

# **BC HYDRO UNDERTAKING**

## **BC HYDRO REVENUE REQUIREMENT HEARING 2004/05 AND 2005/06**

### **HEARING DATE**

**Wednesday, June 9, 2004**

### **TRANSCRIPT REFERENCE**

**Volume 20, pages 3447-3451**

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**REQUESTOR: BCUC Counsel**

### **QUESTION**

**Update BC Hydro's revenue requirements forecasts as discussed in transcript.**

### **RESPONSE**

**Please see attached the June Financial Undertaking.**

## **1 Introduction**

This undertaking was prepared at the request of the Commission to identify the impact on Schedules A-D to the Financial Forecast contained in Chapter 2 of the Application to reflect:

1. the completion of final financial statements for F2004,
2. the availability of actual load data to the end of F2004, and
3. an update of any variables that were modified between the original application and the Revised Evidentiary Update (EU) filed April 2, 2004 for which more current data was available.

The three most significant changes reflected in the June Financial Undertaking are new water flow and load requirement information together with new forward energy market price information.

Water inflows, based on the June 1, 2004 Water Supply Forecast, are expected to be 89 per cent of normal in F2005, whereas the EU was based on the January 1, 2004 Water Supply Forecast of 94 per cent of normal. Average market energy purchase prices, based on the June 2004 forward curves, have increased from the prices used in the EU. Average natural gas prices at Sumas have increased by as much as 10% and 18% for F2005 and F2006 respectively, while average Mid-C electricity prices have increased by as much as 22% and 16% for F2005 and F2006, respectively. These two factors have combined to increase forecast energy costs.

Load requirements have also been adjusted to account for the higher actual loads compared to forecast for F2004 on the assumption that the higher loads in F2004 resulted from sustainable increases in demand. No assessment of that assumption has been performed. Rather, a higher baseline for load growth in F2005 and F2006 was simply assumed. BC Hydro is currently working on the update to the Load Forecast and this adjustment to the baseline may not reflect the actual changes that are made to the final Load Forecast, expected to be completed in the fall. The net impact of this adjustment is to increase the revenue

requirements in the test years as the additional revenue from the increase in load is more than offset by the incremental cost of supplying the increased load.

All relevant A to D schedules, which have changed from the Revised Evidentiary Update, are included in the June Financial Undertaking. The relevant schedules have also been updated with F2004 actual information. As set out in the Schedules, if all of this information were employed in determining BC Hydro's revenue requirement, the required increase for F2005 would rise to 12.7% followed by a reduction of 1.55% in F2006.

## 2 Pro Forma Consolidated Statements

Table 2A-1 is a summarized pro forma statement of operations of BC Hydro based on the June Financial Undertaking. A rate increase of 8.9% in F2005 (i.e., 7.23% already approved on an interim basis plus an additional 1.67% increase assumed for the purposes of this forecast to be effective November 1, 2004), the same as assumed in the April 2004 Revised Evidentiary Update, has been included. The full income statement is shown in Schedule A-1.

**Table 2A-1. Pro forma Statement of Operations**

(\$ millions)	F2004 Actual	F2005 Forecast	F2006 Forecast
<b>Equity</b>	<b>\$2,722</b>	<b>\$3,037</b>	<b>\$3,128</b>
Domestic			
Revenues	2,553	2,758	2,796
Inter-segment revenues	62	124	140
Expenses	(2,696)	(2,662)	(2,636)
	<b>\$(81)</b>	<b>\$220</b>	<b>\$300</b>
Trade Income	\$158	\$89	\$91
<b>Net Income before transfers to RSA/</b>	<b>\$77</b>	<b>\$309</b>	<b>\$391</b>
Transfer from RSA ( <i>Note 1</i> )	21	-	-
<b>Net Income</b>	<b>\$98</b>	<b>\$309</b>	<b>\$391</b>
Allowed rate of return on equity	14.33%	13.91%	13.91%
Allowed Net Income	\$396	\$425	\$436
Requested rate increase (%)	N/A	8.90%	N/A

Based on this updated forecast, BC Hydro's revenue shortfall will be \$116 million and \$52 million for F2005 and F2006, respectively.

### 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 Actual	F2005 Forecast	F2006 Forecast
Retained earnings at beginning of year	\$1,609	\$1,634	\$1,925
Net income	98	309	391
Payment to the province	(73)	(251)	(309)
Asset retirement obligation adjustment	-	233	-
Special dividend to the province for BCTC	-	-	(20)
<b>Retained Earnings at End of Year</b>	<b>\$1,634</b>	<b>\$1,925</b>	<b>\$1,987</b>
Deferred revenue	\$276	\$293	\$313
Contributions arising from the Columbia River Treaty	193	184	175
Contributions in aid of construction	619	635	653
<b>Equity</b>	<b>\$2,722</b>	<b>\$3,037</b>	<b>\$3,128</b>
Actual/forecast rate of return on equity	3.60%	10.17%	12.50%
Allowed rate of return on equity	14.33%	13.91%	13.91%
Allowed net income	\$396	\$425	\$436
Actual/forecast net income	\$98	\$309	\$391

Note that the \$120 million provision for GSX and VIGP expenditures in the F2004 financial statements has a minimal impact on the revenue requirements. The only impact is a reduction in equity and a corresponding decrease in the allowed net income and revenue requirement of \$2.5 million (approximately a 0.1% rate impact). The reduction in the revenue requirement is determined by taking 15% of the reduction in net income (the remaining 85% relates to the reduction in the Payment to the Province) and multiplying this value by BC Hydro's allowed rate of return of 13.91%. ( $\$120 \text{ million} \times 15\% \times 13.91\% = \$2.5 \text{ million}$ ).

It should also be noted that the decrease in retained earnings is partly offset by the higher than forecast Contributions in Aid of Construction balance. As a result total equity at

March 31, 2004 was only \$8 million lower than forecast in the Revised Evidentiary Update. The lower than forecast equity has a \$1 million impact on the revenue requirement (\$8 million x 13.91% = \$1 million).

### 3.2 Domestic Revenues

The adjustments to the Load Forecast for the test years reflect the variance between actual and forecast sales for F2004 carried forward and increased/decreased by the annual growth rate in the respective rate categories. Actual sales volumes in F2004 for the large industrial category were 704 GWh higher than forecast in the Application and actual sales volumes for the light industrial and commercial category were 228 GWh higher than forecast. The variance in the residential and other energy categories, totaling less than 20 GWh, were not carried forward as the variances were insignificant.

Changes in domestic revenues from the EU for F2005 and F2006 are shown in tables 2A-3 to 2A-6. The variance in revenues is due to the increase in forecast sales due to the adjustments in the load described above.

**Table 2A-3. Domestic Revenues, F2005**

(\$ millions)	F2005 June Financial Undertaking	F2005 Revised Evidentiary Update Forecast	Variance
Residential	\$1,050	\$1,050	\$-
Light industrial and commercial	988	976	12
Large industrial	568	542	26
Other energy sales ( <i>Note 1</i> )	72	72	-
	<b>\$2,678</b>	<b>\$2,640</b>	<b>\$38</b>
Other utilities ( <i>Note 2</i> )	\$19	\$19	\$-
Miscellaneous	61	61	-
<b>Total</b>	<b>\$2,758</b>	<b>\$2,720</b>	<b>\$38</b>

Notes:

1. Includes sales to City of New Westminster, Aquila Networks Canada, Irrigation and Street Lighting customers.
2. Other utilities under long-term contracts including Seattle City Light pursuant to the Skagit Valley Treaty agreements.

**Table 2A-4. Domestic Sales Volumes, F2005**

(GWh)	<b>F2005 June Financial Undertaking</b>	<b>F2005 Revised Evidentiary Update Forecast</b>	<b>Variance</b>
Residential	15,836	15,836	-
Light industrial and commercial	17,232	17,003	229
Large industrial	15,435	14,733	702
Other energy sales ( <i>Note 1</i> )	1,404	1,404	-
	<b>49,907</b>	<b>48,976</b>	<b>931</b>
Other utilities ( <i>Note 2</i> )	310	310	-
<b>Total</b>	<b>50,217</b>	<b>49,286</b>	<b>931</b>

Notes:

Refer to notes for Table 2A-3.

**Table 2A-5. Domestic Revenues, F2006**

(\$ millions)	<b>F2006 June Financial Undertaking</b>	<b>F2006 Revised Evidentiary Update Forecast</b>	<b>Variance</b>
Residential	\$1,073	\$1,073	\$-
Light industrial and commercial	1,009	996	13
Large industrial	567	540	27
Other energy sales ( <i>Note 1</i> )	73	73	-
	<b>\$2,722</b>	<b>\$2,682</b>	<b>\$40</b>
Other utilities ( <i>Note 2</i> )	\$19	\$19	\$-
Miscellaneous	55	55	-
<b>Total</b>	<b>\$2,796</b>	<b>\$2,756</b>	<b>\$40</b>

Notes:

Refer to notes for Table 2A-3.

**Table 2A-6. Domestic Sales Volumes, F2006**

(GWh)	<b>F2006 June Financial Undertaking</b>	<b>F2006 Revised Evidentiary Update Forecast</b>	<b>Variance</b>
Residential	16,063	16,063	-
Light industrial and commercial	17,433	17,202	231
Large industrial	15,297	14,604	693
Other energy sales <i>(Note 1)</i>	1,428	1,428	-
	<b>50,221</b>	<b>49,297</b>	<b>924</b>
Other utilities <i>(Note 2)</i>	310	310	-
<b>Total</b>	<b>50,531</b>	<b>49,607</b>	<b>924</b>

Notes:

Refer to notes for Table 2A-3.

**3.3 Intersegment Revenues**

Table 2A-7 identifies the difference between intersegment revenues in the updated forecast and those included in the Revised Evidentiary Update.

**Table 2A-7. Intersegment Revenues, F2005 to F2006, Change from Prior Forecast**

(\$ millions)	<b>F2005</b>	<b>F2006</b>
Total Intersegment Revenues – June Financial Undertaking	\$124	\$140
Total Intersegment Revenues – Revised Evidentiary Update	125	116
<b>Increase (Decrease) in Intersegment Revenues</b>	<b>\$(1)</b>	<b>\$24</b>

Forecast intersegment revenues for F2005 are similar to those forecast in the Revised Evidentiary Update. The increase in forecast intersegment revenues for F2006 is largely due to an increase in the net sales to Powerex of trade account energy. The Trade Account balance at the end of F2004 was higher than forecast. This increase in energy in the Trade Account is expected to be taken by Powerex in F2006. The trade account is projected to be fully drawn down by the end of F2006.

Table 2A-8 summarizes the foregoing.

**Table 2A-8. Intersegment Revenues, F2004 to F2006**

(\$ millions)	F2004 Actual	F2005 Forecast	F2006 Forecast
Net sales to Powerex - Future Use ( <i>Note 1</i> )	\$ –	\$60	\$73
Point-to-point wheeling charge to Powerex ( <i>Note 2</i> )	39	50	53
Point-to-point wheeling charge to BC Hydro ( <i>Note 3</i> )	12	12	12
Allocation of BC Hydro corporate costs to Powerex ( <i>Note 4</i> )	2	2	2
Foreign exchange gain on Trade Payable balance – BC Hydro to Powerex ( <i>Note 5</i> )	1	–	–
Mark to market gain – BC Hydro to Powerex ( <i>Note 6</i> )	8	–	–
<b>Total Inter-segment Revenues</b>	<b>\$62</b>	<b>\$124</b>	<b>\$140</b>

## 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. Powerex would have a corresponding loss.

### 3.4 Domestic Cost of Energy

The most significant differences in domestic cost of energy between the Revised Evidentiary Update and the June Financial Undertaking are:

- The forecast water inflows for the February to September 2004 water year have declined from 94 per cent of normal in the Revised Evidentiary Update to 89 per cent of normal based on the June 2004 water supply forecast. This has the impact of reducing low cost hydro generation and increasing higher cost sources of supply.

- Electricity and natural gas market prices have increased. Average Mid-C forward electricity prices have increased by approximately 22 per cent and 16 per cent for F2005 and F2006 respectively, while average forward gas prices at Sumas have increased by as much as 10 per cent and 18 per cent for F2005 and F2006 respectively. This has the impact of increasing the cost of market purchases of electricity and natural gas.
- Domestic load volumes have increased as discussed in Section 3.2, pages 2-3. This increases the supply required to meet the increase in load.

Table 2A-9 shows the difference between the domestic cost of energy in the June Financial Undertaking and the domestic cost of energy in the Revised Evidentiary Update. The breakdown of the domestic cost of energy forecast is provided in Schedule A-9.

**Table 2A-9. Domestic Cost of Energy, F2005 to F2006, Change from Price Forecast**

(\$ millions)	F2005	F2006
Domestic cost of energy – June Financial Undertaking	\$1,057	\$995
Domestic cost of energy – Revised Evidentiary Update	906	865
<b>Increase in domestic cost of energy</b>	<b>\$155</b>	<b>\$130</b>

The increase in the forecast of domestic cost of energy in F2005 and F2006 is primarily due to an increase in market electricity purchase volumes and an increase in the price of energy purchases. Approximately half of the increase from the Revised Evidentiary Update in domestic cost of energy is due to higher purchase volumes and the other half of the increase is due to higher market prices for energy purchases. The increase in market electricity purchase volumes is due to the increase in domestic load, as discussed in Section 3.2, and to the decrease in hydro generation, including exchange net<sup>1</sup>, due to the lower forecast water inflows. While the forecast for F2006 assumes normal water inflows, hydro generation including exchange net<sup>1</sup> is now lower than was forecast in the Revised Evidentiary Update

<sup>1</sup> 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.

due to the impact of lower forecast water inflows in F2005 (reservoir management is undertaken on a multiple-year basis).

### **3.5 Operations, Maintenance, and Administration (OMA) Costs**

On a consolidated basis, OMA costs are unchanged from the Revised Evidentiary Update. On a functional basis OMA costs have decreased as a result of the decrease in the allocation of Corporate costs (i.e. the decrease in OMA costs in the functions is offset by the decrease in the Corporate recovery).

Corporate costs are forecast to be lower than shown in the Application and the Revised Evidentiary Update due to a reduction in depreciation relating to IT expenditures as mentioned in Section 3.7. The reduction in Corporate costs from the Application is approximately \$4 and \$6 million for F2005 and F2006 respectively.

The components of the Corporate costs are shown on Schedule C6 and the allocation to the functions is shown on Schedules B-3 and B-4. The Corporate costs are allocated to the functions using the same methodology as described in Chapter 2, Section 7.2 of the Application.

### **3.6 Finance Charges**

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.

**Table 2A-10. Finance Charges, F2005 to F2006, Change from Prior Forecast**

(\$ millions)	F2005	F2006
Finance Charges – June Financial Undertaking	\$428	\$458
Finance Charges – Revised Evidentiary Update	430	461
<b>Decrease in finance charges</b>	<b>\$2</b>	<b>\$3</b>

Forecast finance charges are slightly lower than forecast in the Revised Evidentiary Update. This is primarily due to a lower than forecast ending debt balance in F2004 and to an increase in cash flows in the test years. The debt balance as at March 31, 2004 was

approximately \$100 million lower than forecast largely a result of lower capital spending as described in Section 3.7. While domestic energy costs in the test years have increased from the Revised Evidentiary Update, cash flows have increased largely a result of the lower dividend for F2004 and F2005. There is a time lag in cash flows as the dividend to the Province is paid in June following the year-end. A reduction in interest capitalized during construction, largely due to a refinement in the estimate of the average unfinished construction balances, partly offsets the favourable variance. The interest and foreign exchange rate assumptions used in the June Financial Undertaking are the same as used in the Evidentiary Update. These rates are shown in Table 2A-11 for convenience. These rates are the most current rates provided by the Provincial Government.

**Table 2A-11. Interest Rate and Foreign Exchange Rate Forecast, F2005 to F2006**

<i>(Note 1)</i>	<b>F2005 Forecast</b>	<b>F2006 Forecast</b>
Canadian Short-term Interest Rates	2.81%	4.03%
U.S. Short-term Interest Rates	1.74%	3.78%
Canadian Long-term Interest Rates	5.68%	6.26%
U.S. Long-term Interest Rates	5.70%	6.49%
USD/CAD FX Rate	0.7941	0.8006

Notes:

1. Provincial Government Forecast, January 22, 2004.

### **3.7 Capital Expenditures and Amortization Expenses**

Actual capital expenditures in F2004 were lower than originally forecast in the Application and the Revised Evidentiary Update as shown in Table 2A-12. This together with the reduction in forecast capital expenditures for F2005 as shown in Exhibit B1-96, reduces amortization expenses from the Revised Evidentiary Update by \$15 million and \$18 million in F2005 and F2006 respectively. The portion of this reduction in amortization relating to lower capital spending in F2004 is estimated to be \$13 million and \$14 million for F2005 and F2006 respectively. Approximately half this decrease is due to lower Information Technology (IT) spending and the other half due to lower than forecast spending on Power

Smart programs during F2004. The lower spending in the other capital expenditure categories in F2004 have a minimal annual impact on depreciation due to the longer useful lives of these assets. The remainder of the decrease in amortization of \$2 million and \$4 million for F2005 and F2006 respectively is largely due to the lower IT capital expenditures forecast for F2005 compared to the Application.

The Actual and forecast capital expenditures for F2004 are shown below:

**Table 2A-12. F2004 Capital Expenditures**

(\$ millions)	F2004 Actual	F2004 Forecast	Change
Generation Thermal	\$ 8.6	\$38.8	\$30.2
Generation Hydro	111.2	117.1	5.9
Transmission	176.7	176.0	(0.7)
Distribution	200.6	193.2	(7.4)
Computers	43.0	71.4	28.4
Vehicles	14.7	21.5	6.8
SSI and Aboriginal Negotiations	8.2	13.7	5.5
Land and Buildings	3.7	9.9	6.2
General	6.9	11.6	4.7
Power Smart	62.7	116.2	53.5
<b>Total</b>	<b>\$636.3</b>	<b>\$769.4</b>	<b>\$133.1</b>

### **3.8 Taxes**

There are no changes to forecast taxes.

### **3.9 Charges from the British Columbia Transmission Corporation**

There are no changes to forecast BCTC charges.

### **3.10 Trade Income**

There are no changes to the forecast of Trade Income.

## SCHEDULE A-1 (Update of June 2004)

Consolidated Statement of Operations with Proposed Rate Increases For the Years Ended March 31 (\$ millions)				
	A	B	C	D
	F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
<b>REVENUES</b>				
Domestic				
Residential	\$ 923	\$ 960	\$ 1,050	\$ 1,073
Light industrial and commercial	893	912	988	1,009
Large industrial	516	525	568	567
Other energy sales	88	89	91	92
Miscellaneous	55	67	61	55
	<u>2,475</u>	<u>2,553</u>	<u>2,758</u>	<u>2,796</u>
Intersegment revenues	6	62	124	140
	<u>2,481</u>	<u>2,615</u>	<u>2,882</u>	<u>2,936</u>
<b>EXPENSES</b>				
Domestic energy costs	708	995	1,057	995
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	162	140
Depreciation and amortization	414	536	455	451
Taxes	145	146	145	147
	<u>1,773</u>	<u>2,253</u>	<u>2,234</u>	<u>2,178</u>
<b>INCOME BEFORE FINANCE CHARGES, RESTRUCTURING COSTS, TRANSFER FROM RSA AND TRADE INCOME</b>	708	362	648	758
Finance charges	457	435	428	458
<b>INCOME BEFORE RESTRUCTURING COSTS, TRANSFER FROM RSA AND TRADE INCOME</b>	251	(73)	220	300
Restructuring Costs	37	8	-	-
<b>INCOME BEFORE TRANSFER FROM RSA AND TRADE INCOME</b>	214	(81)	220	300
Transfer from RSA	66	21	-	-
<b>DOMESTIC NET INCOME</b>	<u>280</u>	<u>(60)</u>	<u>220</u>	<u>300</u>
<b>TRADE NET INCOME</b>	<u>138</u>	<u>158</u>	<u>89</u>	<u>91</u>
<b>TOTAL NET INCOME</b>	<u>\$ 418</u>	<u>\$ 98</u>	<u>\$ 309</u>	<u>\$ 391</u>
<b>PAYMENT TO THE PROVINCE</b>	<u>\$ 338</u>	<u>\$ 73</u>	<u>\$ 251</u>	<u>\$ 309</u>
<b>ACTUAL/FORECAST RETURN ON EQUITY</b>	15.47%	3.60%	10.17%	12.50%
<b>ALLOWED RETURN ON EQUITY</b>	15.47%	14.33%	13.91%	13.91%
<b>BALANCE IN RSA</b>	<u>\$ 21</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>
<b>RATE INCREASE</b>	0.00%	0.00%	8.90%	0.00%
<b>CUMULATIVE RATE INCREASE</b>	<u>0.00%</u>	<u>0.00%</u>	<u>8.90%</u>	<u>8.90%</u>

52 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-2 (Update of June 2004)

<b>Consolidated Balance Sheet</b>				
<b>As at March 31</b>				
<b>(\$ millions)</b>				
	A	B	C	D
	<b>F2003</b>	<b>F2004</b>	<b>F2005</b>	<b>F2006</b>
	<b>Actual</b>	<b>Actual</b>	<b>Forecast</b>	<b>Forecast</b>
<b>Capital Assets</b>				
Capital assets in service	\$ 14,940	\$ 15,293	\$ 15,843	\$ 16,240
Less accumulated depreciation	5,816	5,964	6,273	6,573
Unfinished construction	9,124	9,329	9,570	9,667
	669	515	559	827
	9,793	9,844	10,129	10,494
<b>Current Assets</b>				
Temporary investments	4	47	4	4
Accounts receivable and accrued revenue	362	323	455	459
Materials and supplies	88	86	88	88
Prepaid expenses	86	108	86	66
Unrealized gains on mark-to-market transactions	10	104	-	-
	550	668	633	617
<b>Other Assets and Deferred Charges</b>				
Loan receivable	23	2	2	2
Sinking funds	1,037	981	984	844
Demand-Side Management programs	123	161	241	304
Deferred debt costs	385	150	84	52
	1,568	1,294	1,311	1,202
	\$ 11,911	\$ 11,806	\$ 12,073	\$ 12,313
Long term debt net of sinking funds	\$ 6,853	\$ 6,900	\$ 6,942	\$ 7,246
Sinking funds presented as assets	1,037	981	984	844
<b>Long-Term Debt</b>	7,890	7,881	7,926	8,090
<b>Foreign Currency Contracts</b>	2	63	65	60
<b>Current Liabilities</b>				
Accounts payable and accrued liabilities	689	672	658	585
Accrued interest	108	115	117	121
Accrued Payment to the Province	338	73	251	309
Unrealized losses on mark-to-market transactions	10	78	-	-
	1,145	938	1,026	1,015
<b>Deferred Credits and Other Liabilities</b>				
Provision for future removal and site restoration costs	174	202	-	-
Asset Retirement Obligation	-	-	19	20
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	1,131	1,161
<b>Retained Earnings</b>	1,609	1,634	1,925	1,987
	\$ 11,911	\$ 11,806	\$ 12,073	\$ 12,313
<b>Debt to Equity Ratio</b>	71.7:28.3	71.6:28.4	69.6:30.4	69.8:30.2

55 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-3 (Update of June 2004)

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Retained earnings at beginning of year	\$ 1,529	\$ 1,609	\$ 1,634	\$ 1,925
Net income	418	98	309	391
Payment to the Province	(338)	(73)	(251)	(309)
Asset Retirement Obligation Adjustment <sup>1</sup>	-	-	233	-
Special Dividend to the Province for BCTC <sup>2</sup>	-	-	-	(20)
Retained earnings at end of year	\$ 1,609	\$ 1,634	\$ 1,925	\$ 1,987

Notes:

1. This adjustment is explained in Section 3.7.3..
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.

Shaded amounts indicate changes from the Revised Evidentiary Update.

## SCHEDULE A-4 (Update of June 2004)

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
<b>Operating Activities</b>				
Net income	\$ 418	\$ 98	\$ 309	\$ 391
Adjustments for:				
Depreciation and amortization	417	539	459	455
Rate stabilization account	(66)	(21)	-	-
Other non-cash items	24	(4)	(9)	(18)
	793	612	759	828
Working capital changes	1	1	(121)	(53)
Cash provided by operating activities	794	613	638	775
<b>Investing Activities</b>				
Capital asset expenditures	(680)	(606)	(695)	(894)
Contributions in aid of construction	62	56	51	54
Demand side management programs	(45)	(63)	(105)	(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)	(762)	(872)
<b>Financing Activities</b>				
Bonds, notes and debentures				
Issued	1,007	790	600	700
Retired	(1,019)	(450)	(598)	(607)
Revolving borrowings changes	147	(47)	118	90
Sinking funds	48	53	34	185
Deferred debt costs	3	7	-	-
Settlement of financial instruments	22	34	-	-
Cash provided by financing activities	208	387	154	368
Payment to the Province	(333)	(338)	(73)	(251)
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

43 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-5 (Update of June 2004)

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

	A	B	C		D	
	F2003	F2004	F2005	F2006	F2005	F2006
	Actual	Actual	%	Forecast	%	Forecast
<b>Revenue</b>						
Residential revenue	\$923	\$960	4%	\$1,050	9%	\$1,073
Revenue variance	n/a	\$37		\$90		\$23
<b>Variance</b>						
Rate increase:		n/a		79		9
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		\$90		\$23
<b>Sales Volume</b> (in GW·h)	15,024	15,646	4%	15,836	1%	16,063

( ) 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 the cooler weather in April and May affecting the heating load and the extreme warm weather in July and August affecting the cooling load.

Fiscal 2003 was a warmer than normal year. Forecast 2005 and 2006 assumes normal weather.

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-6 (Update of June 2004)

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

	A	B	C		D		
	F2003	F2004	F2005		F2006		
	Actual	Actual	%	Forecast	%	Forecast	
<b>Revenue</b>							
Light industrial & commercial	\$893	\$912	2%	\$988	8%	\$1,009	2%
Revenue variance	n/a	\$19		\$76		\$21	
<b>Variance</b>							
Rate increase:		n/a		72		11	
Volume:							
GDP & Employment*	n/a	21		18		20	
Power Smart savings	n/a	(2)		(14)		(10)	
Total Variance	n/a	\$19		\$76		\$21	
<b>Sales Volume (in GW-h)</b>	16,757	17,175	0%	17,232	0%	17,433	1%

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

( ) represents an unfavourable variance

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 from the Revised Evidentiary Update.

**SCHEDULE A-7 (Update of June 2004)**

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

	A	B	C		D		
	F2003	F2004	F2005	F2006	F2005	F2006	
	Actual	Actual	% Forecast	% Forecast	% Forecast	% Forecast	
<b>Revenue (in millions)</b>							
Large industrial	\$516	\$525	2%	\$568	8%	\$567	0%
Revenue variance	n/a	\$9		\$43		\$(1)	
<b>Variance</b>							
Rate increase:		n/a		42		4	
Volume:							
Usage per customer	n/a	14		9		1	
Power Smart savings	n/a	(5)		(8)		(6)	
Total Variance	n/a	\$9		\$43		\$(1)	
<b>Sales Volume (in GW-h)</b>	15,179	15,505	2%	15,435	0%	15,297	-1%

( ) represents and unfavourable variance

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

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

For fiscal 2005 and fiscal 2006, a major customer in the Pulp and Paper sector is expected to return to normal production levels after a strike during fiscal 2004. New coal mines coming on line are also expected to increase demand. The increase in consumption from the above is partially offset by the fact that commodity exporters are expected to remain under pressure from the continued strong Canadian dollar, foreign competition from Chile and Asia, as well as newer, more efficient mines and mills.

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-8 (Update of June 2004)

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

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**Miscellaneous Revenues by Function**

**Generation**

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Plan	Plan
Ancillary services	\$ 2	\$ 2	\$ 3	\$ 5
Other	3	3	4	3
	<u>5</u>	<u>5</u>	<u>7</u>	<u>8</u>

**Distribution**

Meter and transformer rents and power factor surcharges	<u>6</u>	<u>6</u>	<u>5</u>	<u>5</u>
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**Customer Care**

Terasen meter reading <sup>1</sup>	-	3	2	2
Other	2	4	2	2
	<u>2</u>	<u>7</u>	<u>4</u>	<u>4</u>

**Transmission**

Short-term point to point wheeling revenue <sup>2</sup>	1	5	5	-
Aquila general wheeling revenue <sup>2</sup>	4	3	4	-
Transmission secondary revenue	4	5	4	5
	<u>9</u>	<u>13</u>	<u>13</u>	<u>5</u>

**Field Services**

Fleet revenues	<u>7</u>	<u>7</u>	<u>7</u>	<u>7</u>
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**Corporate**

Corporate general rents	6	4	5	5
Net gains on property sales	2	9	2	2
Westech external revenues	5	1	3	3
	<u>13</u>	<u>14</u>	<u>10</u>	<u>10</u>

**Powertech external revenues**

	<u>13</u>	<u>15</u>	<u>15</u>	<u>16</u>
	<u>\$ 55</u>	<u>\$ 67</u>	<u>\$ 61</u>	<u>\$ 55</u>

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 (Update of June 2004)**

<b>Domestic Cost Of Energy</b>					
<b>For the Years Ended March 31</b>					
<b>(\$ millions)</b>					
	A	B	C	D	
	F2003	F2004	F2005	F2006	Reference
	Actual	Actual	Forecast	Forecast	
<b>Domestic cost of energy :</b>					
Water rentals	\$258	\$246	\$253	\$279	D1-2
Independent Power Producers and long-term purchase commitments	290	372	385	416	C2
Market electricity purchases	54	270	343	222	D1-2
Net Purchases from Powerex (Note 1)	50	30			D1-2
Natural gas for thermal generation (Note 2)	28	33	28	28	D1-2
Domestic cost of energy - Non-integrated Areas	14	14	15	15	C4
Domestic transmission	5	16	15	15	D1-2
Gas transportation	5	10	13	13	C2
Cost of market (Note 3)	1	1	1		C3
Other	3	3	4	7	D1-2
<b>Total Domestic cost of energy</b>	<b>\$708</b>	<b>\$995</b>	<b>\$1,057</b>	<b>\$995</b>	
	<b>F2003</b>	<b>F2004</b>	<b>F2005</b>	<b>F2006</b>	
	<b>Actual</b>	<b>Actual</b>	<b>Forecast</b>	<b>Forecast</b>	
<b>Domestic energy:</b>					
<b>GW-h's</b>					
Water rentals	47,665	44,540	44,737	45,932	
Independent Power Producers and long-term purchase commitments	4,950	6,133	6,379	7,019	
Market electricity purchases	896	5,349	6,153	4,406	
Net Purchases from Powerex (Note 1)	1,113				
Thermal generation	251	296	207	214	
Non-integrated Areas	96	99	103	105	
Exchange net	(1,605)	(1,218)	(624)	54	
	<b>53,366</b>	<b>55,199</b>	<b>56,955</b>	<b>57,730</b>	
Less: Line loss and system use	(4,689)	(5,000)	(5,284)	(5,621)	
Net sales to Powerex		(48)	(1,454)	(1,578)	
<b>Domestic sales volumes</b>	<b>48,677</b>	<b>50,151</b>	<b>50,217</b>	<b>50,531</b>	
<b>\$/MW-h</b>					
Water rentals	\$ 5.4	\$ 5.5	\$ 5.7	\$ 6.1	
Independent Power Producers and long-term purchase commitments	58.6	60.7	60.4	59.3	
Market electricity purchases	60.3	50.5	55.7	50.4	
Net Purchases from Powerex	44.9				
Natural gas for thermal generation	111.6	111.5	135.3	130.8	
Domestic cost of energy - Non-integrated Areas	145.8	141.4	145.6	142.9	
<b>Total weighted average cost (Note 4)</b>	<b>\$ 14.5</b>	<b>\$ 19.8</b>	<b>\$ 21.0</b>	<b>\$ 19.7</b>	

**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 from the Revised Evidentiary Update.

SCHEDULE A-10 (Update of June 2004)

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

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
<b>Interest on debt securities</b>				
Bonds, notes and debentures	\$ 536	\$ 507	\$ 483	\$ 506
Revolving borrowings	5	9	12	17
Amortization of deferred debt costs and other expenses	26	28	32	33
	<u>567</u>	<u>544</u>	<u>527</u>	<u>556</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)	(20)	(35)
	<u>(110)</u>	<u>(109)</u>	<u>(99)</u>	<u>(98)</u>
<b>Total</b>	<u>\$ 457</u>	<u>\$ 435</u>	<u>\$ 428</u>	<u>\$ 458</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	2.4%	2.9%	2.8%	4.0%
Average exchange rate in U.S. dollars	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 from the Revised Evidentiary Update.

SCHEDULE A-11 (Update of June 2004)

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

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**CAPITAL ASSETS IN SERVICE**

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Balance at beginning of year	14,608	14,940	15,293	15,843
Assets in Service	461	622	642	584
ARO Implementation asset			14	
Retirements	(129)	(191)	(106)	(187)
Balance Sheet Reclassifications (Note 1)		(78)		
Balance at end of year	14,940	15,293	15,843	16,240

**ACCUMULATED DEPRECIATION**

Balance at beginning of year	5,557	5,816	5,964	6,273
Depreciation	382	405	452	441
ARO implementation Accum dep			7	
Salvage Value Trfr from FRSR			(46)	
Retirements	(123)	(184)	(104)	(141)
Balance Sheet Reclassification (Note 1)		(73)		
Balance at end of year	5,816	5,964	6,273	6,573
<b>NET BOOK VALUE</b>	<b>9,124</b>	<b>9,329</b>	<b>9,570</b>	<b>9,667</b>

**UNFINISHED CONSTRUCTION**

Balance at beginning of year	459	669	515	558
Additions	696	574	694	895
Amortization	(8)	(8)	(8)	(9)
Write-offs/Provision (Note 2)	(17)	(98)		
Inter LoB transfers				
F06 Trfrs to BCTC				(33)
Transfer to assets in service	(461)	(622)	(642)	(584)
Balance at end of year	669	515	559	827
	<b>\$ 9,793</b>	<b>\$ 9,844</b>	<b>\$ 10,129</b>	<b>\$ 10,494</b>

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

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

Shaded amounts indicate changes from the Revised Evidentiary Update.

## SCHEDULE A-12 (Update of June 2004)

<b>Composition of Long-term Debt</b>				
<b>As at March 31</b>				
<b>(\$ millions)</b>				
	A	B	C	D
	<b>F2003</b>	<b>F2004</b>	<b>F2005</b>	<b>F2006</b>
	<b>Actual</b>	<b>Actual</b>	<b>Forecast</b>	<b>Forecast</b>
8	Bonds, notes and debentures			
9	\$ 4,888	\$ 4,938	\$ 5,150	\$ 5,437
10	2,671	2,659	2,374	2,161
11	7,559	7,597	7,524	7,598
12	Less:			
13	1,037	981	984	844
14	Net bonds, notes and debentures			
15	6,522	6,616	6,540	6,754
16	Revolving borrowings			
17	331	284	402	492
18	Long-term debt net of sinking funds			
19	6,853	6,900	6,942	7,246
20	Sinking funds presented as assets			
21	1,037	981	984	844
22	Long-term debt			
23	\$ 7,890	\$ 7,881	\$ 7,926	\$ 8,090
24	Foreign currency contracts (Dr)			
25	(13)	-	-	-
26	Foreign currency contracts Cr			
27	15	63	65	60

29 Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-12-1 (Update for June 2004)

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**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
<b>Balance at Beginning of Year</b>	\$ 6,906	\$ 6,853	\$ 6,900	\$ 6,942
Add (less):				
New financing	1,007	790	600	700
Retirements	(1,019)	(450)	(598)	(607)
Revolving borrowings	147	(57)	118	90
	135	283	120	183
Exchange and other adjustments	(179)	(229)	(60)	(15)
Sinking fund (increase) decrease	(9)	(7)	(18)	136
<b>Balance at End of Year</b>	<b>\$ 6,853</b>	<b>\$ 6,900</b>	<b>\$ 6,942</b>	<b>\$ 7,246</b>

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-13 (Update for June 2004)

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

	A	B	C	D
	<b>F2003</b>	<b>F2004</b>	<b>F2005</b>	<b>F2006</b>
	<b>Actual</b>	<b>Actual</b>	<b>Forecast</b>	<b>Forecast</b>
<b>Contributions in Aid:</b>				
Opening balance	\$ 935	\$ 977	\$ 1,003	\$ 1,026
Current year additions	61	56	51	54
Balance sheet reclassifications <sup>1</sup>	-	(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>
<b>Accumulated Amortization:</b>				
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>
<b>NET CONTRIBUTIONS IN AID</b>	<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.

Shaded amounts indicate changes from the Revised Evidentiary Update.

SCHEDULE A-14 (Update for June 2004)

<b>Contributions Arising from the Columbia River Treaty</b>				
<b>For the Years ended March 31</b>				
<b>(\$ millions)</b>				
	A	B	C	D
	<b>F2003</b>	<b>F2004</b>	<b>F2005</b>	<b>F2006</b>
	<b>Actual</b>	<b>Actual</b>	<b>Forecast</b>	<b>Forecast</b>
Original contribution	\$ 479	\$ 479	\$ 479	\$ 479
Accumulated depreciation:				
Beginning of year	(267)	(276)	(286)	(295)
Amortization	(9)	(10)	(9)	(9)
	<u>(276)</u>	<u>(286)</u>	<u>(295)</u>	<u>(304)</u>
<b>BALANCE AT END OF YEAR</b>	<u><u>\$ 203</u></u>	<u><u>\$ 193</u></u>	<u><u>\$ 184</u></u>	<u><u>\$ 175</u></u>

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.

SCHEDULE A-15 (Update of June 2004)

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

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
<b>Actual/forecast return on equity</b>	15.47%	3.60%	10.17%	12.50%
<b>Allowed return on equity <sup>1</sup></b>	15.47%	14.33%	13.91%	13.91%
<b>Numerator</b>				
Consolidated net income after rate stabilization account transfer	\$ 418	\$ 98	\$ 309	\$ 391
<b>Denominator</b>				
Retained earnings - end of year	\$ 1,609	\$ 1,634	\$ 1,925	\$ 1,987
Deferred credits - end of year	1,091	1,088	1,112	1,141
Equity - end of year	\$ 2,700	\$ 2,722	\$ 3,037	\$ 3,128

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
<b>Deferred Credits</b>				
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 from the Revised Evidentiary Update.

SCHEDULE A-16 (Update of June 2004)

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

	A	B	C	D
	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
<b>Debt to equity</b>	72:28	72:28	70:30	70:30
<b>Debt</b>				
Long term debt net of sinking funds	\$6,853	\$6,900	\$6,942	\$7,246
Temporary investments	(4)	(47)	(4)	(4)
	<u>\$6,849</u>	<u>\$6,853</u>	<u>\$6,938</u>	<u>\$7,242</u>
<b>Equity</b>				
Deferred credits	\$1,091	\$1,088	\$1,112	\$1,141
Retained earnings	1,609	1,634	1,925	1,987
	<u>\$2,700</u>	<u>\$2,722</u>	<u>\$3,037</u>	<u>\$3,128</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 from the Revised Evidentiary Update.

**SCHEDULE B (Update of June 2004)**

		<b>Functionalized Costs F2003</b>							
(\$ millions)		Corporate	Energy Supply	Generation	Transmission <sup>6</sup>	Electricity	Customer	Service	Consolidated
			less Heritage	(Heritage		Distribution	Care <sup>1</sup>	Orgs	
			Payment	Contract) <sup>2</sup>		&NIA <sup>7</sup>		and	
			Obligation <sup>1</sup>					Subsidiaries	
		Chapter 3	Chapter 4	Chapter 5	Chapter 6	Chapter 7	Chapter 8	Chapter 9	
B1	Domestic cost of energy		294.6	399.1	0.8	14.1			708.6
	OMA Expenses								-
	Operations, maintenance, and administration (net)	68.4	12.5	119.5	130.2	86.7	89.8	(1.2)	505.9
	Corporate Allocations	(84.6)	7.6	27.9	28.0	15.3	5.0	0.8	-
B2	Adjusted OMA including Corporate Allocations	(16.2)	20.1	147.4	158.2	102.0	94.8	(0.4)	505.9
B4	Depreciation	50.3	22.4	110.7	129.9	87.6		12.9	413.8
B3	Taxes	7.3		29.0	89.4	18.3		1.0	145.0
B5	Finance charges	-	5.0	213.0	135.0	104.0		-	457.0
B6	Allowed net income (return on equity)		4.0	195.0	123.0	96.0		-	418.0
C3	Other <sup>3</sup>			37.0		52.0			89.0
A-1	Restructuring costs	36.5							36.5
A-8	Miscellaneous external revenues	(12.9)		(165.2)	(96.7)	(6.7)	(2.1)	(19.9)	(303.5)
<b>Cost of Service by Function</b>		<b>65.0</b>	<b>346.1</b>	<b>966.0</b>	<b>539.6</b>	<b>467.3</b>	<b>92.7</b>	<b>(6.4)</b>	<b>2,470.3</b>
A-8	Transmission 3rd party wheeling revenues <sup>4</sup>								(0.8)
A-1	Intersegment revenues <sup>5</sup>								(6.0)
<b>Total Revenue Requirement</b>									<b>2,463.5</b>
Schedule to cross reference		C6	C2	C1	C3	C4	C5	C7	

Notes:

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.
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.
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.
4. Relates to external transmission wheeling revenues which are not deducted in determining the Transmission Cost of Service.
5. See Chapter 2 Section 3.3 for details.
6. Domestic cost of energy for Transmission is from cost of market for transmission (see Schedule C3).
7. Domestic cost of energy for Electricity Distribution & NIA is from Domestic Cost of Energy - Non-Integrated Areas (see line 1, schedule C4).

**SCHEDULE B-1 (Update of June 2004)**

		<b>Functionalized Costs F2004</b>								
		Corporate	Energy Supply	Generation	Transmission <sup>6</sup>	Electricity	Customer	Service	Consolidated	
			less Heritage	(Heritage		Distribution	Care <sup>1</sup>	Orgs		
			Payment	Contract) <sup>2</sup>		&NIA <sup>7</sup>		and		
			Obligation <sup>1</sup>					Subsidiaries		
		Chapter 3	Chapter 4	Chapter 5	Chapter 6	Chapter 7	Chapter 8	Chapter 9		
10	B1	Domestic cost of energy		382.1	597.7	1.0	14.2		995.0	
11		OMA Expenses							-	
12		Operations, maintenance, and administration (net)	46.5	25.3	148.4	159.4	109.2	111.6	(15.8)	584.6
13		Corporate Allocations	(117.5)	9.2	35.7	22.7	18.8	6.1	25.0	-
14	B2	Adjusted OMA including Corporate Allocations	(71.0)	34.5	184.1	182.1	128.0	117.7	9.2	584.6
15	B4	Depreciation	56.8	21.6	216.3	145.5	83.7		12.3	536.2
16	B3	Taxes	9.9		28.2	88.4	18.9		1.0	146.4
17	B5	Finance charges	10.1	4.0	197.0	127.8	96.1		-	435.0
18	B6	Allowed net income (return on equity)		4.0	183.4	119.1	89.5		-	396.0
19	C3	Other <sup>3</sup>			43.3		52.0			95.3
20	A-1	Restructuring costs								-
21	A-8	Miscellaneous external revenues	(14.5)		(181.4)	(103.7)	(6.4)	(6.6)	(21.6)	(334.2)
22		Cost of Service by Function	(8.7)	446.2	1,268.6	560.2	476.0	111.1	0.9	2,854.3
23	A-8	Transmission 3rd party wheeling revenues <sup>4</sup>								(4.9)
24	A-1	Intersegment revenues <sup>5</sup>								(62.0)
25		Total Revenue Requirement								2,787.4
26	Schedule									
27	to cross		C6	C2	C1	C3	C4	C5	C7	
28	reference									

- Notes:
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.
  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.
  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.
  4. Relates to external transmission wheeling revenues which are not deducted in determining the Transmission Cost of Service.
  5. See Chapter 2 Section 3.3 for details.
  6. Domestic cost of energy for Transmission is from cost of market for transmission (see Schedule C3).
  7. Domestic cost of energy for Electricity Distribution & NIA is from Domestic Cost of Energy - Non-Integrated Areas (see line 1, schedule C4).

**SCHEDULE B-2 (Update of June 2004)**

		<b>Functionalized Costs</b>							
		<b>F2005</b>							
(\$ millions)		Corporate	Energy Supply	Generation	Transmission <sup>7</sup>	Electricity	Customer	Service	Consolidated
			less Heritage	(Heritage		Distribution	Care <sup>1</sup>	Orgs and	
			Payment	Contract) <sup>2</sup>		&NIA <sup>8</sup>		Subsidiaries	
			Obligation <sup>1</sup>						
		Chapter 3	Chapter 4	Chapter 5	Chapter 6	Chapter 7	Chapter 8	Chapter 9	
B1	Domestic cost of energy		397.8	643.2	1.0	15.0			1,057.0
	OMA Expenses								-
	Operations, maintenance, and administration (net)	70.4	22.6	125.4	167.5	107.4	101.5	(17.7)	577.1
	Corporate Allocations	(126.6)	12.3	41.5	14.1	25.0	8.2	25.5	-
B2	Adjusted OMA including Corporate Allocations	(56.2)	34.9	166.9	181.6	132.4	109.7	7.8	577.1
B4	Depreciation	49.8	23.1	129.0	150.6	88.0		14.2	454.7
B3	Taxes	7.4		28.6	89.5	18.8		1.1	145.4
B5	Finance charges	9.5	4.2	190.5	125.2	98.6		-	428.0
B6	Allowed net income (return on equity)		4.4	193.3	127.2	100.1		-	425.0
C3	Other <sup>3</sup>			43.3		67.9			111.2
A-1	Restructuring costs	-	-	-	-	-	-	-	-
A-8	Miscellaneous external revenues	(10.5)		(115.2)	(119.2)	(4.5)	(4.2)	(21.6)	(275.2)
	Cost of Service by Function	-	464.4	1,279.6	555.9	516.3	105.5	1.5	2,923.2
A-8	Transmission 3rd party wheeling revenues <sup>4</sup>								(5.5)
A-1	Intersegment revenues <sup>5</sup>								(124.0)
	Total Revenue Requirement <sup>6</sup>								2,793.7
Schedule to cross reference		C6	C2	C1	C3	C4	C5	C7	

Notes:

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.
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.
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.
4. Relates to external transmission wheeling revenues which are not deducted in determining the Transmission Cost of Service
5. See Chapter 2 Section 3.3 for details.
6. Small differences from Chapter 1 Table 3 relate to rounding differences.
7. Domestic cost of energy for Transmission is from cost of market for transmission (see schedule C3)
8. Domestic cost of energy for Electricity Distribution & NIA is from Domestic Cost of Energy - Non-Integrated Areas (see line 1, schedule C4)

Shaded amounts indicate changes from the Revised Evidentiary Update.

**SCHEDULE B-3 (Update of June 2004)**

		<b>Functionalized Costs</b>							
		<b>F2006</b>							
									Consolidated
(\$ millions)		Corporate	Energy Supply	Generation	Transmission	Electricity	Customer	Service	
			less Heritage	(Heritage		Distribution	Care <sup>1</sup>	Orgs	
			Payment	Contract) <sup>2</sup>		&NIA <sup>7</sup>		and	
			Obligation <sup>1</sup>					Subsidiaries	
		Chapter 3	Chapter 4	Chapter 5	Chapter 6	Chapter 7	Chapter 8	Chapter 9	
B1	Domestic cost of energy		428.7	551.6		15.0			995.3
	OMA Expenses								-
	Operations, maintenance, and administration (net)	69.8	20.9	126.0	3.5	107.6	97.3	(18.2)	406.9
	Corporate Allocations	(126.0)	11.9	41.9	14.3	24.4	8.0	25.5	-
B2	Adjusted OMA including Corporate Allocations	(56.2)	32.8	167.9	17.8	132.0	105.3	7.3	406.9
B4	Depreciation	50.7	28.1	124.9	141.2	91.2		15.0	451.1
B3	Taxes	7.5		29.0	90.5	19.1		1.0	147.1
B5	Finance charges	8.1	4.7	201.0	132.4	111.8		-	458.0
B6	Allowed net income (return on equity)		4.5	194.8	128.3	108.4		-	436.0
C3	Other <sup>3</sup>			43.3		68.9			112.2
A-1	Restructuring Costs	-	-	-	-	-	-	-	-
A-8	Miscellaneous external revenues	(10.1)		(118.8)	(117.9)	(4.5)	(4.2)	(22.5)	(278.0)
	Cost of Service by Function	-	498.8	1,193.7	392.3	541.9	101.1	0.8	2,728.6
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>								(140.0)
	Total Revenue Requirement <sup>6</sup>								2,766.3

Schedule to cross reference C6 C2 C1 C3 C4 C5 C7

- Notes:
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.
  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.
  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.
  4. Relates to charges from BCTC
  5. See Chapter 2 Section 3.3 for details.
  6. Small differences from Chapter 1 Table 3 relate to rounding differences.
  7. Domestic cost of energy for Electricity Distribution & NIA is from Domestic Cost of Energy - Non-Integrated Areas (see line 1, schedule C4)

Shaded amounts indicate changes from the Revised Evidentiary Update.



## SCHEDULE B1 (Updated June 2004)

### Domestic Cost of Energy (\$ millions)

<u>Line</u>	<u>Reference</u>	<u>F2003</u> Actual	<u>F2004</u> Actual	<u>F2005</u> Forecast	<u>F2006</u> Forecast
1 Domestic Cost of Energy <sup>1</sup>	A-9	708	995	1,057	995
Domestic Cost of Energy					
2 Domestic Cost of Energy-Generation	D1-2	399.1	597.7	643.2	551.6
3 Domestic Cost of Energy-Energy Supply less Heritage Payment Obligation	C2	294.6	382.1	397.8	428.7
4 Domestic Cost of Energy-Transmission	C3	0.8	1.0	1.0	-
5 Domestic Cost of Energy-Non-integrated areas	C4	14.1	14.2	15.0	15.0
6 Total Domestic Cost of Energy		708.6	995.0	1,057.0	995.3

7 Notes:

8 1. The figures from Schedule A-9 have been rounded to the nearest \$ million.

10 Shaded amounts indicate changes from the Revised Evidentiary Update.

## SCHEDULE B2 (Update of June 2004)

### Operations, Maintenance, and Administration

(\$ millions)

<u>Line</u>	<u>Reference</u>	<u>F2003</u>	<u>F2004</u>	<u>F2005</u>	<u>F2006</u>	
		Actual	Actual	Forecast	Forecast	
Operations, Maintenance, and Administration						
1	Operations	143	168	171	129	
2	Maintenance	196	240	244	138	
3	Administration	<u>167</u>	<u>168</u>	<u>162</u>	<u>140</u>	
4		506	576	577	407	
5	Restructuring costs	<u>37</u>	<u>8</u>	<u>0</u>	<u>0</u>	
6	A-1	<u>543</u>	<u>584</u>	<u>577</u>	<u>407</u>	
Operations, Maintenance, and Administration						
Domestic Operations						
7	Generation (Heritage Contract)	D1-1	147.4	184.1	166.9	167.9
8	Energy Supply Cost less Heritage Payment Obligation	C2	20.1	34.5	34.9	32.8
9	Transmission (Note 1)	D4	158.2	182.1	181.6	17.8
10	Electricity Distribution and Non-Integrated Areas	D5	102.0	128.0	132.4	132.0
11	Customer Care	D6	94.8	117.7	109.7	105.3
12	Corporate	D7	(16.2)	(71.0)	(56.2)	(56.2)
13	Engineering Services	D8	(3.9)	(0.3)	(0.6)	(0.6)
14	Field Services	D9	(3.8)	(4.8)	(7.6)	(8.6)
15	MMBU	D10	(3.0)	(1.2)	0.6	0.6
16	Powertech	C7	<u>10.3</u>	<u>13.2</u>	<u>13.1</u>	<u>13.6</u>
17	Total OMA for Domestic Operations		505.9	582.3	574.8	404.6
18	Allocation of Corporate costs to Powerex		-	2.3	2.3	2.3
19			<u>505.9</u>	<u>584.6</u>	<u>577.1</u>	<u>406.9</u>

20 Note 1: F2004 includes \$8.3 million of restructuring costs.

21 Shaded amounts indicate changes from the Revised Evidentiary Update.

## SCHEDULE B3 (Update of June 2004)

### Taxes (\$ millions)

<u>Line</u>		<u>Reference</u>	<u>F2003</u> Actual	<u>F2004</u> Actual	<u>F2005</u> Forecast	<u>F2006</u> Forecast
	Taxes 1					
1	Grants		\$ 42	\$ 42	\$ 44	\$ 45
2	School Taxes		100	99	101	102
3	Other		3	5		
4	Total	A-1	<u>\$145</u>	<u>\$146</u>	<u>\$145</u>	<u>\$147</u>
	Taxes by Functional Area					
5	Generation (Heritage Contract)	C1	29.0	28.2	28.6	29.0
6	Transmission	C3	89.4	88.4	89.5	90.5
7	Electricity Distribution and Non-Integrated Areas	C4	18.3	18.9	18.8	19.1
8	Corporate	C6	7.3	9.9	7.4	7.5
9	Field Services	C7	0.2	0.2	0.2	0.1
10	MMBU	C7	0.8	0.8	0.9	0.9
11	Total		<u>145.0</u>	<u>146.4</u>	<u>145.4</u>	<u>147.1</u>

12 Note 1: The figures on Schedule A-1 have been rounded to the nearest \$ million.

## SCHEDULE B4 (Update of June 2004)

### Depreciation and Amortization

(\$ millions)

<u>Line</u>	<u>Reference</u>	<u>F2003</u>	<u>F2004</u>	<u>F2005</u>	<u>F2006</u>	
		Actual	Actual	Forecast	Forecast	
Depreciation and Amortization 1						
1	Depreciation of capital assets in service	\$ 379	\$ 402	\$ 447	\$ 437	
2	Amortization of contributions	(42)	(45)	(44)	(45)	
3	Amortization of studies and abandoned projects	11	8	8	9	
4	Amortization of DSM	25	25	26	31	
5	Future removal and site restoration costs	27	35	N/A	N/A	
6	Asset Dismantling and Site Restoration costs			18	19	
7	Capital asset write-offs	14	13			
8	Valuation provision 2		98			
9	Total	<u>\$ 414</u>	<u>\$ 536</u>	<u>\$ 455</u>	<u>\$ 451</u>	
Depreciation and Amortization by Functional Area						
10	Generation 2	C1	110.7	216.3	129.0	124.9
11	Energy Supply Cost less Heritage Payment Obligation	C2	22.4	21.6	23.1	28.1
12	Transmission	C3	129.9	145.5	150.6	141.2
13	Electricity Distribution and Non-Integrated Areas	C4	87.6	83.7	88.0	91.2
14	Corporate	C6	50.3	56.8	49.9	50.7
15	Engineering	C7	0.8	0.3	0.3	0.3
16	Field Services	C7	10.9	11.0	12.5	13.3
17	Powertech	C7	0.6	0.5	0.7	0.7
18	MMBU	C7	0.6	0.5	0.7	0.7
19	Total		<u>413.8</u>	<u>536.2</u>	<u>454.8</u>	<u>451.1</u>

20 Notes:

- 21 1. The figures on Schedule A-1 have been rounded to the nearest \$ million.  
 22 2. Relates to valuation provision to the VIGP/GSX projects. The \$98 million valuation provision in  
 23 F2004 is shown as part of the Generation function.

24 Shaded amounts indicate changes from the Revised Evidentiary Update.

## SCHEDULE B5 (Update of June 2004)

### Finance Charges (\$ millions)

Line	Reference	F2003	F2004	F2005	F2006
		Actual	Actual	Forecast	Forecast
Finance Charges <sup>1</sup>					
	Interest on Debt Securities				
1	- bonds, notes and debentures	\$536	\$507	\$483	\$506
2	- revolving borrowings	5	9	12	17
3	Amortization of deferred debt costs and other expenses	26	28	32	33
4		<u>\$567</u>	<u>\$544</u>	<u>\$527</u>	<u>\$556</u>
Less:					
5	Sinking fund income	(60)	(58)	(53)	(48)
6	Other income	(26)	(34)	(26)	(15)
7	Finance charges capitalized to unfinished construction	(24)	(17)	(20)	(35)
8		<u>(110)</u>	<u>(109)</u>	<u>(99)</u>	<u>(98)</u>
9	Total	<u>457.0</u>	<u>435.0</u>	<u>428.0</u>	<u>458.0</u>
	A-1				
Allocation of Finance Charges by Functional Area					
10	Generation (Heritage Contract)	213.0	197.0	190.5	201.0
11	Energy Supply Cost less Heritage Payment Obligation	5.0	4.0	4.2	4.7
12	Transmission	135.0	127.8	125.2	132.4
13	Electricity Distribution and Non-Integrated Areas	104.0	96.1	98.6	111.8
14	Corporate	-	10.1	9.5	8.1
15	Total	<u>457.0</u>	<u>435.0</u>	<u>428.0</u>	<u>458.0</u>

16 Notes:

17 1. The figures from Schedule A-1 have been rounded to the nearest \$ million.

18 Total finance charges less the portion attributable to Corporate are allocated based on the percentages shown in Schedule B7.

19 The Corporate portion relates to the deemed interest charges on assets held in BCH Service Asset Corporation (see section 6.2.2, chapter 2 of the

20 Shaded amounts indicate changes from the Revised Evidentiary Update.

## SCHEDULE B6 (Update of June 2004)

### Allowed Net Income (Return on Equity) (\$ millions)

<u>Line</u>	<u>Reference</u>	<u>F2003</u>	<u>F2004</u>	<u>F2005</u>	<u>F2006</u>	
		Actual	Actual	Forecast	Forecast	
1	Allowed Net Income (Return on Equity) Allowed ROE%	Chapter 10	15.47%	14.33%	13.91%	13.91%
2	Ending Equity Balance	A-15	\$2,700	\$ 2,722	\$ 3,037	\$ 3,128
3	Allowed Net Income		\$ 418	\$ 396	\$ 425	\$ 436
Allocation of Allowed Net Income (Return on Equity)						
4	Generation (Heritage Contract)	C1	195.0	183.4	193.3	194.8
5	Energy Supply Cost less Heritage Payment Obligation	C2	4.0	4.0	4.4	4.5
6	Transmission	C3	123.0	119.1	127.2	128.3
7	Electricity Distribution and Non-Integrated Areas	C4	96.0	89.5	100.1	108.4
8	Total		<u>418.0</u>	<u>396.0</u>	<u>425.0</u>	<u>436.0</u>

9 Shaded amounts indicate changes from the Revised Evidentiary Update.

## SCHEDULE B7 (Update of June 2004)

<b>Allocation of Finance Charges</b>				
(\$ millions)				
	<b>F2003</b>	<b>F2004</b>	<b>F2005</b>	<b>F2006</b>
	Actual	Actual	Plan	Plan
Net Book Value of Capital Assets	\$ 2,526	\$ 2,588	\$ 2,637	\$ 2,632
10% of Demand Side Management <sup>1</sup>	12	16	23	28
	2,538	2,604	2,660	2,660
CIA	(81)	(85)	(89)	(94)
Transmission Rate Base <sup>2</sup>	\$ 2,457	\$ 2,519	\$ 2,571	\$ 2,566
<b>Transmission Average Balance</b>		2,488	2,545	2,569
Net Book Value of Capital Assets	3,842	3,854	3,908	3,911
CIA	(14)	(10)	(10)	(9)
Generation Rate Base	\$ 3,828	\$ 3,844	\$ 3,898	\$ 3,902
<b>Generation Average Balance</b>		3,836	3,871	3,900
Net Book Value of Capital Assets	2,304	2,373	2,509	2,615
90% of Demand Side Management	110	145	217	273
	2,414	2,518	2,726	2,888
CIA	(510)	(526)	(538)	(552)
Distribution Rate Base	\$ 1,904	\$ 1,992	\$ 2,188	\$ 2,336
<b>Distribution Average Balance</b>		1,948	2,090	2,262
<b>BC Hydro (T,G&amp;D) Average Balance</b>		\$ 8,272	\$ 8,506	\$ 8,731
<b>Portion of Rate Base:</b>				
Transmission	29.49%	30.08%	29.92%	29.42%
Generation (Heritage Contract)	46.60%	46.37%	45.51%	44.67%
Distribution total	23.91%	23.55%	24.57%	25.91%
-Energy Management <sup>3</sup>	0.96%	0.94%	1.00%	1.04%
-Electricity Distribution and Non-Integrated Areas	22.95%	22.61%	23.57%	24.87%
	100.00%	100.00%	100.00%	100.00%

Notes:

1. 10% of DSM costs are allocated to the transmission rate base and 90% of DSM are allocated to the distribution rate base.
2. Includes consolidation of BCTC for F2004 and F2005.
3. The total distribution share is further separated into the shares for the Energy Management (4%) and Electricity Distribution and NIA functions (96%).

Shaded amounts indicate changes from the Revised Evidentiary Update.

## SCHEDULE C (Update of June 2004)

### Functional Revenue Requirements Summary

(\$ millions)

<u>Line</u>	<u>Reference</u>	<u>F2003</u>	<u>F2004</u>	<u>F2005</u>	<u>F2006</u>	
		Actual	Actual	Forecast	Forecast	
1	Cost of Service - Generation (Heritage Contract)	C1	966.0	#####	1,279.6	1,193.7
2	Cost of Service - Energy Supply Cost less Heritage Payment Obligation	C2	346.1	446.2	464.4	498.8
3	Cost of Service - Transmission BC Hydro portion	C3	539.6	560.2	555.9	392.3
4	Cost of Service - Electricity Distribution and Non-Integrated Areas	C4	467.3	476.0	516.3	541.9
5	Cost of Service - Customer Care <sup>1</sup>	C5	92.7	111.1	105.5	101.1
6	Cost of Service - Corporate	C6	65.0	(8.7)	-	-
7	Cost of Service - Service Organizations and Subsidiaries	C7	(6.4)	0.9	1.5	0.8
8			#####	#####	2,923.2	2,728.6
9	Asset Management Fee from BCTC	BCTC	-	-	-	116.7
10	Wholesale Transmission Service Charges from BCTC	BCTC	-	-	-	61.0
11			#####	#####	2,923.2	2,906.3
12	Less: Transmission Point-to-Point Wheeling in Miscellaneous Revenues <sup>1</sup>	A-8	0.8	4.9	5.5	-
13	Inter-Segment Revenues	A-1	6.0	62.0	124.0	140.0
14			6.8	66.9	129.5	140.0
15	Total Cost of Service		#####	#####	2,793.7	2,766.3
Contributions by Customer Segment						
16	Residential		923	960	1,050	1,073
17	Light Industrial and Commercial		893	912	988	1,009
18	Large Industrial		516	525	568	567
19	Other Energy Sales		88	89	91	92
20	Transfer from RSA		66	21	-	-
21			2,486	2,507	2,697	2,741
22	Less: Other Utilities revenues included in Other Energy Sales		22	18	19	20
23			2,464	2,489	2,678	2,721
24	Net Income Shortfall		-	298.4	115.7	45.3
25			(0.5)	-	-	-
26			#####	#####	2,793.7	2,766.3
27	Notes:					
28	1. These relate to Wheeling tariff revenues and are therefore not deducted					
29	in calculating the Transmission Cost of Service. They are deducted in					
30	calculating BC Hydro's total cost of service.					
31	Shaded amounts indicate changes from the Revised Evidentiary Update.					

## SCHEDULE C1 (Update of June 2004)

### Cost of Service - Generation (\$ millions)

<u>Line</u>	<u>Reference</u>	<u>F2003</u> Actual	<u>F2004</u> Actual	<u>F2005</u> Forecast	<u>F2006</u> Forecast
Cost of Service - Generation (Heritage Contract)					
1	D1-1	\$ 147.4	\$ 184.1	\$ 166.9	\$ 167.9
2	D1-2	399.1	597.7	643.2	551.6
3	C3	37.0	43.3	43.3	43.3
4	B3	29.0	28.2	28.6	29.0
5	B4	110.7	216.3	129.0	124.9
6	B5	213.0	197.0	190.5	201.0
7		<u>195.0</u>	<u>183.4</u>	<u>193.3</u>	<u>194.8</u>
8		<u>1,131.2</u>	<u>1,450.0</u>	<u>1,394.8</u>	<u>1,312.5</u>
9	A-1	138.0	158.0	89.0	91.0
10		21.9	18.0	18.9	19.4
11	A-8	<u>5.3</u>	<u>5.4</u>	<u>7.3</u>	<u>8.4</u>
12		<u>165.2</u>	<u>181.4</u>	<u>115.2</u>	<u>118.8</u>
13		<u>\$ 966.0</u>	<u>\$1,268.6</u>	<u>\$1,279.6</u>	<u>\$1,193.7</u>

14 Note:

15 1. This is not the same as the Heritage Payment Obligation. The reconciliation is shown in  
16 Schedules D1-2 and D1-3.

**SCHEDULE C2 (Update of June 2004)**

**Cost of Service - Energy Supply Cost less Heritage Payment Obligation**  
(\$ millions)

<u>Line</u>		<u>Reference</u>	<u>F2003</u> Actual	<u>F2004</u> Actual	<u>F2005</u> Forecast	<u>F2006</u> Forecast
	Cost of Service - Energy Supply Cost less Heritage Payment Obligation					
1	Depreciation and Amortization <sup>1</sup>	B4	22.4	21.6	23.1	28.1
2	Finance Charges <sup>1</sup>	B5	5.0	4.0	4.2	4.7
3	Allowed ROE <sup>1</sup>	B6	4.0	4.0	4.4	4.5
4			31.4	29.6	31.7	37.3
5	Power Smart OMA	D3	12.8	20.2	22.1	21.8
6			44.2	49.8	53.8	59.1
7	IPP Cost of Energy and long-term purchase commitments <sup>2</sup>	A-9	289.4	372.2	384.8	415.7
8	Gas transportation & domestic transmission	A-9	5.2	9.9	13.0	13.0
9	Domestic cost of energy-Energy Supply Cost		294.6	382.1	397.8	428.7
10	Energy Management OMA	D2	7.3	14.3	12.8	11.0
11	Cost of Service-Energy Supply Cost less Heritage Payment Obligation		346.1	446.2	464.4	498.8

Notes:

1. 90% of DSM amortization is shown as part of Energy Supply Cost and 10% is shown as part of Transmission (Schedule C3).
2. Includes purchase commitments entered into before F2001 and agreements from F2001. See Chapter 4 Table 1.

16 Shaded amounts indicate changes from the Revised Evidentiary Update.

## SCHEDULE C3 (Update of June 2004)

### Cost of Service - Transmission (\$ millions)

Line	Reference	F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast		
					BC Hydro	BCTC	
1	Operating, Maintenance & Administration (Note 1)	D4	158.2	182.1	181.6	17.8	166.1
2	Cost of Market (Note 2)	B1	0.8	1.0	1.0	-	5.8
Asset Related Expense							
3	Finance Charge	B5	135.0	127.8	125.2	132.4	1.7
4	Depreciation & Amortization (Note 3)	B4	129.9	145.5	150.6	141.2	16.7
5	Grants & Taxes	B3	89.4	88.4	89.5	90.5	0.3
6	Allowed Return	B6	123.0	119.1	127.2	128.3	3.9
7	<b>Total Cost</b>		<b>636.3</b>	<b>663.9</b>	<b>675.1</b>	<b>510.2</b>	<b>194.5</b>
Less Non-WTS Revenues and Recoveries							
8	Generation Related Transmission Assets	C1	(37.0)	(43.3)	(43.3)	(43.3)	
9	Substation Distribution Asset Management	C4	(52.0)	(52.0)	(67.9)	(68.9)	
10	Aquila General Wheeling Agreement	A8	(3.8)	(3.7)	(3.8)		(3.8)
11	Secondary Revenues	A8	(3.8)	(4.7)	(4.2)	(5.7)	
12	Other Recoveries		(0.1)	-			
13	<b>Total Non-WTS Revenues and Recoveries</b>		<b>(96.7)</b>	<b>(103.7)</b>	<b>(119.2)</b>	<b>(117.9)</b>	<b>(3.8)</b>
14	<b>Total Transmission Revenue Requirement</b>		<b>539.6</b>	<b>560.2</b>	<b>555.9</b>	<b>392.3</b>	<b>190.7</b>

15 Notes:

16 (1) F2004 includes \$8.3 million in restructuring costs.

17 (2) F2003 through F2005 reflects Congestion Mgmt cost only, F206 reflects Ancillary Services cost plus Congestion Mgmt.

18 (3) Includes 10% of amortization relating to DSM. Remaining 90% is shown in Energy Supply Cost - Cost of Service (Schedule C2).

19 Shaded amounts indicate changes from the Revised Evidentiary Update.

**SCHEDULE C4 (Update of June 2004)**

**Cost of Service - Electricity Distribution and Non-Integrated Areas**  
(\$ millions)

<u>Line</u>		<u>Reference</u>	<u>F2003</u>	<u>F2004</u>	<u>F2005</u>	<u>F2006</u>	
			Actual	Actual	Forecast	Forecast	
	Cost of Service - Electricity Distribution and Non-integrated Areas						
1	Domestic Cost of Energy - Non-Integrated Areas	A9	14.1	14.2	15.0	15.0	
2	Electricity Distribution and Non-Integrated Areas OMA	D5	102.0	128.0	132.4	132.0	
3	Taxes	B3	18.3	18.9	18.8	19.1	
4	Depreciation and Amortization	B4	87.6	83.7	88.0	91.2	
5	Finance Charges	B5	104.0	96.1	98.6	111.8	
6	Allowed Net Income	B6	96.0	89.5	100.1	108.4	
7	Sub-Total		<u>422.0</u>	<u>430.4</u>	<u>452.9</u>	<u>477.5</u>	
8	Distribution Substations (from Transmission)	C3	52.0	52.0	67.9	68.9	
9	Cost of Service - Electricity Distribution and Non-Integrated Areas		<u>474.0</u>	<u>482.4</u>	<u>520.8</u>	<u>546.4</u>	
10	Less: Miscellaneous non-tariff revenues	A-8	6.7	6.4	4.5	4.5	
11	Total Cost of Service - Electricity Distribution and Non-integrated areas		<u>467.3</u>	<u>476.0</u>	<u>516.3</u>	<u>541.9</u>	
12	Shaded amounts indicate changes from the Revised Evidentiary Update.						

## SCHEDULE C5 (Update of June 2004)

### Cost of Service - Customer Care (\$ millions)

<u>Line</u>		<u>Reference</u>	<u>F2003</u>	<u>F2004</u>	<u>F2005</u>	<u>F2006</u>
			Actual	Actual	Forecast	Forecast
Cost of Service - Customer Care						
1	Customer Care OMA	D6	94.8	117.7	109.7	105.3
2	Less: Miscellaneous Non-tariff revenues 1	A-8	2.1	6.6	4.2	4.2
3	Total Cost of Service - Customer Care		<u>92.7</u>	<u>111.1</u>	<u>105.5</u>	<u>101.1</u>
Allocation of Customer Care Costs by Customer Group*						
4	Transmission-voltage		1.5	1.8	1.7	1.7
5	General Service and Residential		91.0	109.1	103.6	99.3
6	Other		0.2	0.2	0.2	0.1
7	Total Cost of Service - Customer Care		<u>92.7</u>	<u>111.1</u>	<u>105.5</u>	<u>101.1</u>
8	*Allocation percentages are based on direct spending costs:					
9	1.65% for Transmission customers					
10	98.20% for General Service & Residential customers					
11	0.15% for Other customers					
12	Notes:					
13	1. Composed of Terasen meter reading and other revenues.					
14	Shaded amounts indicate changes from the Revised Evidentiary Update.					

## SCHEDULE C6 (Update of June 2004)

### Cost of Service - Corporate (\$ millions)

Line	Reference	F2003	F2004	F2005	F2006
		Actual	Actual	Forecast	Forecast
Cost of Service - Corporate					
1	D7	(16.2)	(71.0)	(56.2)	(56.2)
2	B3	7.3	9.9	7.4	7.5
3	B4	50.3	56.8	49.8	50.7
4	B5	-	10.1	9.5	8.1
5	A-1	<u>36.5</u>	<u>-</u>	<u>-</u>	<u>-</u>
6		<u>77.9</u>	<u>5.8</u>	<u>10.5</u>	<u>10.1</u>
7	A-8	<u>(12.9)</u>	<u>(14.5)</u>	<u>(10.5)</u>	<u>(10.1)</u>
8		<u>65.0</u>	<u>(8.7)</u>	<u>-</u>	<u>-</u>

9 Notes:

10 The cost of service for F2003 largely relates to the restructuring costs and year-end write-offs and catch up of  
11 depreciation which were not recovered through the corporate allocations.

12 Shaded amounts indicate changes from the Revised Evidentiary Update.

## SCHEDULE C7 (Update of June 2004)

### Cost of Service - Service Organizations and Subsidiaries <sup>1</sup> (\$ millions)

Line	FISCAL 2003	Reference	Engineering	Field Services	MMBU	Powertech <sup>2</sup>	Other	Total
1	OMA expenses		(3.9)	(4.6)	(3.0)	10.3		(1.2)
2	Corporate Allocations		-	0.8				0.8
	Adjusted OMA including							
3	Corporate Allocations	D8, D9, D10	(3.9)	(3.8)	(3.0)	10.3	-	(0.4)
4	Depreciation	B4	0.8	10.9	0.6	0.6		12.9
5	Taxes	B3		0.2	0.8			1.0
6	Miscellaneous revenues	A-8		(6.9)		(13.0)	-	(19.9)
7			(3.1)	0.4	(1.6)	(2.1)	-	(6.4)

#### FISCAL 2004

		Reference	Engineering	Field Services	MMBU	Powertech	Other <sup>3</sup>	Total
8	OMA expenses		(8.0)	(19.8)	(1.2)	13.2		(15.8)
9	Corporate Allocations		7.7	15.0			2.3	25.0
	Adjusted OMA including							
10	Corporate Allocations	D8, D9, D10	(0.3)	(4.8)	(1.2)	13.2	2.3	9.2
11	Depreciation	B4	0.3	11.0	0.5	0.5		12.3
12	Taxes	B3		0.2	0.8			1.0
13	Miscellaneous revenues	A-8		(6.9)		(14.7)		(21.6)
14			-	(0.5)	0.1	(1.0)	2.3	0.9

#### FISCAL 2005

		Reference	Engineering <sup>4</sup>	Field Services <sup>4</sup>	MMBU	Powertech	Other <sup>3</sup>	Total
15	OMA expenses		(8.8)	(22.6)	0.6	13.1		(17.7)
16	Corporate Allocations		8.2	15.0			2.3	25.5
	Adjusted OMA including							
17	Corporate Allocations	D8, D9, D10	(0.6)	(7.6)	0.6	13.1	2.3	7.8
18	Depreciation	B4	0.3	12.5	0.7	0.7		14.2
19	Taxes	B3		0.2	0.9			1.1
20	Miscellaneous revenues	A-8		(6.6)		(15.0)		(21.6)
21			(0.3)	(1.5)	2.2	(1.2)	2.3	1.5

#### FISCAL 2006

		Reference	Engineering <sup>4</sup>	Field Services <sup>4</sup>	MMBU	Powertech	Other <sup>3</sup>	Total
22	OMA expenses		(8.8)	(23.6)	0.6	13.6		(18.2)
23	Corporate Allocations		8.2	15.0			2.3	25.5
	Adjusted OMA including							
24	Corporate Allocations	D8, D9, D10	(0.6)	(8.6)	0.6	13.6	2.3	7.3
25	Depreciation	B4	0.3	13.3	0.7	0.7		15.0
26	Taxes	B3		0.1	0.9			1.0
27	Miscellaneous revenues	A-8		(6.7)		(15.8)		(22.5)
28			(0.3)	(1.9)	2.2	(1.5)	2.3	0.8

#### 29 Notes:

- 30 1. ABS costs are not included in this table and appear under OMA costs in each functional area.
- 31 2. Powertech information is from Chapter 9 Section 6.
- 32 3. Relates to allocation of corporate costs to Powerex. See Schedule E1.
- 33 4. Due to the decrease in depreciation as explained in Section 3.7, page 2A-10 of the June 2004 Update, Engineering and Field Services show an over recovery of costs for the test year. The Engineering and Field Services charges to the functions have not been adjusted as the over recovery is insignificant and there is no impact on the consolidated revenue requirement.

37 Shaded amounts indicate changes from the Revised Evidentiary Update.

## SCHEDULE D1-1 (Update of June 2004)

### Resource Usage - Generation (Heritage Contract) (\$ millions)

Line	F2003	F2004	F2005	F2006
	Actual	Actual	Forecast	Forecast
Operating, Maintenance, and Administration Expenses by Resource				
	Labour			
1	38.8	38.9	43.5	44.7
2	21.7	25.4	24.5	24.1
3	9.0	7.1	6.7	6.7
	Materials			
4	4.7	10.7	6.5	6.6
5	7.7	7.7	11.2	11.2
6	4.6	5.7	3.9	3.9
7	2.4	2.3	1.0	1.0
	Internal Services			
8	11.1	16.7	16.7	16.4
9	25.0	46.5	21.3	21.2
10	1.0	1.1	0.8	0.8
11	0.2	0.4	0.2	0.1
12	27.9	35.7	41.5	41.9
13	(4.7)	(7.8)	(8.0)	(7.9)
	Less: Recoveries			
14	(0.5)	(4.4)	(2.8)	(2.8)
15	(1.5)	(1.9)	(0.1)	
16	<u>147.4</u>	<u>184.1</u>	<u>166.9</u>	<u>167.9</u>
Operating, Maintenance, and Administration Expenses by Category				
17	72.6	95.5	75.8	77.8
18	53.6	67.0	60.5	58.9
19	27.9	35.7	41.5	41.9
20	(4.7)	(7.8)	(8.0)	(7.9)
21	(2.0)	(6.3)	(2.9)	(2.8)
22	<u>147.4</u>	<u>184.1</u>	<u>166.9</u>	<u>167.9</u>
Capital Additions 3				
23	114.9	108.2	114.4	137.4
24	134.4	23.5	71.4	204.1
25	-	-	-	-
26	<u>249.3</u>	<u>131.7</u>	<u>185.8</u>	<u>341.5</u>
27	(5.0)	-	-	-
28	<u>244.3</u>	<u>131.7</u>	<u>185.8</u>	<u>341.5</u>

29 Notes:

- 30 1. Internal charges from the Shared Service organization that was outsourced to ABS in F2004 have been classified as ABS costs for F2003.  
31 2. F2004 includes a valuation provision of \$22 million relating to VIGP/GSX.  
32 3. Includes GSX/VIGP (non-heritage assets) \$57.7 million in 2005 and \$192.6 million in 2006.

33 Shaded amounts indicate changes from the Revised Evidentiary Update.

**SCHEDULE D1-2 (Update of June 2004)**

		F2003	F2004	F2005	F2006	
		Actual	Actual	Forecast	Forecast	Reference
1	<b>Domestic Cost of Energy - Generation (Heritage Contract)</b>					
2	<b>For the Years Ended March 31</b>					
3	<b>(\$ millions)</b>					
4						
5						
6						
7						
8						
9	Domestic Cost of Energy - Generation					
10	Water Rentals	258.2	246.2	252.9	279.2	A-9
11	Market electricity purchases (Note 1)	104.4	299.9	343.0	222.3	A-9
12	Natural gas for thermal generation					
13	Burrard	17.4	21.8	15.2	15.5	A-9
14	Fort Nelson	10.7	10.9	13.0	12.0	A-9
	Prince Rupert	0.1	-			A-9
15	Other					
16	System Operations Fund	(3.4)	(3.7)	(3.5)	-	A-9
17	Compensation and Mitigation Costs	6.8	7.0	7.2	7.3	A-9
18		<u>394.2</u>	<u>582.1</u>	<u>627.8</u>	<u>536.3</u>	
19						
20						
21	Domestic Transmission-US portion	4.9	3.9	3.6	3.5	
22	Domestic Transmission-CDN portion	-	11.7	11.8	11.8	
23		<u>4.9</u>	<u>15.6</u>	<u>15.4</u>	<u>15.3</u>	A-9
24	<b>Total Domestic Cost of Energy - Generation</b>	<u>399.1</u>	<u>597.7</u>	<u>643.2</u>	<u>551.6</u>	
25						
26						
27						
28	<b>Reconciliation of Domestic Cost of Energy - Generation</b>					
29	<b>to the cost of energy component of the Heritage Payment Obligation</b>					
30	Domestic Cost of Energy - Generation (Heritage Contract)	399.1	597.7	643.2	551.6	
31	Displaced Hydro (Note 2)	5.4	(0.2)	(7.1)	(7.6)	
33	Electricity purchases - Powerex (Note 3)	(50.0)	(30.0)			
34	Cost of energy component					
35	of Heritage Payment Obligation	<u>\$354.5</u>	<u>\$567.5</u>	<u>\$636.1</u>	<u>\$544.0</u>	
36						
37	Notes:					
38	1. Includes electricity purchases from Powerex. See Note 3.					
39	2. Displaced Hydro relates to water rentals associated with trade income.					
40	3. This relates to energy purchases made by Powerex for future trade. This energy is sold to BC Hydro					
41	when it enters the system. BC Hydro records a sale to Powerex when the energy is returned. These					
42	are part of the Generation function but are not included in the Heritage Payment Obligation.					
43						
44	This schedule corresponds to Schedule D1-2 on page 2-80 of the Application. As in the Application,					
45	the costs shown on the Domestic Cost of Energy Schedule A-9, relating to IPP and long-term					
46	purchase commitments, net purchases from Powerex, non-integrated energy, gas transportation					
47	and congestion management are not Heritage energy. The remainder of the energy costs shown					
	on Schedule A-9 relate to Heritage energy and tie into the schedule above.					
48	Shaded amounts indicate changes from the Revised Evidentiary Update.					

## SCHEDULE D1-3 (Update of June 2004)

		F2003	F2004	F2005	F2006	Reference
		Actual	Actual	Forecast	Forecast	
1	<b>Forecast Heritage Payment Obligation</b>					
2	<b>For the Years Ended March 31</b>					
3	<b>(\$ millions)</b>					
4						
5						
6						
7						
8						
9	Cost Components of Heritage Payment Obligation					
10	Cost of Energy component of Heritage Payment Obligation	\$ 354.5	\$ 567.5	\$ 636.1	\$ 544.0	D1-2
11	Operating Costs (Note 1)	147.4	162.1	166.9	167.9	
12	Depreciation and Amortization (Note 2)	110.7	118.3	129.0	124.9	
13	Taxes and Grants	29.0	28.2	28.6	29.0	
14	Finance Charges	213.0	197.0	190.5	201.0	
15	GRTA Expenses	37.0	43.3	43.3	43.3	
16	Gross Heritage Payment Obligation	891.6	1,116.4	1,194.4	1,110.1	
17	Less Other Revenues					
18	Skagit Valley Treaty	21.9	18.0	18.9	19.4	
19	Ancillary Services and Other Miscellaneous Revenue	5.3	5.4	7.3	8.4	
20	Total Other Revenues	27.2	23.4	26.2	27.8	
21	Net Costs	864.4	1,093.0	1,168.2	1,082.3	
22	Add: Return on Equity	195.0	183.4	193.3	194.8	
23	Forecast Heritage Payment Obligation	\$ 1,059.4	\$ 1,276.4	\$ 1,361.5	\$ 1,277.1	
24	Note 1:					
25	Reconciliation of Generation Operating costs to Heritage Contract Operating costs for F2004.					
26	Generation operating costs			184.1		B2
27	GSX/VIGP valuation provision			(22.0)		
28	Heritage contract operating costs			162.1		
29	Note 2:					
30	Reconciliation of Generation Depreciation to Heritage Contract Depreciation for F2004.					
31	Generation depreciation			216.3		B4
32	GSX/VIGP valuation provision			(98.0)		
33	Heritage contract depreciation			118.3		
34	The VIGP and GSX assets are part of the Generation function but are not part of the Heritage assets.					
35	Shaded amounts indicate changes from the Revised Evidentiary Update.					

## SCHEDULE D1-4 (Update of June 2004)

### Cost of Service - Generation (Heritage Contract) (reconciled with cost of energy component from Heritage Payment Obligation)

(\$ millions)

<u>Line</u>	<u>Reference</u>	<u>F2003</u> Actual	<u>F2004</u> Actual	<u>F2005</u> Forecast	<u>F2006</u> Forecast
Cost of Service - Generation (Heritage Contract)					
1	Cost of Energy component of Heritage Payment Obligation	\$ 354.5	\$ 567.5	\$ 636.1	\$ 544.0
2	Displaced Hydro	(5.4)	0.2	7.1	7.6
3	Electricity purchases Powerex	50.0	30.0		
4	Domestic cost of energy-Generation (Heritage Contract)	399.1	597.7	643.2	551.6
5	Generation OMA	147.4	184.1	166.9	167.9
6	GRTA charges from Transmission	37.0	43.3	43.3	43.3
7	Taxes	29.0	28.2	28.6	29.0
8	Depreciation and Amortization	110.7	216.3	129.0	124.9
9	Finance Charges	213.0	197.0	190.5	201.0
10	Allowed return on equity	195.0	183.4	193.3	194.8
11	Total Cost	1,131.2	1,450.0	1,394.8	1,312.5
12	Less: Trade Income	138.0	158.0	89.0	91.0
13	Other Utilities	21.9	18.0	18.9	19.4
14	Other miscellaneous Non-tariff revenues	5.3	5.4	7.3	8.4
15		165.2	181.4	115.2	118.8
16	Total Cost of Service - Generation	\$ 966.0	\$ 1,268.6	\$ 1,279.6	\$ 1,193.7

17 Shaded amounts indicate changes from the Revised Evidentiary Update.

## SCHEDULE D2 (Update of June 2004)

### Resource Usage - Energy Management <sup>1</sup> (\$ Millions)

Line		F2003	F2004	F2005	F2006
		Actual	Actual	Forecast	Forecast
<b>Operating Maintenance and Administration Expenses by Resources</b>					
	Labour				
1	Direct	2.3	4.2	4.9	5.0
2	Indirect	1.3	1.3	1.7	1.7
3	Materials	-	0.1	0.1	0.1
	Internal Services				
4	Engineering	0.7	1.4	0.1	0.1
5	Field Services	-	(0.1)	0.1	0.1
6	BC Hydro Corporate Direct Charges	0.5	1.6	0.3	0.3
7	Other BCH Billings	0.4	0.4	0.2	0.2
	External Services				
8	ABS	0.5	1.5	1.5	1.5
9	Other	1.4	4.4	3.4	1.6
10	Buildings & Equipment	0.1	0.1	0.1	0.1
11	Vehicles	-	-	-	-
12	Corporate Allocation	0.3	0.3	0.5	0.4
13	Less: Capitalized Overhead	-	-	-	-
	Less: Recoveries				
14	Internal	-	-	(0.1)	(0.1)
15	External	(0.2)	(0.9)	-	-
16	Total OMA Expenses	7.3	14.3	12.8	11.0
<b>Operating Maintenance and Administration Expenses by Category</b>					
17	Direct	4.0	9.9	8.7	6.9
18	Support	3.2	5.0	3.7	3.8
19	Corporate Allocations	0.3	0.3	0.5	0.4
20	Less: Capitalized Overhead	-	-	-	-
21	Less: Recoveries	(0.2)	(0.9)	(0.1)	(0.1)
22	Total OMA Expenses	7.3	14.3	12.8	11.0
<b>Capital Additions</b>					
23	Sustaining	2.8	0.4	0.3	1.4
24	Growth	1.1	0.3	-	-
25	Deferred Capital	0.2	-	-	-
26	Total Capital Gross of CIA	4.1	0.7	0.3	1.4
27	Sustaining CIA	-	-	-	-
28	Growth CIA	-	-	-	-
29	Total CIA	-	-	-	-
30	Total Net Capital	4.1	0.7	0.3	1.4

31 Shaded amounts indicate changes from the Revised Evidentiary Update.

## SCHEDULE D3 (Update of June 2004)

### Resource Usage - Powersmart<sup>1</sup> (\$ Millions)

Line		F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast
<b>Operating Maintenance and Administration Expenses by Resources</b>					
	Labour				
1	Direct	2.2	3.0	2.0	2.1
2	Indirect	1.3	0.7	1.4	1.4
3	Materials	-	0.3	0.1	0.1
	Internal Services				
4	Engineering	-	0.2	0.2	0.2
5	Field Services	-	2.1	2.0	2.0
6	BC Hydro Corporate Direct Charges	(0.5)	0.4	0.3	0.3
7	Other BCH Billings	1.0	1.6	1.5	1.5
	External Services				
8	ABS	0.9	3.0	3.3	3.1
9	Other	0.6	0.7	0.4	0.4
10	Buildings & Equipment	-	-	-	0.1
11	Vehicles	0.1	-	-	-
12	Corporate Allocation	7.3	8.9	11.8	11.5
13	Less: Capitalized Overhead	-	-	-	-
	Less: Recoveries				
14	Internal	-	-	(0.9)	(0.9)
15	External	(0.1)	(0.7)	-	-
16	Total OMA Expenses	12.8	20.2	22.1	21.8
<b>Operating Maintenance and Administration Expenses by Category</b>					
17	Direct	2.8	5.9	4.5	4.6
18	Support	2.8	6.1	6.7	6.6
19	Corporate Allocations	7.3	8.9	11.8	11.5
20	Less: Capitalized Overhead	-	-	-	-
21	Less: Recoveries	(0.1)	(0.7)	(0.9)	(0.9)
22	Total OMA Expenses	12.8	20.2	22.1	21.8
<b>Capital Additions</b>					
23	Sustaining	1.5	1.5	-	0.8
24	Growth	0.0	6.2	1.5	1.6
25	Deferred Capital	44.5	62.6	105.0	93.8
26	Total Capital Gross of CIA	46.0	70.3	106.5	96.1
27	Sustaining CIA	-	-	-	-
28	Growth CIA	-	-	-	-
29	Total CIA	-	-	-	-
30	Total Net Capital	46.0	70.3	106.5	96.1
31	Shaded amounts indicate changes from the Revised Evidentiary Update.				

## SCHEDULE D4 Resource Usage (Update of June 2004)

### Resource Usage - Transmission (\$ millions)

Line		F2003 Actual	F2004 Actual	F2005 Forecast	F2006 Forecast	
					BC Hydro	BCTC
Operating, Maintenance, and Administration Expenses by Resource						
	Labour					
1	Direct	17.5	23.4	28.1		28.6
2	Indirect	7.4	7.2	11.2		11.4
3	Materials	8.2	4.7	4.4		4.4
BC Hydro Services						
4	Engineering	12.7	17.4	14.2		14.2
5	Field Services	63.0	75.0	69.2		69.2
6	BC Hydro Corporate Direct Charges	3.0	3.2	5.7	4.8	0.9
7	Other BC Hydro Billings	5.9	7.0	3.8		4.9
External Services						
8	ABS*	7.9	12.8	10.0		10.6
9	Other	16.7	18.3	29.5		28.0
10	Buildings & Equipment	1.6	2.0	2.9		2.8
11	Vehicles	0.1	-	0.1		0.1
12	Corporate Allocation	28.0	22.7	14.1	14.3	
13	Less: Capitalized Overhead	(5.2)	(5.1)	(5.2)		(5.2)
Less: Recoveries						
14	Internal	(6.8)	(6.4)	(6.3)	(1.3)	(3.7)
15	External	(1.8)	(0.1)	(0.1)		(0.1)
16	Total OMA Expenses	<u>158.2</u>	<u>182.1</u>	<u>181.6</u>	<u>17.8</u>	<u>166.1</u>
Operating, Maintenance, and Administration Expenses by Category						
17	Direct	123.7	145.7	154.0	4.8	151.1
18	Support	20.3	25.3	25.1		24.0
19	Corporate Allocations	28.0	22.7	14.1	14.3	
20	Less: Capitalized Overhead	(5.2)	(5.1)	(5.2)		(5.2)
21	Less: Recoveries	(8.6)	(6.5)	(6.4)	(1.3)	(3.8)
22	Total OMA Expenses	<u>158.2</u>	<u>182.1</u>	<u>181.6</u>	<u>17.8</u>	<u>166.1</u>
Capital Expenditures						
23	Sustaining	99.1	138.8	155.0	104.0	43.0
24	Growth	68.0	47.2	89.0	162.0	
25	CIA	(12.2)	(9.7)	(8.0)	(9.0)	
26	Total Capital Expenditures	<u>154.9</u>	<u>176.3</u>	<u>236.0</u>	<u>257.0</u>	<u>43.0</u>

27 \* Internal charges from the Shared Service organization that was outsourced to ABS in fiscal 2004 have been classified as ABS costs  
28 for fiscal 2003 even though the outsourcing did not occur until fiscal 2004.

29 F2004 includes \$8.3 million relating to restructuring costs.

30 Shaded amounts indicate changes from the Revised Evidentiary Update.

## SCHEDULE D5 (Update of June 2004)

### Resource Usage - Electricity Distribution and Non-Integrated Areas (\$ Millions)

Line		F2003	F2004	F2005	F2006
		Actual	Actual	Forecast	Forecast
<b>Operating Maintenance and Administration Expenses by Resources</b>					
	Labour				
1	Direct	22.2	27.1	26.4	27.0
2	Indirect	4.7	4.2	5.2	4.8
3	Materials	3.8	2.9	4.3	4.5
	Internal Services				
4	Engineering	4.2	8.2	7.2	7.6
5	Field Services	64.2	81.1	81.5	81.1
6	BC Hydro Corporate Direct Charges	5.9	3.3	3.9	3.9
7	Other BCH Billings	4.2	5.0	3.7	3.7
	External Services				
8	ABS	7.7	14.8	14.9	14.7
9	Other	8.2	8.0	7.0	7.4
10	Buildings & Equipment	2.1	2.5	1.9	2.1
11	Vehicles	1.1	0.7	0.9	0.9
12	Corporate Allocation	15.3	18.7	25.0	24.4
13	Less: Capitalized Overhead	(35.0)	(39.2)	(42.0)	(42.7)
	Less: Recoveries				
14	Internal	(0.2)	(1.9)	(1.0)	(0.5)
15	External	(6.4)	(7.4)	(6.5)	(6.9)
16	Total OMA Expenses	102.0	128.0	132.4	132.0
<b>Operating Maintenance and Administration Expenses by Category</b>					
17	Direct	105.7	129.6	130.6	131.9
18	Support	22.6	28.3	26.3	25.8
19	Corporate Allocations	15.3	18.7	25.0	24.4
20	Less: Capitalized Overhead	(35.0)	(39.2)	(42.0)	(42.7)
21	Less: Recoveries	(6.6)	(9.4)	(7.5)	(7.4)
	Total OMA Expenses	102.0	128.0	132.4	132.0
<b>Capital Additions</b>					
23	Sustaining	60.7	78.7	86.1	88.9
24	Growth	119.8	119.6	123.4	130.9
25	Deferred Capital	0.1	-	-	-
26	Total Capital Gross of CIA	180.6	198.3	209.5	219.8
27	Sustaining CIA	(8.6)	(1.8)	(4.2)	(3.8)
28	Growth CIA	(35.9)	(44.2)	(38.3)	(41.0)
29	Total CIA	(44.5)	(46.0)	(42.6)	(44.8)
30	Total Net Capital	136.1	152.3	167.0	175.0

31 Shaded amounts indicate changes from the Revised Evidentiary Update.

## SCHEDULE D6 (Update of June 2004)

### Resource Usage - Customer Care (\$ Millions)

Line		F2003	F2004	F2005	F2006
		Actual	Actual	Forecast	Forecast
<b>Operating Maintenance and Administration Expenses by Resources</b>					
	Labour				
1	Direct	2.5	2.9	3.2	3.3
2	Indirect	1.3	1.3	1.3	1.3
3	Materials	0.3	0.6	0.3	0.4
	Internal Services				
4	Engineering	-	0.2	0.2	0.2
5	Field Services	0.1	1.4	1.4	1.4
6	BC Hydro Corporate Direct Charges	1.7	0.6	0.6	0.6
7	Other BCH Billings	1.0	0.8	0.5	0.5
	External Services				
8	ABS	80.8	93.4	91.7	87.3
9	Other	13.0	16.6	9.3	9.3
10	Buildings & Equipment	2.2	0.1	0.1	0.1
11	Vehicles	0.1	-	-	-
12	Corporate Allocation	5.0	6.1	8.2	8.0
13	Less: Capitalized Overhead	-	-	-	-
	Less: Recoveries				
14	Internal	(0.8)	(1.4)	(1.7)	(1.7)
15	External	(12.4)	(4.9)	(5.4)	(5.4)
16	Total OMA Expenses	94.8	117.7	109.7	105.3
<b>Operating Maintenance and Administration Expenses by Category</b>					
17	Direct	92.2	106.8	103.9	99.8
18	Support	10.8	11.1	4.7	4.6
19	Corporate Allocations	5.0	6.1	8.2	8.0
20	Less: Capitalized Overhead	-	-	-	-
21	Less: Recoveries	(13.2)	(6.3)	(7.1)	(7.1)
	Total OMA Expenses	94.8	117.7	109.7	105.3
<b>Capital Additions</b>					
23	Sustaining	28.6	19.2	3.8	5.7
24	Growth	-	-	-	-
25	Deferred Capital	-	-	-	-
26	Total Capital Gross of CIA	28.6	19.2	3.8	5.7
27	Sustaining CIA	-	-	-	-
28	Growth CIA	-	-	-	-
29	Total CIA	-	-	-	-
30	Total Net Capital	28.6	19.2	3.8	5.7

31 Shaded amounts indicate changes from the Revised Evidentiary Update.

## SCHEDULE D7 (Update of June 2004)

### Resource Usage Corporate

(\$ millions)

<u>Line</u>		<u>F2003</u>	<u>F2004</u>	<u>F2005</u>	<u>F2006</u>
		Actual	Actual	Forecast	Forecast
	Operating, Maintenance, and Administration Expenses by Resource				
	Labour				
1	Direct	37.2	30.3	32.7	33.2
2	Non-current pension costs - total BCH	30.7	49.3	48.0	47.0
3	Materials	1.0	1.0	0.9	0.9
	Internal Services				
4	Engineering	0.3	1.0	0.1	0.1
5	Field Services including Fleet	0.8	1.9	1.8	1.8
6	Properties/Phones/Rent/Furniture	2.2	8.0	8.2	8.2
7	Inter LOB, Legal, BCH SAC	2.5	11.8	10.6	10.8
	External Services				
8	ABS	12.7	17.7	17.0	16.4
9	Other	30.1	57.6	37.5	33.0
10	Buildings & Equipment	3.4	2.7	3.0	3.5
11	Vehicles	0.0	0.0	0.0	0.0
12	Accruals, Provisions, Adjustments	(3.5)	(16.7)	6.0	6.3
13	Plus: Westech net OMA	(0.9)	3.2	3.0	3.0
14	Less: Capitalized Overhead	0.0	0.0	0.0	0.0
15	Less: External recoveries	(0.8)	(13.7)	(2.9)	(2.9)
16	Less: Internal Recoveries	(31.8)	(71.2)	(51.1)	(49.7)
17	Less: Shared Services net	(15.5)			
18	Less: BCH SAC internal recoveries		(36.4)	(44.4)	(41.8)
19	Total OMA Expenses	<u>68.4</u>	<u>46.5</u>	<u>70.4</u>	<u>69.8</u>
20	Corporate Resources Allocated	<u>(84.6)</u>	<u>(117.5)</u>	<u>(126.6)</u>	<u>(126.0)</u>
21	Net OMA Expenses	<u>(16.2)</u>	<u>(71.0)</u>	<u>(56.2)</u>	<u>(56.2)</u>
	Capital Additions (including BCH SAC, Powertech)				
22	Sustaining - in Corporate	43.5	8.7	18.9	28.8
23	Growth	0.0	0.0	0.0	0.0
24	Deferred Capital	0.2	0.0	0.0	0.0
25	Total Capital Gross of CIA	<u>43.7</u>	<u>8.7</u>	<u>18.9</u>	<u>28.8</u>
26	Sustaining CIA	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>
27	Total Net Capital	<u>43.7</u>	<u>8.7</u>	<u>18.9</u>	<u>28.8</u>

28 Shaded amounts indicate changes from the Revised Evidentiary Update.

## SCHEDULE D8 (Update of June 2004)

### Resource Usage - Engineering

(\$ millions)

Line		F2003	F2004	F2005	F2006
		Actual	Actual	Forecast	Forecast
	Operating, Maintenance, and Administration Expenses by Resource				
	Labour				
1	Direct	46.1	48.0	48.4	50.0
2	Indirect	12.3	10.4	10.3	10.7
3	Materials	1.2	1.1	0.7	0.6
	Internal Services				
4	Field Services	0.7	0.3	0.3	0.3
5	Corporate Direct Charges	1.1	2.8	2.0	2.0
	Other Internal Billings				
	External Services				
6	ABS 1	10.0	12.9	12.3	11.9
7	Other 2	3.3	8.8	11.5	11.1
8	Buildings & Equipment	0.8	1.1	1.4	1.2
9	Vehicles	0.2	0.2	0.1	0.1
10	Corporate Allocation	-	7.7	8.2	8.2
11	Less: Capitalized Overhead				
	Less: Recoveries				
12	Internal	(75.9)	(90.5)	(94.1)	(95.0)
13	External	(3.7)	(3.1)	(1.7)	(1.7)
14	Total OMA Expenses	<u>(3.9)</u>	<u>(0.3)</u>	<u>(0.6)</u>	<u>(0.6)</u>
	Operating, Maintenance, and Administration Expenses by Category				
15	Direct	49.4	57.7	61.3	62.6
16	Support	26.3	27.9	25.7	25.3
17	Corporate Allocations		7.7	8.2	8.2
18	Less: Capitalized Overhead				
19	Less: Recoveries	(79.6)	(93.6)	(95.8)	(96.7)
20	Total OMA Expenses	<u>(3.9)</u>	<u>(0.3)</u>	<u>(0.6)</u>	<u>(0.6)</u>
	Capital Additions				
21	Sustaining	1.8	1.1	1.0	1.0
22	Growth				
23	Deferred Capital				
24	Total Capital Additions	<u>1.8</u>	<u>1.1</u>	<u>1.0</u>	<u>1.0</u>

25 Notes:

- 26 (1) For comparative purposes, F2003 actual have been reclassified to reflect the creation of ABS.
- 27 (2) F2003 excludes costs for Contract Hires and Consultants
- 28 (3) F2004 to F2006 estimate includes Non-Service Pension Costs of \$8.2M in the Recoveries
- 29 These amounts will be allocated through a surcharge via Journal Voucher
- 30 directly to the functions.

## SCHEDULE D9 (Update of June 2004)

### Resource Usage - Field Services

(\$ millions)

<u>Line</u>	<u>F2003</u>	<u>F2004</u>	<u>F2005</u>	<u>F2006</u>	
	Actual	Actual	Forecast	Forecast	
Operating, Maintenance, and Administration Expenses by Resource					
	Labour				
1	Direct	\$93.5	\$102.8	\$94.7	\$ 96.3
2	Indirect	46.7	43.0	44.0	44.6
3	Materials	15.5	16.0	15.0	14.5
	Internal Services				
4	Engineering	0.2	0.7	0.5	0.5
5	Corporate Direct Charges	1.0	4.3	3.4	3.5
6	Other Internal Billings	-	0.9	0.4	0.4
7	External Services				
8	ABS	16.1	21.8	21.9	21.1
9	Other	76.9	94.0	96.9	97.8
10	Buildings & Equipment	3.1	4.4	3.9	3.9
11	Vehicles	1.8	1.2	1.1	0.6
12	Corporate Allocation	0.8	15.0	15.0	15.0
13	Less: Capitalized Overhead				
	Less: Recoveries				
14	Internal	(255.6)	(296.5)	(291.8)	(295.1)
15	External	(3.8)	(12.4)	(12.6)	(11.7)
16	Total OMA Expenses	<u>(\$3.8)</u>	<u>(\$4.8)</u>	<u>(\$7.6)</u>	<u>(\$8.6)</u>
Operating, Maintenance, and Administration Expenses by Category					
17	Direct	161.7	213.8	213.1	214.7
18	Support	93.1	75.3	68.7	68.5
19	Corporate Allocations	0.8	15.0	15.0	15.0
20	Less: Capitalized Overhead				
21	Less: Recoveries				
22	Total OMA Expenses	<u>(259.4)</u>	<u>(308.9)</u>	<u>(304.4)</u>	<u>(306.8)</u>
	Capital Additions				
23	Sustaining	16.9	16.4	22.5	21.4
24	Growth				
25	Deferred Capital				
26	Total Capital Additions	<u>\$16.9</u>	<u>\$16.4</u>	<u>\$22.5</u>	<u>\$21.4</u>

27 Note: F2004 Actual Internal Recoveries includes CBU/SOBU depreciation.

28 Shaded amounts indicate changes from the Revised Evidentiary Update.

## SCHEDULE D10 (Update of June 2004)

### Resource Usage - MMBU

(\$ millions)

<u>Line</u>		<u>F2003</u> Actual	<u>F2004</u> Actual	<u>F2005</u> Forecast	<u>F2006</u> Forecast
<b>Operating Maintenance and Administration Expenses by Resources</b>					
	Labour				
1	Direct	7.2	7.5	7.8	8.0
2	Indirect	0.2	-	-	-
3	Materials	0.4	1.4	0.7	0.7
	Internal Services				
4	Engineering	1.1	1.3	1.2	1.2
5	Field Services	2.8	2.9	1.2	1.2
6	BC Hydro Corporate Direct Charges	0.3	0.3	0.2	0.2
7	Other BCH Billings	1.8	2.3	2.1	2.1
	External Services				
8	ABS	2.0	3.1	5.9	5.9
9	Other	3.0	6.1	6.5	6.3
10	Buildings & Equipment	0.2	0.1	0.1	0.1
11	Vehicles	1.3	1.3	1.3	1.3
12	Corporate Allocation	-	-	-	-
13	Less: Capitalized Overhead	-	-	-	-
	Less: Recoveries				
14	Internal	(22.5)	(25.4)	(25.4)	(25.4)
15	External	(0.8)	(2.1)	(1.0)	(1.0)
16	Total OMA Expenses	<u>(3.0)</u>	<u>(1.2)</u>	<u>0.6</u>	<u>0.6</u>
<b>Operating Maintenance and Administration Expenses by Category</b>					
17	Direct	17.7	23.5	23.5	23.6
18	Support	2.6	2.8	3.5	3.4
19	Corporate Allocations	-	-	-	-
20	Less: Capitalized Overhead	-	-	-	-
21	Less: Recoveries	(23.3)	(27.5)	(26.4)	(26.4)
22	Total OMA Expenses	<u>(3.0)</u>	<u>(1.2)</u>	<u>0.6</u>	<u>0.6</u>
<b>Capital Additions</b>					
23	Sustaining	-	1.0	0.8	0.5
24	Growth	0.0	-	-	-
25	Deferred Capital	-	0.1	-	-
26	Total Capital Gross of CIA	<u>0.0</u>	<u>1.1</u>	<u>0.8</u>	<u>0.5</u>
27	Sustaining CIA	-	-	-	-
28	Growth CIA	-	-	-	-
29	Total CIA	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
30	Total Net Capital	<u>0.0</u>	<u>1.1</u>	<u>0.8</u>	<u>0.5</u>