thereof, at the above described purchase price.

Issuance of Additional Units

The Trust Agreement provides that the Company 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, including receipt by the Trustee of a ruling from the Internal Revenue Service to the effect that neither the existence nor the exercise of the right to assign the additional royalty interest or the power to accept such assignment will adversely affect the classification of the Trust as a grantor trust for federal income tax purposes, the Trust may issue up to an additional 18,600,000 Units. The Company has not conveyed any additional royalty interests to the Trust, and the Trust has not issued any additional Units, since the inception of the Trust.

THE BP SUPPORT AGREEMENT

BP has agreed pursuant to the terms of a Support Agreement, dated February 28, 1989, among BP, the Company, Standard Oil and the Trust (the Support Agreement), to provide financial support to the Company in meeting its payment obligations under the Royalty Interest.

Within 30 days of notice to BP, BP will ensure that the Company is in a position to perform its payment obligations under the Royalty Interest and to satisfy its payment obligations to the Trust under the Trust Agreement, including contributing to the Company such funds as are necessary to make such payments. BP s obligations under the Support Agreement are unconditional and directly enforceable by Unit holders.

Except as described below, no assignment, sale, transfer, conveyance, mortgage or pledge or other disposition of the Royalty Interest will relieve BP of its obligations under the Support Agreement.

Neither BP nor the Company may transfer or assign its rights or obligations under the Support Agreement without the prior written consent of the Trust, except that BP can arrange for its obligations under the Support Agreement to be performed by any affiliate of BP, provided that BP remains responsible for ensuring that such obligations are performed in a timely manner.

The Company 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 the Company 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 the Company s working interest in the Prudhoe Bay Unit if the transferee agrees

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

THE PRUDHOE BAY UNIT

General

The Prudhoe Bay field (the Field) is located on the North Slope of Alaska, 250 miles north of the Arctic Circle and 650 miles north of Anchorage. The Field extends approximately 12 miles by 27 miles and contains nearly 150,000 productive acres. The Field, which was discovered in 1968 by BP and others, has been in production since 1977. The Field is the largest producing oil field in North America. As of December 31, 2003, approximately 10.6 billion STB of oil and condensate had been produced from the Field. Field development is well advanced with approximately $18.5 billion gross capital spent and a total of about 2,109 wells drilled. Other large fields located in the same area include the Kuparuk, Endicott, and Lisburne fields. Production from those fields is not included in the Royalty Interest.

Since several oil companies hold acreage within the Field, the Prudhoe Bay Unit was established to optimize Field development. The Prudhoe Bay Unit Operating Agreement specifies the allocation of production and costs to Prudhoe Bay Unit owners. Prior to July 1, 2000, the Company and a subsidiary of the Atlantic Richfield Company were the two Field operators. On July 1, 2000, following the acquisition by BP of Atlantic Richfield Company, the Company assumed sole-operatorship of the field. Other Field owners include affiliates of Exxon Mobil Corporation (Exxon Mobil), ConocoPhillips, ChevronTexaco Corporation and Forest Oil Corporation.

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 (collectively, PESS) formations. Underlying the Sadlerochit Group are the oil-bearing Lisburne and Endicott formations. The net production referred to herein 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.

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Oil Characteristics

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

The interests of the Unit holders are based upon oil produced from the oil rim and condensate produced from the gas cap, but not upon gas production (which is currently uneconomic) or natural gas liquids production stripped from gas produced.

Prudhoe Bay Unit Operation and Ownership

Since several companies hold acreage within the Field s limits, a unit was established to ensure optimum development of the Field. The Prudhoe Bay Unit, which became effective on April 1, 1977, divided the Field into two operating areas. Prior to July 1, 2000, the Company was the operator of the Western Operating Area and Arco Alaska Inc. was the operator of the Eastern Operating Area. Oil and condensate production came from both the Western Operating Area and the Eastern Operating Area. On July 1, 2000, the Company assumed sole operatorship of the field.

The Prudhoe Bay Unit Operating Agreement specifies the allocation of production and costs to the working interest owners. The Prudhoe Bay Unit Operating Agreement also defines operator responsibilities and voting requirements and is unusual in its establishment of separate participating areas for the gas cap and oil rim.

The ownership of the Prudhoe Bay Unit by participating area as of December 31, 2003 is summarized in the following table:

	Oil Rim	Gas Cap
BP	26.35%(a)	26.35%(b)
Exxon Mobil	36.40	36.40
ConocoPhillips	36.07	36.07
Others	1.18	1.18
Total	100.00%	100.00%

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

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

Historical Production

Production began on June 19, 1977, with the completion of the Trans Alaska Pipeline System. The pipeline has a capacity of approximately 1.4 million STB of oil per day.

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As of December 31, 2003 there were about 1,109 active producing oil wells, 33 gas reinjection wells, 80 water injection wells and 137 water and miscible gas injection wells in the Field. In terms of individual well performance, oil production rates range from 100 to 3,500 STB of oil per day. Currently, the average well production rate is about 350 STB of oil per day.

The Company s share of the hydrocarbon liquids production from the Field includes oil, condensate and natural gas liquids. Using the production allocation procedures from the Prudhoe Bay Unit Operating Agreement, the Field s production and the share of oil and condensate (net of State of Alaska royalty) allocated to the Subject Leases have been as follows during the periods indicated:

	Oil		Condensate	
Year Ended December 31	Total Field	Subject Leases	Total Field	Subject Leases
		(Thousand STB per day)		
1999	380.9	170.7	151.5	18.3
2000	364.0	161.4	146.7	17.8
2001	324.9	144.1	131.2	15.9
2002	293.8	130.3	121.5	14.7
2003	273.2	121.2	113.8	13.8

Transportation of Prudhoe Bay Oil

Production from the Field is carried to Pump Station 1, which is the starting point for the Trans Alaska Pipeline System, through two 34-inch diameter transit lines, one from each half of the Field. At Pump Station 1, Alyeska Pipeline Service Company, the pipeline operator, meters the oil and pumps it south to Valdez where it is either loaded onto marine tankers or stored temporarily. It takes the oil about seven days to make the trip in the 48-inch diameter pipeline.

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 Field reserves.

Several different oil recovery mechanisms are currently active in the 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

The net proved remaining reserves of oil and condensate associated with the Subject Leases is approximately 858.7 million STB as of December 31, 2003. This current estimate of reserves is based upon various assumptions, including a reasonable estimate of the allocation of hydrocarbon liquids between oil and condensate pursuant to the procedures of the Prudhoe Bay Unit Operating Agreement. 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. The Company anticipates that net production from current proved reserves allocated to the Subject Leases will exceed

90,000 Barrels per day until the year 2013. The occurrence of major gas sales could accelerate the time at which the Company s net production would fall below 90,000 Barrels per day, due to the consequent decline in

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reservoir pressure. The Company also projects continued economic production thereafter, at a declining rate, until the year 2035; however, for the economic conditions and production forecast as of December 31, 2003, it is estimated that royalty payments will cease following the year 2018.

The Company s reserve estimates and production assumptions and projections are predicated upon a reasonable estimate of hydrocarbon allocation between oil and condensate. 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 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 Subject Leases will vary over time according to the proportions of hydrocarbon liquid being allocated as condensate or as oil under the Prudhoe Bay Unit Operating Agreement allocation procedures. 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 billion Barrels has been allocated to the working interest owners.

The reserves attributable to the Trust s Royalty Interest constitute only a part of the overall reserves allocated to the Subject Leases. The Company has estimated that the net remaining proved reserves attributable to the Trust as of December 31, 2003 were 77.94 million Barrels of oil and condensate. Using procedures specified in Financial Accounting Standards Board Statement of Financial Standards No. 69, the Company calculated that as of December 31, 2003 production of oil and condensate from the proved reserves allocated to the Trust will result in estimated future net revenues to the Trust of $644.7 million, with a present value of $395.3 million. The Company 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.

There is no precise method of forecasting the allocation of reserve volumes between the Company 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 Field. 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 Field 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 Subject Leases, the net proved reserves allocated to the Trust, and the WTI Prices on the dates indicated:

	Net Proved Reserves		
December 31	**Subject Leases (a)**	**Trust (b)**	**WTI Price Per Barrel**
	(Million STB)		
1999	1,007.6	93.6	$25.60
2000	999.6	90.7	26.83
2001	961.7	43.2	19.78
2002	908.7	85.8	31.23
2003	858.7	77.9	32.55

(a)

Includes proved undeveloped reserves of 108 million STB at December 31, 1999; 137.3 million STB at December 31, 2000; 112.5 million STB at December 31, 2001; 5.5 million STB at December 31, 2002; and 139.9 million STB at December 31, 2003.

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(b) Includes proved undeveloped reserves of 4.5 million STB at December 31, 1999; 6.4 million STB at December 31, 2000; 0.03 million STB at December 31, 2002; and 11.0 STB at December 31, 2003. No proved undeveloped reserves were attributable to the Trust at December 31, 2001.

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 future additions by the Company of proved reserves. 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 6 (unaudited) of the Notes to Financial Statements in Item 8.

The Company 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. However, several such investments which would augment Prudhoe Bay projects are already in progress. These include additional drilling, water flood expansions and miscible injection continuation/expansion projects. Other possible investments could include expanded gas cycling, miscible/water flood infill drilling, miscible injection supply increases to peripheral areas, heavy oil tar recovery and development of the smaller reservoirs. While there is no assurance that the Prudhoe Bay Unit working interest owners will make any such investments they do regularly assess the technical and economic attractiveness of implementing further projects to increase Prudhoe Bay Unit proved reserves.

In the event of changes in the Company 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.
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February 12, 2004

The Bank of New York
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, 2003

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, 2003. 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 are summarized in the report prepared by BP Exploration (Alaska) Inc. and transmitted with a cover letter dated February 10, 2004 addressed to Ms. Marie E. Trimboli of The Bank of New York and signed by Ms. Maureen Johnson. 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 estimate 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

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Future Net Revenues and Present Value of Estimated Future Net Revenues are not intended and should not be interpreted to represent fair market values for the estimated reserves.

The Prudhoe Bay (Permo-Triassic) Reservoir is defined in the Prudhoe Bay Unit Operating Agreement. The Prudhoe Bay Unit is an oil and gas unit situated on the North Slope of Alaska. The BP Prudhoe Bay Royalty Trust is entitled to a royalty payment on 16.4246 percent of the first 90,000 barrels of the actual average daily net production of oil and condensate for each calendar quarter from the BP Exploration (Alaska) Inc. working interest as defined in the Overriding Royalty Conveyance. The payment amount depends upon the Per Barrel Royalty 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, 2003, of 77.94 million barrels of oil and condensate are, in the aggregate, reasonable. Of the 77.94 million barrels of total Proved Reserves, 66.94 million barrels are Proved Developed Reserves, and 11.0 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, 2003 production of the Proved Reserves will result in Estimated Future Net Revenues of $644.7 million and Present Value of Estimated Future Net Revenues of $395.3 million to the BP Prudhoe Bay Royalty Trust. These estimates are reasonable.

6. BP Exploration (Alaska) Inc. estimated that, as of December 31, 2003, 815.0 million barrels of Proved Reserves have been added to Current Reserves. This estimate is

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reasonable. Current Reserves are defined in the Overriding Royalty Conveyance as net Proved Reserves of 2,035.6 million barrels as of December 31, 1987. Net additions to Proved Reserves after December 31, 1987 affect the Chargeable Costs that are used to calculate the Per Barrel Royalty paid to the BP Prudhoe Bay Royalty Trust.

7. The BP Exploration (Alaska) Inc. projection that its net production of oil and condensate from Proved Reserves will continue at an average rate exceeding 90,000 barrels per day until the year 2013 is reasonable. As long as the Per Barrel Royalty has a positive value, average daily production attributable to the BP Prudhoe Bay Royalty Trust will remain constant until the net production falls below 90,000 barrels per day; thereafter, 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 of the 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 $32.55 per barrel on December 31, 2003, 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 2018 is reasonable. BP Exploration (Alaska) Inc. expects continued economic production at a declining rate through the year 2035; however, for the economic conditions and production forecast as of December 31, 2003 the Per Barrel Royalty will be zero following the year 2018. 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 estimate 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.

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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 expects continued economic production from the reservoir at a declining rate through the year 2035. 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 normal 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 seven to nine 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.

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 [SEAL]

William P. Koza
Vice President

WPK/hsd

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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, the Company 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. The Company 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 the Company has advised that the existence of legislation and regulation has had no material adverse effect on the Company s current method of operations, existing and future legislation and regulations cannot be predicted.

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. The Company 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 establish a reserve or borrow money to satisfy debts and liabilities of the Trust income used to establish the reserve or to repay the loan must be reported by the Unit holder, even though the income is not distributed to the Unit holder.

The Trust makes quarterly distributions to Unit holders 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 of on the gross income produced by the Royalty Interest at a rate equal to 30 percent (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 allows the election to be made annually.

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

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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 person is a corporation which made an election under Internal Revenue Code section 882(d), the corporation would also be subject to a 30 percent 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 31 percent 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.

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.

ITEM 2. PROPERTIES

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

ITEM 3. LEGAL PROCEEDINGS

There are no pending legal proceedings to which the Trust is a party or of which any of its property is the subject.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF UNIT HOLDERS

No matters were submitted to a vote of Unit holders during the fourth quarter ended December 31, 2003.

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PART II

ITEM 5. MARKET FOR THE UNITS, RELATED UNIT HOLDER 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, 2003.

	High	Low	Distributions Per Unit
2002:			
First Quarter	$15.01	$10.98	$0.216
Second Quarter	14.37	11.20	0.230
Third Quarter	14.49	10.70	0.476
Fourth Quarter	15.10	12.50	0.585
2003:			
First Quarter	$16.39	$13.61	$0.580
Second Quarter	19.18	13.75	0.808
Third Quarter	20.19	16.19	0.552
Fourth Quarter	28.90	19.44	0.623

As of March 24, 2004, 21,400,000 Units were outstanding and were held by 913 holders of record. No Units were purchased by the Trust or any affiliated purchaser during the year ended December 31, 2003.

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, the Chargeable Costs, the rates of Production Taxes prevailing from time to time, and the actual production from the Prudhoe Bay Unit. See THE ROYALTY INTEREST in Item 1.

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ITEM 6. SELECTED FINANCIAL DATA

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

	2003	2002	2001	2000	1999
	(in thousands, except per Unit amounts)				
Royalty revenues	$ 55,986	33,061	59,934	65,026	13,443
Interest income	$ 10	23	70	92	60
Trust administration expenses	$ 1,168	822	724	732	798
Expenses reserve	$			500	500
Cash earnings	$ 54,828	32,262	59,280	63,886	12,205
Cash distributions	$ 54,867	32,246	59,319	63,838	12,205
Cash distributions per unit	$ 2.564	1.507	2.772	2.983	0.570
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

Cautionary Statement

The Trustee, its officers or its agents on behalf of the Trustee may, from time to time, make forward-looking statements (other than statements of historical fact). When used herein, the words anticipates, expects, believes, intends or projects and similar expressions are intended to identify forward-looking statements. To the extent that any forward-looking statements are made, the Trustee is unable to predict future changes in oil prices, oil production levels, economic activity, legislation and regulation, and certain changes in expenses of the Trust. In addition, the Trust s future results of operations and other forward looking statements contained in this item and elsewhere in this report involve a number of risks and uncertainties. As a result of variations in such factors, actual results may differ materially from any forward looking statements. Some of these factors are described below. The Trustee disclaims any obligation to update forward looking statements and all such forward-looking statements in this document are expressly qualified in their entirety by the cautionary statements in this paragraph.

Liquidity and Capital Resources

The Trust is a passive entity, and 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 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 Trustee does have a limited power to borrow, establish a cash reserve, or dispose of all or part of the Trust Estate, under limited circumstances pursuant to the terms of the Trust Agreement. See the discussion under BUSINESS The Trust in Item 1.

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The decline in WTI Prices during the fourth quarter of 1998 and the first quarter of 1999 resulted in the Trust not receiving quarterly distributions during the first and second quarters of 1999. See THE ROYALTY INTEREST Per Barrel Royalty Calculations. Upon the increase in the WTI Price in the second quarter of 1999 and the resumption of distributions in the third quarter of 1999, the Trustee established a cash reserve to provide liquidity to the Trust during any future periods in which the Trust does not receive a distribution. The Trustee set aside $1,000,000 in the cash reserve account, from quarterly distributions received by the Trust, in four equal quarterly installments commencing with the July 1999 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.

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 the Company and paid to the holders of Units on each Quarterly Record Date. The Trustee anticipates that it will keep this cash reserve program in place until termination of the Trust.

As discussed under BUSINESS Certain Tax Considerations, amounts received by the Trust as quarterly distributions (and earnings on investment of the cash reserve) are income to the holders of the Units for the taxable year in which such amounts are received by the Trust and must be reported by the holders of the Units even if a portion of such amounts are used to repay borrowings by the Trust or add to the cash reserve and are not received by the holders of the Units.

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

As long as the Company s average daily net production from the Prudhoe Bay Unit exceeds 90,000 Barrels, which the Company currently projects will continue until the year 2013, the only 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, changes in Production Taxes, changes in the expenses of the Trust, contributions to the cash reserve and interest earned on the cash reserve.

During the year 2003 and the period of 2004 up to the date of this report, the 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 2004 will depend on WTI Prices prevailing during the remainder of the year.

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2003 compared to 2002

Royalty revenues and cash distributions increased during 2003 by approximately 69% and 70%, respectively, from 2002. The increases were due to increases in WTI Prices, commencing during 2003, which averaged approximately 26% higher during the twelve-month period ended September 30, 2003 (on which calendar 2003 cash basis revenues were based) than during the preceding twelve-month period. A scheduled increase in Chargeable Costs from $11.25 to $11.75 beginning in the first quarter of 2003, a small increase in the average Cost Adjustment Factor and increases in Production Taxes, which averaged approximately 34% higher during the twelve months ended September 30, 2003 than during the preceding twelve months, combined to offset somewhat the effect on royalty revenues of the higher WTI Prices during fiscal 2003.

Trust administrative expenses increased approximately $346,000 (approximately 46%) in 2003 from the prior year. The increase was due principally to a one-time $315,360 payment by the Trust to BP America Inc., a subsidiary of BP, during the first quarter of 2003 to reimburse BP America for annual fees paid by BP America to the New York Stock Exchange for listing the Units. Such annual listing fees are payable by the Trust under the terms of the Trust Agreement. The listing fees for the years 1990 through 1999, aggregating $315,360, were invoiced by the New York Stock Exchange to BP America, which inadvertently paid them on behalf of the Trust.

2002 compared to 2001

Royalty revenues and cash distributions in calendar 2002 decreased by approximately 44.8% and 45.6%, respectively, from 2001. The decline was due principally to a sharp drop in average WTI Prices during the fourth quarter of 2001 and the first quarter of 2002. Although WTI prices recovered later in 2002 to approximately the same levels as at the beginning of 2001, overall the average WTI Price for the twelve months ended September 30, 2002 (on which calendar 2002 cash basis revenues were based) was approximately 16% lower than for the immediately preceding twelve-month period. Royalty revenues also were negatively affected by the scheduled increase in Chargeable Costs from $10.75 to $11.25 in the first quarter of 2002; however this impact was somewhat offset by Production Taxes, which declined approximately 21% during the twelve-month period ended September 30, 2002 from the preceding period as a consequence of the decreases in average WTI Prices. The Cost Adjustment Factor had a neutral effect during 2002, as it remained substantially constant on average from the previous year.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

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

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Bp Prudhoe Bay Royalty Trust

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Independent Auditors Report

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, 2003 and 2002, 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, 2003. These financial statements are the responsibility of 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 auditing standards generally accepted in the United States of America. 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, these financial statements were prepared on the modified basis of cash receipts and disbursements, which is a comprehensive basis of accounting other than generally accepted accounting principles.

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets and liabilities and trust corpus of BP Prudhoe Bay Royalty Trust as of December 31, 2003 and 2002, and its cash earnings and distributions and its changes in trust corpus for each of the years in the three-year period ended December 31, 2003, on the basis of accounting described in Note 2.

New York, New York
March 4, 2004

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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, 2003	December 31, 2002
Assets		
Royalty Interest, net (Notes 1, 2 and 3)	$ 14,060	$ 16,068
Cash and cash equivalents (Note 2)	986	1,025
Total Assets	$ 15,046	$ 17,093
Liabilities and Trust Corpus		
Accrued expenses	$ 316	$ 595
Trust Corpus (40,000,000 units of beneficial interest authorized, 21,400,000 units issued and outstanding	14,730	16,498
Total Liabilities and Trust Corpus	$ 15,046	$ 17,093

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)

	December 31,		
	2003	**2002**	**2001**
Royalty revenues	$ 55,986	$ 33,061	$ 59,934
Interest income	10	23	70
Less: Trust administrative expenses	(1,168)	(822)	(724)
Cash earnings	$ 54,828	$ 32,262	$ 59,280
Cash distributions	$ 54,867	$ 32,246	$ 59,319
Cash distributions per unit	$ 2.564	$ 1.507	$ 2.772
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)

	December 31,		
	2003	**2002**	**2001**
Trust Corpus at beginning of year	$ 16,498	$ 18,564	$ 20,669
Cash earnings	54,828	32,262	59,280
Decrease (increase) in accrued expenses	279	(73)	(58)
Cash distributions	(54,867)	(32,246)	(59,319)
Amortization of Royalty Interest	(2,008)	(2,009)	(2,008)
Trust Corpus at end of year	$ 14,730	$ 16,498	$ 18,564

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, 2003

(1) Formation of the Trust and Organization

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

Effective January 1, 2000, the Company and all other Prudhoe Bay working interest owners cross-assigned interests in the Prudhoe Bay Field pursuant to the Prudhoe Bay Unit Alignment Agreement. The Company retained all rights, obligations, and liabilities associated with the Trust. This transaction is not expected to have a material effect on the Trust s operation.

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 the Company s working interest in the Prudhoe Bay Field (the Field) as of February 28, 1989, 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 or fall, on average, below 90,000 barrels per day in any quarter. BP has guaranteed the performance of the Company of its payment obligations with respect to the Royalty Interest.

The trustees of the Trust are The Bank of New York, a New York corporation authorized to do a banking business, and The Bank of New York (Delaware), a Delaware banking corporation. The Bank of New York (Delaware) serves as co-trustee in order to satisfy certain requirements of the Delaware Trust Act. The Bank of New York 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 in certain situations for inflation) and Production Taxes (based on statutory rates then in existence). For years subsequent to 2006, Chargeable Costs will be reduced up to a maximum amount of $1.20 per barrel in each year if additions to the Field s proved reserves do not meet certain specific levels.

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.

BP Prudhoe Bay Royalty Trust
Notes to Financial Statements
(Prepared on a Modified Basis of Cash Receipts and Disbursements)
December 31, 2003

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 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. 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, 2003, 2002, and 2001 was $0.37. 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, 2003 and 2002, and the modified cash earning and distributions and changes in Trust Corpus for the years ended December 31, 2003, 2002 and 2001. 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, 2003 and 2002, cash equivalents which represent the cash reserve consist of US 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, 2003

Certain reclassifications have been made to prior year financial statements to conform to the 2003 presentation.

(3) Royalty Interest

The Royalty Interest is comprised of the following at December 31, 2003 and 2002 (in thousands):

	December 31,	
	2003	2002
Royalty Interest (at inception)	$ 535,000	$ 535,000
Less: Accumulated amortization	(347,422)	(345,414)
Impairment write-down	(173,518)	(173,518)
Balance, end of period	$ 14,060	$ 16,068

(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.

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(5) Summary of Quarterly Results (Unaudited)

A summary of selected quarterly financial information for the years ended December 31, 2003, 2002, and 2001 is as follows (in thousands, except unit data):

	2003 Fiscal Quarter			
	First	Second	Third	Fourth
Royalty revenues	$12,538	17,722	12,147	13,579
Interest income	4	2	2	2
Trust administrative expenses	(469)	(333)	(225)	(141)
Cash earnings	12,073	17,391	11,924	13,440
Cash distributions	12,412	17,291	11,823	13,341
Cash distributions per unit	0.580	0.808	0.553	0.623

	2002 Fiscal Quarter			
	First	Second	Third	Fourth
Royalty revenues	$4,841	5,205	10,314	12,701
Interest income	7	5	6	5
Trust administrative expenses	(216)	(298)	(130)	(178)
Cash earnings	4,632	4,912	10,190	12,528
Cash distributions	4,621	4,931	10,185	12,509
Cash distributions per unit	0.216	0.230	0.476	0.585

	2001 Fiscal Quarter			
	First	Second	Third	Fourth
Royalty revenues	$19,932	14,418	13,269	12,315
Interest income	19	17	23	11
Trust administrative expenses	(158)	(253)	(269)	(44)
Cash earnings	19,793	14,182	13,023	12,282
Cash distributions	19,777	14,167	13,096	12,279
Cash distributions per unit	0.924	0.662	0.612	0.574

	Fiscal Year Ended		
	2003	2002	2001
Royalty revenues	$55,986	33,061	59,934
Interest income	10	23	70
Trust administrative expenses	(1,168)	(822)	(724)
Cash earnings	54,828	32,262	59,280
Cash distributions	54,867	32,246	59,319
Cash distributions per unit	2.564	1.507	2.772

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(6) 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 the Company and the Trust were based on Company-prepared reserve estimates. The Company 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 the Company 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 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, 2003 ($32.55 per barrel), December 31, 2002 ($31.23 per barrel), and December 31, 2001 ($19.78 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. The Royalty Interest includes a provision under which, in years subsequent to 2006, if additions to the Field s proved reserves from January 1, 1988 (after certain adjustments) do not meet certain specified levels, Chargeable Costs will be reduced up to a maximum amount of $1.20 per barrel in each year. Under the provisions of FASB 69, no consideration can be given to reserves not considered proved at the present time. Accordingly, in estimating the reserve volumes attributable to the Trust, Chargeable Costs were reduced by the maximum amount in years subsequent to 1998, after considering the amount of reserves that have been added to the Field s proved reserves from January 1, 1988.

Net proved reserves of oil and condensate attributable to the Trust as of December 31, 2003, 2002, and 2001, based on the Company s latest reserve estimate at such time, the WTI Prices on December 31, 2003, 2002, and 2001 and a reduction in Chargeable Costs in years subsequent to 1998, were estimated to be 78, 86, and 43 million barrels, respectively (of which 67, 86, and 43 million barrels, respectively, are proved developed).

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 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

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may be produced after the currently anticipated end of field life. At December 31, 2003, 2002, and 2001, 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 $32.55, $31.23, and $19.78, respectively, were as follows (in thousands):

	December 31,		
	2003	**2002**	**2001**
Future net cash flows	$ 644,691	$ 653,236	$ 64,584
10% annual discount for estimated timing of cash flows	(249,373)	(264,803)	(17,543)
Standardized measure of discounted future net cash flow relating to proved reserves	$ 395,318	$ 388,433	$ 47,041

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

	December 31,		
	2003	**2002**	**2001**
Revisions of prior estimates:			
Reserve volumes	$ (3,915)	$ 90,906	$ 47,566
WTI price	56,270	351,779	(314,605)
Chargeable costs - inflation	(15,712)	(11,116)	(24,460)
Production taxes	(7,666)	(52,134)	48,033
Other	8	0	667
	28,985	379,435	(242,799)
Royalty income received (b)	(60,943)	(42,747)	(47,032)
Accretion of discount	38,843	4,704	30,625
Net increase (decrease) during the year	$ 6,885	$341,392	$(259,206)

(b) For the purpose of this calculation, Royalty income received for 2003, 2002, and 2001 includes the following:

Period October 1, 2003 through December 31, 2003	$14,659
Period October 1, 2002 through December 31, 2002	$12,538
Period October 1, 2001 through December 31, 2001	$ 4,841

The above royalty income was received by the Trust in January 2004, 2003, and 2002, respectively.

The changes in quantities of proved oil and condensate were as follows (in thousands of barrels):

Estimated net proved reserves of oil and condensate at December 31, 2001	43,193
Production	(5,395)

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Reserve estimate revisions	
Change caused by prices/costs	48,020
Estimated net proved reserves of oil and condensate at December 31, 2002	85,818
Production	(5,395)
Reserve estimate revisions	(2,481)
Change caused by prices/costs	
Estimated net proved reserves of oil and condensate at December 31, 2003	77,942
Proved reserves:	
December 31, 2001	43,193
December 31, 2002	85,818
December 31, 2003	77,942

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, 2003.

ITEM 9A. CONTROLS AND PROCEDURES

As of the end of the period covered by this report, the Trustee carried out an evaluation of the effectiveness of the design and operation of the Trust s disclosure controls and procedures pursuant to Exchange Act Rule 13a-15 and 15d-15. Based upon that evaluation, the Trustee concluded that the Trust s disclosure controls and procedures are effective in timely alerting the Trustee to material information relating to the Trust required to be included in the Trust s periodic filings with the SEC. In its evaluation of disclosure controls and procedures, the Trustee has relied, to the extent considered reasonable, on information provided by BP Exploration (Alaska) Inc. There has not been any change in the Trust s internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Trust s internal control over financial reporting.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The Trust has no directors or executive officers. The Trustee has only such rights and powers as are necessary to achieve the purposes 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 by the Trustee and receive no compensation specifically related to their services to the Trust.

The compensation received by the Trustee from the Trust during the three fiscal years ended December 31, 2003 was as follows:

Year ended December 31,	Trustee s Fees	Transfer Agent and Registrar Fees
2003	$114,572	$7,381
2002	114,572	7,889
2001	114,572	6,827

Under the Trust Agreement, the Trustee is entitled to receive on each Quarterly Record Date a quarterly fee consisting of: (i) a quarterly administrative fee, per Unit outstanding on the Quarterly Record Date, of $0.0011; and (ii) a transfer service fee, per Unit holder account as of such Quarterly Record Date, of $1.50. Both the administrative service fee and the transfer service fee are subject to increase for each calendar year commencing after December 31, 1990 by the proportionate increase, if any, during the preceding calendar year in the Consumer Price Index, as defined in the Overriding Royalty Conveyance, during the preceding calendar year. Pursuant to the Trust Agreement, the Trustee also bills the Trust for certain reimbursable expenses.

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

Securities Authorized for Issuance under Equity Compensation Plans

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

Unit Ownership of Certain Beneficial Owners

As of March 24, 2004, 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 the Company, Standard Oil, nor BP owns any Units. No Units are owned by The Bank of New York, as Trustee or in its individual capacity, or by The Bank of New York (Delaware), as co-trustee or in its individual capacity.

Changes in Control

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

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Not applicable.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Fees for services performed by KPMG LLP for the years ended December 31, 2003 and 2002 are:

	2003	2002
Audit	$ 73,000	$ 61,760
Audit related	14,500	14,500
Tax	200,000	180,000
Other		
	$287,500	$256,260

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.

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ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) FINANCIAL STATEMENTS

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

Independent Auditors Report
Statements of Assets, Liabilities and Trust Corpus as of December 31, 2003 and 2002
Statements of Cash Earnings and Distributions for the years ended December 31, 2003, 2002 and 2001
Statements of Changes in Trust Corpus for the years ended December 31, 2003, 2002 and 2001
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.

(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 among The British Petroleum Company p.l.c., BP Exploration (Alaska) Inc., The Standard Oil Company and BP Prudhoe Bay Royalty Trust.

31 Rule 13a-14(a) certification.

32 Section 1350 certification.

(d) REPORTS ON FORM 8-K

No reports on Form 8-K were filed with the Securities and Exchange Commission by the Trust during the quarter ended December 31, 2003.

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SIGNATURES

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

BP PRUDHOE BAY ROYALTY TRUST

By: THE BANK OF NEW YORK, as Trustee

By: /s/ Ming J. Ryan

Ming J. Ryan
Vice President

April 23, 2004

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.

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.
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 among The British Petroleum Company p.l.c., BP Exploration (Alaska) Inc., The Standard Oil Company and BP Prudhoe Bay Royalty Trust.
31	Rule 13a-14(a) certification. Filed herewith
32	Section 1350 certification. Filed herewith.

* 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, 1996 (File No. 1-10243).