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July 16, 2007

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 (BCUC) Order G-96-04  
Decision, October 29, 2004, Page 45, Directive No. 17 Page 218**

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Pursuant to BCUC Directive No. 17 of the October 29, 2004 Decision concerning BC Hydro's 2004/05 to 2005/06 Revenue Requirements Application, BC Hydro attaches its Fiscal 2007 (F2007) Fourth Quarter (Q4) Deferral Account Report as at March 31, 2007. This report 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 Deferral Account (BCTC DA).

Yours sincerely,



Joanna Sofield  
Chief Regulatory Officer

Enclosure (1)

**BC Hydro**

**Deferral Account Report**

**For the Year Ended**  
**March 31, 2007**

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British Columbia Hydro and Power Authority  
 Summary of Deferral Accounts  
 For the Year Ended March 31, 2007  
 (\$ in millions)

Schedule A

Particulars (1)	Opening Balance (2)	Additions (Sch B) (3)	Amort. (4)	Interest (5)	Ending Balance (6)
Heritage Deferral Account (HDA)	\$ 240.7	\$ (23.4)	\$ (53.3)	\$ 14.1	\$ 178.1
Non-Heritage Deferral Account (NHDA)	204.6	35.5	(45.3)	14.0	208.8
Trade Income Deferral Account (TIDA)	(213.3)	(20.2)	47.2	(15.9)	(202.2)
BCTC Deferral Account	24.9	(14.4)	1.6	1.2	13.3
<b>Total</b>	<b>\$ 256.9</b>	<b>\$ (22.6)</b>	<b>\$ (49.8)</b>	<b>\$ 13.4</b>	<b>\$ 198.0</b>

The transfers to the HDA and NHDA are related to variances in energy costs from the forecast used in establishing rates as set out in the Evidentiary Update filed on August 31, 2006 to the F07/F08 Revenue Requirements Filing, and agreed to as part of the Negotiated Settlement Agreement of November 2006.

The transfers to the HDA are related to lower net hydro generation and lower market prices for energy. The decision to import energy instead of utilizing hydrogeneration is based on many factors, such as the forecast market price of energy in future periods relative to the current period, current reservoir levels and future demand requirements.

The NHDA energy cost variances are largely due to transactions with Powerex (Net Sales to Powerex - Future Use). The offsetting transactions are recorded as part of Trade Income. An increase in market purchases to offset the decrease in deliveries from Independent Power Producers also contributed to the variance.

The transfer to the TIDA relates to the higher than forecast Trade Income. This includes the offsets for the amounts included in the NHDA transfer noted above.

Amortization of the deferral accounts reflects the \$39.6 million fixed portion agreed to in the Negotiated Settlement Agreement and the 2% rate rider starting in February 2007. The amortization is allocated to each deferral account based on the proportion of the ending F2006 deferral account balances

Interest is calculated on the ending monthly balance (excluding the interest portion) in each deferral account. The interest rate used is BC Hydro's weighted cost of debt for the prior fiscal year ended as agreed to in the NSA.

British Columbia Hydro and Power Authority  
 Summary of Deferral Account Additions  
 For the Year Ended March 31, 2007  
 (\$ in millions)

Schedule B

Particulars (1)	Actual (2)	Plan (3)	Variance (4)	Ref. (5)
<b>Heritage Deferral Account</b>				
Cost of Energy - Total Heritage	\$ 458.0	\$ 493.0	\$ (35.0)	Sch C- L7
Notional Water Rental (Displaced Hydro)	2.5	(2.4)	4.9	Sch F- Note 1
Mark to market (gains)/losses on derivatives	1.3	(2.9)	4.2	Sch F- Note 2
Significant unplanned major maintenance costs	1.1	-	1.1	Sch F- Note 4
Significant unplanned major capital expenditures	-	-	-	
Amortization of unplanned deferred capital cost per BCUC Order No. G-53-02	4.2	4.5	(0.3)	
Skagit Valley Treaty revenue	(22.6)	(23.6)	1.0	
Subtotal	<u>\$ 444.5</u>	<u>\$ 468.6</u>	<u>(24.1)</u>	
Cost of energy - Variable cost related to thermal generation			0.7	Sch F- Note 3
Total			<u>\$ (23.4)</u>	
<b>Non-Heritage Deferral Account</b>				
Cost of Energy - Total Non-Heritage	\$ 594.8	\$ 559.8	\$ 35.0	Sch C- L18
Notional Water Rental (Displaced Hydro)	(2.5)	2.4	(4.9)	Sch F- Note 1
Mark to market (gains)/losses on derivatives	19.8	16.5	3.3	Sch F- Note 2
Net sales to Powerex - future use	-	(4.0)	4.0	Sch E
FX gain on Powerex trade account	(0.2)	(5.1)	4.9	Sch F.1- Note 5
Significant unplanned major maintenance costs	(2.7)	-	(2.7)	Sch F- Note 7
Founding Partner Benefits - ABS Contract	(0.6)	-	(0.6)	
Subtotal	<u>\$ 608.6</u>	<u>\$ 569.6</u>	<u>39.0</u>	
Customer Load Variance			(3.5)	Sch F.1- Note 6
Total			<u>\$ 35.5</u>	
<b>Trade Income Deferral Account</b>				
Actual Trade Income			\$ 259.1	
Excess over Cap for deferral account transfer			(59.1)	
			<u>200.0</u>	
Less: Trade Income included in the NSA			179.8	
Total			<u>\$ (20.2)</u>	
<b>BCTC Deferral Account</b>				
BCTC Asset Management Fee				
Transmission Assets	\$ 87.3	\$ 87.3	\$ -	
Generation Related Transmission Assets	5.4	5.4	-	
Substation Distribution Assets	12.7	11.7	1.0	
BCTC Wholesale Transmission Service / BCTC Revenue Forecast				
BCTC Network Integrated Transmission Service (NITS)	49.9	49.9	-	
BCTC Point to Point (PTP)	(43.6)	(37.6)	(6.0)	
Ancillary Services	(8.5)	(8.5)	-	
Refund from BCTC related to F2006	(23.8)	-	(23.8)	
Adjustment for prior year	14.4	-	14.4	Sch F.2- Note 8
Total	<u>\$ 93.8</u>	<u>\$ 108.2</u>	<u>\$ (14.4)</u>	

British Columbia Hydro and Power Authority  
Domestic Cost of Energy  
For the Year Ended March 31, 2007  
(\$ in millions)

Schedule C

Particulars (1)	Actual (2)	Plan (3)	Variance (4)	Ref. (5)
<b>Heritage Energy:</b>				
Water rentals	257.5	268.6	(11.1)	
Market electricity purchases	114.4	168.4	(54.0)	
Natural gas for thermal generation	65.0	35.8	29.2	
Domestic Transmission	14.9	15.6	(0.7)	
Other	6.2	4.6	1.6	
	<u>458.0</u>	<u>493.0</u>	<u>(35.0)</u>	
<b>Non-Heritage Energy:</b>				
IPP's and long-term purchase commitments	364.4	428.8	(64.4)	
Market electricity purchases	135.3	100.9	34.4	
Non-Integrated Areas:				
NIA Fuel	12.7	12.0	0.7	
NIA IPP's	7.7	7.0	0.7	
Gas and Other Transportation	7.9	11.1	(3.2)	
	<u>528.0</u>	<u>559.8</u>	<u>(31.8)</u>	
Net purchases from Powerex (Trade Account)	66.8	-	66.8	Sch F.2-Note 9
	<u>594.8</u>	<u>559.8</u>	<u>35.0</u>	
BCTC NITS & External PTP	36.8	71.0	34.2	
<b>Total Domestic Cost of Energy</b>	<u><b>1,089.6</b></u>	<u><b>1,123.8</b></u>	<u><b>34.2</b></u>	
<b>Heritage Energy (GWh):</b>				
Water rentals	44,476	45,746	(1,270)	
Net sales to Powerex (Displaced Hydro)	656	(465)	1,121	
Market electricity purchases	2,611	3,511	(900)	
Natural gas for thermal generation	847	326	521	
Exchange net	410	(118)	528	
	<u>49,000</u>	<u>49,000</u>	<u>-</u>	
<b>Non-Heritage Energy (GWh):</b>				
IPP's and long-term purchase commitments	6,041	6,953	(912)	
Market electricity purchases	3,087	2,105	982	
Non-Integrated Areas:				
NIA Fuel	74	69	5	
NIA IPP's	38	40	(2)	
Net purchases from Powerex	-	-	-	
	<u>9,240</u>	<u>9,167</u>	<u>73</u>	
Total sources of supply	58,240	58,167	73	
Less : Line loss and system use	(5,329)	(5,025)	(304)	
<b>Total Domestic Sales Volumes</b>	<u><b>52,911</b></u>	<u><b>53,142</b></u>	<u><b>(231)</b></u>	

British Columbia Hydro and Power Authority  
Consolidated Statement of Operations  
For the Year Ended March 31, 2007  
(\$ in millions)

Schedule D

Particulars (1)	Actual (2)	Plan (3)	Variance (4)	Ref. (5)
<b>REVENUES</b>				
Domestic				
Residential	\$ 1,070.4	\$ 1,090.9	\$ (20.5)	
Light industrial and commercial	1,024.6	1,029.1	(4.5)	
Large industrial	556.5	588.1	(31.6)	
Other energy sales	97.6	90.4	7.2	
Miscellaneous	41.9	34.9	7.0	
	<u>2,791.0</u>	<u>2,833.4</u>	<u>(42.4)</u>	
Intersegment revenues	41.3	59.1	(17.8)	Sch E
	<u>2,832.3</u>	<u>2,892.5</u>	<u>(60.2)</u>	
<b>EXPENSES</b>				
Domestic energy costs	1,089.6	1,123.8	34.2	Sch C
Operating costs	595.8	554.4	(42.4)	
Depreciation and amortization	416.3	408.4	(7.9)	
Taxes	149.1	146.8	(2.0)	
Finance charges	454.9	452.7	(2.2)	
	<u>2,705.7</u>	<u>2,686.1</u>	<u>(20.3)</u>	
<b>DOMESTIC INCOME (LOSS) BEFORE TRANSFER (TO)/FROM DEFERRAL ACCTS</b>	<b>126.6</b>	<b>206.4</b>	<b>(79.8)</b>	
<b>TRADE INCOME</b>	<b>259.1</b>	<b>179.8</b>	<b>79.3</b>	
<b>POWERTECH NET INCOME</b>	<b>1.4</b>	<b>1.0</b>	<b>-</b>	
<b>TOTAL INCOME BEFORE TRANSFER (TO)/FROM DEFERRAL ACCOUNTS</b>	<b>387.1</b>	<b>387.2</b>	<b>(0.5)</b>	
Heritage Deferral Account transfers	(76.7)	(50.2)	(26.5)	Sch A
Non- Heritage Deferral Account transfers	(10.1)	(42.7)	32.6	Sch A
Trade Income Deferral Account transfers	27.0	44.5	(17.5)	Sch A
BCTC Deferral Account transfers	(12.8)	(1.6)	(11.2)	Sch A
Regulatory provision for future removal and site restoration costs	16.0	19.9	(3.9)	
Depreciation Study Adjustments	19.2	19.2	-	
First Nation Negotiations, Litigation and Settlement Costs	6.6	6.6	-	
Large Hydro Investigation Costs (Site C)	3.6	10.0	(6.4)	
CIA Amortization Variance	14.0	-	14.0	
F2007 Unplanned Major Storm Restoration Costs Regulatory Asset	32.9	-	32.9	
	<u>19.7</u>	<u>5.7</u>	<u>14.0</u>	
<b>TOTAL NET INCOME</b>	<b>\$ 406.8</b>	<b>\$ 392.9</b>	<b>\$ 13.5</b>	

British Columbia Hydro and Power Authority  
Intersegment Revenues  
For the Year Ended March 31, 2007  
(\$ in millions)

Schedule E

Particulars (1)	Actual (2)	Plan (3)	Variance (4)	Ref. (5)
Point-to-Point wheeling charge to Powerex	\$ 33.8	\$ 31.2	\$ 2.6	1)
Point-to-Point wheeling charge to BCH	20.5	22.9	(2.4)	2)
Allocation of BCH Corporate costs to Powerex	4.6	4.6	-	3)
Mark to Market losses on energy derivatives with Powerex	(17.6)	(3.6)	(14.0)	4)
Net sales to Powerex - Future Use	-	4.0	(4.0)	Sch F.2-Note 9
Total	\$ 41.3	\$ 59.1	\$ (17.8)	

1) 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.

2) 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, Canadian Entitlement Agreement (BCTC OATT Schedule 02) and Scheduling, System Control & Dispatch services (BCTC OATT Schedule 03). These revenues are eliminated against domestic cost of energy on consolidation.

3) These revenues relate to an allocation of corporate costs to Powerex and are eliminated against trade income on consolidation.

4) This relates to mark to market losses on energy derivatives with Powerex. This revenue is eliminated against trade income on consolidation. See Sch F, Note 2 and Sch F.2, Note 9.

Particulars

(1)

- 1 Notional water rentals (Displaced Hydro) relates to water rentals associated with trade income. The notional water rental mechanism is described in the response to BCUC IR No. 1.2.36 dated January 23, 2004. The transactions relating to the notional water rental are eliminated on consolidation and there is no net impact on the combined HDA and NHDA as the transactions are mirrored within each account.
- 2 In order to mitigate some of the commodity risk on domestic energy costs, BC Hydro enters into various forward contracts with Powerex for the purchase of electricity and natural gas. Powerex can then choose to match these forward contracts with a third party or can take on the risk/benefits on their own. The transactions between BC Hydro and Powerex are eliminated on consolidation. With respect to the deferral accounts, any gain or loss on the derivative instruments on the Powerex side would flow through the TIDA and the corresponding gain/loss on the BC Hydro side would flow through through the HDA and NHDA. While the gain/loss on these derivative instruments are not shown as part of energy costs on the financial statements due to GAAP reporting requirements, these gains/losses are reclassified for the calculation of deferral account transfers as they are part of managing the energy purchase costs.

The loss on energy derivatives related to Heritage energy totalled \$0.3 million for the year ended March 31, 2007 with the corresponding gain shown as part of Trade Income. The loss on energy derivatives related to Non-Heritage energy totalled \$17.3 million with the corresponding gain shown as part of Trade income. The gain/loss on BC Hydro's side related to these energy derivatives is shown as part of intersegment revenues.

BC Hydro also enters into derivatives with third parties to manage foreign exchange exposure on the corresponding energy derivatives. These foreign exchange derivative transactions are made on a cash flow basis of the underlying or gas electricity derivatives which, by market convention, settle on the 20th or 25th of the following month. Gains and losses on these transactions are netted against Heritage and Non-Heritage Energy purchase costs as they are used to manage these energy costs and mitigate risk. On the consolidated income statement these gains/losses are recorded as part of other miscellaneous income to comply with GAAP reporting requirements. The loss for the year ended March 31, 2007 was \$1.0 million related to Heritage Energy and a loss of \$2.5 million related to Non-Heritage Energy.

	Heritage	Non-Heritage	Total
Gain / (Loss) on energy derivatives	\$ (0.3)	\$ (17.3)	\$ (17.6)
Gain / (Loss) on Foreign exchange derivatives	(1.0)	(2.5)	(3.5)
Total Gain/(Loss) on Derivatives	\$ (1.3)	\$ (19.8)	\$ (21.1)
Total Gain/(Loss) on Electricity (a)	\$ 2.1	\$ 2.5	\$ 4.6
Total Gain/(Loss) on Gas	(3.4)	(22.3)	(25.7)
	\$ (1.3)	\$ (19.8)	\$ (21.1)

- 3 Variance from plan related to natural gas for thermal generation GW.h (per Sch C- L29) 521  
 Average cost per MW.h of additional production per RRA filing \$ 1.25  
 Total variable cost related to thermal generation \$ 0.7
- 4 Significant unplanned major maintenance costs of \$1.1 million is due to repairs to the GM Shrum Generating Unit. On December 10, 2006 Generating Unit # 6 tripped due to a fault which caused damage to the exciter bus work, the unit exciter and control board, and a field ground on the rotor.

Particulars  
 (1)

- 5 This relates to the foreign exchange gain/loss on the Trade Account payable to Powerex. Powerex would have a corresponding loss on their receivable and this loss would be part of Trade Income. Foreign exchange gains/losses arise as the Trade Account is recorded in \$US. The gain/loss on the BC Hydro side is eliminated against the loss/gain on the Powerex side of consolidation within the finance charge component. As the mirror entry for Trade Income relating to F/X on the Trade Account is recorded on the Non-Heritage energy side, there is no net impact on the combined NHDA and TIDA due to these transactions.
- 6 Load Variance for HDA is calculated as the Load Volume variance multiplied by the actual average price of market electricity purchases net of the gain/losses on mark to market electricity transactions. (\$ 43.02 X 0 = \$0 )

	Heritage	Non-Heritage		Total
		IPP	Non integ	
Load Volume Variance (Schedule C- L40)	-	70.0	3.0	73.0
Average price of market electricity (\$/MW.h)	\$ 43.02	\$ 43.02	\$ 170.86	
Load Volume variance \$ millions	\$ -	\$ 3.0	\$ 0.5	\$ 3.5

Load Variance for NHDA is calculated as sum of the IPP, Long Term Purchase Commitments and Electricity Purchases Transfer from Heritage Energy volume variances multiplied by the actual average price of market electricity purchases

Total Heritage energy (including Skagit commitments) is limited to 49,000 Gwh in terms of the Heritage Contract. This Heritage Contract limit would be exceeded if all market energy purchases were allocated to Heritage Energy supply. Therefore, a portion of the market purchases are allocated to Non-Heritage Energy in order to reduce the Heritage Energy volumes to the Heritage Contract limits as follows:

	GW.h
Total Heritage Energy excluding Market Purchases	45,733
Less: Net Sales to Powerex (Displaced Hydro Generation)	656
100% of Market Energy Purchases	5,698
Total Heritage Energy including 100% of Market Energy Purchases	52,087
Less : Heritage Contract Limit of 49,000 GW.h	49,000
Excess Market Purchases over 49,000 GW.h	3,087

The cost of market energy purchases and related energy and foreign exchange derivatives are allocated between Heritage Energy and Non-Heritage Energy based on allocation of market purchases

	Heritage	Non-Heritage	Total
Market Electricity Purchase volumes - GWh (Sch C)	2,611	3,087	5,698
Total Market Energy Purchases costs (Sch C)	\$ 114.4	\$ 135.3	\$ 249.7
Mark to Market loss/(gains) - (Sch F, note 3)	(2.1)	(2.5)	(4.6)
Total Market Energy Purchases costs (\$millions)	\$ 112.3	\$ 132.8	\$ 245.1
Average Price of Market Electricity Purchases(\$ / MW.h)	\$ 43.02	\$ 43.01	\$ 43.02

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Particulars

(1)

- 7 BC Hydro transferred \$7.3 million into the non-heritage deferral account in F2006 for work performed by BC Hydro related to the Mountain Pine Beetle issue. In F2007, BC Hydro was able to recover an unanticipated \$2.7 million of costs incurred in F2006 from Telus. Accordingly this cost recovery has been included in the non-heritage deferral account.
- 8 Adjustment is due to the correction of a prior year error. Procedures have now been implemented to mitigate future risks associated with this type of error.
- 9 These sales relate to the return of energy bought by Powerex in prior periods to enable future sales. These revenues are eliminated against trade cost of energy on consolidation. The transactions between BC Hydro and Powerex has no net impact on the combined NHDA and the TIDA.

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 *Commission Directive October 29, 2004 Page 41:*

8 *Commission Findings*

9 *The Commission Panel approves the HDA as proposed by BC Hydro, and approves BC*  
10 *Hydro's forecast of the cost components of the HPO for F2005 and F2006.*

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

- 13 1. Cost of energy, except those arising from changes in customer load \*<sup>1</sup>.
- 14 This item is expanded in greater detail below to provide clarification on the methodology used  
15 to determine variances:
- 16 • Market electricity purchases are treated as the dispatchable resource\*<sup>3</sup>.
  - 17 • If no market purchases are planned or made, the next dispatchable resource is assumed  
18 to be generation from the Burrard facility.
  - 19 • If total Heritage and non-Heritage energy volumes are lower than Plan, the Load variance  
20 is calculated using the Plan YTD average market purchase price of electricity\*<sup>3</sup>.
  - 21 • If total Heritage and non-Heritage energy volumes are higher than Plan, the Load  
22 variance is calculated using the Actual YTD average market purchase price of electricity  
23 (netted for any gains/losses on energy derivatives and financial instruments used to  
24 manage energy costs)\*<sup>3</sup>.
  - 25 • The total Heritage Energy (including Skagit / Seattle City Light commitments) is limited to  
26 49000 GWh in terms of the Heritage contract. If the Heritage Energy including 100% of  
27 market electricity purchases exceeds the Heritage Energy limit, the excess purchases are  
28 transferred to Non-Heritage Energy in order to reduce the Heritage Energy volumes to  
29 the Heritage Contract limit.
  - 30 • Cost of energy variances resulting from changes to compensation and mitigation costs,  
31 water rental remissions, or Skagit energy transportation contracts are eligible for deferral.  
32 These are price variances as they do not vary with volume.
- 33 2. Variable costs related to thermal generation\*<sup>1</sup>.
- 34 3. Significant unplanned major maintenance costs greater than \$1 million related to single event  
35 equipment or infrastructure failure or caused by weather related events\*<sup>1</sup>.
- 36 4. Significant unplanned major capital expenditures having an incremental annual impact on the  
37 Income Statement greater than \$1 million related to single event equipment or infrastructure  
38 failure or caused by weather related events\*<sup>1</sup>.
- 39 5. Amortization of unplanned deferred capital costs pursuant to Commission Order No. G-53-  
40 02\*<sup>1</sup>.
- 41 6. All net revenues from surplus hydro electricity sales\*<sup>2</sup>.
- 42 7. Skagit Valley Treaty revenues and ancillary services revenues\*<sup>2</sup>.

## Schedule G

- 1 • An interest charge/credit<sup>\*3</sup> is to be calculated on the ending monthly balance (excluding the  
2 interest portion) in each deferral account. The interest rate used is BC Hydro's weighted cost  
3 of debt for the prior fiscal year ended.

4 <sup>\*1</sup> Per Commission Directive October 29, 2004 Page 30, Section 4.4 & Page 41 (Commission Findings)

5 <sup>\*2</sup> Per Commission Directive October 29, 2004 Page 31, Section 4.4 & Page 41 (Commission Findings)

6 <sup>\*3</sup> Per Commission Directive October 29, 2004 Page 45, Section 4.11 and amended by the Negotiated  
7 Settlement Agreement of November 2006.

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

2 *Commission Directive October 29, 2004 Page 41:*

3 *Commission Findings*

4 *The Commission Panel approves all elements of the NHDA, except the distribution*  
 5 *emergency restoration costs elements, item 4, because it can be forecast with some*  
 6 *confidence, unlike unplanned major capital expenditures and unplanned major*  
 7 *maintenance expenditures, and because of risk/reward considerations. Given the denial of*  
 8 *item 4 of the NHDA, item 3 of the NHDA is to be as set forth in Final Argument. The*  
 9 *Commission Panel approves BC Hydro's forecast of the NHDA non-HPO cost of energy for*  
 10 *F2005 and F2006.*

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

- 13 1. Cost of energy - all non-HPO energy costs except those arising from changes in customer  
 14 load, \*<sup>1</sup>. This item is expanded in greater detail below to provide clarification on the  
 15 methodology used to determine variances:
- 16 • If total Heritage and Non-Heritage energy volumes are lower than Plan, the Non-Heritage  
 17 Load Variance (volume variances for IPP, Long term purchases and Market Purchases  
 18 transferred from Heritage Energy) is calculated using the Plan YTD average market  
 19 purchases price of electricity \*<sup>2</sup>. For Non – Integrated supply, the fuel costs are treated as  
 20 the next dispatchable resource.
  - 21 • If total Heritage and Non-Heritage energy volumes are higher than Plan, the Non-  
 22 Heritage Load Variance (volume variances for IPP, Long term purchases and Market  
 23 Purchases transferred from Heritage Energy) is calculated using the Actual YTD average  
 24 market purchases price of electricity (netted for any gains/losses on energy derivatives  
 25 and financial instruments used to manage energy costs) \*<sup>2</sup>. For Non – Integrated supply,  
 26 the fuel costs are treated as the next dispatchable resource.
  - 27 • Any variances relating to fixed price gas transportation contracts would flow through the  
 28 deferral accounts as they do not vary with volume;
  - 29 • Future Trade: when Powerex purchases energy for future trade the cost of the purchase  
 30 from the external party and the sale to BC Hydro of this energy is recorded in Powerex  
 31 and is included as part of Trade Income. The BC Hydro side of this entry is shown as part  
 32 of domestic energy costs (on consolidation, the Powerex revenue from BC Hydro and the  
 33 BCH energy costs from Powerex are eliminated). The difference between Actual and  
 34 Plan on the BC Hydro side relating to energy for future trade will flow through the Non-  
 35 Heritage Deferral Account. The Powerex side of the transaction is part of Trade Income  
 36 and flows through the Trade Income Deferral Account. Similar treatment is made when  
 37 the energy is returned to Powerex; and
  - 38 • Future Trade: when Powerex purchases energy for future trade, the Heritage Payment  
 39 Obligation (HPO) is charged with a notional water rental charge for the use of this energy.  
 40 The other side of this entry is shown as part of Non-Heritage energy. These entries are  
 41 eliminated on consolidation. The difference between the Actual and Plan notional water  
 42 rentals that is part of the HPO would flow through the Heritage Deferral Account. The  
 43 opposite variance relating to the Non-Heritage side of the notional water rental  
 44 transaction will flow through the Non-Heritage Deferral Account.
- 45 2. Significant unplanned major maintenance costs greater than \$1 million related to single event  
 46 equipment or infrastructure failure or caused by weather related events\*<sup>1</sup>.

## Schedule G

- 1 3. Significant unplanned major capital expenditures having an incremental annual impact on the  
2 Income Statement greater than \$1 million related to single event equipment or infrastructure  
3 failure or caused by weather related events\*<sup>1</sup>.
- 4 4. Founding Partner Benefits and any CIS Credits under the ABS Contract\*<sup>1</sup>.
- 5 • An interest charge/credit\*<sup>2</sup> is to be calculated on the ending monthly balance (excluding the  
6 interest portion) in each deferral account. The interest rate used is BC Hydro's weighted cost  
7 of debt for the prior fiscal year ended.

8 \*<sup>1</sup> Per Commission Directive October 29, 2004 Page 37, Section 4.5 & Page 41 (Commission Findings).

9 \*<sup>2</sup> Per Commission Directive October 29, 2004 Page 45, Section 4.11 and amended by the Negotiated  
10 Settlement Agreement of November 2006.

11

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

2 *Commission Directive October 29, 2004 Page 42, Section 4.6*

3 **Commission Findings**

4 ***The Commission Panel approves the TIDA as proposed by BC Hydro, and approves BC***  
5 ***Hydro's forecast of Trade Income for F2005 and F2006.***

- 6 • Any variance between the forecast Trade Income and the actual trade income\*<sup>1</sup> will flow  
7 through the TIDA except where Annual Trade Income is below \$Nil and above \$200 million.
- 8 • An interest charge/credit\*<sup>2</sup> 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 for the prior fiscal year ended.

11 \*<sup>1</sup> Per Commission Directive October 29, 2004 Page 42, Section 4.6

12 \*<sup>2</sup> Per Commission Directive October 29, 2004 Page 45, Section 4.11 and amended by the Negotiated  
13 Settlement Agreement of November 2006.

14

1 **BCTC Deferral Account (BCTC DA)**

2 *Commission Directive October 29, 2004 Page 42 & 43, Section 4.7*

3 **Commission Findings**

4 *The Commission Panel approves the BCTC DA as proposed by BC Hydro, and approves*  
5 *BC Hydro's F2005 and F2006 forecast, subject to the adjustments required by this*  
6 *Decision, of the Asset Management / Maintenance Revenue Requirement and the BCTC*  
7 *Revenue Requirement for the purpose of the BCTC TDA.*

8 • The BCTC Deferral Account relates to two variances:

9 • a) variances between BC Hydro's Asset Management/Maintenance Revenue  
10 Requirement forecast in BC Hydro's Revenue Requirement and BC Hydro's actual Asset  
11 Management/Maintenance charges from BCTC, and

12 • b) variances between BCTC's Revenue Requirement forecast charges to BC Hydro in  
13 BC Hydro's Revenue Requirement and the BCTC charges to BC Hydro for transmission  
14 services.

15 • An interest charge/credit\*<sup>1</sup> is to be calculated on the ending annual balance (excluding the  
16 interest portion) in each deferral account. The interest rate used is BC Hydro's weighted cost  
17 of debt for the prior fiscal year ended.

18 \*<sup>1</sup> Per Commission Directive October 29, 2004 Page 45, Section 4.11 and amended by the Negotiated  
19 Settlement Agreement of November 2006.  
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