

Richard Stout
Chief Regulatory Officer
Phone: (604) 623-4046
Fax: (604) 623-4407

15 November 2004

Mr. Robert J. Pellatt
Commission Secretary
British Columbia Utilities Commission
PO Box 250
600 – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Pellatt:

**RE: British Columbia Hydro and Power Authority (“BC Hydro”)
November 15, 2004 Compliance Filing**

Pursuant to paragraph 3 of BCUC Order No. G-96-04, BC Hydro has recalculated its F2005 rates and encloses for filing financial schedule A to the Application, recalculated in accordance with the directives contained in the Commission's Revenue Requirements Application Decision of 29 October 2004 (the “Decision”).

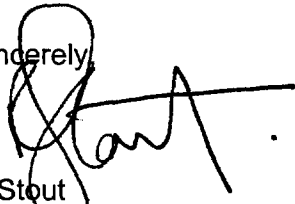
Schedule A to the Application contains the summary financial tables that permit BC Hydro's revenue requirement and rates to be calculated and make transparent the effect of the adjustments directed by the Commission. BC Hydro is continuing its efforts to prepare the backup Schedules B through E to reflect the Commission's decision and expects to be able to file those Schedules with the Commission prior to 31 December 2004.

BC Hydro is taking steps to ensure the timely preparation of the various other additional filings contemplated by the Decision. In particular, BC Hydro expects to be able to file new rate schedules and issue bills consistent with the Decision within 30 days of the Commission accepting this letter and enclosures as consistent with the Decision. BC Hydro intends to rebate and credit individual customers with a rebate for the period from 01 April 2004 to the date at which bills calculated under the new rates are issued. This rebate will appear on bills commencing in January 2005. BC Hydro will keep the Commission apprised of its progress in connection with other compliance filings as preparation continues. In addition to those filings, BC Hydro is currently working on the following:

1. 19 November 2004 report on the CFT process for Vancouver Island supply;
2. Preparation of stepped, time-of-use and standby rates for industrial customers and development of companion retail access provisions to be filed by January 2005;
3. February/March 2005 Resource Expenditure and Acquisition Plan and 2005 Resource Option Report filings; and
4. Preparation of a general tariff application that will afford an opportunity for a comprehensive review of BC Hydro's rate design for filing in June 2005.

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

Yours sincerely,

A handwritten signature in black ink, appearing to read 'R. Stout', with a long horizontal stroke extending to the right.

Richard Stout
Chief Regulatory Officer

Enclosure (20)

c: 2004/05 and 2005/06 Revenue Requirements Intervenors

Revenue Requirement Application
2004/05 and 2005/06



Submission in Response to G-96-04

- **Impact of Commission Directives on BC Hydro's Revenue Requirement**
- **Consolidated Financial 'A' Schedules**
- **Appendix 1 – FRSR/ARO**
- **Appendix 2 – Disallowed Load Displacement Costs**

November 15, 2004

INDEX

Impact of Commission directives on BC Hydro's Revenue Requirement.....	3
Consolidated Financial A Schedules	6
Appendix 1 – FRSR/ARO.....	27
Appendix 2 – Disallowed Load Displacement Costs.....	30

1 **Impact of Commission Directives on BC Hydro's Revenue**
 2 **Requirement**

3 BC Hydro has calculated its F2005 rate increase in accordance with the directives in the
 4 Commission's Decision of October 29, 2004 to be 4.85%. The rate increase for F2006,
 5 of an additional 0.30% increase, has been included for information purposes only.
 6 Following the determination of the 2005 allowed return on equity and the effective
 7 income tax rate for Terasen Gas Inc., BC Hydro will apply to adjust its F2006 tariff rates
 8 based on its allowed pre-tax rate of return for F2006.

9 All relevant A schedules, which have changed from the Revised Evidentiary Update, are
 10 included in this filing. The relevant schedules have been updated for the following
 11 directives in the Commission's decision and a summary of the impact is presented in
 12 Table 1, *Impact of Commission Directives on BC Hydro's Revenue Requirement*.

13 **Table 1**
 14 **Impact of Commission Directives on BC Hydro's Revenue Requirement**
 15

Directive:	Impact on F2005 Revenue Requirement Decrease(Increase) \$ millions	Impact on F2006 Revenue Requirement Decrease(Increase) \$ millions
34. Corporate Sustainability – R&D program	6	6
35. Burrard Generating Station – Depreciation rate	10	8
36. Distribution Transformers - Depreciation rate	13	9
40. Investigation costs for Revelstoke and Mica ¹	-	-
41. Site C expenditures ¹	-	-
50. FRSR/ARO ² :		
F2004 FRSR balance (\$251m x 13.91%)	35	35
Dismantling costs	18	19
59. VIGP/GSX costs (\$120m x 15%) x 13.91%	(2)	(2)
59. F2004 Balance Sheet Adjustments:		
Actual capital expenditures	13	14
Actual ending debt balance	2	3
Actual ending equity	1	1
63. Load Displacement projects ³	-	-
Decrease in water rental expenses due to lower rate increase ⁴	3	10
Increase in finance charges due to lower rate increase ⁵	(1)	(5)
Total Decrease in Revenue Requirement	98	98

1 Notes:

- 2 1. There is no revenue requirement impact for the capital expenditures of \$6.5 million
 3 for Revelstoke and \$5.5 million for Site C that have been disallowed for F2006 as
 4 these amounts are not depreciated in the test years. These expenditures may be
 5 approved in the future following the filing of the 2005 REAP. The capital expenditure
 6 schedules have not been adjusted to remove these amounts. BC Hydro will remove
 7 these amounts when it refiles its rate increase for F2006.
- 8 2. Appendix 1 includes a discussion of how BC Hydro has interpreted this directive.
- 9 3. The disallowed Load Displacement projects have been calculated to be \$2.8 million
 10 and \$0.2 million for F2005 and F2006 respectively. (See Appendix 2). The impact on
 11 depreciation expenses is less than \$0.5 million.
- 12 4. As indicated in the Application, water rental rates are indexed to BC Hydro's general
 13 rate increases. Therefore a decrease in general tariff rates will reduce water rental
 14 expenses.
- 15 5. Finance charges increase as a result of a reduction in cash flows that result from the
 16 decrease in the rate increase.

17 The changes to BC Hydro's Revenue Requirement are shown in Table 2 and Schedule
 18 A-19 shows the calculation of BC Hydro's domestic revenues before and after rate
 19 increases.

20 **Table 2**
 21 **Changes in BC Hydro's Revenue Requirement**
 22

	F2005	F2006
Revenue Requirement per Revised Evidentiary Update (April 2004). Page 2A-31	\$2,660	\$2,687
Decrease per Commission Directives (Table 1-1)	(98)	(98)
Revised Revenue Requirement (Schedule A-18 attached)	\$2,562	\$2,589

23 The changes to BC Hydro's average rates are shown in Table 3.

24 **Table 3**
 25 **Average Rates, Before and After Increase**
 26

Customer Class (\$ per MWh)	Previous Rates (before interim April 1, 2004 increase)	F2005	F2006
Residential	61.3	64.3	64.5
Light industrial and commercial	53.2	55.8	56.0
Large industrial	34.0	35.6	35.7

27
 28 An average BC Hydro customer with a detached house will pay an additional \$34.20 per
 29 year, or less than \$3 extra per month, after the 4.85% rate increase for F2005. The
 30 estimated rebate amount (for the 8 months with the 7.23% interim increase) is \$11.20 or

1 \$1.40 per month. This is based on a non-electrically heated house using 11,500 kWh per
2 year.

3 An average BC Hydro customer with an apartment will pay an additional \$20.16 per
4 year, or less than \$2 extra per month, after the 4.85% rate increase. The estimated
5 rebate amount for the 8 months with the 7.23% interim increase is \$6.64 or \$0.83 per
6 month. This is based on an electrically heated apartment using 6,500 kWh per year.

Consolidated Financial 'A' Schedules

Consolidated Statement of Operations with Proposed Rate Increases				
For the Years Ended March 31				
(\$ millions)				
	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
REVENUES				
Domestic				
Residential	\$ 923	\$ 960	\$ 1,018	\$ 1,036
Light industrial and commercial	893	912	948	961
Large industrial	516	525	526	522
Other energy sales	88	89	89	90
Miscellaneous	55	67	61	55
	<u>2,475</u>	<u>2,553</u>	<u>2,642</u>	<u>2,664</u>
Intersegment revenues	6	62	125	116
	<u>2,481</u>	<u>2,615</u>	<u>2,767</u>	<u>2,780</u>
EXPENSES				
Domestic energy costs	708	995	903	855
BCTC wholesale transmission service	-	-	-	61
BCTC asset management fee	-	-	-	117
Operations expense	143	168	171	129
Maintenance expense	196	240	244	138
Administration expense	167	168	156	134
Depreciation and amortization	414	536	416	420
Taxes	145	146	145	147
	<u>1,773</u>	<u>2,253</u>	<u>2,035</u>	<u>2,001</u>
INCOME BEFORE FINANCE CHARGES, RESTRUCTURING COSTS, TRANSFER FROM RSA AND TRADE INCOME	708	362	732	779
Finance charges	457	435	428	463
INCOME BEFORE RESTRUCTURING COSTS, TRANSFER FROM RSA AND TRADE INCOME	251	(73)	304	316
Restructuring Costs	37	8	-	-
INCOME BEFORE TRANSFER FROM RSA AND TRADE INCOME	214	(81)	304	316
Transfer from RSA	66	21	-	-
DOMESTIC NET INCOME	<u>280</u>	<u>(60)</u>	<u>304</u>	<u>316</u>
TRADE NET INCOME	<u>138</u>	<u>158</u>	<u>89</u>	<u>91</u>
TOTAL NET INCOME	<u>\$ 418</u>	<u>\$ 98</u>	<u>\$ 393</u>	<u>\$ 407</u>
PAYMENT TO THE PROVINCE	<u>\$ 338</u>	<u>\$ 73</u>	<u>\$ 318</u>	<u>\$ 316</u>
ACTUAL/FORECAST RETURN ON EQUITY	15.47%	3.60%	13.91%	13.91%
ALLOWED RETURN ON EQUITY	<u>15.47%</u>	<u>14.33%</u>	<u>13.91%</u>	<u>13.91%</u>
BALANCE IN RSA	<u>\$ 21</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>
RATE INCREASE	0.00%	0.00%	4.85%	0.30%
CUMULATIVE RATE INCREASE	<u>0.00%</u>	<u>0.00%</u>	<u>4.85%</u>	<u>5.17%</u>

Shaded amounts indicate changes to the test years from the Revised Evidentiary Update.

Consolidated Balance Sheet
As at March 31
(\$ millions)

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Capital Assets				
Capital assets in service	\$ 14,940	\$ 15,293	\$ 15,861	\$ 16,262
Less accumulated depreciation	5,816	5,964	6,252	6,540
	9,124	9,329	9,609	9,722
Unfinished construction	669	515	562	827
	9,793	9,844	10,171	10,549
Current Assets				
Temporary investments	4	47	4	4
Accounts receivable and accrued revenue	362	323	435	437
Materials and supplies	88	86	88	88
Prepaid expenses	86	108	87	68
Unrealized gains on mark-to-market transactions	10	104	-	-
	550	668	614	597
Other Assets and Deferred Charges				
Loan receivable	23	2	2	2
Sinking funds	1,037	981	984	844
Demand-Side Management programs	123	161	238	301
Deferred debt costs	385	150	84	51
Regulatory asset - VIGP/GSX (net) ¹	0	0	18	18
	1,568	1,294	1,326	1,216
	\$ 11,911	\$ 11,806	\$ 12,111	\$ 12,362
Long term debt net of sinking funds	\$ 6,853	\$ 6,900	\$ 7,008	\$ 7,401
Sinking funds presented as assets	1,037	981	984	844
Long-Term Debt	7,890	7,881	7,992	8,245
Foreign Currency Contracts	2	63	65	60
Current Liabilities				
Accounts payable and accrued liabilities	689	672	537	456
Accrued interest	108	115	117	121
Accrued Payment to the Province	338	73	318	316
Unrealized losses on mark-to-market transactions	10	78	-	-
	1,145	938	972	893
Deferred Credits and Other Liabilities				
Provision for future removal and site restoration costs	174	202	-	-
Asset Retirement Obligation	-	-	19	20
Regulatory liability for FRSR provision ²	-	-	233	214
Deferred revenue	258	276	293	313
Rate stabilization account	21	-	-	-
Contributions arising from the Columbia River Treaty	203	193	184	175
Contributions in aid of construction	609	619	635	653
	1,265	1,290	1,364	1,375
Retained Earnings	1,609	1,634	1,718	1,789
	\$ 11,911	\$ 11,806	\$ 12,111	\$ 12,362
Debt to Equity Ratio	71.7:28.3	71.6:28.4	71.2:28.8	71.6:28.4

Notes:

1. As per Commission directive No. 59 of the October 29, 2004 decision.
2. As per Commission directive No. 50 of the October 29, 2004 decision.

Shaded amounts indicate changes to the test years from the Revised Evidentiary Update.

Consolidated Statement of Retained Earnings
For the Years ended March 31
(\$ millions)

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Retained earnings at beginning of year	\$ 1,529	\$ 1,609	\$ 1,634	\$ 1,700
Net income	418	98	393	407
Payment to the Province	(338)	(73)	(318)	(316)
Asset Retirement Obligation Adjustment ¹	-	-	(9)	-
Special Dividend to the Province for BCTC ²	-	-	-	(20)
Retained earnings at end of year	<u>\$ 1,609</u>	<u>\$ 1,634</u>	<u>\$ 1,700</u>	<u>\$ 1,771</u>
Regulatory Adjustment for VIGP/GSX ³	-	-	18	18
Regulatory Retained Earnings	<u>\$ 1,609</u>	<u>\$ 1,634</u>	<u>\$ 1,718</u>	<u>\$ 1,789</u>

Notes:

1. Relates to prior period adjustments to set up the ARO.
2. The Special Dividend to the Province for BCTC was paid in fiscal 2004. It is shown in fiscal 2006, because BCTC is consolidated with BC Hydro in fiscal 2004 and fiscal 2005.
3. Relates to Commission directive of October 29, 2004 decision.
- A regulatory asset is also shown on the balance sheet for this amount.

Shaded amounts indicate changes to the test years from the Revised Evidentiary Update.

SCHEDULE A-4 (November 2004)

Consolidated Statement of Cash Flows
For the Years ended March 31
(\$ millions)

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Operating Activities				
Net income	\$ 418	\$ 98	\$ 393	\$ 407
Adjustments for:				
Depreciation and amortization	417	539	421	424
Rate stabilization account	(66)	(21)	-	-
Other non-cash items	24	(4)	2	(18)
	793	612	816	813
Working capital changes	1	1	(226)	(60)
Cash provided by operating activities	794	613	590	753
Investing Activities				
Capital asset expenditures	(680)	(606)	(716)	(894)
Contributions in aid of construction	62	56	51	54
Demand side management programs	(45)	(63)	(102)	(94)
Future removal and site restoration costs	(12)	(15)	-	-
Net asset dismantling costs	-	-	(17)	(17)
Loan receivable	(8)	(1)	-	-
Proceeds from property and asset sales	1	10	4	79
Cash used for investing activities	(682)	(619)	(780)	(872)
Financing Activities				
Bonds, notes and debentures				
Issued	1,007	790	600	700
Retired	(1,019)	(450)	(598)	(607)
Revolving borrowings changes	147	(47)	184	179
Sinking funds	48	53	34	185
Deferred debt costs	3	7	-	-
Settlement of financial instruments	22	34	-	-
Cash provided by financing activities	208	387	220	457
Payment to the Province	(333)	(338)	(73)	(318)
Special Dividend to the Province for BCTC	-	-	-	(20)
Increase (decrease) in cash	(13)	43	(43)	-
Cash at beginning of year	17	4	47	4
Cash at end of year	\$ 4	\$ 47	\$ 4	\$ 4

Shaded amounts indicate changes to the test years from the Revised Evidentiary Update.

Residential Revenues
For the Years Ended March 31
(\$ millions)

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31
32
33

	A		B		C		D	
	F2003	F2004	F2005	F2006	F2003	F2004	F2005	F2006
	Actual	Actual	%	Forecast	%	Forecast	%	Forecast
Revenue								
Residential revenue	\$923	\$960	4%	\$1,018	6%	\$1,036	2%	
Revenue variance	n/a	\$37		\$58		\$18		
Variance								
Rate increase:		n/a		47		4		
Volume:								
Number of customers	n/a	15		15		17		
Usage per customer	n/a	28		(1)		1		
Power Smart savings	n/a	(6)		(3)		(4)		
Total Variance	n/a	\$37		\$58		\$18		
Sales Volume (in GW·h)	15,024	15,646	4%	15,836	1%	16,063	1%	

() represents a negative variance.

Residential revenues are expected to increase primarily due to the proposed rate increase and customer growth which is expected to be an average of 1.70% over the period from 2004 to 2006.

The usage variance in fiscal year 2004 is high due to Fiscal 2003 having a warmer than normal year. Forecast 2005 and 2006 assumes normal weather.

Shaded amounts indicate changes to the test years from the Revised Evidentiary Update.

Light Industrial And Commercial Revenue
For the Years Ended March 31
(\$ millions)

	A	B	C		D		
	F2003	F2004	F2005		F2006		
	Actual	Actual	%	Forecast	%	Forecast	%
Revenue							
Light industrial & commercial	\$893	\$912	2%	\$948	4%	\$961	1%
Revenue variance	n/a	\$19		\$36		\$13	
Variance							
Rate increase:		n/a		44		3	
Volume:							
GDP & Employment*	n/a	21		6		20	
Power Smart savings	n/a	(2)		(14)		(10)	
Total Variance	n/a	\$19		\$36		\$13	
Sales Volume (in GW-h)	16,757	17,175	0%	17,003	-1%	17,202	1%

() represents a negative variance.

* includes floor stock growth rates and end-use building intensities

Light industrial and commercial customers is comprised of small and large accounts. Small customers are defined as those with a monthly demand of less than 35 kilowatts and includes small retail operations, offices, schools and warehouses. Large accounts include retail, industrial and manufacturing customers whose monthly demand is 35 kilowatts or more.

The major change in revenues in fiscal 2005 and fiscal 2006 is due to the proposed rate increase and to increased volume from GDP, employment, floor stock building growth rates and end-use building intensities partially offset by expected Power Smart savings.

Shaded amounts indicate changes to the test years from the Revised Evidentiary Update.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21

Large Industrial Revenue
For the Years Ended March 31
(\$ millions)

	A	B		C		D	
	F2003	F2004		F2005		F2006	
	Actual	Actual	%	Forecast	%	Forecast	%
Revenue (in millions)							
Large industrial	\$516	\$525	2%	\$526	0%	\$522	-1%
Revenue variance	n/a	\$9		\$1		\$(4)	
Variance							
Rate increase:		n/a		24		1	
Volume:							
Usage per customer	n/a	14		(15)		1	
Power Smart savings	n/a	(5)		(8)		(6)	
Total Variance	n/a	\$9		\$1		\$(4)	
Sales Volume (in GW·h)	15,179	15,505	2%	14,733	-5%	14,604	-1%

22 () represents a negative variance.

23
24 Large industrial revenues are expected to increase largely due to the impact of the proposed rate
25 increases. The increase in 2004 is due primarily to increased sales to metal mining customers,
26 pulp and paper customers, wood manufacturing customers and pulp chemical customers.
27 The metal mines, pulp and paper mills and wood manufacturers are commodity exporters
28 whose sales have been positively impacted by the improvement in the Global economy. The pulp
29 chemical sales are dependent on the pulp and paper sector and therefore have also been
30 positively impacted.

31
32 Fiscal 2005 and fiscal 2006 revenues are expected to increase largely due to the impact of
33 the proposed rate increases.

Shaded amounts indicate changes to the test years from the Revised Evidentiary Update.

Schedule A-8 (November 2004)
Miscellaneous Revenues
For the Years Ended March 31

(\$ millions)

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Plan	Plan
Miscellaneous Revenues by Function				
Generation				
Ancillary services	\$ 2	\$ 2	\$ 3	\$ 5
Other	3	3	4	3
	5	5	7	8
Distribution				
Meter and transformer rents and power factor surcharges	6	6	5	5
Customer Care				
Terasen meter reading ¹	-	3	2	2
Other	2	4	2	2
	2	7	4	4
Transmission				
Short-term point to point wheeling revenue ²	1	5	5	-
Fortis general wheeling revenue ²	4	3	4	-
Transmission secondary revenue	4	5	4	5
	9	13	13	5
Field Services				
Fleet revenues	7	7	7	7
Corporate				
Corporate general rents	6	4	5	5
Net gains on property sales	2	9	2	2
Westech external revenues	5	1	3	3
	13	14	10	10
Powertech external revenues				
	13	15	15	16
	\$ 55	\$ 67	\$ 61	\$ 55

Notes:

- The Terasen revenue was classified as an Operations, Maintenance, and Administration recovery in fiscal 2003.
- The revenues for fiscal 2006 will be part of BCTC's revenues. Prior to fiscal 2006, BCTC is consolidated with BC Hydro due to their financial and operational dependence. BCTC will apply for their own tariff rates in F2006 and will therefore no longer be operationally and financially dependent on BC Hydro.

Schedule A-9 (November 2004)

Domestic Cost Of Energy
For the Years Ended March 31
(\$ millions)

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Domestic cost of energy :				
Water rentals	\$258	\$246	\$255	\$271
Independent Power Producers and long-term purchase commitments	290	372	380	395
Market electricity purchases	54	270	183	112
Net Purchases from Powerex (Note 1)	50	30		
Natural gas for thermal generation (Note 2)	28	33	36	26
Domestic cost of energy - Non-integrated Areas	14	14	15	15
Domestic transmission	5	16	16	16
Gas transportation	5	10	13	13
Cost of market (Note 3)	1	1	1	
Other	3	3	4	7
Total Domestic cost of energy	\$708	\$995	\$903	\$855
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Domestic energy:				
GW-h's				
Water rentals	47,665	44,540	44,980	46,045
Independent Power Producers and long-term purchase commitments	4,950	6,133	6,540	6,951
Market electricity purchases	896	5,349	4,266	2,757
Net Purchases from Powerex (Note 1)	-			
Thermal generation	251	296	338	233
Non-integrated Areas	96	99	105	105
Exchange net	(1,605)	(1,218)	54	199
	52,253	55,199	56,283	56,290
Less: Line loss and system use	(4,689)	(5,000)	(5,447)	(5,483)
Net sales to Powerex		(48)	(1,550)	(1,200)
Domestic sales volumes	48,677	50,151	49,286	49,607
\$/MW-h				
Water rentals	\$ 5.4	\$ 5.5	\$ 5.7	\$ 5.9
Independent Power Producers and long-term purchase commitments	58.6	60.7	58.1	56.8
Market electricity purchases	60.3	50.5	42.9	40.6
Net Purchases from Powerex	#DIV/0!			
Natural gas for thermal generation	111.6	111.5	106.5	111.6
Domestic cost of energy - Non-integrated Areas	145.8	141.4	142.9	142.9
Total weighted average cost (Note 4)	\$ 14.5	\$ 19.8	\$ 18.3	\$ 17.2

Notes:

- In F2004, Powerex drew down the trade account by 48 GWh, which is made up of 1,693 GWh out of the trade account and 1,645 GWh into the trade account. The value of the energy going into the trade account is more expensive than the current average cost of the trade account. This difference results in a net cost to domestic cost of energy of \$30 million. (i.e., The revenues BC Hydro would record from Powerex when the trade account is drawn down is less than the cost BC Hydro records from Powerex when the trade account is increased.) This does not have an impact on the Heritage Contract.
- This includes fixed transportation costs of approximately \$10 million related to the Bypass Transportation Agreement between Terasen and BC Hydro.
- Domestic cost of energy transmission which includes congestion management cost.
- Calculated as total cost divided by sales volumes.

Shaded amounts indicate changes to the test years from the Revised Evidentiary Update.

Finance Charges
For the Years Ended March 31
(\$ millions)

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31
32
33
34
35
36
37
38

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Interest on debt securities				
Bonds, notes and debentures	\$ 536	\$ 507	\$ 483	\$ 506
Revolving borrowings	5	9	17	28
Amortization of deferred debt costs and other expenses	26	28	32	33
	<u>567</u>	<u>544</u>	<u>532</u>	<u>567</u>
Less:				
Sinking fund income	(60)	(58)	(53)	(48)
Other income <i>(Note 1)</i>	(26)	(34)	(26)	(15)
Finance charges capitalized to unfinished construction	(24)	(17)	(25)	(41)
	<u>(110)</u>	<u>(109)</u>	<u>(104)</u>	<u>(104)</u>
Total	<u>\$ 457</u>	<u>\$ 435</u>	<u>\$ 428</u>	<u>\$ 463</u>

Note:

1. Other income largely relates to income on interest rate and cross currency swaps.

Average interest rates

Long-term debt

Canadian	8.3%	7.7%	7.4%	7.3%
Foreign	4.5%	4.4%	4.7%	5.6%

Short-term debt

Average exchange rate in U.S. dollars

2.4%	2.9%	2.8%	4.0%
0.65	0.74	0.79	0.80

Average interest rates relate to the weighted average interest rate and represents the effective rate of interest on fixed-rate bonds and notes and the current interest rate in effect at March 31 for floating-rate bonds and notes, all before considering the effect of derivative financial instrument used to manage interest rate risk.

Shaded amounts indicate changes to the test years from the Revised Evidentiary Update.

Consolidated Capital Asset
For the Years Ended March 31
(\$ millions)

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
10	CAPITAL ASSETS IN SERVICE			
11	14,608	14,940	15,293	15,861
12	461	622	660	588
13			14	
14	(129)	(191)	(106)	(187)
15		(78)		
16	<u>14,940</u>	<u>15,293</u>	<u>15,861</u>	<u>16,262</u>
17	ACCUMULATED DEPRECIATION			
19	5,557	5,816	5,964	6,252
20	382	405	431	429
21			7	
22			(46)	
23	(123)	(184)	(104)	(141)
24		(73)		
25	<u>5,816</u>	<u>5,964</u>	<u>6,252</u>	<u>6,540</u>
26	<u>9,124</u>	<u>9,329</u>	<u>9,609</u>	<u>9,722</u>
27	UNFINISHED CONSTRUCTION			
29	459	669	515	562
30	696	574	715	895
31	(8)	(8)	(8)	(9)
32	(17)	(98)		
33				
34				(33)
35	(461)	(622)	(660)	(588)
36	<u>669</u>	<u>515</u>	<u>562</u>	<u>827</u>
37				
38	<u>\$ 9,793</u>	<u>\$ 9,844</u>	<u>\$ 10,171</u>	<u>\$ 10,549</u>

41 Note 1: Primarily relates to assets transferred to BCTC. Accumulated Depreciation on assets
42 transferred to BCTC was netted against the original cost of the assets in BCTC's records.
43 As BCTC is consolidated with BC Hydro for F2005, this reclassification is needed to
44 correctly show the consolidated Capital Asset in Service and Accumulated Depreciation
45 balances.

46 Note 2: F2004 includes the provision relating to VIGP/GSX.

Shaded amounts indicate changes from the Revised Evidentiary Update.

Composition of Long-term Debt
As at March 31
(\$ millions)

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Bonds, notes and debentures				
Canadian	\$ 4,888	\$ 4,938	\$ 5,150	\$ 5,437
Foreign	2,671	2,659	2,374	2,161
	<u>7,559</u>	<u>7,597</u>	<u>7,524</u>	<u>7,598</u>
Less:				
Sinking funds	1,037	981	984	844
Net bonds, notes and debentures	6,522	6,616	6,540	6,754
Revolving borrowings	331	284	468	647
Long-term debt net of sinking funds	6,853	6,900	7,008	7,401
Sinking funds presented as assets	1,037	981	984	844
Long-term debt	<u>\$ 7,890</u>	<u>\$ 7,881</u>	<u>\$ 7,992</u>	<u>\$ 8,245</u>
Foreign currency contracts (Dr)	(13)	-	-	-
Foreign currency contracts Cr	15	63	65	60

Shaded amounts indicate changes to the test years from the Revised Evidentiary Update.

Net Long-term Debt
For the Years Ended March 31
(\$ millions)

Long-term debt consists of bond, notes and debentures and revolving borrowings obtained under a borrowing agreement with the Province. Long-term debt is presented net of sinking funds.

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Balance at Beginning of Year	\$ 6,906	\$ 6,853	\$ 6,900	\$ 7,008
Add (less):				
New financing	1,007	790	600	700
Retirements	(1,019)	(450)	(598)	(607)
Revolving borrowings	147	(57)	184	179
	135	283	186	272
Exchange and other adjustments	(179)	(229)	(60)	(15)
Sinking fund (increase) decrease	(9)	(7)	(18)	136
Balance at End of Year	\$ 6,853	\$ 6,900	\$ 7,008	\$ 7,401

Shaded amounts indicate changes to the test years from the Revised Evidentiary Update.

Contributions in Aid
For the Years ended March 31
(\$ millions)

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Contributions in Aid:				
Opening balance	\$ 935	\$ 977	\$ 1,003	\$ 1,026
Current year additions	61	56	51	54
Balance sheet reclassifications ¹	-	(12)	-	-
Less retirements	(19)	(18)	(28)	(26)
Balance at end of year	<u>977</u>	<u>1,003</u>	<u>1,026</u>	<u>1,054</u>
Accumulated Amortization:				
Opening balance	354	368	384	391
Current year amortization	33	35	35	36
Less retirements	(19)	(19)	(28)	(26)
Balance at end of year	<u>368</u>	<u>384</u>	<u>391</u>	<u>401</u>
NET CONTRIBUTIONS IN AID	<u>\$ 609</u>	<u>\$ 619</u>	<u>\$ 635</u>	<u>\$ 653</u>

Certain customers contribute amounts towards the cost of capital assets required for extension of services. These amounts are amortized over the expected useful life of the related assets.

Note:

1. Amounts transferred to Capital Assets from contributions in aid to correct classification error.

Contributions Arising from the Columbia River Treaty
For the Years ended March 31
(\$ millions)

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Original contribution	\$ 479	\$ 479	\$ 479	\$ 479
Accumulated depreciation:				
Beginning of year	(267)	(276)	(286)	(295)
Amortization	(9)	(10)	(9)	(9)
	(276)	(286)	(295)	(304)
BALANCE AT END OF YEAR	\$ 203	\$ 193	\$ 184	\$ 175

Contributions Arising from the Columbia River Treaty relate to three dams built by BC Hydro in the mid-1960's to regulate the flow of the Columbia River. The proceeds received were contributed to BC Hydro to assist in financing the dams' construction. These proceeds were deferred and are amortized to income over the period ending in fiscal 2025, the minimum term of the treaty.

Deferred Revenue
For the Years ended March 31
(\$ millions)

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
10 Balance at beginning of year - Skagit	\$ (237)	\$ (257)	\$ (275)	\$ (292)
11 Add:				
12 Payments received	(35)	(28)	(28)	(27)
13 Interest	(7)	(8)	(8)	(12)
14	<u>(279)</u>	<u>(293)</u>	<u>(311)</u>	<u>(331)</u>
15 Less:				
16 Revenue earned	(22)	(18)	(19)	(19)
17 Total deferred revenue - Skagit	<u>\$ (257)</u>	<u>\$ (275)</u>	<u>\$ (292)</u>	<u>\$ (312)</u>
18				
19 Other deferred revenue	(1)	(1)	(1)	(1)
20				
21 Total deferred revenue	<u>\$ (258)</u>	<u>\$ (276)</u>	<u>\$ (293)</u>	<u>\$ (313)</u>

Deferred revenue consists principally of amounts received under the Skagit Agreements which commenced in fiscal 1986. Annual fixed payments are to be made by Seattle City Light under the Skagit Agreement up to and including December 31, 2020. These payments are deferred and included in income as revenue on an annuity basis over the energy delivery period, which is scheduled to end January 1, 2066. Revenues recognized are calculated using a method that results in a constant (inflation adjusted) rate of return on the deferred revenue balance.

Other deferred revenue consists mainly of amounts received from transmission cell site customers. These customers are billed once a year in January for services to be provided for the year.

Shaded amounts indicate changes to the test years from the Revised Evidentiary Update.

Return on Equity
For the Years Ended March 31
(\$ millions)

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Actual/forecast return on equity	15.47%	3.60%	13.91%	13.91%
Allowed return on equity ¹	15.47%	14.33%	13.91%	13.91%
Numerator				
Consolidated net income after rate stabilization account transfer	\$ 418	\$ 98	\$ 393	\$ 407
Denominator				
Retained earnings - end of year	\$ 1,609	\$ 1,634	\$ 1,718	\$ 1,789
Deferred credits - end of year	1,091	1,088	1,112	1,141
Equity - end of year	\$ 2,700	\$ 2,722	\$ 2,830	\$ 2,930

Note:

1. Return on equity is calculated in accordance with HSD #2 - see section 3.1.

Definition of Return on Equity

Return on equity = Consolidated Net Income / Ending Equity

Where Equity = Retained earnings + Deferred credits

Where Deferred credits = Deferred revenue + Contributions arising from the Columbia River Treaty and Contributions in aid of construction + RSA balance

	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Deferred Credits				
Deferred revenue	\$ 258	\$ 276	\$ 293	\$ 313
Contributions arising from the Columbia River Treaty	203	193	184	175
Contributions in aid of construction	609	619	635	653
Rate stabilization account	21	-	-	-
	\$ 1,091	\$ 1,088	\$ 1,112	\$ 1,141

Shaded amounts indicate changes to the test years from the Revised Evidentiary Update.

Debt To Equity Ratio
For the Years Ended March 31
(\$ millions)

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31
32

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Debt to equity	72:28	72:28	71:29	72:28
Debt				
Long term debt net of sinking funds	\$6,853	\$6,900	\$7,008	\$7,401
Temporary investments	(4)	(47)	(4)	(4)
	<u>\$6,849</u>	<u>\$6,853</u>	<u>\$7,004</u>	<u>\$7,397</u>
Equity				
Deferred credits	\$1,091	\$1,088	\$1,112	\$1,141
Retained earnings	1,609	1,634	1,718	1,789
	<u>\$2,700</u>	<u>\$2,722</u>	<u>\$2,830</u>	<u>\$2,930</u>

Definition of Debt to Equity

$$\frac{\text{Debt}}{\text{Debt} + \text{Equity}} \times 100: \frac{\text{Equity}}{\text{Debt} + \text{Equity}} \times 100$$

Where Debt = Bonds + Notes + Debentures + Revolving borrowings - Sinking funds -
 Term debentures - Temporary investments

Where Equity = Retained earnings + Deferred credits

Where Deferred credits = Deferred revenue + Contributions arising from the Columbia
 River Treaty + Contributions in Aid of Construction + RSA balance

Shaded amounts indicate changes to the test years from the Revised Evidentiary Update.

Schedule A-18 (November 2004)

Revenue Requirements
For the Years Ended March 31
(\$ millions)

	A	B
	F2005	F2006
	<u>Forecast</u>	<u>Forecast</u>
8 Domestic energy costs	\$ 903	\$ 855
9 BCTC wholesale transmission service		61
10 BCTC asset management fee		117
11 Operations expense	171	129
12 Maintenance expense	244	138
13 Administration expense	156	134
14 Amortization	416	420
15 Taxes	145	147
16 Finance charges	428	463
17 Total expenditures	<u>2,463</u>	<u>2,464</u>
18 Plus: Allowed return	393	407
19 Less:		
20 Trade Income	(89)	(91)
21 Intersegment revenues	(125)	(116)
22 Miscellaneous revenues	(61)	(55)
23 Revenues from Other Utilities	(19)	(20)
24	<u>\$ 2,562</u>	<u>\$ 2,589</u>

Schedule A-19 (November 2004)

Domestic revenues
For the Years Ended March 31
(\$ millions)

	A	B
	F2005	F2006
	Forecast	Forecast
Domestic revenues before rate increase ¹	\$ 2,649	\$ 2,653
Less: Non-tariff revenues ² :		
Miscellaneous	(61)	(55)
Skagit River Treaty	(19)	(19)
Light fixture charges on Street Lighting	(10)	(10)
Intersegment revenues	(125)	(116)
Tariff revenues before rate increase	2,434	2,453
Cumulative Rate increase % ³	4.85%	5.17%
Tariff revenues after rate increase	<u>\$ 2,552</u>	<u>\$ 2,580</u>
Domestic revenues after rate increase ⁴	\$ 2,767	\$ 2,780
Less: Non-tariff revenues:		
Miscellaneous	(61)	(55)
Skagit River Treaty	(19)	(19)
Light fixture charges on Street Lighting	(10)	(10)
Intersegment revenues	(125)	(116)
Tariff revenues after rate increase	<u>\$ 2,552</u>	<u>\$ 2,580</u>

Notes:

1. From Table 2-2 in the December 2003 Application adjusted for changes in intersegment and Skagit revenues as documented in the Revised Evidentiary Update.
2. As per the Revised Evidentiary Update
3. Includes rate increase of 4.85% in F2005 and a further 0.30% in F2006.
4. From Schedule A-1 (November 2004)

Appendix 1

FRSR/ARO

FRSR/ARO

Further to the Section 7.5 (FRSR/ARO) of the BCUC decision on the BC Hydro 2004/05 to 2005/06 Revenue Requirements Application, the panel has ordered "*..a variance from GAAP and requires that the F2004 balance in the FRSR account remain a liability to be utilized for dismantling costs that are incurred in F2005 and future years...*"

Implementation of the Commission's order requires the following procedures:

FRSR liability

BC Hydro will reinstate the FRSR liability of approximately \$251M as at March 31, 2004. This will be a departure from GAAP for regulatory purposes. The liability will be reduced by the application of dismantling costs as detailed below.

Asset Retirement Obligations

AROs will be calculated and presented in accordance with GAAP (Section 3110 of the CICA Handbook).

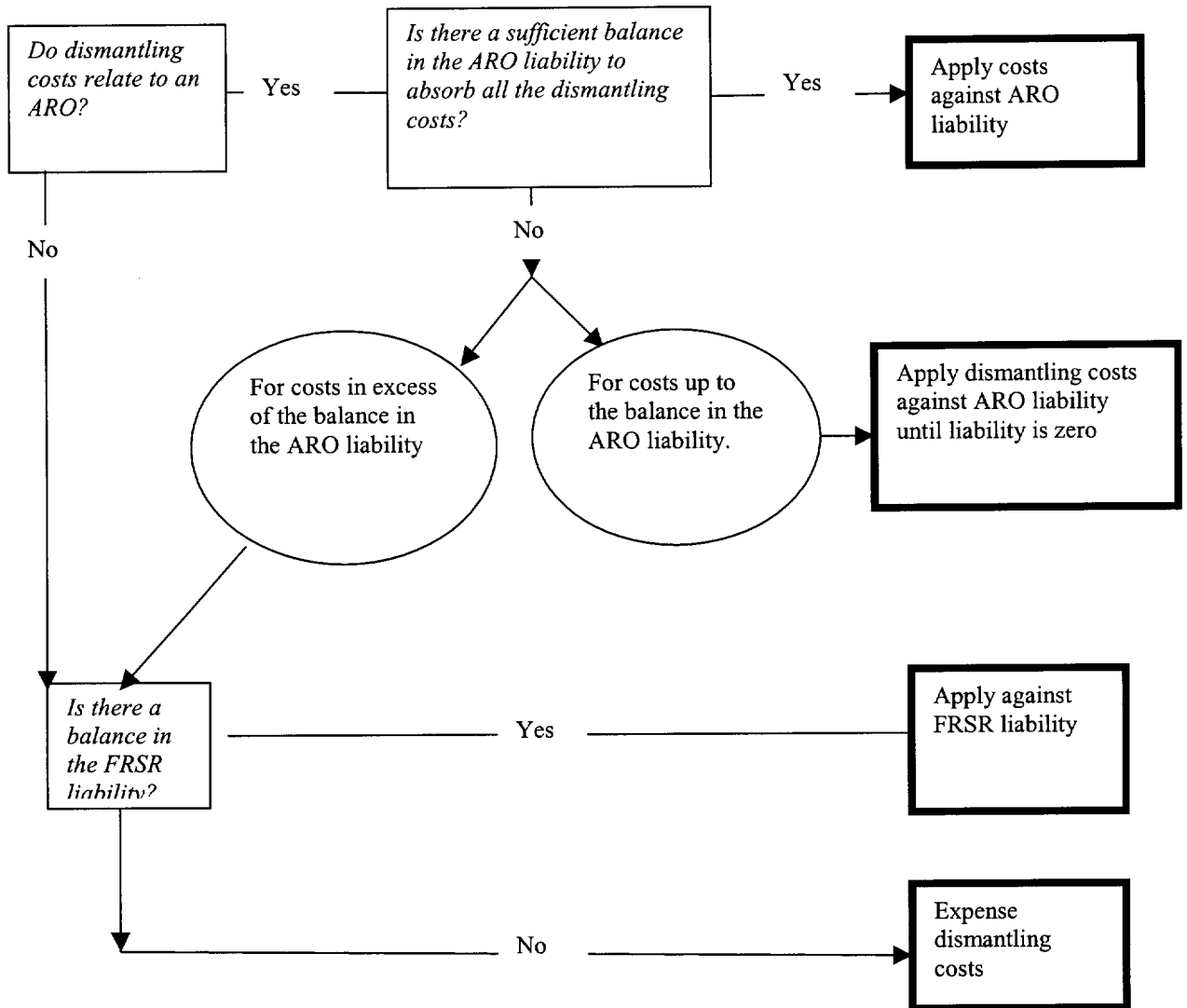
Dismantling Costs

All dismantling costs incurred by BC Hydro will be applied against the FRSR liability unless they relate to an ARO liability. Once the FRSR liability is retired, all dismantling costs will be expensed, unless they relate to an ARO liability.

For greater clarity:

- Unless dismantling costs relate to an ARO, apply them against the overall FRSR liability.
- If the costs relate to an ARO, apply them against the appropriate ARO balance.
- If the costs relate to an ARO and there is insufficient or no ARO balance for that asset, apply the costs against the FRSR liability.
- If there is no balance in the FRSR liability, any dismantling costs that would otherwise be applied against the liability will be expensed.
- When the FRSR liability is finally retired, dismantling costs on non-ARO assets will need to be considered in revenue requirements once again.

Treatment of Dismantling costs



Appendix 2

Disallowed Load Displacement Costs

Disallowed Load Displacement Costs (\$000s)

	F2005	F2006
Incentives for 4 LD projects*	\$ 2,580	\$ -
3.3% of Load Displacement non-incentive program costs	\$ 49	\$ 33
1.2% of industrial sector enabling costs	\$ 10	\$ 12
0.7% of portfolio-level costs	\$ 131	\$ 127
Total Disallowed Deferred Capital	\$ 2,770	\$ 172

Assumptions

From 10 Year Plan V 2.0

		F2005	F2006	F2012
Industrial Load Displacement non-incentive program costs	Table 4.3	\$ 1,481	\$ 1,008	
Industrial sector enabling costs	Table 4.5	\$ 897	\$ 1,035	
Portfolio level costs	Table 4.5	\$ 19,026	\$ 18,470	
Load displacement run-rate GWh/yr	Table 4.2			760
Industrial sector run-rate GWh/yr	Table 4.2			2,145
Portfolio run-rate GWh/yr	Table 4.2			3,618
Run rate GWh/yr of 4 LD projects				25
as a % of load displacement				3.3%
as a % of industrial sector				1.2%
as a % of portfolio				0.7%

* Cariboo Pulp, Norske Elk Falls ePoints, Norske Powell River ePoints, Canfor Intercon

Based on the Power Smart 10 Year Plan, by the end of F06, BCH planned for 576 GWh/yr of Load Displacement with total incentives of \$67,896.

BCH has secured 566 GWh/yr of Load Displacement ** with total incentives of \$65,760 through agreements that pre-date the application

** Weyerhaeuser Kamloops, Norske Crofton, Norske Port Alberni, Gibraltar, Canfor PGPP