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February 6, 2006

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

Dear Mr. Pellatt:

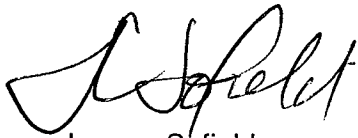
**RE: British Columbia Hydro and Power Authority (BC Hydro)  
2004/05 and 2005/06 Revenue Requirements Application  
British Columbia Utilities Commission (Commission) Order G-96-04  
Decision, October 29, 2004, Page 45, Directive No. 17 Page 218**

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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 Fiscal 2006 Third Quarter Deferral Account Report as at December 31, 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,



Joanna Sofield  
Chief Regulatory Officer

Enclosures (5)

**BC Hydro**  
**Deferral Account Report**  
**December 31, 2005**

January 2006

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**SUMMARY OF DEFERRAL ACCOUNTS**  
For the nine months ended December 31, 2005

	Reference Schedule	Heritage Deferral Account (HDA)	Non- Heritage Deferral Account (NHDA)	Trade Income Deferral Account (TIDA)	BCTC Transition Deferral Account (TIDA)	Total
1 General ledger (G/L) account numbers for Deferral Accounts		076000	076100	076200	076400	
2 G/L account numbers for interest on Deferral Accounts		076001	076101	076201	076401	
3 Balance as of April 1, 2005 (including interest)		137.8	131.3	(114.5)	-	154.6
4 Transfers for the nine months ended 5 December 31, 2005	A-2	(31.7)	5.9	(76.4)	21.5	(80.7)
6 Interest on deferral accounts ( <i>Note 1</i> )		7.1	5.9	(7.2)	0.4	6.2
7		<u>113.2</u>	<u>143.1</u>	<u>(198.1)</u>	<u>21.9</u>	<u>80.1</u>

8 • The transfers to the HDA and NHDA are related to variances in energy costs, not related to changes  
9 in load, from the forecast used in establishing rates (See Schedule C).

10 • The HDA energy cost variances are largely due to higher than planned market purchase volumes  
11 and prices offset by the load variance (not deferred). The decision to import energy instead of  
12 utilizing hydro generation is based on many factors, such as the forecast market price of energy  
13 in future periods relative to the current period, current reservoir levels and future demand  
14 requirements.

15 • The NHDA energy cost variances are largely due to lower IPP and long term purchase  
16 commitment volumes, higher net sales to Powerex related to previous purchases made for future  
17 use by Powerex (offset in Powerex in the Trade Income Deferral Account transfers) and gains on  
18 commodity risk management activities with Powerex (offset in Powerex in the Trade Income  
19 Deferral Account transfers). These NHDA variances are offset by higher energy costs from IPPs,  
20 mainly ICG, due to higher gas prices.

21 • The transfer to the TIDA relates to the lower than Plan Trade Income. This includes the offsets for the  
22 amounts included in the NHDA transfer noted above.

23 Notes:

24 1. The interest charge/credit is shown as part of finance charges on the Statement of Operations  
25 (Schedule A - 3). Interest is calculated on the ending monthly balance (excluding the interest portion) in  
26 each deferral account. The interest rate used is BC Hydro's weighted cost of debt.

1

## Deferral Account Rules

2 The following “rules” are used by BC Hydro to provide clarity in determining the deferral account  
3 transfers. These rules are derived from BC Hydro’s interpretation of the evidence and testimony  
4 provided during the 2004 Revenue Requirement proceedings and in response to Commission  
5 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 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 generation volumes are lower than Plan, the Load Variance is calculated using the Plan  
20 YTD average market purchase price of electricity; \*<sup>3</sup>
  - 21 • If generation volumes are higher than Plan, the Load Variance is calculated using the  
22 Actual YTD average market purchase price of electricity (netted for any gains/losses on  
23 energy derivatives and financial instruments used to manage energy costs); \*<sup>3</sup> and
  - 24 • Cost of energy variances resulting from changes to compensation and mitigation costs,  
25 water rental remissions, and Skagit energy transportation contracts are eligible as  
26 deferrals. These are price variances as they do not vary with volume.
- 27 2. Variable costs related to thermal generation\*<sup>1</sup>.
- 28 3. Significant unplanned major maintenance costs greater than \$1 million related to single event  
29 equipment or infrastructure failure or caused by weather related events\*<sup>1</sup>.
- 30 4. Significant unplanned major capital expenditures having an incremental annual impact on the  
31 Income Statement greater than \$1 million related to single event equipment or infrastructure  
32 failure or caused by weather related events\*<sup>1</sup>.
- 33 5. Amortization of unplanned deferred capital costs pursuant to Commission Order No. G-53-  
34 02\*<sup>1</sup>.
- 35 6. All net revenues from surplus hydro electricity sales\*<sup>2</sup>.
- 36 7. Skagit Valley Treaty revenues and ancillary services revenues\*<sup>2</sup>.
  - 37 • An interest charge/credit\*<sup>4</sup> is to be calculated on the ending monthly balance (excluding the  
38 interest portion) in each deferral account. The interest rate used is BC Hydro’s weighted cost  
39 of debt during the period.

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

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

42 \*<sup>3</sup> Per Commission Decision October 29, 2004, Page 38, Section 4.5.1.1

43 \*<sup>4</sup> Per Commission Directive October 29, 2004 Page 45, Section 4.11

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 supply volumes are lower than Plan, the Load Variance is calculated using the Plan  
 17 average YTD unit purchase price for IPP's. For Non-Integrated Supply, the fuel costs are  
 18 treated as the next dispatchable resource;
  - 19 • If supply volumes are higher than Plan, for IPP's the Load Variance is calculated using  
 20 the weighted average actual YTD unit prices of IPP's. For Non-Integrated supply, the fuel  
 21 costs are treated as the next dispatchable resource. The weighted average unit price  
 22 would include any YTD gains/losses on energy derivatives and financial instruments used  
 23 to manage energy costs;
  - 24 • Any variances relating to fixed price gas transportation contracts would flow through the  
 25 deferral accounts as they do not vary with volume;
  - 26 • Future Trade: when Powerex purchases energy for future trade the cost of the purchase  
 27 from the external party and the sale to BC Hydro of this energy is recorded in Powerex  
 28 and is included as part of Trade Income. The BC Hydro side of this entry is shown as part  
 29 of domestic energy costs (on consolidation, the Powerex revenue from BC Hydro and the  
 30 BCH energy costs from Powerex are eliminated). The difference between Actual and  
 31 Plan on the BC Hydro side relating to energy for future trade will flow through the Non-  
 32 Heritage Deferral Account. The Powerex side of the transaction is part of Trade Income  
 33 and flows through the Trade Income Deferral Account. Similar treatment is made when  
 34 the energy is returned to Powerex; and
  - 35 • Future Trade: when Powerex purchases energy for future trade, the Heritage Payment  
 36 Obligation (HPO) is charged with a notional water rental charge for the use of this energy.  
 37 The other side of this entry is shown as part of Non-Heritage energy. These entries are  
 38 eliminated on consolidation. The difference between the Actual and Plan notional water  
 39 rentals that is part of the HPO would flow through the Heritage Deferral Account. The  
 40 opposite variance relating to the Non-Heritage side of the notional water rental  
 41 transaction will flow through the Non-Heritage Deferral Account.
- 42 2. Significant unplanned major maintenance costs greater than \$1 million related to single event  
 43 equipment or infrastructure failure or caused by weather related events\*<sup>1</sup>.
- 44 3. Significant unplanned major capital expenditures having an incremental annual impact on the  
 45 Income Statement greater than \$1 million related to single event equipment or infrastructure  
 46 failure or caused by weather related events\*<sup>1</sup>.
- 47 4. Founding Partner Benefits and any CIS Credits under the ABS Contract\*<sup>1</sup>.

## Schedule A-1

- 1 • An interest charge/credit<sup>\*2</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 during the period.

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

5 <sup>\*2</sup> Per Commission Directive October 29, 2004 Page 45, Section 4.11

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 during the period.

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

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

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

3 **Commission Findings**

4 *The Commission Panel approves the BCTC TDA 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 Transition Deferral Account\*<sup>1</sup> relates to two variances:

- 9 • a) variances between BC Hydro's Asset Management/Maintenance Revenue  
10 Requirement forecast at \$116.7 million\*<sup>2</sup> in BC Hydro's Revenue Requirement and BC  
11 Hydro's actual Asset Management/Maintenance charges from BCTC, and
- 12 • b) variances between BCTC's Revenue Requirement forecast charges to BC Hydro of  
13 \$61.0 million\*<sup>2</sup> in BC Hydro's Revenue Requirement and the BCTC charges to BC Hydro.
- 14 • An interest charge/credit\*<sup>3</sup> is to be calculated on the ending monthly balance (excluding the  
15 interest portion) in each deferral account. The interest rate used is BC Hydro's weighted cost  
16 of debt during the period.

17 \*<sup>1</sup> Per Commission Directive October 29, 2004 Pages 42-43, Section 4.7

18 \*<sup>2</sup> Per BC Hydro 2004/05 and 2005/06 Revenue Requirement Application (November 15, 2004 Compliance  
19 Filing), Chapter 2, Schedule B-3

20 \*<sup>3</sup> Per Commission Directive October 29, 2004 Page 45, Section 4.11

**Summary of Deferral Account Transfers**  
**For the nine months ended December 31, 2005**  
**(\$ in millions)**

	F2006 Actual YTD	Reference Schedule
<b><u>Heritage Deferral Account</u></b>		
1) Cost of energy (except those arising from changes in customer load)	(31.7)	C-1 (line 11)
2) Variable costs related to thermal generation.	-	C-1 (line 8)
3) Significant unplanned major maintenance costs greater than \$1 million related to single event equipment or infrastructure failure or caused by weather related events	-	
4) Significant unplanned major capital expenditures having an incremental annual impact on the Income Statement greater than \$1 million related to single event equipment or infrastructure failure or caused by weather related events	-	
5) Amortization of unplanned deferred capital costs pursuant to Commission Order No. G-53-02.	-	
6) All net revenues from surplus hydro electricity sales.	-	
7) Skagit Valley Treaty revenues and ancillary services revenues.	0.0	C-1 (line10)
Transfer to Heritage Deferral Account for nine months ended December 31, 2005	<u>(31.7)</u>	A;A-3
<b><u>Non-Heritage Deferral Account</u></b>		
1) Cost of energy - all non-HPO energy costs except those arising from changes in customer load	5.8	C-1 (line 14-17)
2) Significant unplanned major maintenance costs greater than \$1 million related to single event equipment or infrastructure failure or caused by weather related events	2.3	C-1 (line 18)
3) Significant unplanned major capital expenditures having an incremental annual impact on the Income Statement greater than \$1 million related to single event equipment or infrastructure failure or caused by weather related events.	-	
4) Founding Partner Benefits and any CIS Credits under the ABS Contract	-	
5) F2006 Return on Equity Deferral (BCUC Order G-48-05)	(2.2)	C-1 (line 19)
Transfer to Non Heritage Deferral Account for nine months ended December 31, 2005	<u>5.9</u>	A; A-3
<b><u>Trade Income Deferral Account</u></b>		
Transfer to Trade Income Deferral Account for nine months ended December 31, 2005	<u>(76.4)</u>	A; A-3
<b><u>BCTC Transition Deferral Account</u></b>		
1) BCTC Asset Management / Maintenance Fee	(0.8)	C-5
2) BCTC Wholesale Transmission Service / BCTC Revenue Forecast	22.3	C-5
Transfer to BCTC Transition Deferral Account for nine months ended December 31, 2005	<u>21.5</u>	A; A-3

**Consolidated Statement of Operations**  
**For nine months ended December 31, 2005**  
**(\$ Millions)**

	A	B	C	
	<u>Actual</u>	<u>Plan</u>	<u>Variance</u>	<u>Reference Schedule</u>
<b>REVENUES</b>				
Domestic				
Residential	731	710	21	
Light industrial and commercial	728	705	22	
Large industrial	439	392	47	
Other energy sales	62	61	1	
Miscellaneous	37	42	(5)	
	<u>1,997</u>	<u>1,909</u>	<u>87</u>	
Intersegment revenues	126	92	35	D
	<u>2,123</u>	<u>2,001</u>	<u>122</u>	
<b>EXPENSES</b>				
Domestic energy costs	762	625	(138)	B
BCTC wholesale transmission service	59	46	(14)	
BCTC asset management fee	87	88	1	
Operations expense	104	97	(7)	
Maintenance expense	105	104	(1)	
Administration expense	108	93	(15)	
Depreciation and amortization	309	315	6	
Taxes	108	110	2	
Finance charges	327	349	22	
	<u>1,969</u>	<u>1,825</u>	<u>(144)</u>	
<b>DOMESTIC INCOME (LOSS) BEFORE TRANSFER (TO)/FROM DEFERRAL ACCTS</b>	<b>154</b>	<b>176</b>	<b>(22)</b>	
<b>TRADE INCOME</b>	<b>168</b>	<b>92</b>	<b>76</b>	
<b>TOTAL INCOME BEFORE TRANSFER (TO)/FROM DEFERRAL ACCOUNTS</b>	<b>322</b>	<b>267</b>	<b>54</b>	
Heritage Deferral Account transfers	(32)	-	(32)	C
Non- Heritage Deferral Account transfers	6	(2)	8	C
Trade Income Deferral Account transfers	(76)	-	(76)	C-3
BCTC Transition Deferral Account transfers	21	-	21	C-4
Regulatory provision for future removal and site restoration costs	9	-	9	
<b>TOTAL NET INCOME</b>	<b>250</b>	<b>265</b>	<b>(15)</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 nine months ended December 31, 2005

(\$ millions)	Actual	Plan	Variance	Reference Schedule
<b>Heritage Energy:</b>				
Water rentals	206	195	(11)	
Market electricity purchases	143	69	(73)	C-2
Natural gas for thermal generation	24	20	(4)	
Domestic Transmission	12	12	(1)	
Other	4	5	1	
	<b>389</b>	<b>301</b>	<b>(88)</b>	C
<b>Non-Heritage Energy:</b>				
IPP's and long-term purchase commitments	351	303	(47)	
Non-Integrated Areas:				
NIA Fuel	8	3	(5)	
NIA IPP's	5	8	3	
Gas and Other Transportation	10	10	(0)	
Net purchases from Powerex (Trade Account)	-	-	-	
	<b>373</b>	<b>324</b>	<b>(50)</b>	C
<b>Total Domestic Cost of Energy</b>	<b>762</b>	<b>625</b>	<b>(138)</b>	A - 3
<b>(GW.h)</b>				
<b>Heritage Energy:</b>				
Water rentals	35,783	32,971	(2,812)	
Market electricity purchases	2,593	1,952	(641)	C-2
Natural gas for thermal generation	153	183	30	
Exchange net	(266)	318	585	
	<b>38,263</b>	<b>35,425</b>	<b>(2,837)</b>	C
<b>Non-Heritage Energy:</b>				
IPP's and long-term purchase commitments	5,243	5,426	183	
Non-Integrated Areas:				
NIA Fuel	52	30	(22)	
NIA IPP's	25	45	20	
	<b>5,319</b>	<b>5,501</b>	<b>182</b>	C-3
<b>Total sources of supply</b>	<b>43,582</b>	<b>40,926</b>	<b>(2,656)</b>	
Less : Line loss and system use	(3,955)	(3,965)	(10)	C-3
Net sales to Powerex	(1,738)	(1,058)	680	C
<b>Domestic Sales Volumes</b>	<b>37,889</b>	<b>35,903</b>	<b>(1,986)</b>	C-3
<b>(\$/MW.h)</b>				
Water rentals	5.8	5.9	0.1	
Market electricity purchases	55.0	35.5	(19.5)	
Natural gas for thermal generation	157.5	108.8	(48.7)	
IPP's and long-term purchase commitments	66.9	55.9	(11.0)	C-3
Non-Integrated Areas:				
NIA Fuel	158.0	104.2	(53.8)	
NIA IPP's	186.1	168.2	(17.9)	
<b>Total weighted average cost</b>	<b>17.5</b>	<b>15.3</b>	<b>(2.2)</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.

**TRANSFERS TO HERITAGE (HDA) AND NON-HERITAGE (NHDA) DEFERRAL ACCOUNTS**  
**For the nine months ended December 31, 2005**

1				Reference	
2				Schedule	
3					
4	<b>Reconciliation of Energy costs for Deferral Account Treatment</b>				
5					
6	Actual	Plan	Variance		
7	<b>(\$ millions)</b>				
8	<b>Heritage Energy:</b>				
9	Heritage Energy costs	\$ 389.1	\$ 300.9	\$ (88.2)	B
10	Notional Water rental (Displaced Hydro) (Note 1)	(8.4)	(5.1)	3.3	
11	Mark to market (gain)/loss on energy derivatives and financial settlements (Note 2)	11.7		(11.7)	C-2
12	<b>Cost of energy portion of Heritage Payment Obligation</b>	<b>\$ 392.4</b>	<b>\$ 295.8</b>	<b>\$ (96.6)</b>	(a)
13					
14	<b>Non-Heritage Energy:</b>				
15	Non-Heritage Energy costs	\$ 373.3	\$ 323.6	\$ (49.7)	B
16	Net sales to Powerex - Future Use (Note 3)	(57.6)	(43.3)	14.3	D
17	Notional water rentals (Displaced Hydro) (Note 1)	8.4	5.1	(3.3)	
18	F/X loss(gain) on Pwx trade account (Note 4)	(4.3)	-	4.3	
19	Mark to market (gain)/loss on energy derivatives and financial settlements (Note 2)	(38.6)	-	38.6	C-2
20	<b>Cost of energy portion of Non-Heritage Payment Obligation</b>	<b>\$ 281.3</b>	<b>\$ 285.4</b>	<b>\$ 4.1</b>	(b)
21					
22	<b>(GW.h)</b>				
23					
24	<b>Heritage Energy:</b>				
25	Heritage Energy Supply	38,263	35,425	(2,837)	B
26	Notional water rentals (Displaced Hydro)	(1,738)	(1,058)	680	B
27	<b>Heritage Payment Obligation Energy</b>	<b>36,525</b>	<b>34,367</b>	<b>(2,158)</b>	C-2
28					
29					
30					
31	<b>Notes:</b>				

32 1. Notional water rentals (Displaced Hydro) relates to water rentals associated with trade income. The  
33 notional water rental mechanism is described in the response to BCUC IR No. 1.2.36 dated January 23,  
34 2004. The transactions relating to the notional water rental are eliminated on consolidation and there is no  
35 net impact on the combined HDA and NHDA as the transactions are mirrored within each account.

36 2. In order to mitigate some of the commodity risk on domestic energy costs, BC Hydro enters into various  
37 forward contracts with Powerex for the purchase of electricity and natural gas. Powerex can then choose  
38 to match these forward contracts with a third party or can take on the risk/benefits on their own. The  
39 transactions between BC Hydro and Powerex are eliminated on consolidation. With respect to the deferral  
40 accounts, any gain or loss on the derivative instruments on the Powerex side would flow through the Trade  
41 Income Deferral Account (TIDA) and the corresponding gain/loss on the BC Hydro side would flow through  
42 through the HDA and NHDA. While the gain/loss on these derivative instruments are not shown as part of  
43 energy costs on the financial statements due to GAAP reporting requirements, these gains/losses are  
44 reclassified for the calculation of deferral account transfers as they are part of managing the energy purchase costs.

1 **Transfer to HDA and NHDA continued**

2

3 **(\$millions)**4 **Transfer to HDA:**

5	Total Heritage energy variance	(a)	96.6	
6	Less: Load Variance ( <i>Note 5</i> )		<u>128.3</u>	
7			(31.7)	

8 Add: Variable Costs related to Thermal Generation

9 Add: Skagit Valley Treaty Revenues and

10 Ancillary Services Revenues

11 Transfer to HDA (31.7)

A;A-2

12

13 **Transfer to NHDA:**

14 Total Non-Heritage energy variance (b) (4.1)

15 Add: Load Variance - IPP's (*Note 6*) 10.2

16

17 Load Variance - Non-Integrated areas (0.3)

18 Add: Mountain Pine Beetle costs 2.3

19 Less: F2006 Return on Equity Deferral (*BCUC Order G-48-05*) (2.2)20 Transfer to NHDA 5.9

A;A-2

21

**Transfer to HDA and NHDA continued**

**Schedule C-2**

1 The loss on energy derivatives related to Heritage energy totalled \$9.7 million for the nine months ended  
 2 December 31, 2005 with the corresponding gain shown as part of Trade Income. The gain on energy  
 3 derivatives related to Non-Heritage energy totalled \$45.2 million with the corresponding loss shown as part  
 4 of Trade Income. The gain/loss on BC Hydro's side related to these energy derivatives is shown as part of  
 5 intersegment revenues.  
 6  
 7 BC Hydro also enters into derivatives with third parties to manage foreign exchange exposure on the corresponding  
 8 energy derivatives. These foreign exchange derivative transactions are made on a cash flow basis of the underlying  
 9 or gas electricity derivatives which, by market convention, settle on the 20th or 25th of the following month.  
 10 Gains and losses on these transactions are netted against Heritage and Non-Heritage Energy purchase costs  
 11 as they are used to manage these energy costs and mitigate risk. On the consolidated income statement these  
 12 gains/losses are recorded as part of other miscellaneous income to comply with GAAP reporting requirements.  
 13 The loss for the nine months ended December 31, 2005 was \$2 million related to Heritage Energy and a loss of \$7.3 million  
 14 related to Non-Heritage Energy.

15 (\$millions)

16 **Summary:**

	Heritage	Non-	Total	Reference Schedule
19 Gain / (Loss) on energy derivatives	(9.7)	47.7	38.0	D
20 ADD Unrealized F/X Gain (loss) on US\$ denominated commodity derivatives	-	(1.8)	(1.8)	
21 Gain / (Loss) on energy derivatives	(9.7)	45.9	36.2	
23 Gain / (Loss) on Foreign exchange derivatives	(2.0)	(9.1)	(11.1)	
24 LESS Unrealized F/X Gain (loss) on US\$ denominated commodity derivatives	-	1.8	1.8	
25 Gain / (Loss) on Foreign exchange derivatives	(2.0)	(7.3)	(9.3)	
27 Total Gain/(Loss) on Derivatives	<u>\$ (11.7)</u>	<u>\$ 38.6</u>	<u>\$ 26.9</u>	

28  
 29  
 30 3. These sales relate to the return of energy bought by Powerex in prior periods to enable future sale. These revenues are  
 31 eliminated against trade cost of energy on consolidation. The transactions between BC Hydro and Powerex has no net impact on  
 32 the combined NHDA and the Trade Income Deferral Account.

33  
 34 4. This relates to the foreign exchange gain on the Trade Account payable to Powerex. Powerex would have a corresponding loss  
 35 on their receivable and this loss would be part of Trade Income. Foreign exchange gains/losses arise as the Trade Account is  
 36 recorded in \$US. The gain/loss on the BC Hydro side is eliminated against the loss/gain on the Powerex side on consolidation  
 37 within the finance charge component. As the mirror entry for Trade Income relating to F/X on the Trade Account is recorded on  
 38 the Non-Heritage energy side, there is no net impact on the combined NHDA and TIDA due to these transactions.  
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 41

42 5. Load Variance for HDA is calculated as the Load Volume variance multiplied by the actual average price of market  
 43 purchases net of the gain/losses on mark to market energy transactions. (2,158 GW.h \* \$59.5/MW.h) = \$128.3 million.

44 (\$millions)

			Reference Schedule
48 Market energy purchases	\$ 142.5		B
49 Mark to market (Gains)/Losses	11.7		C
50	<u>\$ 154.2</u>	(1)	
52 Market energy purchase volumes (GW.h)	2,593	(2)	B
54 Average price ((1)/(2)) (\$/MW.h)	59.5		
56 Load Volume variance (GW.h)	2,158		C

57

**Transfer to HDA and NHDA continued**

**Schedule C-3**

		<b>Reference Schedule</b>
1	6. Load Variance for NHDA calculated as Load Volume variance multiplied by the Plan average price of IPP and	
2	long-term purchase commitments (183 GW.h * \$55.87/MW.h) = \$10.24 million.	C-1
3		
4	<b>Reconciliation of Energy Volumes (GW.h)</b>	
5		
6	Increase in domestic sales volumes from Plan	1,986
7	Decrease in line loss and system use	<u>(10)</u>
8	Net change in volumes	<u>1,976</u>
9		
10	Change in HPO energy volumes	2,158
11	Change in Non-Heritage energy:	
12	IPP's and long-term purchase commitments	(183)
13	Non-Integrated areas	<u>1</u>
14		<u>1,976</u>
15		
16		
17		
18	7. F2006 Return on Equity Deferral included in existing deferral accounts as per BCUC Order G-48-05, dated May 20, 2005.	

Schedule C-4

			Reference Schedule
1	<b>Transfer to Trade Income Deferral Account</b>		
2	<b>For the nine months ended December 31, 2005</b>		
3	<b>(\$ in millions)</b>		
4			
5			
6			
7			
8	Actual Trade Income	168	A-3
9	Excess over Cap for deferral account transfer	-	
10		<u>168</u>	
11	Less: Plan Trade Income	<u>92</u>	A-3
12	Transfer to Trade Income Deferral Account	<u><u>76</u></u>	A; A-2

**Transfer to BCTC Transition Deferral Account**  
**For the nine months ended December 31, 2005**  
(\$ in millions)

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	F2006 Actual	F2006 Plan	Variance	Reference Schedule
<u>BCTC Asset Management Fee</u>				
Transmission Assets	68.6	71.0	(2.4)	
Generation Related Transmission Assets	7.7	7.7	(0.1)	
Substation Distribution Assets	10.5	8.9	1.7	
	<u>86.7</u>	<u>87.5</u>	<u>(0.8)</u>	
<u>BCTC Wholesale Transmission Service / BCTC Revenue Forecast (Note 2)</u>				
BCTC Network Integrated Transmission Service (NITS)	43.1	45.8	(2.7)	
BCTC Point to Point (PTP) Expenses	20.6	-	20.6	
Ancillary Services Expenses and other	4.4	-	4.4	
	<u>68.1</u>	<u>45.8</u>	<u>22.3</u>	
<b>Total</b>	<u>154.8</u>	<u>133.3</u>	<u>21.5</u>	A;A-2

**Notes:**

1. The transfer to the BCTC Transition Deferral Account\*<sup>1</sup> relates to two variances:

- a) variances between BC Hydro's Asset Management/Maintenance Revenue Requirement forecast at \$116.7 million\*<sup>2</sup> 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\*<sup>2</sup> 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.

\*<sup>1</sup> Per Commission Directive October 29, 2004 Page 43, Section 4.7

\*<sup>2</sup> Per BC Hydro 2004/05 and 2005/06 Revenue Requirement Application, Chapter 2, Schedule B-3 (November 15, 2004 Compliance Filing)

**INTERSEGMENT REVENUES**  
**For the nine months ended December 31, 2005**

	<u>Actual</u>	<u>Plan</u>	<u>Variance</u>	<u>Reference Schedule</u>
Net sales to Powerex - Future Trade <i>(Note 1)</i>	58	43	14	C
Point-to-Point wheeling charge to Powerex <i>(Note 2)</i>	16	38	(22)	
Point-to-Point wheeling charge to BCH <i>(Note 3)</i>	14	9	5	
Allocation of BCH Corporate costs to Powerex <i>(Note 4)</i>	2	2	(0)	
Mark to Market gains on energy derivatives with Powerex <i>(Note 5)</i>	38	-	38	C
<b>Total</b>	<b>126</b>	<b>92</b>	<b>35</b>	A - 3

**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, 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.
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 gains on energy derivatives with Powerex. This revenue is eliminated against trade income on consolidation.

References to Commission Directives and Revenue Requirement Application

Reference:	Wording in Document:
<p>Commission Directive October 29, 2004 Page 30-31, Section 4.4</p>	<p>4.4 Heritage Payment Obligation Deferral Account</p> <p>The cost elements for the HPO set forth in BC Hydro’s Final Argument are itemized as follows:</p> <ol style="list-style-type: none"> <li>1. cost of energy – all variances except those arising from changes in customer load (part of (a)(i));</li> <li>2. cost of energy – variable costs related to thermal generation. (part of (a)(ii));</li> <li>3. significant unplanned major maintenance costs greater than \$1 million related to single event equipment or infrastructure failure or caused by weather related events (part of (a)(ii));</li> <li>4. significant unplanned major capital expenditures having an incremental annual impact on the Income Statement greater than \$1 million related to single event equipment or infrastructure failure or caused by weather related events (part of (a)(iii));</li> <li>5. amortization of unplanned deferred capital costs pursuant to Commission Order No. G-53-02 (part of (a)(iv));</li> <li>6. all net revenues from surplus hydro electricity sales (all revenues in (b)(iii)); and</li> <li>7. Skagit Valley Treaty revenues (all revenues in (b)(i)) and ancillary services revenues (all revenues in (b)(ii)).</li> </ol>
<p>Commission Directive October 29, 2004 Page 37, Section 4.5</p>	<p>4.5 Non-Heritage Deferral Account</p> <p>BC Hydro’s Non-Heritage Deferral Account proposal, as set forth in BC Hydro Argument and amended during the oral phase of argument (T22: 4161), is set forth below:</p> <ol style="list-style-type: none"> <li>1. cost of energy – all variances in non-HPO energy costs except those arising from changes in customer load;</li> <li>2. significant unplanned major maintenance costs greater than \$1 million related to single event equipment or infrastructure failure or caused by weather related events;</li> <li>3. significant unplanned major capital expenditures having an incremental annual impact on the Income Statement greater than \$1 million related to single event equipment or infrastructure failure;</li> <li>4. distribution emergency restoration costs – all variances in emergency restoration expenditures; and</li> <li>5. all Founding Partner Benefits and CIS Credits under the ABS Contract.</li> </ol>
<p>Per Commission Decision October 29, 2004, Page 38, Section 4.5.1.1</p>	<p>BC Hydro proposes that load variances be valued at the actual average cost of the highest priced resource option used to serve the load when the load variance is positive, that is, when actuals are higher than forecast. When actuals are lower than forecast, BC Hydro proposes that load variances be valued at forecast costs.</p> <p>When actuals are less than forecast, BC Hydro will not be purchasing power so BC Hydro proposes to use the average of the forecast of the highest resource option. When actuals are greater than forecast, BC Hydro will be purchasing power to meet the variance so BC Hydro proposes to use the average of the actual highest resource option purchases.</p>

## Appendix 1

### References to Commission Directives and Revenue Requirement Application

<p>Commission Directive October 29, 2004 Page 41</p>	<p><b>Commission Findings</b>  The Commission Panel approves the HDA as proposed by BC Hydro, and approves BC Hydro's forecast of the cost components of the HPO for F2005 and F2006.</p> <p>The Commission Panel approves all elements of the NHDA, except the distribution emergency restoration costs elements, item 4, because it can be forecast with some confidence, unlike unplanned major capital expenditures and unplanned major maintenance expenditures, and because of risk/reward considerations. Given the denial of item 4 of the NHDA, item 3 of the NHDA is to be as set forth in Final Argument. The Commission Panel approves BC Hydro's forecast of the NHDA non-HPO cost of energy for F2005 and F2006.</p>
<p>Commission Directive October 29, 2004 Page 42, Section 4.6</p>	<p>BC Hydro proposes to record variances between BC Hydro's forecast Trade Income and actual Trade Income, as defined in HC2, in the TIDA and submits that its TIDA proposal is consistent with the requirements of subsection 7(a)(ii) of HC2 (BC Hydro Argument p. 76).</p> <p><b>Commission Findings</b>  The Commission Panel approves the TIDA as proposed by BC Hydro, and approves BC Hydro's forecast of Trade Income for F2005 and F2006.</p>
<p>Commission Directive October 29, 2004 Page 42 &amp; 43, Section 4.7</p>	<p>BC Hydro applies under section 7(b) of HC2 for a deferral account for two elements of the F2006 Transmission Revenue Requirement as set out in Exhibit B1-108. The two elements are: (1) BC Hydro Asset Management/ Maintenance Revenue Requirement forecast at \$116.7 million, and (2) BCTC Revenue Requirement forecast at \$74 million. The Commission Panel accepts that any variances from such amounts would only arise as a result of the Commission's decision on BCTC's F2006 revenue requirement application, and would be beyond BC Hydro's control (BC Hydro Argument, p. 78).</p> <p><b>Commission Findings</b>  The Commission Panel approves the BCTC TDA as proposed by BC Hydro, and approves BC Hydro's F2005 and F2006 forecast, subject to the adjustments required by this Decision, of the Asset Management/ Maintenance Revenue Requirement and the BCTC Revenue Requirement for the purpose of the BCTC TDA.</p>
<p>Commission Directive October 29, 2004 Page 45, Section 4.11</p>	<p>The Commission Panel approves BC Hydro's proposal that annually the average balance in each deferral account attract an interest charge or credit equivalent to BC Hydro's weighted cost of debt during the same period.</p>
<p>BC Hydro 2004/05 and 2005/06 Revenue Requirement Application (November 15, 2004 Compliance Filing), Chapter 2, Schedule B-3</p>	<p>Refer to Schedule B-3 below table.</p>

## References to Commission Directives and Revenue Requirement Application

SCHEDULE B-3 (November 2004)									
Functionalized Costs									
F2006									
	(\$ millions)	Corporate	Energy Supply less Heritage Payment Obligation <sup>1</sup>	Generation (Heritage Contract) <sup>2</sup>	Transmission	Electricity Distribution &NIA <sup>7</sup>	Customer Care <sup>1</sup>	Service Orgs and Subsidiaries	Consolidated
		Chapter 3	Chapter 4	Chapter 5	Chapter 6	Chapter 7	Chapter 8	Chapter 9	
B1	Domestic cost of energy		408.0	431.6		15.0			854.6
	OMA Expenses								-
	Operations, maintenance, and administration (net)	63.8	20.9	126.0	3.5	107.6	97.3	(18.2)	400.9
	Corporate Allocations	(121.3)	11.3	39.3	14.7	23.0	7.5	25.5	-
B2	Adjusted OMA including Corporate Allocations	(57.5)	32.2	165.3	18.2	130.6	104.8	7.3	400.9
B4	Depreciation	52.0	27.9	113.4	138.0	71.1		17.2	419.6
B3	Taxes	7.5		29.0		90.5		1.0	147.1
B5	Finance charges	8.1	4.7	203.4	133.3	113.5		-	463.0
B6	Allowed net income (return on equity)		4.2	181.9	119.3	101.6		-	407.0
C3	Other <sup>3</sup>			43.3		66.7			110.0
A-1	Restructuring Costs	-	-	-	-	-	-	-	-
A-8	Miscellaneous external revenues	(10.1)		(118.8)	(115.7)	(4.5)	(4.2)	(22.5)	(275.8)
	Cost of Service by Function	-	477.0	1,049.1	383.6	513.1	100.6	3.0	2,526.4
BCTC	Asset Management Fee to BCTC <sup>4</sup>								116.7
BCTC	WTS Charges from BCTC <sup>4</sup>								61.0
A-1	Intersegment revenues <sup>5</sup>								(116.0)
	Total Revenue Requirement <sup>6</sup>								2,588.1
Schedule to cross reference		C6	C2	C1	C3	C4	C5	C7	
Notes:	<p>1. Power Smart and Energy Management costs are discussed in Chapter 8 "Power Smart, Customer Care and Energy Management" but are included together with Energy Supply costs as discussed in Chapter 4.</p> <p>2. The Generation (Heritage Contract) component of the domestic cost of energy does not equal the cost of energy component of the Heritage Payment Obligation for reasons explained in the notes to schedule D1-2.</p> <p>3. Relates to Generation Related Transmission Asset charges from BC Hydro Transmission to BC Hydro Generation and to Substation Distribution Asset Management charges from BC Hydro Transmission to BC Hydro Distribution.</p> <p>4. Relates to charges from BCTC</p> <p>5. See Chapter 2 Section 3.3 for details.</p> <p>6. Small differences from Chapter 1 Table 3 relate to rounding differences.</p> <p>7. Domestic cost of energy for Electricity Distribution &amp; NIA is from Domestic Cost of Energy - Non-Integrated Areas (see line 1, schedule C4)</p>								
	Shaded amounts indicate changes to the test years from the Revised Evidentiary Update.								