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September 30, 2005

Mr. Robert J. Pellatt  
Commission Secretary  
British Columbia Utilities Commission  
Sixth Floor – 900 Howe Street  
Vancouver, BC V6Z 2N3

Dear Mr. Pellatt:

**RE: British Columbia Hydro and Power Authority (BC Hydro)  
2004/05 and 2005/06 Revenue Requirements Application  
British Columbia Utilities Commission (Commission) Order G-96-04  
Decision, October 29, 2004, Page 45, Directive No. 17 Page 218**

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Pursuant to British Columbia Utilities Commission (Commission) Directive No. 17 of the October 29, 2004 Decision concerning BC Hydro's 2004/05 to 2005/06 Revenue Requirements Application, BC Hydro is filing herein its First Quarter Deferral Account Report as at June 30, 2005. This contains information on the Heritage Payment Obligation Deferral Account (HDA), the Non-Heritage Deferral Account (NHDA), the Trade Income Deferral Account (TIDA) and the BCTC Transition Deferral Account (BCTC TDA).

We trust the Commission will find all of the above in order.

Yours sincerely,



Tony Morris  
Acting Chief Regulatory Officer

**BC Hydro**  
**Deferral Account Report**  
**June 30, 2005**

August 2005

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**SUMMARY OF DEFERRAL ACCOUNTS**  
**For the three months ended June 30, 2005**

	<u>Reference Schedule</u>	<u>Heritage Deferral Account (HDA)</u>	<u>Non- Heritage Deferral Account (NHDA)</u>	<u>Trade Income Deferral Account (TIDA)</u>	<u>BCTC Transition Deferral Account (TIDA)</u>	<u>Total</u>
10 Balance as of April 1, 2005 (including interest)		137.8	131.3	(114.5)	-	154.6
11 Transfers for the three months ended 12 June 30, 2005	C, C-2	54.3	10.9	(48.6)	(0.3)	16.4
13 Interest on deferral accounts <i>(Note 1)</i>		3.3	2.9	(3.0)	-	3.2
14		<u>195.4</u>	<u>145.1</u>	<u>(166.1)</u>	<u>(0.3)</u>	<u>174.2</u>
16 General ledger (G/L) account numbers for Deferral Accounts <i>(Note 2)</i>		076000	076100	076200	076400	
17 G/L account numbers for interest on Deferral Accounts <i>(Note 2)</i>		076001	076101	076201	076401	

- 18 • The transfers to the HDA and NHDA relates to variances in energy costs, not related to changes  
19 in load, from the forecast used in establishing rates (See Schedule C). These energy cost  
20 variances are largely due to higher than planned market prices for energy purchases and to the  
21 greater use of energy purchases in place of planned hydro generation. Hydro generation was  
22 reduced by approximately 131 GW.h due to lower water inflows and increased energy purchases  
23 as a result of greater market opportunities for economic purchases. The decision to import energy  
24 instead of utilizing hydro generation is based on many factors, such as the forecast market price  
25 of energy in future periods relative to the current period, current reservoir levels and future  
26 demand requirements.
- 27 • The transfer to the TIDA relates to the higher than Plan Trade Income.
- 28 • The transfer to the BCTC Transition Deferral Account relates to two variances: (See Schedule C-  
29 3)
- 30 • a) variances between BC Hydro's Asset Management/Maintenance Revenue  
31 Requirement forecast at \$116.7 million in BC Hydro's Revenue Requirement and BC  
32 Hydro's actual Asset Management/Maintenance charges from BCTC, and
- 33 • b) variances between BCTC's Revenue Requirement forecast charges to BC Hydro of  
34 \$61.0 million in BC Hydro's Revenue Requirement and the BCTC charges to BC Hydro.
- 35 • Notes:
- 36 1. The interest charge/credit is shown as part of finance charges on the Statement of Operations  
37 (Schedule A - 2). Interest is calculated on the ending months balance (excluding the interest  
38 portion) in each deferral account. The interest rate used is BC Hydro's weighted cost of debt.
- 39 2. In compliance with Commission Directive No.19 of the October 29, 2004 Decision, BC Hydro is  
40 providing the G/L accounts from its Code of Accounts used to track the deferral account  
41 balances. The G/L accounts ending in 00 above refer to the deferral account balances before  
42 interest and the G/L accounts ending in 01 above refer to the interest portion on the deferral  
43 accounts. The G/L accounts are Balance Sheet items.

1

## Deferral Account Rules

2 The following “rules” are used by BC Hydro for providing clarity in determining the deferral  
3 account transfers. These rules are derived from BC Hydro’s interpretation of the evidence and  
4 testimony provided during the 2004 Revenue Requirement proceeding and in response to  
5 Commission directive No. 19 of the October 29, 2004 Decision.

### 6 Heritage Payment Obligation Deferral Account (HDA)

7 Variances between the forecast and the actual cost for the following components of the Heritage  
8 Payment Obligation will flow through the HDA:

- 9 1. Cost of energy, except those arising from changes in customer load. This item is expanded in  
10 greater detail below to provide clarification on the methodology used to determine variances:
  - 11 • Market electricity purchases are treated as the dispatchable resource;
  - 12 • If no market purchases are planned or made, the next dispatchable resource is assumed  
13 to be generation from the Burrard facility;
  - 14 • If generation volumes are lower than Plan, the Load Variance is calculated using the Plan  
15 YTD average market purchase price of electricity;
  - 16 • If generation volumes are higher than Plan, the Load Variance is calculated using the  
17 Actual YTD average market purchase price of electricity (netted for any gains/losses on  
18 energy derivatives and financial instruments used to manage energy costs); and
  - 19 • Cost of energy variances resulting from changes to compensation and mitigation costs,  
20 water rental remissions, or Skagit energy transportation contracts are eligible for deferral.  
21 These are price variances as they do not vary with volume.
- 22 2. Variable costs related to thermal generation.
- 23 3. Significant unplanned major maintenance costs greater than \$1 million related to single event  
24 equipment or infrastructure failure or caused by weather related events.
- 25 4. Significant unplanned major capital expenditures having an incremental annual impact on the  
26 Income Statement greater than \$1 million related to single event equipment or infrastructure  
27 failure or caused by weather related events.
- 28 5. Amortization of unplanned deferred capital costs pursuant to Commission Order No. G-53-02.
- 29 6. All net revenues from surplus hydro electricity sales.
- 30 7. Skagit Valley Treaty revenues and ancillary services revenues.
  - 31 • An interest charge/credit is to be calculated on the ending monthly balance (excluding the  
32 interest portion) in each deferral account. The interest rate used is BC Hydro’s weighted cost  
33 of debt during the period.

1 **Non-Heritage Deferral Account (NHDA)**

2 Variances between the forecast and the actual cost for the following components of the Non-  
3 Heritage Cost of Energy will flow through the NHDA:

4 1. Cost of energy - all non-HPO energy costs except those arising from changes in customer  
5 load. This item is expanded in greater detail below to provide clarification on the methodology  
6 used to determine variances:

7 • If supply volumes are lower than Plan, the Load Variance is calculated using the Plan  
8 average YTD unit purchase price for IPP's. For Non-Integrated Supply, the fuel costs are  
9 treated as the next dispatchable resource;

10 • If supply volumes are higher than Plan, for IPP's the Load Variance is calculated using  
11 the weighted average actual YTD unit prices of IPP's. For Non-Integrated supply, the fuel  
12 costs are treated as the next dispatchable resource. The weighted average unit price  
13 would include any YTD gains/losses on energy derivatives and financial instruments used  
14 to manage energy costs;

15 • Any variances relating to fixed price gas transportation contracts would flow through the  
16 deferral accounts as they do not vary with volume;

17 • Future Trade: when Powerex purchases energy for future trade the cost of the purchase  
18 from the external party and the sale to BC Hydro of this energy is recorded in Powerex  
19 and is included as part of Trade Income. The BC Hydro side of this entry is shown as part  
20 of domestic energy costs (on consolidation, the Powerex revenue from BC Hydro and the  
21 BCH energy costs from Powerex are eliminated). The difference between Actual and  
22 Plan on the BC Hydro side relating to energy for future trade will flow through the Non-  
23 Heritage Deferral Account. The Powerex side of the transaction is part of Trade Income  
24 and flows through the Trade Income Deferral Account. Similar treatment is made when  
25 the energy is returned to Powerex; and

26 • Future Trade: when Powerex purchases energy for future trade, the Heritage Payment  
27 Obligation (HPO) is charged with a notional water rental charge for the use of this energy.  
28 The other side of this entry is shown as part of Non-Heritage energy. These entries are  
29 eliminated on consolidation. The difference between the Actual and Plan notional water  
30 rentals that is part of the HPO would flow through the Heritage Deferral Account. The  
31 opposite variance relating to the Non-Heritage side of the notional water rental  
32 transaction will flow through the Non-Heritage Deferral Account.

33 2. Significant unplanned major maintenance costs greater than \$1 million related to single event  
34 equipment or infrastructure failure or caused by weather related events.

35 3. Significant unplanned major capital expenditures having an incremental annual impact on the  
36 Income Statement greater than \$1 million related to single event equipment or infrastructure  
37 failure or caused by weather related events.

38 4. Founding Partner Benefits and any CIS Credits under the ABS Contract.

39 • An interest charge/credit is to be calculated on the ending monthly balance (excluding the  
40 interest portion) in each deferral account. The interest rate used is BC Hydro's weighted cost  
41 of debt during the period.

**1 Trade Income Deferral Account (TIDA)**

- 2 • Any variance between the forecast Trade Income and the actual trade income will flow  
3 through the TIDA except where Annual Trade Income is below \$Nil and above \$200 million.
- 4 • An interest charge/credit is to be calculated on the ending monthly balance (excluding the  
5 interest portion) in each deferral account. The interest rate used is BC Hydro's weighted cost  
6 of debt during the period.

1 **BCTC Transition Deferral Account (BCTC TDA)**

2 • The BCTC Transition Deferral Account relates to two variances:

3 • a) variances between BC Hydro's Asset Management/Maintenance Revenue  
4 Requirement forecast at \$116.7 million in BC Hydro's Revenue Requirement and BC  
5 Hydro's actual Asset Management/Maintenance charges from BCTC, and

6 • b) variances between BCTC's Revenue Requirement forecast charges to BC Hydro of  
7 \$61.0 million in BC Hydro's Revenue Requirement and the BCTC charges to BC Hydro.

8 • An interest charge/credit is to be calculated on the ending monthly balance (excluding the  
9 interest portion) in each deferral account. The interest rate used is BC Hydro's weighted cost  
10 of debt during the period.

**Consolidated Statement of Operations**  
**For three months ended June 30, 2005**  
**(\$ Millions)**

	A	B	C	
	Actual	Plan	Variance	Reference Schedule
<b>REVENUES</b>				
Domestic				
Residential	218	220	(2)	
Light industrial and commercial	239	227	11	
Large industrial	143	131	12	
Other energy sales	19	16	3	
Miscellaneous	14	14	(0)	
	<u>633</u>	<u>608</u>	<u>24</u>	
Intersegment revenues	4	12	(8)	D
	<u>637</u>	<u>621</u>	<u>16</u>	
<b>EXPENSES</b>				
Domestic energy costs	297	214	(83)	B
BCTC wholesale transmission service	19	15	(4)	
BCTC asset management fee	29	29	0	
Operations expense	45	32	(13)	
Maintenance expense	34	35	0	
Administration expense	31	32	1	
Depreciation and amortization	102	105	3	
Taxes	36	37	1	
Finance charges	128	112	(16)	
	<u>722</u>	<u>612</u>	<u>(110)</u>	
<b>DOMESTIC INCOME (LOSS) BEFORE TRANSFER (TO)/FROM DEFERRAL ACCTS</b>	<b>(85)</b>	<b>8</b>	<b>(94)</b>	
<b>TRADE INCOME</b>	<b>70</b>	<b>21</b>	<b>49</b>	
<b>TOTAL INCOME BEFORE TRANSFER (TO)/FROM DEFERRAL ACCOUNTS</b>	<b>(15)</b>	<b>30</b>	<b>(45)</b>	
Heritage Deferral Account transfers	54	-	54	C
Non- Heritage Deferral Account transfers	11	(1)	12	C
Trade Income Deferral Account transfers	(49)	-	(49)	C-2
BCTC Transition Deferral Account transfers	(0)	-	(0)	
Regulatory provision for future removal and site restoration costs	4	-	4	
<b>TOTAL NET INCOME</b>	<b><u>5</u></b>	<b><u>29</u></b>	<b><u>(24)</u></b>	

1. The Statement of Operations is presented in a consistent format to the Statement of Operations presented in the 2004 Revenue Requirement Application.
2. The 'Plan' is the 2006 Plan per the Revenue Requirement in terms of the BCUC October 29, 2004 Decision.

**DOMESTIC COST OF ENERGY**  
**For the three months ended June 30, 2005**

(\$ millions)	Actual	Plan	Variance	Reference Schedule
<b>Heritage Energy:</b>				
Water rentals	53	56	3	
Market electricity purchases	120	46	(73)	C-1
Natural gas for thermal generation	7	7	(0)	
Domestic Transmission	4	4	(0)	
Other	1	2	1	
	<b>184</b>	<b>115</b>	<b>(70)</b>	C
<b>Non-Heritage Energy:</b>				
IPP's and long-term purchase commitments	106	93	(13)	
Non-Integrated Areas:				
NIA Fuel	2	1	(1)	
NIA IPP's	2	3	1	
Gas and Other Transportation	3	3	(0)	
Net purchases from Powerex (Trade Account)	-	-	-	
	<b>113</b>	<b>100</b>	<b>(13)</b>	C
<b>Total Domestic Cost of Energy</b>	<b>297</b>	<b>214</b>	<b>(83)</b>	A - 2
<b>(GW.h)</b>				
<b>Heritage Energy:</b>				
Water rentals	8,937	9,068	131	
Market electricity purchases	2,252	1,496	(756)	C-1
Natural gas for thermal generation	50	65	15	
Exchange net	218	273	55	
	<b>11,457</b>	<b>10,902</b>	<b>(555)</b>	C
<b>Non-Heritage Energy:</b>				
IPP's and long-term purchase commitments	1,601	1,632	31	
Non-Integrated Areas:				
NIA Fuel	16	10	(5)	
NIA IPP's	9	15	6	
	<b>1,625</b>	<b>1,657</b>	<b>31</b>	C-1
<b>Total sources of supply</b>	<b>13,082</b>	<b>12,558</b>	<b>(524)</b>	
Less : Line loss and system use	(1,082)	(1,126)	(45)	C-1
Net sales to Powerex	(69)	61	130	C
<b>Domestic Sales Volumes</b>	<b>11,931</b>	<b>11,493</b>	<b>(438)</b>	C-1
<b>(\$/MW.h)</b>				
Water rentals	5.9	6.2	0.2	
Market electricity purchases	53.1	31.1	(22.0)	
Natural gas for thermal generation	140.6	104.2	(36.4)	
IPP's and long-term purchase commitments	66.0	56.9	(9.1)	C-1
Non-Integrated Areas:				
NIA Fuel	136.3	104.2	(32.1)	
NIA IPP's	186.0	168.2	(17.9)	
<b>Total weighted average cost</b>	<b>22.7</b>	<b>17.1</b>	<b>(5.7)</b>	

The Cost of Energy Schedule is presented in a similar format to the Cost of Energy Schedule (Schedule A-9) presented as part of the 2004 Revenue Requirement Application. The only exception is that this schedule further breaks down energy costs between Heritage and Non-Heritage cost of energy.



**Transfer to HDA and NHDA continued**

**Schedule C-1**

1 BC Hydro also enters into derivatives with third parties to manage foreign exchange exposure on the corresponding  
 2 energy derivatives. These foreign exchange derivative transactions are made on a cash flow basis of the underlying  
 3 or gas electricity derivatives which, by market convention, settle on the 20th or 25th of the following month.  
 4 Gains and losses on these transactions are netted against Heritage and Non-Heritage Energy purchase costs  
 5 as they are used to manage these energy costs and mitigate risk. On the consolidated income statement these  
 6 gains/losses are recorded as part of other miscellaneous income to comply with GAAP reporting requirements.  
 7 The gain for the three months ended June 30, 2005 was nil related to Heritage Energy and a loss of \$0.8 million  
 8 related to Non-Heritage Energy.

9  
 10 (\$millions)  
 11 **Summary:**

	<u>Heritage</u>	<u>Non-</u>	<u>Total</u>	<b>Reference Schedule</b>
13 Gain / (Loss) on energy derivatives	(9.4)	1.9	(7.5)	D
14 ADD Unrealized F/X Gain (loss) on US\$ denominated commodity derivatives	0.3	0.1	0.4	
15 Gain / (Loss) on energy derivatives	(9.1)	1.9	(7.2)	
17 Gain / (Loss) on Foreign exchange derivatives	0.3	(0.8)	(0.5)	
18 LESS Unrealized F/X Gain (loss) on US\$ denominated commodity derivatives	(0.3)	(0.1)	(0.4)	
19 Gain / (Loss) on Foreign exchange derivatives	-	(0.8)	(0.8)	
21 Total Gain/(Loss) on Derivatives	<u>\$ (9.1)</u>	<u>\$ 1.1</u>	<u>\$ (8.0)</u>	

22  
 23  
 24 3. These sales relate to the return of energy bought by Powerex in prior periods to enable future sale. These revenues are  
 25 eliminated against trade cost of energy on consolidation. The transactions between BC Hydro and Powerex has no net impact  
 26 on the combined NHDA and the Trade Income Deferral Account.

27  
 28 4. This relates to the foreign exchange gain on the Trade Account payable to Powerex. Powerex would have a corresponding  
 29 loss on their receivable and this loss would be part of Trade Income. Foreign exchange gains/losses arise as the Trade Account  
 30 is recorded in \$US. The gain/loss on the BC Hydro side is eliminated against the loss/gain on the Powerex side on consolidation  
 31 within the finance charge component. As the mirror entry for Trade Income relating to F/X on the Trade Account is recorded on  
 32 the Non-Heritage energy side, there is no net impact on the combined NHDA and TIDA due to these transactions.

33  
 34  
 35  
 36 5. Load Variance for HDA is calculated as the Load Volume variance multiplied by the actual average price of market  
 37 purchases net of the gain/losses on mark to market energy transactions. (425 GW.h \* \$57.2/MW.h) = \$24.3 million.

			<b>Reference Schedule</b>
40 (\$millions)			
42 Market energy purchases	\$ 119.6		B
43 Mark to market gains	9.1		C
44	<u>\$ 128.7</u>	(1)	
46 Market energy purchase volumes (GW.h)	2,252	(2)	B
48 Average price ((1)/(2)) (\$/MW.h)	57.2		
50 Load Volume variance (GW.h)	425		C
52 6. Load Variance for NHDA calculated as Load Volume variance multiplied by the Plan average price of IPP and 53 long-term purchase commitments (30 GW.h * \$56.9/MW.h) = \$1.7 million.			C

<b>Reconciliation of Energy Volumes (GW.h)</b>		
57 Increase in domestic sales volumes from Plan	438	B
58 Decrease in line loss and system use	(45)	B
59 Net change in volumes	<u>394</u>	
61 Change in HPO energy volumes	425	C
62 Change in Non-Heritage energy:		
63 IPP's and long-term purchase commitments	(31)	B
64 Non-Integrated areas	(1)	
65	<u>394</u>	

Schedule C - 2

1	<b>Transfer to Trade Income Deferral Account</b>			
2	<b>For the three months ended June 30, 2005</b>			
3	(\$ in millions)			
4				
5				<b>Reference</b>
6				<b>Schedule</b>
7				
8	Actual Trade Income	\$ 70.0		A - 2
9	Excess over Cap for deferral account transfer	-		
10		<u>70.0</u>		
11	Less: Plan Trade Income	21.4		A - 2
12	Transfer to Trade Income Deferral Account	<u><u>48.6</u></u>		A

**Transfer to BCTC Transition Deferral Account**  
**For the three months ended June 30, 2005**  
(\$ in millions)

	F2006 Annual Forecast	F2006 Annual Plan	Variance	Reference Schedule
<u>BCTC Asset Management Fee</u>				
Transmission Assets	90.2	94.6	(4.4)	
Generation Related Transmission Assets	10.1	10.3	(0.2)	
Substation Distribution Assets	10.9	11.8	(0.9)	
	<u>111.2</u>	<u>116.7</u>	<u>(5.5)</u>	
<u>BCTC Wholesale Transmission Service / BCTC Revenue Forecast (Note 2)</u>				
BCTC Network Integrated Transmission Service (NITS)	57.4	61.0	(3.6)	
BCTC Point to Point (PTP) Expenses	4.9	-	4.9	
Ancillary Services Expenses	3.3	-	3.3	
	<u>65.6</u>	<u>61.0</u>	<u>4.6</u>	
<b>Total</b>	<u><u>176.8</u></u>	<u><u>177.7</u></u>	<u><u>(0.9)</u></u>	
BCTC Transition Deferral - Annual Forecast			(0.9)	
BCTC Transition Deferral - 3 Months			<u><u>(0.3)</u></u>	A

**Notes:**

1. The transfer to the BCTC Transition Deferral Account relates to two variances:

a) variances between BC Hydro's Asset Management/Maintenance Revenue Requirement forecast at \$116.7 million in BC Hydro's Revenue Requirement and BC Hydro's actual Asset Management / Maintenance charges from BCTC, and

b) variances between BCTC's Revenue Requirement forecast charges to BC Hydro of \$61.0 million in BC Hydro's Revenue Requirement and the BCTC charges to BC Hydro.

2. At the time of preparing the BC Hydro Revenue Requirement, it was not anticipated that BCTC would be sharing in the Point to Point (PTP) revenues collected and any PTP revenues collected by BCTC were credited back to BC Hydro. Therefore, BC Hydro's Revenue Requirement did not include any net costs for collection from BC Hydro customers for any net external PTP expenses on consolidation.

In terms of the BCUC Decision on BCTC's Revenue Requirement, BC Hydro is now sharing both the Network Integrated Transmission Service (NITS) and PTP revenues with BCTC. Therefore, on consolidation BC Hydro now has net external PTP expenses that were not included in its approved revenue requirement. Based on BCTC's Approved Revenue Requirement, BCTC is collecting approximately \$43.3 million in PTP from BC Hydro, of which BC Hydro is then credited with \$38.4 million as revenues. On consolidation this results in a net external PTP expenses of \$4.9 million. Similarly, Ancillary Services costs of \$3.3 million were not anticipated in the BC Hydro Revenue Requirement.

**INTERSEGMENT REVENUES**  
**For the year three months ended June 30, 2005**

	<u>Actual</u>	<u>Plan</u>	<u>Variance</u>	<u>Reference Schedule</u>
Net sales to Powerex - Future Trade <i>(Note 1)</i>	2	\$ (3)	\$ 5	C
Point-to-Point wheeling charge to Powerex <i>(Note 2)</i>	4	11	(7)	
Point-to-Point wheeling charge to BCH <i>(Note 3)</i>	4	3	1	
Allocation of BCH Corporate costs to Powerex <i>(Note 4)</i>	1	1	(0)	
Mark to Market losses on energy derivatives with Powerex <i>(Note 5)</i>	(7)	-	(7)	C
<b>Total</b>	<b>4</b>	<b>\$ 12</b>	<b>\$ (8)</b>	A - 2

**Notes:**

1. These sales in the Plan relate to a return of energy bought by Powerex in prior periods to enable future sale. These revenues are eliminated against trade cost of energy on consolidation.
2. These transmission revenues relate to an allocation of BC Hydro's cost of purchases of point-to-point transmission within BC for export and some import transactions. These revenues are eliminated against trade cost of energy on consolidation.
3. These transmission revenues relate to an allocation of BC Hydro's cost of purchases of point-to-point transmission relating to BC Hydro's Skagit Valley Treaty commitment. These revenues are eliminated against domestic cost of energy on consolidation.
4. These revenues relate to an allocation of corporate costs to Powerex and are eliminated against trade income on consolidation.
5. This relates to a mark to market losses on energy derivatives with Powerex. This revenue is eliminated against trade income on consolidation. The loss is broken down as a \$9.4 million loss on Heritage Energy and a \$1.8 million gain on Non-Heritage Energy.