Revenue Requirement Application 2004/05 and 2005/06

BC hydro

Volume 1

Chapter 2A.

Evidentiary Update

Consolidated Revenue Requirements and Financial Schedules

BC hydro

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1 Introduction

This Evidentiary Update reflects changes in a number of key assumptions since BC Hydro's Revenue Requirements application was filed on December 15, 2003 (the Application). The forecasts in this update are consistent with the forecasts in BC Hydro's Service Plan issued on February 17, 2004 and forecasts in the Provincial Government's budget. In summary, the updated net income forecast is $39 million lower in F2005 and $6 million higher in F2006 than the forecasts filed in the Application before nominal deferral account transfers (see paragraph below for discussion). The major reasons for the changed forecasts include lower forecast water inflows in F2005, and revised interest and foreign exchange rate assumptions provided by the Provincial Government in respect of F2005 and F2006. Based on the January 01, 2004 snowpack levels, water inflows are expected to be 94 per cent of normal, whereas the Application was based on an assumption of normal water inflows. Forecast energy costs have increased as a result of the impact of the lower expected inflows. Revised interest rate forecasts are lower and the Canadian/US dollar foreign exchange rate forecasts are higher than those used in the Application. These changes in the forecast interest and foreign exchange rates result in a lower finance charge forecast. These changes are explained in more detail below.

For illustrative reasons, and for consistency with the Service Plan, the discussion and schedules that follow assume that the forecast changes described in this Evidentiary Update are flowed through the deferral account mechanisms BC Hydro has proposed in the Application. Actual credits or debits to the deferral accounts will be based on the Commission's decision in this proceeding and on actual results for F2005 and F2006.

2 Pro Forma Consolidated Statements

Table 2A-1 is a summarized pro forma statement of operations of BC Hydro showing rate increases of 7.23% in F2005 and 2.00% in F2006 as requested in the Application and showing the differences for F2005 and F2006 being carried forward in deferral accounts. The full income statement is shown in Schedule A-1-A.

Table 2A-1. Pro forma Statement of Operations

($ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Equity	**$2,700**	**$2,730**	**$3,069**	**$3,181**
Domestic				
Revenues	2,475	2,552	2,701	2,768
Inter-segment revenues	6	81	125	116
Expenses	(2,267)	(2,551)	(2,527)	(2,527)
	214	**82**	**299**	**357**
Trade Income	138	108	89	91
Net Income before transfers to RSA/deferral accounts	**352**	**190**	**388**	**448**
Transfer from RSA *(Note 1)*	66	21	-	-
Transfers to deferral accounts	-	-	54	38
Net Income	**$418**	**$211**	**$442**	**$486**
Allowed rate of return on equity	15.47%	14.33%	13.91%	13.91%
Allowed Net Income	$418	$396	$427	$442
Requested rate increase (%)	N/A	N/A	7.23%	2.00%

Notes:

1. It is anticipated that the RSA balance will be nil at the end of F2004.

3 Discussion of Financial Forecasts

3.1 BC Hydro Equity

The current forecast equity and the components that make up equity for F2004 to F2006 are shown in Table 2A-2.

Table 2A-2. Equity

($ millions)	F2004 Forecast	F2005 Plan	F2006 Plan
Retained earnings at beginning of year	$1,609	$1,653	$1,968
Net income	211	442	486
Payment to the province	(167)	(360)	(383)
Asset retirement obligation adjustment	-	233	-
Special dividend to the province for BCTC	-	-	(20)
Retained Earnings at End of Year	**$1,653**	**$1,968**	**$2,051**
Deferred revenue *(Note 1)*	275	292	312
Contributions arising from the Columbia River Treaty	193	184	175
Contributions in aid of construction	609	625	643
Equity	**$2,730**	**$3,069**	**$3,181**
Forecast rate of return on equity	7.73%	14.40%	15.28%
Allowed rate of return on equity	14.33%	13.91%	13.91%
Allowed net income	$395	$427	$442
Forecast net income before transfers to RSA/deferral accounts	$190	$388	$448

Notes:

1. The changes in forecast deferred revenue from the Application are primarily due to the change in forecast foreign exchange rates. In this Evidentiary Update, the deferred revenue balances are $1 million, $4 million and $8 million lower for F2004 to F2006 respectively.

3.2 Domestic Revenues

Current domestic sales volume forecasts remain unchanged for F2005 and F2006 from the forecasts in the Application. The only changes to forecast revenues in the test years are reductions in revenues from other utilities of $1 million and $2 million for F2005 and F2006 respectively. The reductions relate to the new forecasts of the foreign exchange rate applied to the revenues from the Skagit Valley Treaty agreements. Because revenues from the Skagit Valley Treaty are in US dollars, a stronger Canadian dollar decreases the Canadian dollar equivalent of these revenues. Changes in domestic revenues and sales volumes for F2004 are shown in Tables 2A-3 and 2A-4.

Table 2A-3. Domestic Revenues, F2004

($ millions)	F2004 Evidentiary Update Forecast	F2004 Application Forecast	Variance
Residential	$974	$959	$15
Light industrial and commercial	909	901	8
Large industrial	513	503	10
Other			
Irrigation	3	3	-
Street lighting	24	23	1
City of New Westminster	14	13	1
Aquila Networks Canada	30	27	3
Total Revenue Requirement	**$2,467**	**$2,429**	**$38**
Other utilities *(Note 1)*	18	20	(2)
Miscellaneous	67	67	-
Total	**$2,552**	**$2,516**	**$36**

Notes:

1. Other utilities under long-term contracts including Seattle City Light pursuant to the Skagit Valley Treaty agreements.

Table 2A-4. Domestic Sales Volumes, F2004

(GWh)	F2004 Evidentiary Update Forecast	F2004 Application Forecast	Variance
Residential	15,881	15,654	227
Light industrial and commercial	17,127	16,947	180
Large industrial	15,102	14,801	301
Other			
Irrigation	89	88	1
Street lighting	214	218	(4)
City of New Westminster	406	401	5
Aquila Networks Canada	747	708	39
Other utilities	309	314	(5)
Total	**49,875**	**49,131**	**744**

The increase in residential revenues and volumes are due primarily to weather impacts. Revenues from light industrial and commercial customers increased due to improvements from the prior forecast in the forestry and commercial sectors. The increase in large industrial revenues is a result of greater pulp and paper production and increased lumber production due to a stronger demand from the U.S.

3.3 Intersegment Revenues

Table 2A-5 identifies the difference between Intersegment Revenues in the revised forecast and those included in the Application.

Table 2A-5. Intersegment Revenues, F2004 to F2006, Change from Prior Forecast

($ millions)	F2004 Forecast	F2005 Plan	F2006 Plan
Total Intersegment Revenues – Evidentiary Update	$81	$125	$116
Total Intersegment Revenues – Application	76	124	91
Increase in Intersegment Revenues	**$5**	**$1**	**$25**

The forecast of intersegment revenues for F2004 has increased primarily due to a changed forecast of mark to market gain on the trade account between BC Hydro and Powerex. Increases in forecast intersegment revenues for F2005 and F2006 are largely due to increases in the forecasts of net sales to Powerex of trade account energy. In F2005, the increase in forecast net sales of trade account energy to Powerex was mostly offset by a decrease in PTP transmission charges to Powerex, which was due to the deferred commencement of transmission services under the Guichon contract. On December 1, 2003, BC Hydro advised BCTC that, in accordance with Tariff Supplement 30, it was exercising its right to defer the commencement of transmission services under the Guichon contract by one year. The contract was originally scheduled to take effect on December 3, 2003 and that date was assumed in the Application. With the one-year deferral to December 3, 2004, the PTP transmission revenues are lower by $5 million and $10 million for F2004 and F2005 respectively.[1]

Table 2A-6 summarizes the foregoing.

[1] With the decrease in PTP transmission revenues, the revenue requirement for the Network Integration Transmission Service (NITS) as detailed in Table 6-29 on page 6-85 of the December 2003 application will increase by a corresponding amount. There is no net impact on the overall BC Hydro Revenue Requirement.

Table 2A-6. Intersegment Revenues, F2004 to F2006

($ millions)	F2004 Forecast	F2005 Plan	F2006 Plan
Net sales to Powerex - Future Use *(Note 1)*	–	$61	$49
Point-to-point wheeling charge to Powerex *(Note 2)*	44	50	53
Point-to-point wheeling charge to BC Hydro *(Note 3)*	12	12	12
Allocation of BC Hydro corporate costs to Powerex *(Note 4)*	2	2	2
Foreign exchange gain on Trade Payable balance – BC Hydro to Powerex *(Note 5)*	15	–	–
Mark to market gain on Trade Account – BC Hydro to Powerex *(Note 6)*	8	–	–
Total Inter-segment Revenues	**$81**	**$125**	**$116**

Notes:
1. These sales relate to a return of energy bought by Powerex in prior periods to enable future sale. These revenues are eliminated against trade cost of energy on consolidation.
2. These transmission revenues relate to an allocation of BC Hydro's cost of purchases of point-to-point transmission within BC for export and some import transactions. These revenues are eliminated against trade cost of energy on consolidation.
3. These transmission revenues relate to an allocation of BC Hydro's cost of purchases of point-to-point transmission relating to BC Hydro's Skagit Valley Treaty commitment. These revenues are eliminated against domestic cost of energy on consolidation.
4. These revenues relate to an allocation of corporate costs to Powerex and are eliminated against trade income on consolidation.
5. This relates to the foreign exchange gain on the payable to Powerex. Powerex would have a corresponding loss on their receivable. The receivable relates to energy purchased to enable future sale by Powerex and sold to BC Hydro when brought into the system.
6. This relates to a mark to market gain on the trade account. Powerex would have a corresponding loss.

3.4 Domestic Cost of Energy

The most significant difference between the Application and this Evidentiary Update is the change in forecast water inflows for the February to September 2004 water year. Water inflows in the updated forecast are expected to be 94 per cent of normal for this period based on January 01, 2004 snowpack levels. In the Application, normal water inflows were assumed. The decrease in forecast water inflows results in a reduction in hydro generation.

Table 2A-7 shows the difference between the domestic cost of energy in this Evidentiary Update and the domestic cost of energy in the Application. The breakdown of the domestic cost of energy forecast is provided in Schedule A-9-A.

Table 2A-7. Domestic Cost of Energy, F2004 to F2006

($ millions)	F2004 Forecast	F2005 Plan	F2006 Plan
Domestic cost of energy – Evidentiary Update	$968	$905	$862
Domestic cost of energy – Application	944	824	808
Increase in domestic cost of energy	**$24**	**$81**	**$54**

The increase in the forecast of domestic cost of energy in F2004 is largely due to the increase in sales volumes of approximately 750 GWh, as explained in Section 3.2. The majority of the increase in load is met by energy purchases.

The increase in the forecast of domestic cost of energy in F2005 is primarily due to the impact of lower forecast water inflows. Due to lower forecast water inflows, hydro generation including exchange net[2] is forecast to decrease by approximately 1,650 GWh in F2005 from the previous forecast and be replaced by market electricity purchases to meet load. As the cost of market electricity purchases is significantly greater than the incremental cost of hydro generation, the cost of energy forecast is expected to increase.

The increase in the forecast of domestic cost of energy in F2006 is largely due to the impact of the lower forecast water inflows in F2005 (reservoir management is undertaken on a multiple-year basis) and to a change in the exchange net[2] assumptions. The forecasts in this Evidentiary Update and the Application both assume normal water inflows for F2006. Hydro generation including exchange net is currently forecast to be approximately 710 GWh less than previously forecast. It is expected that the 710 GWh will be replaced by market electricity purchases.

3.5 Operations, Maintenance, and Administration Costs

There are no changes to the forecasts of Operations, Maintenance and Administration costs stated in the Application.

[2] Exchange net relates to non-treaty storage agreements with Bonneville Power Administration, Kootenay Canal Plant Agreement with Aquila Networks Canada and Keenleyside Entitlement Agreement with Columbia Power Corporation. The exchange net forecasts have also been revised due to changes in forecast Kootenay Canal Entitlement, and are reflected in Schedule A-9-A.

3.6 *Finance Charges*

The provincial government provided revised interest and foreign exchange rate forecasts for F2004 to F2006 in January 2004. These forecast rates are used by all Crown Corporations and the Government itself in forecasting the Provincial budget. This Evidentiary Update reflects the revised rates, which are shown in Table 2A-8.

Table 2A-8. Updated Interest Rate and Foreign Exchange Rate Forecast, F2004 to F2006

(Note 1)	F2004 Forecast	F2005 Plan	F2006 Plan
Canadian Short-term Interest Rates	3.00%	2.81%	4.03%
U.S. Short-term Interest Rates	1.20%	1.74%	3.78%
Canadian Long-term Interest Rates	5.41%	5.68%	6.26%
U.S. Long-term Interest Rates	5.00%	5.70%	6.49%
USD/CAD FX Rate	0.7454	0.7941	0.8006

Notes:
1. Provincial Government Forecast, January 22, 2004.

For convenience, Table 2A-9 shows the interest and foreign exchange rates used in the Application.

Table 2A-9. December 2003 Application Interest Rate and Foreign Exchange Rate Forecast, F2004 to F2006

(Note 1)	F2004 Forecast	F2005 Forecast	F2006 Forecast
Canadian Short-term Interest Rates	3.15%	3.63%	5.06%
U.S. Short-term Interest Rates	1.26%	2.00%	4.00%
Canadian Long-term Interest Rates	5.45%	5.91%	6.64%
U.S. Long-term Interest Rates	5.06%	5.78%	6.54%
USD/CAD FX Rate	0.7324	0.7490	0.7500

Notes:
1. Provincial Government Forecast, August 2003.

Table 2A-10 identifies finance charges during the test periods. The detailed components of the updated finance charge forecasts are shown in Schedule A-10-A.

Table 2A-10. Finance Charges, F2004 to F2006

($ millions)	F2004 Forecast	F2005 Plan	F2006 Plan
Finance Charges – Evidentiary Update	$444	$430	$462
Finance Charges – Application	454	463	497
Decrease in finance charges	**$10**	**$33**	**$35**

Forecast finance charges are less than in the Application due primarily to the new (lower) forecast interest rates. The current forecast Canadian short-term interest rates are 82 basis points less in F2005 and 103 basis points less in F2006 than as indicated in the Application. The current forecast of a stronger Canadian dollar also contributes to the decrease in finance charges.

3.7 Depreciation and Amortization

There are no changes to forecast depreciation and amortization.

3.8 Taxes

There are no changes to forecast taxes.

3.9 Restructuring Costs

There are no changes to forecast restructuring costs.

3.10 Charges from the British Columbia Transmission Corporation

There are no changes to forecast BCTC charges.

3.11 Transfers to Deferral Accounts

3.11.1 Background

Section 7 of HSD#2 requires the Commission to allow BC Hydro to establish deferral account mechanisms for the purpose of recording differences between the forecasts of the Heritage Payment Obligation (HPO) and Trade Income used to establish rates, and the actual, after-the-fact Heritage Payment Obligation and Trade Income.

The forecasts of Heritage Payment Obligation and Trade Income in the Application were based on the assumption of normal water. The forecast update has resulted in changes to the forecast HPO and Trade Income due to uncontrollable variables for which the deferral accounts were originally proposed. These differences are transferred to the deferral accounts. BC Hydro expects to file a more detailed account on the operation of the Heritage Payment Obligation Deferral Account that will provide additional information on the use of the Heritage Payment Obligation Deferral Account described below.

3.11.2 Heritage Payment Obligation Deferral Account

The impact of lower expected water inflows, as discussed in Section 3.4, has resulted in an increase in the cost of energy and a corresponding increase in the HPO. Lower expected revenues from the Skagit Valley Treaty due to changes in the foreign exchange rate assumptions also contributed to the increase in the HPO. A decrease in finance charges, as discussed in Section 3.6, partly offsets the increase in the HPO. The results of these factors are transfers to the Heritage Payment Obligation Deferral Account of $62.7 million in F2005 and $39.5 million in F2006. This deferral account is shown as an asset on the updated forecast balance sheet on Schedule A-2-A.

Table 2A-11. Transfers to Heritage Payment Obligation Deferral Account, F2005 to F2006

($ millions)	F2005 Plan	F2006 Plan
Heritage Payment Obligation – Evidentiary Update (Schedule D1-3-A)	$1,221.0	$1,177.7
Heritage Payment Obligation – Table 5-1, page 5-2 in the Application	1,158.3	1,138.2
Transfers to Heritage Payment Obligation Deferral Account	**$62.7**	**$39.5**

3.11.3 Trade Income Deferral Account

The updated forecast Trade Income is higher than the forecast filed in the December 2003 application. This difference of $9 million in F2005 and $2 million in F2006 will be transferred to the Trade Income Deferral Account. This deferred amount is shown as a liability on the updated forecast balance sheet on Schedule A-2-A.

Table 2A-12. Transfers to Trade Income Deferral Account, F2005 to F2006

($ millions)	F2005 Plan	F2006 Plan
Trade Income – Evidentiary Update (Schedule A-1-A)	$89	$91
Trade Income – Schedule A1, page 2-40 in the Application	80	89
Transfers to Trade Income Deferral Account	**$9**	**$2**

The F2005 increase in Trade Income is due to the deferral of the Guichon contract as discussed in Section 3.3. The forecast in the Application included the cost of the contract in point to point transmission costs.

F2006 Trade Income is comparable to the forecast in the Application. The negative impact of the stronger Canadian dollar is offset by slightly higher margins.

BC hydro

SCHEDULE A-1-A

Consolidated Statement of Operations with Proposed Rate Increases
For the Years Ended March 31
($ millions)

	A	B	C	D
	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
REVENUES				
Domestic				
Residential	$ 923	$ 974	$ 1,041	$ 1,077
Light industrial and commercial	893	909	970	1,000
Large industrial	516	513	539	543
Other energy sales	88	89	90	93
Miscellaneous	55	67	61	55
	2,475	2,552	2,701	2,768
Intersegment revenues	6	81	125	116
	2,481	2,633	2,826	2,884
EXPENSES				
Domestic energy costs	708	968	905	862
BCTC wholesale transmission service	-	-	-	61
BCTC asset management fee	-	-	-	117
Operations expense	143	169	171	129
Maintenance expense	196	228	243	140
Administration expense	167	161	163	139
Depreciation and amortization	414	428	470	470
Taxes	145	142	145	147
	1,773	2,096	2,097	2,065
INCOME BEFORE FINANCE CHARGES, RESTRUCTURING COSTS, TRANSFER FROM RSA, TRANSFERS TO DEFERRAL ACCOUNTS AND TRADE INCOME	708	537	729	819
Finance charges	457	444	430	462
INCOME BEFORE RESTRUCTURING COSTS, TRANSFER FROM RSA, TRANSFERS TO DEFERRAL ACCOUNTS AND TRADE INCOME	251	93	299	357
Restructuring Costs	37	11	-	-
INCOME BEFORE TRANSFER FROM RSA, TRANSFERS TO DEFERRAL ACCOUNTS AND TRADE INCOME	214	82	299	357
Transfer from RSA	66	21	-	-
DOMESTIC NET INCOME BEFORE TRANSFERS TO DEFERRAL ACCOUNTS	**280**	**103**	**299**	**357**
TRADE NET INCOME	**138**	**108**	**89**	**91**
TOTAL NET INCOME BEFORE TRANSFERS TO DEFERRAL ACCOUNTS	**418**	**211**	**388**	**448**
Transfer to Heritage Payment Obligation Deferral Account	-	-	63	40
Transfer to Trade Income Deferral Account	-	-	(9)	(2)
TOTAL NET INCOME	**$ 418**	**$ 211**	**$ 442**	**$ 486**
PAYMENT TO THE PROVINCE	$ 338	$ 167	$ 360	$ 383
ACTUAL/FORECAST RETURN ON EQUITY	15.47%	7.73%	14.40%	15.28%
ALLOWED RETURN ON EQUITY	15.47%	14.33%	13.91%	13.91%
BALANCE IN RSA	$ 21	$ -	$ -	$ -
RATE INCREASE	0.00%	0.00%	7.23%	2.00%
CUMULATIVE RATE INCREASE	0.00%	0.00%	7.23%	9.37%

SCHEDULE A-2-A

Consolidated Balance Sheet
As at March 31
($ millions)

	A	B	C	D
	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Capital Assets				
Capital assets in service	$ 14,940	$ 15,513	$ 16,092	$ 16,492
Less accumulated depreciation	5,816	6,030	6,329	6,641
	9,124	9,483	9,763	9,851
Unfinished construction	669	517	552	817
	9,793	10,000	10,315	10,668
Current Assets				
Temporary investments	4	4	4	4
Accounts receivable and accrued revenue	362	422	449	455
Materials and supplies	88	88	88	88
Prepaid expenses	86	95	87	68
Unrealized gains on mark-to-market transactions	10	-	-	-
	550	609	628	615
Other Assets and Deferred Charges				
Loan receivable	23	2	2	2
Sinking funds	1,037	979	984	844
Demand-Side Management programs	123	215	289	346
Heritage payment obligation deferral account	-	-	63	103
Deferred debt costs	385	142	84	52
	1,568	1,338	1,422	1,347
	$ 11,911	$ 11,947	$ 12,365	$ 12,630
Long term debt net of sinking funds	$6,853	$6,990	$7,136	$7,472
Sinking funds presented as assets	1,037	979	984	844
Long-Term Debt	7,890	7,969	8,120	8,316
Foreign Currency Contracts	2	75	65	60
Current Liabilities				
Accounts payable and accrued liabilities	689	707	606	538
Accrued interest	108	119	117	121
Accrued Payment to the Province	338	167	360	383
Unrealized losses on mark-to-market transactions	10	-	-	-
	1,145	993	1,083	1,042
Deferred Credits and Other Liabilities				
Provision for future removal and site restoration costs	174	180	-	-
Asset Retirement Obligation	-	-	19	20
Trade income deferral account	-	-	9	11
Deferred revenue	258	275	292	312
Rate stabilization account	21	-	-	-
Contributions arising from the Columbia River Treaty	203	193	184	175
Contributions in aid of construction	609	609	625	643
	1,265	1,257	1,129	1,161
Retained Earnings	1,609	1,653	1,968	2,051
	$ 11,911	$ 11,947	$ 12,365	$ 12,630
Debt to Equity Ratio	71.7:28.3	71.9:28.1	69.9:30.1	70.1:29.9