BP PRUDHOE BAY ROYALTY TRUST
Form 10-Q
August 08, 2008

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2008

OR

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

For the transition period from __________ to __________

Commission file number 1-10243

BP PRUDHOE BAY ROYALTY TRUST

(Exact Name of Registrant as Specified in Its Charter)

Delaware	13-6943724
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
The Bank of New York Mellon, 101 Barclay Street, New York, NY	10286
(Address of Principal Executive Offices)	(Zip Code)

Registrant s Telephone Number, Including Area Code: (212) 815-6908

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

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

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o	Smaller reporting company o

(Do not check if a smaller reporting company)

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

As of August 8, 2008, 21,400,000 Units of Beneficial Interest were outstanding.

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PART I
FINANCIAL INFORMATION

Item 1. Financial Statements

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)

	June 30, 2008 (Unaudited)	December 31, 2007
Assets		
Royalty interest, net (Notes 1, 2 and 3)	$ 5,022	$ 6,026
Cash and cash equivalents (Note 2)	1,001	1,009
Total assets	$ 6,023	$ 7,035
Liabilities and Trust Corpus		
Accrued expenses	$ 710	$ 443
Trust corpus (40,000,000 units of beneficial interest authorized, 21,400,000 units issued and outstanding)	5,313	6,592
Total liabilities and trust corpus	$ 6,023	$ 7,035

See accompanying notes to financial statements (unaudited).

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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)
(Unaudited)
(In thousands, except unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	**2007**	**2008**	**2007**
Royalty revenues	$ 57,859	$ 39,250	$ 123,207	$ 82,456
Interest income	7	20	26	40
Less: Trust administrative expenses	(738)	(391)	(922)	(560)
Cash earnings	$ 57,128	$ 38,879	$ 122,311	$ 81,936
Cash distributions	$ 57,137	$ 38,879	$ 122,319	$ 81,938
Cash distributions per unit	$ 2.6699	$ 1.8168	$ 5.7158	$ 3.8289
Units outstanding	21,400,000	21,400,000	21,400,000	21,400,000

See accompanying notes to financial statements (unaudited).

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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)
(Unaudited)
(In thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	**2007**	**2008**	**2007**
Trust corpus at beginning of period	$ 5,776	$ 8,128	$ 6,592	$ 8,853
Cash earnings	57,127	38,879	122,311	81,936
(Increase) decrease in accrued expenses	49	(376)	(267)	(597)
Cash distributions	(57,137)	(38,879)	(122,319)	(81,938)
Amortization of royalty interest	(502)	(502)	(1,004)	(1,004)
Trust corpus at end of period	$ 5,313	$ 7,250	$ 5,313	$ 7,250

See accompanying notes to financial statements (unaudited).

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BP Prudhoe Bay Royalty Trust
Notes to Financial Statements (Unaudited)
(Prepared on a Modified Basis of Cash Receipts and Disbursements)
June 30, 2008

(1) Formation of the Trust and Organization

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

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

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

The Per Barrel Royalty in effect for any day is equal to the price of West Texas Intermediate crude oil (the WTI Price) for that day less scheduled Chargeable Costs (adjusted for inflation) and Production Taxes (based on statutory rates then in effect). See Note 5 for information concerning recent changes in Alaska oil and gas production taxes which have affected the calculation of the Per Barrel Royalty.

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

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BP Prudhoe Bay Royalty Trust
Notes to Financial Statements (Unaudited)
(Prepared on a Modified Basis of Cash Receipts and Disbursements)
June 30, 2008

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 holders of not less than 70% of the outstanding Trust Units.

b. After December 31, 2010: (i) upon a vote of 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 *force majeure* events).

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

(2) Basis of Accounting

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

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

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

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

d. Amortization of the Royalty Interest is calculated based on the units of production method. Such amortization is charged directly to the Trust corpus, and does not affect cash earnings. The daily rate for amortization per net equivalent barrel of oil for the three months ended June 30, 2008 and 2007 was $0.38 and $0.38, respectively, and for the six months ended June 30, 2008 and 2007 was $0.38 and $0.38, respectively. The Trust evaluates impairment of the Royalty Interest by comparing the undiscounted cash flows expected to be realized from the Royalty Interest to the carrying value, pursuant to Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* 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

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BP Prudhoe Bay Royalty Trust
Notes to Financial Statements (Unaudited)
(Prepared on a Modified Basis of Cash Receipts and Disbursements)
June 30, 2008

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. These modified cash basis financial statements are unaudited but, in the opinion of the Trustee, include all adjustments necessary to present fairly the assets, liabilities and corpus of the Trust as of June 30, 2008 and 2007, and the modified cash earning and distributions and changes in Trust corpus for the three-month and six-month periods ended June 30, 2008 and 2007. 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 June 30, 2008 and December 31, 2007, cash equivalents which represent the cash reserve consist of U.S. Treasury bills with an initial term of less than three months.

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

These unaudited financial statements should be read in conjunction with the financial statements and related notes in the Trust s Annual Report on Form 10-K for the fiscal year ended December 31, 2007. The cash earnings and distributions for the interim period presented are not necessarily indicative of the results to be expected for the full year.

(3) Royalty Interest

The Royalty Interest is comprised of the following at June 30, 2008 and December 31, 2007 (in thousands):

	June 30, 2008 (Unaudited)	December 31, 2007
Royalty Interest (at inception)	$ 535,000	$ 535,000
Less: Accumulated amortization	(356,460)	(355,456)
Impairment write-down	(173,518)	(173,518)
Balance, end of period	$ 5,022	$ 6,026

(4) Income Taxes

The Trust files its federal tax return as a grantor trust subject to the provisions of subpart E of Part I of Subchapter J of the Internal Revenue Code of 1986, as amended, rather than as an association taxable as a corporation. The Trust Unit holders are treated as the owners of

BP Prudhoe Bay Royalty Trust
Notes to Financial Statements (Unaudited)
(Prepared on a Modified Basis of Cash Receipts and Disbursements)
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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.

The Trustee assumes that some Trust Units are held by a middleman, as such term is broadly defined in the U.S. Treasury Regulations (which includes custodians, nominees, certain joint owners, and brokers holding an interest for a custodian in street name). Therefore, the Trustee considers the Trust to be a widely held fixed investment trust (WHFIT) for U.S. Federal income tax purposes. The Bank of New York Mellon is the representative of the Trust that will provide tax information in accordance with applicable U.S. Treasury Regulations governing the information reporting requirements of the Trust as a WHFIT. For information contact The Bank of New York Mellon, Corporate Trust Trustee Administration, 101 Barclay Street, New York, NY 10286, telephone number (212) 815-6908.

(5) Alaska Oil and Gas Production Tax

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

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

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BP Prudhoe Bay Royalty Trust
Notes to Financial Statements (Unaudited)
(Prepared on a Modified Basis of Cash Receipts and Disbursements)
June 30, 2008

The Trustee and BP Alaska entered into a letter agreement in October 2006 and an amendment thereto in January 2008 (the Letter Agreement) to resolve issues associated with the 2006 Tax and the 2007 Tax. The Letter Agreement modified the calculation of Production Taxes in the daily Per Barrel Royalty calculation effective as of August 20, 2006, in the case of the 2006 Tax, and effective December 20, 2007, in the case of the 2007 Tax.

(6) Legal Expense Contingency

The Trust has incurred, and may continue to incur, legal fees and expenses in amounts which may be significant as a result of litigation and other issues arising out of the August 2006 shutdown of the Prudhoe Bay field. Legal fees and expenses are the principal cause of the increase in Trust administrative expenses for the three and six months ended June 30, 2008.

(7) Royalty Revenue Adjustments

The royalty payments received by the Trust in January 2008 and 2007 with respect to the quarters ended December 31, 2007 and 2006 were adjusted by BP Alaska to compensate for underpayment of the royalties due with respect to the quarters ended September 30, 2007 and 2006, respectively. Average net production of crude oil and condensate was less than 90,000 barrels per day during the third quarter of 2007 and the third quarter of 2006. Royalty payments by BP Alaska with respect to those quarters were based on estimates by BP Alaska of production levels because actual data were not available by the dates on which payments were required to be made to the Trust. Subsequent recalculation by BP Alaska of royalty payments due based on actual production data for the third quarters of 2007 and 2006 resulted in the payment adjustments shown in the table below:

	Payment Received	
	January 2008	**January 2007**
Royalty payment as calculated	$ 65,284,449	$ 41,470,000
Adjustment for previous quarter s underpayment, plus accrued interest	63,775	1,736,000
Net payment received	$ 65,348,224	$ 43,206,000

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Item 2. Trustee s Discussion and Analysis of Financial Condition and Results of Operations.

Cautionary Statement

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

The actual results, performance and prospects of the Trust could differ materially from those expressed or implied by forward-looking statements. Descriptions of some of the risks that could affect the future performance of the Trust appear in Item 1A, Risk Factors, of the Trust s Annual Report on Form 10-K for the fiscal year ended December 31, 2007 (the 2007 Annual Report) and in Item 1A of Part II this report. There may be additional risks of which the Trustee is unaware or which are currently deemed immaterial.

In the light of these risks, uncertainties and assumptions, you should not rely unduly on any forward-looking statements. Forward-looking events and outcomes discussed in the 2007 Annual Report and in this report may not occur or may transpire differently. The Trustee undertakes no obligation to update forward-looking statements after the date of this report, except as required by law, and all such forward-looking statements in this report are qualified in their entirety by the preceding cautionary statements.

Liquidity and Capital Resources

The Trust is a passive entity. The Trustee s activities are limited to collecting and distributing the revenues from the Royalty Interest and paying liabilities and expenses of the Trust. Generally, the Trust has no source of liquidity and no capital resources other than the revenue attributable to the Royalty Interest that it receives from time to time. See the discussion under THE ROYALTY INTEREST in Part I, Item 1 of the 2007 Annual Report for a description of the calculation of the Per Barrel Royalty, and the discussion under THE PRUDHOE BAY UNIT AND FIELD Reserve Estimates and INDEPENDENT OIL AND GAS CONSULTANTS REPORT in Part I, Item 1 of the 2007 Annual Report for information concerning the estimated future net revenues of the Trust. However, the Trustee has 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 THE TRUST in Part I, Item 1 of the 2007 Annual Report.

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

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

As discussed under CERTAIN TAX CONSIDERATIONS in Part I, Item 1 of the 2007 Annual Report, amounts received by the Trust as quarterly distributions are income to the holders of the Units, (as are any earnings on investment of the cash reserve) and must be reported by the holders of the Units, even if such amounts are used by the Trustee to repay borrowings or replenish 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 for and supply of energy throughout the world and future prices of oil cannot be accurately projected.

Under the terms of the Conveyance of the Royalty Interest to the Trust, the Per Barrel Royalty for any day is the WTI Price for the day less the sum of (i) Chargeable Costs multiplied by the Cost Adjustment Factor and (ii) Production Taxes. The narrative under the captions THE TRUST Trust Property and THE ROYALTY INTEREST in the 2007 Annual Report explains the meanings of the terms Conveyance, Royalty Interest, Per Barrel Royalty, WTI Price, Chargeable Costs and Cost Adjustment Factor and should be read in conjunction with this report.

Royalty revenues are generally received on the fifteenth day of the month following the end of the calendar quarter in which the related Royalty Production occurred (the Quarterly Record Date). The Trustee, to the extent possible, pays all accrued expenses of the Trust on each Quarterly Record Date from the royalty payment received. Revenues and Trust expenses presented in the statement of cash earnings and distributions are recorded on a modified cash basis and, as a result, royalty revenues and distributions shown in such statements for the three-month and six-month periods ended June 30, 2008 and 2007, respectively, are attributable to BP Alaska s operations during the three-month and six-month periods ended March 31, 2008 and 2007, respectively.

The following table summarizes the factors which determined the Per Barrel Royalties used to calculate the payments received by the Trust in January and April 2008 and 2007 (see Note 1 of Notes to Financial Statements (Unaudited) in Part I, Item 1). The information in the table has been furnished by BP Alaska.

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Royalty Payment in	Is Based on Data for Quarter Ended	Average WTI Price	Chargeable Costs	Data for Quarter Cost Adjustment Factor	Adjusted Chargeable Costs	Average Production Taxes	Average Per Barrel Royalty[1]
Apr. 2008	03/31/2008	$124.34	$13.00	1.668	$21.68	$52.37[2]	$50.29[3]
Jan. 2008	12/31/2007	90.93	12.75	1.618	20.63	22.29	48.01
Apr. 2007	03/31/2007	58.17	12.75	1.567	19.98	8.66	29.54
Jan. 2007	12/31/2006	60.17	12.50	1.552	19.39	9.31	31.46[4]

(1) The average daily net production of oil and condensate from the BP Working Interests exceeded 90,000 barrels per day during the quarter unless otherwise indicated.

(2) Production Taxes reflect the application during the full quarter of the 2007 amendment to the Alaska oil and gas production tax statutes. See Alaska Oil and Gas Production Tax Changes below.

(3) Royalty Production was calculated on the basis of a preliminary estimate of 87,855 barrels

of average daily net production.

(4) Royalty Production was calculated on the basis of a preliminary estimate of 87,221 barrels of average daily net production.

Royalty Production for each day in a calendar quarter is 16.4246% of the first 90,000 barrels of the actual average daily net production of oil and condensate for the quarter from the BP Working Interests. So long as BP Alaska s average daily net production from the BP Working Interests exceeds 90,000 barrels, the principal factors affecting the Trust s revenues and distributions to Unit holders are changes in WTI Prices, scheduled annual increases in Chargeable Costs, changes in the Consumer Price Index and changes in Production Taxes. However, BP Alaska has advised the Trustee that, as a consequence of a program of field wide infrastructure renewal, pipeline replacement and well mechanical improvements, it anticipates that net production of oil and condensate from the BP Working Interests will be below 90,000 barrels per day on an annual average basis in 2007.

BP Alaska estimates Royalty Production from the BP Working Interests for purposes of calculating quarterly royalty payments to the Trust because complete actual field production data for the preceding calendar quarter generally is not available by the Quarterly Record Date. To the extent that average net production from the BP Working Interests is below 90,000 barrels per day in any quarter, recalculation by BP Alaska of actual Royalty Production data may result in revisions of prior Royalty Production estimates. Revisions by BP Alaska of its Royalty Production calculations may cause BP Alaska to adjust its quarterly royalty payments to the Trust to compensate for overpayments or underpayments of royalties with respect to prior quarters. Such adjustments, if material, may adversely affect certain Unit holders who buy or sell Units between the Quarterly Record Dates for the Quarterly Distributions affected.

The Quarterly Distributions received by the Trust from BP Alaska in January 2008 and January 2007 were adjusted by BP Alaska to compensate for underpayment of royalties due to the Trust in the quarters ended December 31, 2007 and 2006, respectively. See Note 7 of Notes to Financial Statements (Unaudited) in Item 1. Because the statements of cash earnings and

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distributions of the Trust are prepared on a modified cash basis, royalty revenues for the six-month periods ended June 30, 2008 and 2007 reflect the amounts of the adjustments with respect to the earlier fiscal periods.

Alaska Oil and Gas Production Tax Changes

In August 2006, Alaska adopted a new oil and gas production tax (the 2006 Tax) which replaced an oil production tax levied at the flat rate of 15% of the gross value at the point of production of taxable oil produced from a producer s leases or properties in the State of Alaska. Under the 2006 Tax, producers were taxed on the production tax value of taxable oil (gross value at the point of production for the calendar year less the producer s direct costs of exploring for, developing, or producing oil or gas deposits located within the producer s leases or properties in Alaska (Lease Expenditures) for the year) at a rate equal to the sum of 22.5% plus a progressivity rate determined by the average monthly production tax value of the oil produced. The progressivity portion of the 2006 Tax was equal to 0.25% times the amount by which the simple average for each calendar month of the daily production tax values per barrel of the oil produced during the month exceeded $40 per barrel. In addition, the 2006 Tax increased the surcharge on oil produced from leases or properties in Alaska from $0.03 to $0.04 per barrel.

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

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

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

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

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

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

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

2006 Tax	2007 Tax
22.5%	25%

Three Months Ended June 30, 2008 Compared to
Three Months Ended June 30, 2007

As explained above, Trust royalty revenues received during the second quarter of the fiscal year are based on Royalty Production during the first quarter of the fiscal year. Royalty revenues received by the Trust in the quarter ended June 30, 2008 increased 47% from the corresponding quarter of 2007, reflecting a 114% period-to-period increase in the Average WTI Price from $58.17 per barrel during the quarter ended March 31, 2007 to $124.34 per barrel during the quarter ended March 31, 2008. The average Per Barrel Royalty, however, increased by only 70%, principally due to a 505% period-to-period increase in average Production Taxes which rose from $8.66 per barrel in the quarter ended March 31, 2007 to $52.37 per barrel in the quarter ended March 31, 2008 as a consequence of the progressivity feature and higher tax rates of the 2007 Tax. Trust administrative expenses were 89% higher in the quarter ended June 30, 2008 than in the corresponding period in 2007, primarily due to on-going legal fees and expenses related to issues arising from the August 2006 shutdown of the Prudhoe Bay field.

Six Months Ended June 30, 2008 Compared to
Six Months Ended June 30, 2007

Trust royalty revenues increased 49% in the six months ended June 30, 2008 from the corresponding period of 2007, reflecting the cumulative effect of an 82% increase in the Average WTI Price during the six-month period ended March 31, 2008 from the six-month period ended March 31, 2007. The average Per Barrel Royalty payable with respect to the six months ended March 31, 2008 received the brunt of the new Alaska oil and gas production taxes and increased by only 61%, as a consequence of both the progressivity feature of the 2006 Tax and 2007 Tax and the higher 2007 Tax rates which became applicable during the latter part of December 2007. Average Production Taxes chargeable with respect to the six-month period ended March 31, 2008 increased 315% over the average Production Taxes chargeable with respect to the six months ended March 31, 2007. Trust administrative expenses were 65% higher during the six months ended June 30, 2007 than in the corresponding period in 2007, primarily due to on-going legal fees and expenses related to issues arising from the August 2006 shutdown of the Prudhoe Bay field.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

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

Item 4. Controls and Procedures.

Disclosure Controls and Procedures

The Trustee has disclosure controls and procedures (as defined in Rule 13a-15(e) and Rule 15d-15(e) under the Exchange Act) that are designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Securities Exchange Act of 1934, as amended (the Exchange Act) is recorded, processed, summarized and reported, within the time periods specified in the SEC s rules and forms. These controls and procedures include but are not limited to controls and procedures designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act is accumulated and communicated to the responsible trust officers of the Trustee to allow timely decisions regarding required disclosure.

Under the terms of the Trust Agreement and the Conveyance, BP Alaska has significant disclosure and reporting obligations to the Trust. BP Alaska is required to provide the Trust such information concerning the Royalty Interest as the Trustee may need and to which BP Alaska has access to permit the Trust to comply with any reporting or disclosure obligations of the Trust pursuant to applicable law and the requirements of any stock exchange on which the Units are listed. These reporting obligations include furnishing the Trust a report by February 28 of each year containing all information of a nature, of a standard and in a form consistent with the requirements of the SEC respecting the inclusion of reserve and reserve valuation information in filings under the Exchange Act and with applicable accounting rules. The report is required to set forth, among other things, BP Alaska s estimates of future net cash flows from proved reserves attributable to the Royalty Interest, the discounted present value of such proved reserves, the assumptions utilized in arriving at the estimates contained in the report, and the estimate of the quantities of proved reserves (including reductions of proved reserves as a result of modification of BP Alaska s estimates of proved reserves from prior years) added during the preceding year to the total proved reserves allocated to the BP Working Interests as of December 31, 1987.

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

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

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

Internal Control Over Financial Reporting

There has not been any change in the Trust s internal control over financial reporting identified in connection with the evaluation required by paragraph (d) of Rule 13a-15 or Rule 15d-15 under the Exchange Act that occurred during the Trust s last fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Trust s internal control over financial reporting.

Item 4T. Controls and Procedures.

Not applicable.

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PART II
OTHER INFORMATION

Item 1. Legal Proceedings.

None.

Item 1A. Risk Factors

The following paragraphs supplement the disclosure which appears in Part I, Item 1A of the Trust s 2007 Annual Report under the caption *Construction of a proposed gas pipeline from the North Slope of Alaska to the Midwestern United States could accelerate the decline in Royalty Production from the Prudhoe Bay field* and in Part II, Item 1A of the Trust s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008:

On August 1, 2008, the Alaska legislature approved Trans Canada s application under the Alaska Gasline Inducement Act for a license to construct a natural gas pipeline from the North Slope to the lower 48 states. Under the license, the state will provide up to $500 million in matching funds and other incentives in exchange for TransCanada doing its best to secure customers for the pipeline, financing, and regulatory clearances from the Federal Energy Regulatory Commission and Canadian authorities.

See Item 1A in Part II of the Trust s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 for information concerning a competing pipeline plan proposed by BP and ConocoPhillips. The award of the state license to Trans Canada does not preclude BP and ConocoPhillips from proceeding with their independent plan.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

None.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Submission of Matters to a Vote of Security Holders.

None.

Item 5. Other Information.

(a) On July 15, 2008 the Trust received a cash distribution of $66,030,352 from BP Alaska with respect to the quarter ended June 30, 2008. On July 17, 2008, after adding interest income received from investment of the cash reserve and deducting Trust administrative expenses, the Trustee distributed $65,343,974 (approximately $3.05 per Unit) to Unit holders of record on July 11, 2008 (Form 8-K, Item 8.01).

(b) Not applicable.

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Item 6. 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.

4.5 Letter agreement executed October 13, 2006 between BP Exploration (Alaska) Inc. and The Bank of New York, as Trustee.

4.6 Letter agreement executed January 11, 2008 between BP Exploration (Alaska) Inc. and The Bank of New York, as Trustee.

31 Rule 13a-14(a)/15d-14(a) Certification.

32 Section 1350 Certification.

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SIGNATURE

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

BP PRUDHOE BAY ROYALTY TRUST

By: THE BANK OF NEW YORK MELLON,
as Trustee

By: /s/Remo Reale

Remo Reale
Vice President

Date: August 8, 2008

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

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INDEX TO EXHIBITS

Exhibit No.	Exhibit Description
4.1	BP Prudhoe Bay Royalty Trust Agreement dated February 28, 1989 among The Standard Oil Company, BP Exploration (Alaska) Inc., The Bank of New York, Trustee, and F. James Hutchinson, Co-Trustee. Incorporated by reference to the correspondingly numbered exhibit to the Registrant s Annual Report on Form 10-K for the fiscal year ended December 31, 2006 (File No. 1-10243).
4.2	Overriding Royalty Conveyance dated February 27, 1989 between BP Exploration (Alaska) Inc. and The Standard Oil Company. Incorporated by reference to the correspondingly numbered exhibit to the Registrant s Annual Report on Form 10-K for the fiscal year ended December 31, 2006 (File No. 1-10243).
4.3	Trust Conveyance dated February 28, 1989 between The Standard Oil Company and BP Prudhoe Bay Royalty Trust. Incorporated by reference to the correspondingly numbered exhibit to the Registrant s Annual Report on Form 10-K for the fiscal year ended December 31, 2006 (File No. 1-10243).
4.4	Support Agreement dated as of February 28, 1989 among The British Petroleum Company p.l.c., BP Exploration (Alaska) Inc., The Standard Oil Company and BP Prudhoe Bay Royalty Trust. Incorporated by reference to the correspondingly numbered exhibit to the Registrant s Annual Report on Form 10-K for the fiscal year ended December 31, 2006 (File No. 1-10243).
4.5	Letter agreement executed October 13, 2006 between BP Exploration (Alaska) Inc. and The Bank of New York, as Trustee. Incorporated by reference to the correspondingly numbered exhibit to the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 1-10243).
4.6	Letter agreement executed January 11, 2008 between BP Exploration (Alaska) Inc. and The Bank of New York, as Trustee. Incorporated by reference to the correspondingly numbered exhibit to the Registrant s Current Report on Form 8-K dated January 11, 2008 (File No. 1-10243).
31*	Rule 13a-14(a) certification.
32*	Section 1350 certification.

* Filed herewith.

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Operating income

4,773

4,427

OTHER INCOME (EXPENSES):

Interest on debt

(1,310
)

(1,310
)
Allowance for funds used during construction

31

13

Other income (expenses), net

(74
)

(59
)

(1,353
)

(1,356
)

Income before income taxes

3,420

3,071

Income taxes

1,281

1,130

Net Income

$

2,139

$
1,941

Basic Earnings Per Share

$
0.17

$
0.15

Cash Dividends Declared Per Share

$
0.1383

$
0.1336

The accompanying notes are an integral part of these statements.

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THE YORK WATER COMPANY

Statements of Common Stockholders' Equity (Unaudited)
(In thousands of dollars, except per share amounts)
For the Periods Ended March 31, 2013 and 2012

	Common Stock Shares	Common Stock Amount	Retained Earnings	Total
Balance, December 31, 2012	12,918,633	$ 79,299	$ 20,526	$ 99,825
Net income	-	-	2,139	2,139
Dividends	-	-	(1,790)	(1,790)
Retirement of common stock	(10,639)	(197)	-	(197)
Issuance of common stock under dividend reinvestment, direct stock and employee stock purchase plans	42,761	776	-	776
Balance, March 31, 2013	12,950,755	$ 79,878	$ 20,875	$ 100,753

	Common Stock Shares	Common Stock Amount	Retained Earnings	Total
Balance, December 31, 2011	12,791,671	$ 77,113	$ 18,152	$ 95,265
Net income	-	-	1,941	1,941
Dividends	-	-	(1,710)	(1,710)
Issuance of common stock under dividend reinvestment, direct stock and employee stock purchase plans	32,718	568	-	568
Balance, March 31, 2012	12,824,389	$ 77,681	$ 18,383	$ 96,064

The accompanying notes are an integral part of these statements.

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THE YORK WATER COMPANY

Statements of Cash Flows (Unaudited)
(In thousands of dollars, except per share amounts)

	Three Months Ended March 31 2013			2012		
CASH FLOWS FROM OPERATING ACTIVITIES:						
Net income	$	2,139		$	1,941	
Adjustments to reconcile net income to net cash provided by operating activities:						
Depreciation and amortization		1,364			1,279	
Increase in deferred income taxes		657			515	
Other		52			58	
Changes in assets and liabilities:						
Decrease in accounts receivable and unbilled revenues		633			349	
Decrease in recoverable income taxes		-			197	
Increase in materials and supplies, prepaid expenses, regulatory and other assets		(393	)		(304	)
Decrease in accounts payable, accrued compensation and benefits, accrued expenses, deferred employee benefits, and other deferred credits		(1,061	)		(875	)
Increase in accrued interest and taxes		669			162	
Net cash provided by operating activities		4,060			3,322	
CASH FLOWS FROM INVESTING ACTIVITIES:						
Utility plant additions, including debt portion						

of allowance for funds used during construction of $17 in 2013 and $7 in 2012		(2,442)		(2,076)
Acquisitions of water and wastewater systems		(27)		-
Decrease in notes receivable		8		10
Net cash used in investing activities		(2,461)		(2,066)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Customers' advances for construction and contributions in aid of construction		220		62
Repayments of customer advances		(58)		(82)
Repayments of long-term debt		(11)		(11)
Repurchase of common stock		(197)		-
Issuance of common stock		776		568
Dividends paid		(1,787)		(1,709)
Net cash used in financing activities		(1,057)		(1,172)
Net change in cash and cash equivalents		542		84
Cash and cash equivalents at beginning of period		4,012		4,006
Cash and cash equivalents at end of period	$	4,554	$	4,090
Supplemental disclosures of cash flow information:				
Cash paid during the period for:				
Interest, net of amounts capitalized	$	808	$	1,146
Income taxes		7		-

Supplemental schedule of non-cash investing and financing activities:
Accounts payable includes $360 in 2013 and $843 in 2012 for the construction of utility plant.

The accompanying notes are an integral part of these statements.

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THE YORK WATER COMPANY

Notes to Interim Financial Statements
(In thousands of dollars, except per share amounts)

1. Basis of Presentation

The interim financial statements are unaudited but, in the opinion of management, reflect all adjustments, consisting of only normal recurring accruals, necessary for a fair presentation of results for such periods. Because the financial statements cover an interim period, they do not include all disclosures and notes normally provided in annual financial statements, and therefore, should be read in conjunction with the financial statements and notes thereto contained in the Company's Annual Report on Form 10-K for the year ended December 31, 2012.

Operating results for the three month period ended March 31, 2013 are not necessarily indicative of the results that may be expected for the year ending December 31, 2013.

2. Common Stock and Basic Earnings Per Share

Basic earnings per share for the three months ended March 31, 2013 and 2012 were based on weighted average shares outstanding of 12,937,549 and 12,801,706, respectively.

Since the Company has no common stock equivalents outstanding, there are no diluted earnings per share.

On March 11, 2013, the Board of Directors authorized a share repurchase program granting the Company authority to repurchase up to 1,200,000 shares of the Company's common stock from time to time. Under the stock repurchase program, the Company may repurchase shares in the open market or through privately negotiated transactions. The Company may suspend or discontinue the repurchase program at any time. During the three months ended March 31, 2013, the Company repurchased and retired 10,639 shares. As of March 31, 2013, 1,189,361 shares remain available for repurchase.

3. Commitments

In November 2011, during a routine tank cleaning, the Company discovered a small amount of mercury in the bottom of the tank. The tank was not in service at the time of the discovery and remains out of service. A number of tests were performed to confirm no mercury entered the water supply and no employees or contractors present during the discovery were impacted. The tank will remain out of service until it is approved for service by the Pennsylvania Department of Environmental Protection, or DEP. No disruption of service to any customers has occurred or is expected to occur. The Company incurred total costs of $186 through March 31, 2013. Recent tests have shown the tank is in compliance with safe drinking water standards and the Company has requested permission to place the tank back into service from the DEP. If the DEP does not approve based on the testing completed, other options will be reviewed, including a project to reline and strengthen the interior of the tank or replace the tank through capital expenditures.

4. Pensions

Components of Net Periodic Pension Cost

	Three Months Ended March 31	
	2013	2012
Service cost	$297	$263
Interest cost	320	322
Expected return on plan assets	(411)	(360)
Amortization of actuarial loss	174	160
Amortization of prior service cost	3	4
Rate-regulated adjustment	15	9
Net periodic pension expense	$398	$398

Employer Contributions

The Company previously disclosed in its financial statements for the year ended December 31, 2012 that it expected to contribute $1,593 to its pension plans in 2013. As of March 31, 2013, contributions of $1,593 had been made. At this time, the Company does not expect to contribute any additional amount during the remainder of 2013.

5. Interest Rate Swap Agreement

The Company is exposed to certain risks relating to its ongoing business operations. The primary risk managed by using derivative instruments is interest rate risk. The Company utilizes an interest rate swap agreement to effectively convert the Company's $12,000 variable-rate debt issue to a fixed rate. Interest rate swaps are contracts in which a series of interest rate cash flows are exchanged over a prescribed period. The notional amount on which the interest payments are based ($12,000) is not exchanged. The interest rate swap provides that the Company pays the counterparty a fixed interest rate of 3.16% on the notional amount of $12,000. In exchange, the counterparty pays the Company a variable interest rate based on 59% of LIBOR on the notional amount. The intent is for the variable rate received from the swap counterparty to approximate the variable rate the Company pays to bondholders on its variable rate debt issue, resulting in a fixed rate being paid to the swap counterparty and reducing the Company's interest rate risk. The Company's net payment rate on the swap was 3.00% during the three months ended March 31, 2013.

The interest rate swap agreement is classified as a financial derivative used for non-trading activities. The professional standards regarding accounting for derivatives and hedging activities require companies to recognize all derivative instruments as either assets or liabilities at fair value on the balance sheet. In accordance with the standards, the interest rate swap is recorded on the balance sheet in other deferred credits at fair value (see Note 6).

The Company uses regulatory accounting treatment rather than hedge accounting to defer the unrealized gains and losses on its interest rate swap. Instead of the effective portion being recorded as other comprehensive income and the ineffective portion being recognized in earnings using the cash flow hedge accounting rules provided by the derivative accounting standards, the entire unrealized swap value is recorded as a regulatory asset. Based on current ratemaking treatment, the Company expects the unrealized gains and losses to be recognized in rates as a component of interest expense as the swap settlements occur. Swap settlements are recorded in the income statement with the hedged item as interest expense. During the three months ended March 31, 2013, $90 was reclassified from regulatory assets to interest expense as a result of swap settlements. The overall swap result was a gain of $128 for the three months ended March 31, 2013. The Company expects to reclassify $354 from regulatory assets to interest expense as a result of swap settlements over the next 12 months.

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The interest rate swap agreement contains provisions that require the Company to maintain a credit rating of at least BBB- with Standard & Poor's. If the Company's rating were to fall below this rating, it would be in violation of these provisions, and the counterparty to the derivative could request immediate payment if the derivative was in a liability position. On April 26, 2013, Standard & Poor's affirmed the Company's credit rating at A-, with a stable outlook and adequate liquidity. The Company's interest rate swap was in a liability position as of March 31, 2013. If a violation due to credit rating, or some other default provision, were triggered on March 31, 2013, the Company would have been required to pay the counterparty approximately $2,759.

The interest rate swap will expire on October 1, 2029. Other than the interest rate swap, the Company has no other derivative instruments.

6. Fair Value Measurements

The professional standards regarding fair value measurements establish a fair value hierarchy which indicates the extent to which inputs used in measuring fair value are observable in the market. Level 1 inputs include quoted prices for identical instruments and are the most observable. Level 2 inputs include quoted prices for similar assets and observable inputs such as interest rates, commodity rates and yield curves. Level 3 inputs are not observable in the market and include management's own judgments about the assumptions market participants would use in pricing the asset or liability.

The Company has recorded its interest rate swap liability at fair value in accordance with the standards. The liability is recorded under the caption "Other deferred credits" on the balance sheet. The table below illustrates the fair value of the interest rate swap as of the end of the reporting period.

Description	March 31, 2013	Fair Value Measurements at Reporting Date Using Significant Other Observable Inputs (Level 2)
Interest Rate Swap	$2,621	$2,621

Fair values are measured as the present value of all expected future cash flows based on the LIBOR-based swap yield curve as of the date of the valuation. These inputs to this calculation are deemed to be Level 2 inputs. The balance sheet carrying value reflects the Company's credit quality as of March 31, 2013. The rate used in discounting all prospective cash flows anticipated to be made under this swap reflects a representation of the yield to maturity for 30-year debt on utilities rated A- as of March 31, 2013. The use of the Company's credit rating resulted in a reduction in the fair value of the swap liability of $138 as of March 31, 2013. The fair value of the swap reflecting the Company's credit quality as of December 31, 2012 is shown in the table below.

Description	December 31, 2012	Fair Value Measurements at Reporting Date Using Significant Other Observable Inputs (Level 2)
Interest Rate Swap	$2,836	$2,836

The carrying amount of current assets and liabilities that are considered financial instruments approximates fair value as of the dates presented. The Company's long-term debt (including current maturities), with a carrying value of $84,964 at March 31, 2013, and $84,975 at December 31, 2012, had an estimated fair value of approximately $104,000 and $107,000, respectively. The estimated fair value of debt was calculated using a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration and risk profile. These inputs to this calculation are deemed to be Level 2 inputs. The Company recognized its credit rating in determining the yield curve, and did not factor in third party credit enhancements including bond insurance on the 2004 PEDFA Series A and 2006 Industrial Development Authority issues, and the letter of credit on the 2008 PEDFA Series A issue.

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Customers' advances for construction and notes receivable have carrying values at March 31, 2013 of $13,104 and $330, respectively. At December 31, 2012, customers' advances for construction and notes receivable had carrying values of $12,949 and $338, respectively. The relative fair values of these amounts cannot be accurately estimated since the timing of future payment streams is dependent upon several factors, including new customer connections, customer consumption levels and future rate increases.

7. Debt

	As of Mar. 31, 2013	As of Dec. 31, 2012
4.05% Pennsylvania Economic Development Financing Authority Exempt Facilities Revenue Bonds, Series A, due 2016	$2,350	$2,350
5.00% Pennsylvania Economic Development Financing Authority Exempt Facilities Revenue Bonds, Series A, due 2016	4,950	4,950
10.17% Senior Notes, Series A, due 2019	6,000	6,000
9.60% Senior Notes, Series B, due 2019	5,000	5,000
1.00% Pennvest Loan, due 2019	279	290
10.05% Senior Notes, Series C, due 2020	6,500	6,500
8.43% Senior Notes, Series D, due 2022	7,500	7,500
Variable Rate Pennsylvania Economic Development Financing Authority Exempt Facilities Revenue Bonds, Series 2008A, due 2029	12,000	12,000
4.75% Industrial Development Authority Revenue Bonds, Series 2006, due 2036	10,500	10,500
6.00% Pennsylvania Economic Development Financing Authority Exempt Facilities Revenue Bonds, Series 2008B, due 2038	14,885	14,885
5.00% Monthly Senior Notes, Series 2010A, due 2040	15,000	15,000
Total long-term debt	84,964	84,975
Less current maturities	(42)	(42)
Long-term portion	$84,922	$84,933

As of March 31, 2013, the Company maintained unsecured lines of credit aggregating $29,000 with three banks. The Company is required to maintain a demand deposit account with an average monthly balance of $500 in order to retain one of its lines of credit. The use of the funds in the account in excess of the $500 is not restricted in any way.

8. Acquisitions

On March 7, 2013, the Company completed the acquisition of the Windy Brae Mobile Home Park water assets of Barkas, Inc. in York County, Pennsylvania. The Company began operating the existing system through an interconnection with its current distribution system on March 11, 2013. The acquisition resulted in the addition of approximately 135 new water customers at a purchase price and acquisition costs to date of approximately $27.

The results have been immaterial to total company results.

9. Rate Matters

From time to time, the Company files applications for rate increases with the Pennsylvania Public Utility Commission, or PPUC, and is granted rate relief as a result of such requests. The most recent rate request was filed by the Company on May 14, 2010. Effective November 4, 2010, the PPUC authorized an average increase of 8.7% in rates designed to produce approximately $3,400 in additional annual revenues. The Company plans to file a rate increase request in the second quarter of 2013.

The PPUC permits water utilities to collect a distribution system improvement charge (DSIC). The DSIC allows the Company to add a charge to customers' bills for qualified replacement costs of certain infrastructure without submitting a rate filing. This surcharge mechanism typically adjusts periodically based on additional qualified capital expenditures completed or anticipated in a future period. The DSIC is capped at 5% of base rates, and is reset to zero when new base rates that reflect the costs of those additions become effective or when a utility's earnings exceed a regulatory benchmark. The DSIC provided revenues of $328 for the three months ended March 31, 2013 and $0 for the three months ended March 31, 2012.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations (In thousands of dollars, except per share amounts)

Forward-looking Statements

Certain statements contained in this report on Form 10-Q constitute "forward-looking statements" within the meaning of Section 21E of the Securities Exchange Act of 1934 and Section 27A of the Securities Act of 1933. Words such as "may," "should," "believe," "anticipate," "estimate," "expect," "intend," "plan" and similar expressions are intended to identify forward-looking statements. These forward-looking statements include certain information relating to the Company's business strategy; statements including, but not limited to:

- statements regarding the amount and timing of rate increases and other regulatory matters including the recovery of costs recorded as regulatory assets;
- expected profitability and results of operations;
- statements as to trends;
- goals, priorities and plans for, and cost of, growth and expansion;
- strategic initiatives;
- availability of water supply;
- water usage by customers; and
- ability to pay dividends on common stock and the rate of those dividends.

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The forward-looking statements in this report reflect what the Company currently anticipates will happen. What actually happens could differ materially from what it currently anticipates will happen. The Company does not intend to make any public announcement when forward-looking statements in this report are no longer accurate, whether as a result of new information, what actually happens in the future or for any other reason. Important matters that may affect what will actually happen include, but are not limited to:

- changes in weather, including drought conditions or extended periods of heavy rainfall;
- levels of rate relief granted;
- the level of commercial and industrial business activity within the Company's service territory;
- construction of new housing within the Company's service territory and increases in population;
- changes in government policies or regulations, including the tax code;
- the ability to obtain permits for expansion projects;
- material changes in demand from customers, including the impact of conservation efforts which may impact the demand of customers for water;
- changes in economic and business conditions, including interest rates, which are less favorable than expected;
- changes in, or unanticipated, capital requirements;
- changes in accounting pronouncements;
- changes in the Company's credit rating or the market price of its common stock;
- the ability to obtain financing; and
- other matters set forth in Item 1A, "Risk Factors" of the Company's Annual Report on Form 10-K for the year ended December 31, 2012.

General Information

The primary business of the Company is to impound, purify to meet or exceed safe drinking water standards and distribute water. The Company also operates a single wastewater collection and treatment system. The Company operates within its franchised territory, which covers 39 municipalities within York County, Pennsylvania and eight municipalities within Adams County, Pennsylvania. The Company is regulated by the Pennsylvania Public Utility Commission, or PPUC, in the areas of billing, payment procedures, dispute processing, terminations, service territory, debt and equity financing and rate setting. The Company must obtain PPUC approval before changing any practices associated with the aforementioned areas.

Water service is supplied through the Company's own distribution system. The Company obtains the bulk of its water supply from both the South Branch and East Branch of the Codorus Creek, which together have an average daily flow of 73.0 million gallons. This combined watershed area is approximately 117 square miles. The Company has two reservoirs, Lake Williams and Lake Redman, which together hold up to approximately 2.2 billion gallons of water. The Company has a 15-mile pipeline from the Susquehanna River to Lake Redman which provides access to an additional supply of 12.0 million gallons of untreated water per day. The Company also owns two wells which are capable of providing a safe yield of approximately 100,000 gallons per day to supply water to its customers in Carroll Valley, Adams County. As of March 31, 2013, the Company's average daily availability was 35.0 million gallons, and average daily consumption was approximately 18.5 million gallons. The Company's service territory had an estimated population of 189,000 as of December 31, 2012. Industry within the Company's service territory is diversified, manufacturing such items as fixtures and furniture, electrical machinery, food products, paper, ordnance units, textile products, air conditioning systems, laundry detergent, barbells and motorcycles.

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The Company's water business is somewhat dependent on weather conditions, particularly the amount of rainfall. Revenues are particularly vulnerable to weather conditions in the summer months. Prolonged periods of hot and dry weather generally cause increased water usage for watering lawns, washing cars, and keeping golf courses and sports fields irrigated. Conversely, prolonged periods of dry weather could lead to drought restrictions from governmental authorities. Despite the Company's adequate water supply, customers may be required to cut back water usage under such drought restrictions which would negatively impact revenues. The Company has addressed some of this vulnerability by instituting minimum customer charges which are intended to cover fixed costs of operations under all likely weather conditions.

The Company's business does not require large amounts of working capital and is not dependent on any single customer or a very few customers for a material portion of its business. Increases in revenues are generally dependent on the Company's ability to obtain rate increases from the PPUC in a timely manner and in adequate amounts and to increase volumes of water sold through increased consumption and increases in the number of customers served. The Company continuously looks for water and wastewater acquisition and expansion opportunities both within and outside its current service territory as well as additional opportunities to enter into bulk water contracts with municipalities and other entities to supply water.

The Company has agreements with several municipalities to provide sewer billing services. Starting in 2012, the Company piloted a service line protection program in order to further diversify its business. Under this optional program, customers pay a fixed monthly fee, and the Company will repair or replace damaged customer service lines, as needed, subject to an annual maximum dollar amount. The Company plans to expand its pilot program during the second half of 2013.

Results of Operations

Three Months Ended March 31, 2013 Compared
With Three Months Ended March 31, 2012

Net income for the first quarter of 2013 was $2,139, an increase of $198, or 10.2%, from net income of $1,941 for the same period of 2012. The primary contributing factor to the increase was higher operating revenues which were partially offset by higher income taxes and depreciation expense.

Operating revenues for the three months ended March 31, 2013 increased $400, or 4.1%, from $9,669 for the three months ended March 31, 2012 to $10,069 for the corresponding 2013 period. The primary reasons for the increase were the distribution surcharge allowed by the PPUC and an increase in customers. The distribution surcharge allows the Company to add a charge to customers' water bills for qualified replacement costs of certain infrastructure without submitting a rate filing. The distribution surcharge added $328 to revenues during the first quarter of 2013 as compared to same period of 2012. The average number of customers served in the first quarter of 2013 increased as compared to the same period of 2012 by 922 customers, from 62,888 to 63,810 customers, primarily due to acquisitions. The total per capita volume of water sold in the first quarter of 2013 was consistent with the corresponding 2012 period. Industrial per capita consumption increased, but commercial and residential per capita consumption decreased. For the remainder of the year, the Company expects revenues to increase moderately based on the continuation of the distribution surcharge, higher summer demand and a potential rate increase expected to go into effect during the fourth quarter of the year. Other regulatory actions and weather patterns could impact results.

Operating expenses for the first quarter of 2013 increased $54, or 1.0%, from $5,242 for the first quarter of 2012 to $5,296 for the corresponding 2013 period. The increase was primarily due to higher depreciation expense of approximately $85 and increased customer accounts expense of approximately $35 for supplies related to a bill processing equipment upgrade and higher credit card fees. Other expenses increased by a net of $9. The increase was partially offset by reduced distribution system maintenance expense of approximately $44 and the absence of $31 in rate case expense. For the remainder of the year, depreciation expense is expected to continue to rise due to investment in utility plant and other operating expenses are expected to increase at a moderate rate as a result of increased summer activity and as costs to maintain and extend the distribution system continue to rise.

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Interest expense on debt for both the first quarter of 2013 and the first quarter of 2012 was $1,310, with no borrowings under the lines of credit. For the remainder of the year, interest expense is expected to remain consistent with 2012.

Allowance for funds used during construction increased $18, from $13 in the first quarter of 2012 to $31 in the 2013 period, due to a higher volume of eligible construction. For the remainder of the year, allowance for funds used during construction is expected to show a modest increase based on a projected increase in the amount of construction expenditures.

Other income (expenses), net for the first quarter of 2013 reflects increased expenses of $15 as compared to the same period of 2012. The net change was primarily due to lower income on life insurance policies of approximately $20. The increase in the value of the life insurance policies held as retirement program assets in the first quarter of 2013 was not as significant as the same period last year. Other expenses aggregating approximately $5 decreased as compared to the same period of 2012. For the remainder of the year, other income (expenses) will be largely determined by the change in market returns and discount rates for retirement programs and related assets.

Income taxes for the first quarter of 2013 increased $151, or 13.4%, compared to the same period of 2012 due to higher taxable income. The Company's effective tax rate was 37.5% for the first quarter of 2013 and 36.8% for the first quarter of 2012.

Rate Matters

See Note 9 to the financial statements.

Effective April 1, 2013, the Company's tariff included a distribution surcharge on revenues of 3.39%.

Acquisitions

See Note 8 to the financial statements.

The Company is also pursuing other water and wastewater acquisitions in and around its service territory to help offset further declines in per capita water consumption.

Capital Expenditures

For the three months ended March 31, 2013, the Company invested $2,442 in construction expenditures for routine items as well as various replacements of aging infrastructure. In addition, the Company invested $27 in the acquisition of a water system. The Company was able to fund operating activities, construction expenditures and acquisitions using internally-generated funds, customer advances and proceeds from its stock purchase plans.

The Company anticipates construction expenditures for the remainder of 2013 of approximately $11,700 exclusive of any potential acquisitions. In addition to routine transmission and distribution projects, a portion of the anticipated expenditures will be for additional main extensions, further upgrades to water treatment facilities, and various replacements of aging infrastructure. The Company intends to use primarily cash on hand and internally-generated funds for its anticipated construction and fund the remainder through line of credit borrowings, proceeds from its stock purchase plans, the DSIC and customer advances and contributions. Customer advances and contributions are expected to account for less than 5% of funding requirements in 2013. The Company believes it will have adequate availability under its lines of credit to meet its anticipated capital needs in 2013.

Liquidity and Capital Resources

Cash

The Company manages its cash through a cash management account that is directly connected to a line of credit. Excess cash generated automatically pays down outstanding borrowings under the line of credit arrangement. If there are no outstanding borrowings, the cash is used as an earnings credit to reduce banking fees. Likewise, if additional funds are needed beyond what is generated internally for payroll, to pay suppliers, or to pay debt service, funds are automatically borrowed under the line of credit. The cash balance of $4,554 as of March 31, 2013 represents the funds from operations generated internally primarily due to lower cash required for income taxes due to bonus depreciation. The Company expects the cash balance to decline in 2013 based on higher expected capital expenditures and the buyback of stock under the share repurchase program. After the cash balance is fully utilized, the cash management facility is expected to provide the necessary liquidity and funding for the Company's operations and buybacks of stock under the share repurchase program for the foreseeable future based on its past experience.

Accounts Receivable

The accounts receivable balance tends to follow the change in revenues but is also affected by the timeliness of payments by customers and the level of the reserve for doubtful accounts. A reserve is maintained at a level considered adequate to provide for losses that can be reasonably anticipated based on inactive accounts with outstanding balances. Management periodically evaluates the adequacy of the reserve based on past experience, agings of the receivables, adverse situations that may affect a customer's ability to pay, current economic conditions, and other relevant factors. If the status of these factors deteriorates, the Company may incur additional expenses for uncollectible accounts and experience a reduction in its internally-generated funds.

Internally-generated Funds

The amount of internally-generated funds available for operations and construction depends on the Company's ability to obtain timely and adequate rate relief, changes in regulations, customers' water usage, weather conditions, customer growth and controlled expenses. In the first three months of 2013, the Company generated $4,060 internally from operations as compared to $3,322 in the first three months of 2012. The collection of receivables and a decrease in interest paid due to the timing of interest payments increased cash flow from operating activities.

Credit Lines

Historically, the Company has borrowed $15,000 to $20,000 under its lines of credit before refinancing with long-term debt or equity capital. As of March 31, 2013, the Company maintained unsecured lines of credit aggregating $29,000 with three banks at interest rates ranging from LIBOR plus 1.20% to LIBOR plus 1.50%. The Company had no outstanding borrowings under any of its lines of credit as of March 31, 2013. The Company plans to renew its $5,000 line of credit that expires in June 2013 for an additional year, as well as extend the maturity of its $13,000 and $11,000 lines of credit into 2015, under similar terms and conditions.

The Company has taken steps to manage the risk of reduced credit availability by maintaining committed lines of credit that cannot be called on demand and obtaining a 2-year revolving maturity on its larger facilities. There is no guarantee that the Company will be able to obtain sufficient lines of credit with favorable terms in the future. In addition, if the Company is unable to refinance its line of credit borrowings with long-term debt or equity when necessary, it may have to eliminate or postpone capital expenditures. Management believes the Company will have adequate capacity under its current lines of credit to meet anticipated financing needs throughout 2013.

Long-term Debt

The Company's loan agreements contain various covenants and restrictions. As of March 31, 2013, management believes it was in compliance with all of these restrictions. See Note 4 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012 for additional information regarding these restrictions.

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The Company's debt (long-term debt plus current portion of long-term debt) as a percentage of the total capitalization, defined as total common stockholders' equity plus long-term debt (including current portion of long-term debt), was 45.7% as of March 31, 2013, compared with 46.0% as of December 31, 2012. The Company will likely allow the debt percentage to trend upward until it approaches fifty percent before matching increasing debt with additional equity. A debt to total capitalization ratio near fifty percent has historically been acceptable to the PPUC in rate filings. Due to its recent ability to generate more cash internally, the Company has been able to keep its ratio below fifty percent.

Deferred Income Taxes and Uncertain Tax Positions

The Company has seen an increase in its deferred income tax liability amounts over the last several years. This is primarily a result of the accelerated and bonus depreciation deduction available for federal tax purposes which creates differences between book and tax depreciation expense. The Company expects this trend to continue as it makes significant investments in capital expenditures and as the tax code continues to extend bonus depreciation. Bonus depreciation is currently expected to expire on January 1, 2014.

The Company has a substantial deferred income tax asset primarily due to the differences between the book and tax balances of the pension and deferred compensation plans from lower discount rates. The Company does not believe a valuation allowance is required due to the expected generation of future taxable income during the periods in which those temporary differences become deductible. The Company has determined there are no uncertain tax positions that require recognition as of March 31, 2013.

Common Stock

Common stockholders' equity as a percent of the total capitalization was 54.3% as of March 31, 2013, compared with 54.0% as of December 31, 2012. The volume of share repurchases could reduce this percentage. It is the Company's intent to target a ratio near fifty percent.

Credit Rating

On April 24, 2013, Standard & Poor's affirmed the Company's credit rating at A-, with a stable outlook and adequate liquidity. The Company's ability to maintain its credit rating depends, among other things, on adequate and timely rate relief, which it has been successful in obtaining, its ability to fund capital expenditures in a balanced manner using both debt and equity and its ability to generate cash flow. For the remainder of 2013, the Company's objectives will be to continue to maximize its funds provided by operations and maintain a strong capital structure.

Environmental Matters

In November 2011, during a routine tank cleaning, the Company discovered a small amount of mercury in the bottom of the tank. The tank was not in service at the time of the discovery and remains out of service. A number of tests were performed to confirm no mercury entered the water supply and no employees or contractors present during the discovery were impacted. The tank will remain out of service until it is approved for service by the Pennsylvania Department of Environmental Protection, or DEP. No disruption of service to any customers has occurred or is expected to occur. The Company incurred total costs of $186 through March 31, 2013. Recent tests have shown the tank is in compliance with safe drinking water standards and the Company has requested permission to place the tank back into service from the DEP. If the DEP does not approve based on the testing completed, other options will be reviewed, including a project to reline and strengthen the interior of the tank or replace the tank through capital expenditures.

Labor Relations

The current union contract expired on April 30, 2013. Management and the union leadership have agreed to honor the expired contract and continue to work under its terms. Both sides are negotiating in good faith and the Company expects to reach an operationally and fiscally responsible agreement with no interruption of service.

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Critical Accounting Estimates

The methods, estimates and judgments the Company used in applying its accounting policies have a significant impact on the results reported in its financial statements. The Company's accounting policies require management to make subjective judgments because of the need to make estimates of matters that are inherently uncertain. The Company's most critical accounting estimates include regulatory assets and liabilities, revenue recognition and accounting for its pension plans. There has been no significant change in accounting estimates or the method of estimation during the quarter ended March 31, 2013.

Off-Balance Sheet Arrangements

The Company does not use off-balance sheet transactions, arrangements or obligations that may have a material current or future effect on financial condition, results of operations, liquidity, capital expenditures, capital resources or significant components of revenues or expenses. The Company does not use securitization of receivables or unconsolidated entities. The Company uses a derivative financial instrument, an interest rate swap agreement discussed in Note 5 to the financial statements included herein, for risk management purposes. The Company does not engage in trading or other risk management activities, does not use other derivative financial instruments for any purpose, has no lease obligations, no guarantees and does not have material transactions involving related parties.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The Company's operations are exposed to market risks primarily as a result of changes in interest rates under its lines of credit. The Company has unsecured lines of credit with three banks having a combined maximum availability of $29,000. The first line of credit, in the amount of $13,000, is a committed line of credit with a revolving 2-year maturity (currently May 2014), and carries an interest rate of LIBOR plus 1.20%. The second line of credit, in the amount of $11,000, is a committed line of credit, which matures in May 2014 and carries an interest rate of LIBOR plus 1.25%. This line of credit has a compensating balance requirement of $500 (see Note 7 to the financial statements included herein). The third line of credit, in the amount of $5,000, is a committed line of credit, which matures in June 2013 and carries an interest rate of LIBOR plus 1.50%. The Company had no outstanding borrowings under any of its lines of credit as of March 31, 2013. Other than lines of credit, the Company has long-term fixed rate debt obligations as discussed in Note 7 to the financial statements included herein and a variable rate Pennsylvania Economic Development Financing Authority (PEDFA) loan agreement described below.

In May 2008, the PEDFA issued $12,000 aggregate principal amount of PEDFA Exempt Facilities Revenue Bonds, Series A (the "Bonds"). The proceeds of this bond issue were used to refund the $12,000 PEDFA Exempt Facilities Revenue Bonds, Series B of 2004 which were refunded due to bond insurer downgrading issues. The PEDFA then loaned the proceeds to the Company pursuant to a variable interest rate loan agreement with a maturity date of October 1, 2029. The interest rate under this loan agreement averaged 0.13% during the three months ended March 31, 2013. In connection with the loan agreement, the Company retained its interest rate swap agreement whereby the Company effectively exchanged its floating rate obligation for a fixed rate obligation. The purpose of the interest rate swap is to manage the Company's exposure to fluctuations in the interest rate. If the interest rate swap agreement works as intended, the receive rate on the swap should approximate the variable rate the Company pays on the PEDFA Series A Bond Issue, thereby minimizing its risk. See Note 5 to the financial statements included herein for additional information regarding the interest rate swap.

In addition to the interest rate swap agreement, the Company entered into a Reimbursement, Credit and Security Agreement with PNC Bank, National Association ("the Bank"), dated as of May 1, 2008, in order to enhance the marketability of and to minimize the interest rate on the Bonds. This agreement provides for a direct pay letter of credit issued by the Bank to the trustee for the Bonds. The current expiration date of the letter of credit is May 6, 2015. It is reviewed annually for a potential extension of the expiration date. The Company's responsibility under this agreement is to reimburse the Bank on a timely basis for interest payments made to the bondholders and for any tendered Bonds that could not be remarketed. The Company has fourteen months from the time Bonds are tendered to reimburse the Bank. If the direct pay letter of credit is not renewed, the Company would be required to pay the Bank immediately for any tendered Bonds and reclassify a portion of the Bonds as current liabilities. In addition, the interest rate swap agreement would terminate causing a potential payment by the Company to the counterparty. Both the letter of credit and the swap agreement can potentially be transferred upon this type of event.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Company's management, with the participation of the Company's President and Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this report. Based upon this evaluation, the Company's President and Chief Executive Officer along with the Chief Financial Officer concluded that the Company's disclosure controls and procedures as of the end of the period covered by this report are effective such that the information required to be disclosed by the Company in reports filed under the Securities Exchange Act of 1934, as amended, is (i) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and (ii) accumulated and communicated to the Company's management, including the President and Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding disclosure. A controls system cannot provide absolute assurance, however, that the objectives of the controls system are met, and no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within a company have been detected.

No change in the Company's internal control over financial reporting occurred during the Company's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Part II – OTHER INFORMATION

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table summarizes the Company's purchases of its common stock for the quarter ended March 31, 2013.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as a Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
Jan. 1 – Jan. 31, 2013	-	$-	-	-
Feb. 1 – Feb. 28, 2013	-	$-	-	-

Mar. 1 – Mar. 31, 2013	10,639	$18.56	10,639	1,189,361
Total	10,639	$18.56	10,639	1,189,361

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On March 11, 2013, the Board of Directors authorized a share repurchase program granting the Company authority to repurchase up to 1,200,000 shares of the Company's common stock from time to time. Under the stock repurchase program, the Company may repurchase shares in the open market or through privately negotiated transactions. The Company may suspend or discontinue the repurchase program at any time. The Company did not repurchase any shares that were not part of the publicly announced plan during the quarter ended March 31, 2013.

The Company's loan agreements contain various covenants and restrictions regarding dividends and share repurchases. As of March 31, 2013, management believes it was in compliance with all of these restrictions. See Note 4 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012 for additional information regarding these restrictions.

The Company will fund repurchases under the share repurchase program with internally generated funds and borrowings under its credit facilities if necessary.

Item 6.	Exhibits
Exhibit No.	Description
3	Amended and Restated Articles of Incorporation. Incorporated herein by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 4, 2010.
3.1	Amended and Restated By-Laws. Incorporated herein by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on January 26, 2012.
31.1	Certification of Chief Executive Officer, pursuant to Rule 13a-14(a)/15d-14(a)

	under the Securities Exchange Act of 1934.
31.2	Certification of Chief Financial Officer, pursuant to Rule 13a-14(a)/15d-14(a) under the Securities Exchange Act of 1934.
32.1	Certification of Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase
101.LAB	XBRL Taxonomy Extension Label Linkbase

101.PRE	XBRL Taxonomy Extension Presentation Linkbase

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SIGNATURES

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

	THE YORK WATER COMPANY
Date: May 8, 2013	/s/Jeffrey R. Hines Jeffrey R. Hines Principal Executive Officer
Date: May 8, 2013	/s/Kathleen M. Miller Kathleen M. Miller Principal Financial and Accounting Officer

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