
Revenue Requirement Application
2004/05 and 2005/06



Volume 1

Chapter 2.

Consolidated Revenue Requirements
and Financial Schedules

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1 **1 Introduction**

2 This chapter of the application provides:

- 3 • BC Hydro's forecasts of revenues and costs in the test periods, both with and without the
4 applied-for rate increases, on a consolidated basis (section 2);
- 5 • summary explanations of the variances between consolidated cost and revenue items
6 from year to year (section 3);
- 7 • a description of the deferral accounts BC Hydro seeks approval for in this application
8 (section 4);
- 9 • reconciliations between the consolidated costs and revenue forecasts as described in
10 sections 2 and 3, and the forecasts of costs and revenues of the lines of business and
11 service organizations described in chapters 3 to 9 (sections 5 and 6); and
- 12 • a description of the methodology employed by BC Hydro to allocate corporate costs to
13 the lines of business, service organizations, and subsidiaries (section 7).

1 **2 Pro Forma Consolidated Statements**

2 Table 2-1 is a summarized pro forma statement of operations of BC Hydro assuming
 3 electricity rates remain unchanged.

4 **Table 2-1. Pro forma Statement of Operations, No Rate Increase**

(\$ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Equity	\$2,700	\$2,726	\$3,042	\$3,120
Domestic				
Revenues	2,475	2,516	2,525	2,539
Inter-segment revenues	6	76	124	91
Expenses	(2,267)	(2,537)	(2,478)	(2,498)
	214	55	171	132
Trade Income	138	91	80	89
Transfer from RSA <i>(Note 1)</i>	66	21		
Net Income	\$418	\$167	\$251	\$221
Rate of return on equity	15.47%	6.13%	8.25%	7.08%
Allowed rate of return on equity	15.47%	14.33%	13.91%	13.91%
Required rate increase (%)	N/A	N/A	7.23%	2.00%

5 Notes:

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

7 BC Hydro's allowed rate of return on equity for the test periods F2005 and F2006 is
 8 calculated pursuant to HSD #2 in chapter 10 of this application. As can be seen from
 9 Table 2-1, BC Hydro expects to significantly under-earn in each of F2004 through F2006
 10 under its current rates. The revenue shortfalls for F2005 and F2006 are forecast to be \$177
 11 million and \$231 million respectively.

12 Table 2-2 shows the detailed pro forma consolidated statement of operations with tariff rates
 13 unchanged and Table 2-3 shows the same statement with rates increased by the proposed
 14 rate increases of 7.23% and 2.00%. As can be noted, the impact of the rate increases
 15 would be to increase domestic revenues and decrease finance charges. Energy costs and
 16 taxes would also be increased as the water rental rate and some grants in lieu of taxes are
 17 indexed to electricity rates. This indexing is discussed further in sections 3.4.2. and 3.8.2.

1 **Table 2-2. Pro forma Consolidated Statement of Operations with Rates Unchanged**

For the Years Ended March 31 (\$ millions)	A F2003 Actual	B F2004 Forecast	C F2005 Plan	D F2006 Plan
REVENUES				
Domestic				
Residential	\$ 923	\$ 959	\$ 971	\$ 985
Light industrial and commercial	893	901	904	914
Large industrial	516	503	502	496
Other energy sales	88	86	87	89
Miscellaneous	55	67	61	55
	2,475	2,516	2,525	2,539
Intersegment revenues	6	76	124	91
	2,481	2,592	2,649	2,630
EXPENSES				
Domestic cost of energy	708	944	819	788
BCTC wholesale transmission service	-	-	-	61
BCTC asset management fee	-	-	-	117
Operations expense	143	169	171	129
Maintenance expense	196	228	243	140
Administration expense	167	161	163	139
Depreciation and amortization	414	428	470	470
Taxes	145	142	145	147
	1,773	2,072	2,011	1,991
INCOME BEFORE FINANCE CHARGES, RESTRUCTURING COSTS, TRANSFER FROM RSA AND TRADE INCOME	708	520	638	639
Finance charges	457	454	467	507
INCOME BEFORE RESTRUCTURING COSTS, TRANSFER FROM RSA AND TRADE INCOME	251	66	171	132
Restructuring Costs	37	11	-	-
INCOME BEFORE TRANSFER FROM RSA AND TRADE INCOME	214	55	171	132
Transfer from RSA	66	21	-	-
DOMESTIC NET INCOME	\$ 280	\$ 76	\$ 171	\$ 132
TRADE INCOME	138	91	80	89
TOTAL NET INCOME	\$ 418	\$ 167	\$ 251	\$ 221
PAYMENT TO THE PROVINCE	\$ 338	\$ 128	\$ 195	\$ 156
ACTUAL RETURN ON EQUITY	15.47%	6.13%	8.25%	7.08%
ALLOWED RETURN ON EQUITY	15.47%	14.33%	13.91%	13.91%
BALANCE IN RSA	\$ 21	\$ -	\$ -	\$ -
RATE INCREASE	0.00%	0.00%	0.00%	0.00%
CUMULATIVE RATE INCREASE	0.00%	0.00%	0.00%	0.00%

1 **Table 2-3. Pro forma Consolidated Statement of Operations with Proposed Rate**
 2 **Increases**

For the Years Ended March 31 (\$ millions)	A F2003 Actual	B F2004 Forecast	C F2005 Plan	D F2006 Plan
REVENUES				
Domestic				
Residential	\$ 923	\$ 959	\$ 1,041	\$ 1,077
Light industrial and commercial	893	901	970	1,000
Large industrial	516	503	539	543
Other energy sales	88	86	91	95
Miscellaneous	55	67	61	55
	<u>2,475</u>	<u>2,516</u>	<u>2,702</u>	<u>2,770</u>
Intersegment revenues	6	76	124	91
	<u>2,481</u>	<u>2,592</u>	<u>2,826</u>	<u>2,861</u>
EXPENSES				
Domestic cost of energy	708	944	824	808
BCTC wholesale transmission service	-	-	-	61
BCTC asset management fee	-	-	-	117
Operations expense	143	169	171	129
Maintenance expense	196	228	243	140
Administration expense	167	161	163	139
Depreciation and amortization	414	428	470	470
Taxes	145	142	145	147
	<u>1,773</u>	<u>2,072</u>	<u>2,016</u>	<u>2,011</u>
INCOME BEFORE FINANCE CHARGES, RESTRUCTURING COSTS, TRANSFER FROM RSA AND TRADE INCOME	708	520	810	850
Finance charges	457	454	463	497
INCOME BEFORE RESTRUCTURING COSTS, TRANSFER FROM RSA AND TRADE INCOME	251	66	347	353
Restructuring Costs	37	11	-	-
INCOME BEFORE TRANSFER FROM RSA AND TRADE INCOME	214	55	347	353
Transfer from RSA	66	21	-	-
DOMESTIC NET INCOME	<u>\$ 280</u>	<u>\$ 76</u>	<u>\$ 347</u>	<u>\$ 353</u>
TRADE INCOME	<u>138</u>	<u>91</u>	<u>80</u>	<u>89</u>
TOTAL NET INCOME	<u>\$ 418</u>	<u>\$ 167</u>	<u>\$ 427</u>	<u>\$ 442</u>
PAYMENT TO THE PROVINCE	<u>\$ 338</u>	<u>\$ 128</u>	<u>\$ 344</u>	<u>\$ 344</u>
ACTUAL RETURN ON EQUITY	15.47%	6.13%	13.91%	13.91%
ALLOWED RETURN ON EQUITY	15.47%	14.33%	13.91%	13.91%
BALANCE IN RSA	<u>\$ 21</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>
RATE INCREASE	0.00%	0.00%	7.23%	2.00%
CUMULATIVE RATE INCREASE	<u>0.00%</u>	<u>0.00%</u>	<u>7.23%</u>	<u>9.37%</u>

1 **3 Discussion of Financial Forecasts**

2 **3.1 BC Hydro Equity**

3 HSD #2 defines BC Hydro’s equity, for rate-making purposes, as the following:

4 “equity” means the sum of the following amounts at the end of the fiscal year:

- 5 (a) retained earnings;
- 6 (b) deferred revenue;
- 7 (c) contributions arising from the Columbia River Treaty; and
- 8 (d) contributions in aid of construction.

9 Actual equity for F2003, and forecast equity for F2004 to F2006, is shown in Table 2-4. The
10 following table shows the components of equity in those periods.

11 **Table 2-4. Equity for Rate Making Purposes**

(\$ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Retained earnings at beginning of year	\$1,529	\$1,609	\$1,648	\$1,964
Net income	418	167	427	442
Payment to the province	(338)	(128)	(344)	(344)
Asset retirement obligation adjustment (Note 1)	-	-	233	-
Special dividend to the province for BCTC (Note 2)	-	-	-	(20)
Retained Earnings at End of Year	\$1,609	\$1,648	\$1,964	\$2,042
Deferred revenue	258	276	296	320
Contributions arising from the Columbia River Treaty	203	193	184	175
Contributions in aid of construction	609	609	625	643
Rate Stabilization Account	21	-	-	-
Equity	\$2,700	\$2,726	\$3,069	\$3,180
Allowed rate of return on equity	15.47%	14.33%	13.91%	13.91%
Allowed return on equity	\$418	\$391	\$427	\$442

12 Notes:

- 13 1. This adjustment is explained in section 3.7.3.
- 14 2. The special dividend to the province was paid in F2004. It is shown in F2006 because BCTC is
15 consolidated with BC Hydro in F2004 and F2005.

1 **3.2 Domestic Revenues**

2 Domestic revenues are the proceeds from sales of electricity to customers within the
 3 province and proceeds from sales of electricity at the border to certain customers outside of
 4 the province under treaty or long-term contracts with BC Hydro (mainly Skagit Valley Treaty
 5 commitment and Hyder, Alaska).

6 Domestic revenues have been determined using the applied-for rates and forecast sales
 7 volumes for major rate classes. Table 2-5 and Table 2-6 show breakdowns of domestic
 8 revenues and sales volumes, respectively, by those rate classes. More detailed revenue
 9 schedules are included at the end of this chapter.

10 **Table 2-5. Domestic Revenues (with applied for rate increases)**

(\$ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Residential	\$923	\$959	\$1,041	\$1,077
Light industrial and commercial	893	901	970	1,000
Large industrial	516	503	539	543
Other				
Irrigation	3	3	3	3
Street lighting	23	23	24	24
City of New Westminster	14	13	15	16
Aquila Networks Canada	26	27	29	31
Total Revenue Requirement	\$2,398	\$2,429	\$2,621	\$2,694
Other utilities (<i>Note 1</i>)	22	20	20	21
Miscellaneous	55	67	61	55
Total	\$2,475	\$2,516	\$2,702	\$2,770

11 Notes:

12 1. Other utilities under long-term contracts.

13 **Table 2-6. Domestic Sales**

(GWh)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Residential	15,024	15,654	15,836	16,063
Light industrial and commercial	16,757	16,947	17,003	17,202
Large industrial	15,179	14,801	14,734	14,601
Other				
Irrigation	84	88	89	90
Street lighting	219	218	221	224
City of New Westminster	423	401	402	403
Aquila Networks Canada	673	708	688	707
Other utilities	318	314	314	314
Total	48,677	49,131	49,287	49,604

1 Table 2-7 identifies the average rates by customer class, before and after the proposed rate
2 increases.

3 **Table 2-7. Average Rates, Before and After Proposed Increases**

Customer Class (\$ per MWh)	Current Rates	F2005	F2006
Residential	61.3	65.7	67.0
Light industrial and commercial	53.2	57.0	58.2
Large industrial	34.0	36.5	37.2

4 **3.3 Inter-Segment Revenues**

5 In accordance with HSD #2 and the definition of Trade Income within it, the pro forma
6 statements of operations presented in this application identify Trade Income as a distinct line
7 item. Trade Income is Powerex's net income, adjusted for rate-making purposes if
8 necessary to be no more than \$200 million and no less than \$0.00. It includes Powerex's
9 revenues and costs arising from transactions with BC Hydro. Inter-segment revenues reflect
10 the BC Hydro side of such transactions. For example, a sale of energy by BC Hydro to
11 Powerex is a cost item in the calculation of Trade Income. The revenue side to BC Hydro
12 from that sale is included in inter-segment revenues.

13 Table 2-8 identifies specific elements identified as Inter-segment revenues in the pro forma
14 consolidated statements of operations.

1 **Table 2-8. Inter-Segment Revenues, F2003 to F2006**

(\$ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Net sales to Powerex - Future Use <i>(Note 1)</i>	–	\$3	\$50	\$24
Point-to-point wheeling charge to Powerex <i>(Note 2)</i>	–	49	60	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>	6	10	–	–
Total Inter-segment Revenues	\$6	\$76	\$124	\$91

2 Notes:

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

16 **3.4 Domestic Cost of Energy**

17 The “domestic cost of energy” shown on the pro forma consolidated statements of
18 operations is composed of the following items:

- 19 • water rental costs;
- 20 • purchases from IPPs and other long-term purchase commitments;
- 21 • other energy purchases (short-term);
- 22 • natural gas purchases for thermal generation and re-marketing;
- 23 • transmission charges and other expenses; and
- 24 • energy costs arising from the provision of services in the non-integrated areas.

1 3.4.1 Summary

2 Table 2-9 summarizes the domestic cost of energy forecast for the test periods. More
 3 details are provided in schedule B1, which shows that the domestic cost of energy is the
 4 sum of the cost of energy component from generation (Heritage Contract) (chapter 5),
 5 energy supply less Heritage Payment Obligation (chapter 4), transmission (chapter 6), and
 6 Non-Integrated Areas (chapter 7).

7 **Table 2-9. Domestic Cost of Energy, F2003 to F2006**

	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Domestic cost of energy (\$ millions)	\$708	\$944	\$824	\$808
Change from prior year – increase (decrease)		236	(120)	(16)
Domestic sales volumes (GWh)	48,677	49,131	49,287	49,604
Domestic energy unit cost (\$/MWh)	\$14.5	\$19.2	\$16.7	\$16.3
Variance (\$ millions):				
increase (decrease) in unit cost			(123)	(21)
increase in volume			3	5
			\$(120)	\$(16)

8 3.4.2 F2005 Compared to F2004

9 Domestic cost of energy is forecast to decline in F2005 from F2004 largely due to the impact
 10 of water inflows. F2005 assumes normal inflow levels compared to the below normal levels
 11 experienced in F2004. This allows for an increase in low cost hydro generation. Hydro
 12 generation is expected to increase by approximately 1,400 GWh in F2005 over F2004
 13 levels.

14 As mentioned in section 2, the proposed rate increase will increase the water rental fees,
 15 which are indexed to BC Hydro’s electricity rates. Water rental rates increase in January of
 16 each year, following a rate increase. For example, an electricity rate increase on April 1,
 17 2004 will increase water rental rates effective January 1, 2005. Water rental charges are
 18 projected to increase in F2005 by \$5 million due to the proposed rate increase in F2005.

19 3.4.3 F2006 Compared to F2005

20 The forecast small decrease in domestic cost of energy in F2006 from F2005 is largely due
 21 to the expected decline in the average cost of market purchases under the Heritage

1 Contract. This is partly offset by the effect of the proposed rate increase on water rental
2 charges.

3 **3.5 Operations, Maintenance, and Administration Costs**

4 BC Hydro has recently initiated a change in its internal financial reporting, moving away from
5 reporting on the basis of aggregated operations, maintenance, and administration costs
6 (OMA), and instead moving to reporting those costs on a disaggregated basis. BC Hydro
7 believes this will allow a sharper focus in the budgeting and planning process, make more
8 transparent the manner in which the objectives of the organization are to be realized, and
9 enhance the ability of BC Hydro to see if objectives have been achieved. This is a very
10 recent initiative and the functional costs reported in chapters 3 to 9 have not, with some
11 exceptions, been disaggregated in this manner. Table 2-10 presents OMA consolidated
12 across BC Hydro but on a disaggregated basis. BC Hydro will be able to provide the OMA
13 disaggregation at the cost of service level by function ('C' schedules) by mid-January 2004.

14 **Table 2-10. Disaggregated OMA, F2003 to F2006**

(\$ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan <i>(Note 1)</i>
Operations expense	\$143	\$169	\$171	\$129
Maintenance expense	196	228	243	140
Administration expense	167	161	163	139
Total OMA	\$506	\$558	\$577	\$408

15 Notes:

16 1. F2006 does not include OMA for BCTC.

17 3.5.1 F2005 Increase over F2004

18 The OMA increase in plan F2005 over forecast F2004 is due in part to the following:

- 19 • Increased net maintenance costs of \$14 million to maintain existing reliability levels. The
20 increased maintenance costs are necessary due to the ageing of assets. An increase of
21 \$21 million is budgeted in F2005 but due to an unanticipated \$7 million expense incurred
22 in F2004 for system restoration and maintenance costs required as a result of forest fires
23 there is a net increase of \$14 million.
- 24 • An increase in incremental ongoing costs of \$5 million associated with the establishment
25 of corporate functions within BCTC. See discussion at chapter 6.

- 1 • Increased funding of \$7 million for strategic research and development programs. See
2 discussion at chapter 3.
- 3 • The increases are offset by a net decrease of \$6 million in information system related
4 costs.

5 3.5.2 F2006 Decrease from F2005

6 The OMA decrease in plan F2006 from plan F2005 is primarily due to the following:

- 7 • Beginning in F2006, the costs of BCTC are no longer consolidated with BC Hydro.
8 BCTC charges wheeling costs and a service fee to BC Hydro. The wheeling charge and
9 the service fee are not included in BC Hydro's F2006 OMA costs. This change results in
10 a reduction of OMA costs of \$163 million. This reduction is expected to be fully reflected
11 in increased payments to BCTC in F2006 as described in chapter 6.
- 12 • Net administrative costs reductions of \$6 million including cost savings of \$5 million
13 arising from the purchase of ABS services.

14 **3.6 Finance Charges**

15 3.6.1 Background

16 As with most utility companies, BC Hydro is financed to a large extent by debt. BC Hydro's
17 long-term debt is comprised of bonds, notes and debentures, with all debt issued with a
18 maturity of five years or longer having annual sinking fund requirements. BC Hydro also has
19 revolving borrowings obtained under agreement with the province. BC Hydro's debt is either
20 held or guaranteed by the province.

21 BC Hydro also uses derivative financial instruments, principally interest rate and foreign
22 currency swaps, options and forward rate agreements, to manage interest rate and foreign
23 exchange risks related to debt.

24 Good performance in the management of the debt portfolio is measured through
25 benchmarking against internal targets and other Government-owned and debt-guaranteed,
26 integrated electric utilities. Internal targets are designed to incorporate operational aspects
27 of BC Hydro's business as well as economic aspects, rather than the alternative where the

1 debt portfolio is managed in isolation of the underlying business. This approach to debt
2 management is a best practice in the industry.

3 Relative to other government-owned and debt-guaranteed integrated electric utilities,
4 BC Hydro is at or above average in most debt-related statistical measures. For example,
5 BC Hydro's cash flow to adjusted total debt ratio is equal to the group average, both with a
6 ratio of \$0.09 per dollar of debt. BC Hydro's average coupon rate of 6.8% is well below the
7 peer-group average of 7.93%, even after accounting for differences in credit rating.

8 In the process of forecasting finance charges, BC Hydro employs a number of economic
9 assumptions as inputs, primarily short and long term interest rates in both Canada and the
10 US, along with the Canada/US exchange rate. These economic assumptions are developed
11 and provided to BC Hydro by the Treasury Board of the Province of BC. This methodology
12 has a number of benefits, the most important being a common set of economic assumptions
13 across all crown corporations and the government itself in forecasting net provincial income.
14 Table 2-11 identifies the interest rate assumptions used in the test periods.

15 **Table 2-11. Interest Rate Forecast, F2004 to F2006**

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

16 Notes:

17 1. Provincial Government Forecast, August 2003, for F2004 to F2007.

18 3.6.2 Bond Ratings

19 BC Hydro is a crown corporation that utilizes the province as its fiscal agent for all borrowing
20 activity. As a result, BC Hydro's credit rating is not based solely on its own financial
21 soundness but also includes the impact of the provincial guarantee. This leads to similar
22 ratings for both BC Hydro and the province by all rating agencies. In addition, the major
23 bond rating agencies consider BC Hydro's financial condition and trend as an important part
24 of their review of the province, and this is reflected in the ratings that they assign the
25 province.

1 The province currently holds a Aa2 long-term debt rating from Moody's, AA- from Standard
2 and Poor's, and an AAlow from Canada's Dominion Bond Rating Service (all agencies have
3 their own scales).

4 Table 2-12 identifies Finance Charges during the test periods.

5 **Table 2-12. Finance Charges, F2003 to F2006**

(\$ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Interest on debt securities				
Bonds, notes and debentures	\$ 536	\$ 510	\$ 505	\$ 540
Revolving borrowings	5	16	22	21
Amortization of deferred debt costs and other expenses <i>(Note 1)</i>	26	28	30	33
	567	554	557	594
Less:				
Sinking fund income	(60)	(62)	(58)	(52)
Other income <i>(Note 2)</i>	(26)	(18)	(11)	(4)
Finance charges capitalized to unfinished construction	(24)	(20)	(25)	(41)
	(110)	(100)	(94)	(97)
Total Finance Charges	\$ 457	\$ 454	\$ 463	\$ 497

6 Notes:

- 7 1. As per Order G-47-02. See discussion in section 3.6.3.
8 2. Other income largely relates to gains on interest rate and cross currency swaps.

9 3.6.3 Foreign Currency Translation

10 Foreign currency-denominated revenues and expenses are translated into Canadian dollars
11 at the rate of exchange in effect at the transaction date. Foreign currency-denominated
12 monetary assets and liabilities are translated into Canadian dollars at the rate of exchange
13 prevailing at the balance sheet date.

14 Gains and losses arising from the translation of foreign denominated long-term monetary
15 items are deferred and amortized . On July 11, 2002, the Commission approved, under
16 Order G-47-02, the continued deferral and amortization of foreign exchange gains and
17 losses on the translation of foreign denominated long-term monetary items, using the
18 straight-line pooled method of amortization, to be applied on a prospective basis for the
19 fiscal year beginning April 1, 2002.

1 For long-term debt, the straight-line pooled method is based on the weighted average
2 remaining term to maturity of the long-term foreign currency-denominated debt portfolio.
3 Where foreign currency-denominated long-term debt is refinanced in the same currency, any
4 unamortized foreign currency translation gains and losses associated with the refinanced
5 debt continue to be deferred and amortized. Where a portion of the foreign currency
6 denominated long-term debt is refinanced in a different currency, a pro rata portion of the
7 related pool of any unamortized foreign currency translation gains or losses are included in
8 finance charges at the refinancing date.

9 For sinking funds, the straight-line pooled method is based on the weighted average term to
10 maturity of the underlying long-term foreign currency-denominated debt weighted by its
11 sinking fund balances.

12 3.6.4 F2005 compared to F2004

13 Finance charges are expected to be similar in these years. An expected decrease in
14 interest charges on long-term debt due to the refinancing of maturing long-term debt at lower
15 rates is offset by an expected increase in the average volume of debt.

16 3.6.5 F2006 compared to F2005

17 Finance charges are expected to increase in F2006 largely due to the projected increase in
18 both US and Canadian interest rates. Projected refinancings of Canadian revolving
19 borrowings and a US floating debt issue with Canadian long-term debt also contribute to the
20 increase in finance charges.

21 **3.7 Depreciation and Amortization**

22 Depreciation and amortization (Depreciation) is the allocation of the cost of capital assets
23 and deferred assets over their estimated service lives. Assets are depreciated on a straight-
24 line basis with the exception of vehicles, which are depreciated on a declining balance
25 basis. Capital assets in service are depreciated on an individual or a pooled basis.

1 Depreciation includes the following components:

- 2 • depreciation of capital assets in service;
- 3 • amortization of contributions arising from the Columbia River Treaty and contributions in
4 aid of construction;
- 5 • amortization of studies and abandoned or indefinitely deferred projects;
- 6 • amortization of deferred Aboriginal negotiation and settlement costs;
- 7 • amortization of demand-side management programs and the cost of an interest free loan
8 to Howe Sound Pulp and Paper Limited;
- 9 • amortization of Future Removal and Site Restoration costs and, effective F2005, Asset
10 Retirement Obligations – see section 3.7.3 regarding the latter; and
- 11 • gains or losses on disposal, retirement or write-down of capital assets.

12 These components are amortized on the following basis:

- 13 • capital assets are amortized over their estimated useful lives;
- 14 • contributions in aid of construction (CIA) are amortized over the useful life of the related
15 asset;
- 16 • studies and deferred projects are amortized over five years;
- 17 • deferred Aboriginal negotiation and settlement costs are amortized over 10 years; and
- 18 • demand-side management programs are amortized over ten years.

19 Depreciation expenses for F2003 and forecast years F2004 to F2006 are shown in
20 Table 2-13.

1 **Table 2-13. Depreciation and Amortization Expense, F2003 to F2006**

(\$ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Depreciation expense	\$379	\$416	\$456	\$450
Contributions in aid amortization	(42)	(45)	(44)	(45)
DSM amortization	25	24	31	36
Asset dismantling and site restoration expenses <i>(Note 1)</i>				
Future removal and site restoration costs	27	21	n/a	n/a
Asset dismantling costs	n/a	n/a	18	19
Amortization of studies and abandoned or indefinitely deferred projects	11	9	9	10
Loss (gain) on disposal of assets	14	3	-	-
Total Depreciation and Amortization	\$414	\$428	\$470	\$470

2 Notes:

- 3 1. The impact of implementing the new accounting standard Section 3110 – Asset Retirement
 4 Obligation is to reduce future removal and site restoration amortization and increase asset
 5 dismantling costs (see section 3.7.3).

6 3.7.1 F2005 Compared to F2004

7 The increase in F2005 depreciation expense over F2004 is due primarily to growth in capital
 8 infrastructure in F2005 resulting in correspondingly higher depreciation as follows:

- 9 • \$4 million resulting from additional distribution system assets in-service;
- 10 • \$6 million due to increased generation assets in-service;
- 11 • \$6 million due to both increased transmission assets in-service, and the impact of the
 12 reduction in estimated salvage values of communication assets;
- 13 • \$7 million due to increased information technology infrastructure in service, most notably
 14 computer hardware and software assets related to the December 2003 implementation
 15 of the Customer Information System;
- 16 • \$7 million due to accelerated depreciation on Burrard Generating Station to reflect the
 17 current estimated useful life of the facility;
- 18 • \$9 million due to a revision in the estimated useful life of certain distribution assets; and
- 19 • \$7 million due to increased DSM amortization expense due to increased DSM program
 20 activity.

1 3.7.2 F2006 Compared to F2005

2 Increased depreciation from F2005 to F2006 resulting from increased assets in-service is
3 offset by the elimination of assets transferred to BCTC and no longer consolidated with
4 BC Hydro after F2005. In particular, the transfer to BCTC of certain limited transmission
5 assets necessary for the independent operation and dispatch of the transmission system
6 causes the depreciation expense to decrease by \$15 million. This decrease is partially
7 offset by a \$5 million increase in depreciation on transmission assets owned by BC Hydro,
8 due to additional assets in-service, and a \$3 million due to increased computer hardware
9 and software assets in-service.

10 Depreciation expense also increased by a net \$1 million due to increased assets in service
11 offset by asset retirements.

12 The increased DSM amortization expense of \$5 million results from increased DSM program
13 activity.

14 3.7.3 Asset Retirement Obligations

15 BC Hydro's accounting for costs associated with the retirement of capital assets will change
16 in F2005 as necessitated by a change in Generally Accepted Accounting Principles (GAAP).
17 The change, introduced by the Canadian Institute of Chartered Accountants, effectively
18 replaces the old accounting treatment of asset retirement costs with Section 3110 - Asset
19 Retirement Obligations, effective for fiscal years beginning on or after January 1, 2004.

20 Section 3110 requires the recognition of all legal obligations associated with the retirement
21 of a tangible long-lived asset. These legal obligations are referred to as Asset Retirement
22 Obligations (AROs). If a reasonable estimate of the fair value can be made, the obligations
23 must be recorded on a company's balance sheet as a liability. If a reasonable estimate of
24 the fair value of the obligation cannot be made, they must be disclosed in the notes to the
25 financial statements and may not be recognized until the period in which a reasonable
26 estimate can be made which may not be until they are incurred.

27 Section 3110 is to be applied on a retroactive basis with a restatement of financial
28 statements of prior years, effective F2005.

1 The change in accounting standard has a significant impact in F2005 on BC Hydro's
2 depreciation expense, Future Removal and Site Restoration (FRSR) provisions, and equity.

3 Consistent with the existing requirements of GAAP, BC Hydro currently accounts for asset
4 retirement costs by creating a provision for FRSR, which is a liability on BC Hydro's balance
5 sheet that increases every year until the asset is de-commissioned. The yearly increase to
6 the liability account on the balance is reflected as depreciation expense on the statement of
7 operations. Actual de-commissioning costs are charged against the liability on the balance
8 sheet as incurred.

9 Under the new Section 3110, the existing FRSR provisions are to be eliminated and
10 replaced where applicable with AROs. BC Hydro has very few assets with ARO liabilities.
11 As a result most of the FRSR provisions currently reflected on BC Hydro's balance sheet will
12 no longer be eligible for that treatment, and may only be disclosed in the notes to the
13 financial statements as required by Section 3110. The effect is to increase BC Hydro's
14 retained earnings. Dismantling and site restoration costs associated with assets that do not
15 have ARO liabilities on the balance sheet will be expensed as they are incurred.

16 Currently, BC Hydro's FRSR balance consists of two components: provision for future
17 dismantling costs (credit balance of \$244 million), and provision for future salvage proceeds
18 (debit balance of \$64 million). Under Section 3110 the provision for future dismantling costs
19 (\$244 million) will be transferred to retained earnings. The provision for salvage proceeds
20 (\$64 million) will be transferred to accumulated depreciation. Based on current estimates,
21 AROs will be created with an asset cost base of \$14 million. As at April 1, 2004, the
22 accumulated depreciation on these ARO assets, which will be reflected in retained earnings,
23 will be \$7 million. The present value of the ARO liability as at April 1, 2004 will be \$18
24 million. The accumulated accretion to April 1, 2004 on this liability, which will be reflected in
25 retained earnings, will be \$4 million.

26 **Table 2-14. Estimated Impact of AROs on Retained Earnings, F2005**

(\$ millions)	Estimated Impact
Reversal of FRSR provision	\$244
Retroactive accumulated depreciation on ARO asset	(7)
Retroactive accretion on ARO liability	(4)
Net increase in Retained Earnings	\$233

1 **3.8 Taxes**

2 Taxes include school taxes, grants-in-lieu of general taxes, and the Corporation Capital Tax.

3 3.8.1 School Taxes

4 The *British Columbia Hydro and Power Authority Act* exempts the property of BC Hydro from
5 all property taxes other than those levied in respect of schools. School taxes are based on
6 the assessed value of taxable assets prepared by BC Assessment and school tax rates
7 established by the province. School taxes are paid on all assessable property with the
8 exception of certain facilities related to the generation of power on the Peace, Pend-
9 d'Oreille, and Columbia Rivers.

10 3.8.2 Grants-in-Lieu

11 The *British Columbia Hydro and Power Authority Act* authorizes BC Hydro to pay grants-in-
12 lieu of general municipal, regional district and local improvement taxes. Order-In-Council
13 1218 sets out the formula used to calculate the grant payments. Annual grants paid include
14 the following items:

- 15 • General grants equivalent to general, regional district and local improvement taxes on
16 the assessed value of all land of BC Hydro and on the assessed value of improvements
17 such as office buildings, garages, warehouses, line stores and substation buildings.
18 Assessed values of generating plants, substation equipment, transmission lines and
19 distribution lines are excluded from this calculation.
- 20 • Revenue grants equal to one per cent of gross revenue from sales of electricity within
21 each municipality or unorganized area, excluding revenue from power sold to other
22 distribution systems for resale. These grants are deemed to be in lieu of general taxes
23 on transmission and distribution lines, substation equipment and generation facilities.
- 24 • Special grants-in-lieu of general taxes on dams, reservoirs and powerhouses. These
25 grants are based on installed capacity, or imputed nameplate generating capacity in the
26 case of storage dams.

1 3.8.3 Corporation Capital Tax

2 BC Hydro has in the past paid a corporation capital tax equal to 0.3 per cent of taxable paid-
 3 up capital. Taxable paid-up capital is approximately equal to retained earnings, plus
 4 liabilities, less accounts payable and certain eligible expenditures.

5 The corporation capital tax rate was reduced in F2002 and eliminated in F2003.

6 3.8.4 Summary of Taxes and Grants

7 Table 2-15 identifies the tax and grants forecast for the test periods.

8 **Table 2-15. Taxes and Grants-in-Lieu, F2003 to F2006**

(\$ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Grants-in-Lieu	\$42	\$42	\$44	\$45
School taxes	100	100	101	102
Corporation capital tax	3	-	-	-
Total Taxes and Grants-in-Lieu	\$145	\$142	\$145	\$147

9 The provincial government is currently reviewing the taxation of crown corporations, which
 10 are currently not subject to income tax. This forecast assumes the current tax regime will
 11 continue to apply through F2006.

12 **3.9 Restructuring Costs**

13 Table 2-16 identifies restructuring costs during the test periods.

14 **Table 2-16. Restructuring Costs, F2003 to F2006**

(\$ millions)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Restructuring costs	\$37	\$11	\$0	\$0

15 Restructuring costs in F2003 related to one-time costs resulting from the outsourcing of
 16 some of BC Hydro's support and administrative functions to ABS. Restructuring costs for
 17 F2004 relate to one-time set up costs resulting from the transfer of the transmission
 18 operations of BC Hydro to BCTC.

1 **3.10 Charges from the British Columbia Transmission Corporation**

2 BCTC's costs and revenues are consolidated with BC Hydro's for F2004 and F2005 while it
 3 continues to act on behalf of BC Hydro, providing service under BC Hydro tariffs. It is
 4 anticipated BCTC will begin providing service under its own tariff on April 1, 2005. This
 5 results in a reclassification of some costs in F2006.

6 Costs that were part of BCTC's OMA, depreciation, finance charges and taxes were
 7 consolidated to the same line items on BC Hydro's pro forma consolidated statements of
 8 operations for F2004 and F2005. In F2006, these BCTC costs will be charged as part of
 9 their tariff charge for wheeling and as part of a service fee to BC Hydro as described in
 10 chapter 7. These charges are as shown in Table 2-17.

11 **Table 2-17. Charges from BCTC, F2006**

(\$ millions)	F2006 Plan
BCTC Wholesale Transmission Service	\$61
BCTC Asset Management Fee	\$117

12 See chapter 6 for further details on these amounts.

1 **4 BC Hydro Deferral Accounts**

2 **4.1 Introduction**

3 As noted in chapter 1, BC Hydro applies in this application for Commission approval of three
4 new deferral accounts, being the “Heritage Payment Obligation Deferral Account”, the
5 “Trade Income Deferral Account”, and the “BCTC Transition Deferral Account”. This section
6 elaborates on those proposed deferral accounts.

7 **4.2 Heritage Deferral Accounts**

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

12 Regarding the Heritage Payment Obligation Deferral Account, BC Hydro proposes that it
13 record variances between the following components of the Heritage Payment Obligation, as
14 defined in schedule A to appendix A of HSD #2:

- 15 • cost of energy (all costs in (a)(i));
- 16 • variable operating costs related to thermal generation (part of (a)(ii));
- 17 • major maintenance expenditures greater than \$1 million related to single event
18 equipment or infrastructure failure (part of (a)(ii));
- 19 • major operating, maintenance or general and administration expenses greater than \$1
20 million related to single weather-related events (part of (a)(ii));
- 21 • major capital expenditures incurred or advanced related to single event equipment or
22 infrastructure failure or weather related events with an incremental impact on annual
23 depreciation and finance charges greater than \$1 million (part of (a)(iii));
- 24 • finance and amortization charges, including amortization of costs capitalized pursuant to
25 Commission Order G-53-02 (part of (a)(iv));
- 26 • net revenues from surplus hydro electricity sales (all costs in (b)(iii)); and
- 27 • Skagit Valley Treaty revenues and ancillary services revenues (all costs in b(i) and b(ii)).

1 Each of the foregoing is proposed to be included in the Heritage Payment Obligation
2 Deferral Account because they are cost or revenue items that are largely out of BC Hydro's
3 control. Note that "variable operating costs related to thermal generation" refers to operating
4 costs arising primarily from the operation of Burrard Generating Station. Variations to
5 planned operations of Burrard Generating Station are driven by the same factors that make
6 cost of energy so volatile, which is why BC Hydro proposes to include it in the Heritage
7 Payment Obligation Deferral Account. Unplanned, single-event capital or maintenance
8 expenditures arising from weather or equipment failure are included in the Heritage Payment
9 Obligation Deferral Account as an alternative to building contingencies into the revenue
10 requirement. Variations in Skagit Valley Treaty revenues from forecasts are due to foreign
11 exchange differences. Variances in ancillary services revenues are market driven.
12 Revenues from the sale of surplus hydro electricity sales are forecast as zero for at least the
13 next few years. Not including them in the Heritage Payment Obligation Deferral Account
14 would mean that ratepayers would not get the benefit of any such revenues that did arise.

15 BC Hydro proposes that no cap or limit be set on the Heritage Payment Obligation Deferral
16 Account, but that instead it be cleared through an adjustment to BC Hydro's revenue
17 requirement, upon application, and in light of balances that may have accrued in other
18 BC Hydro deferral accounts and BC Hydro's overall financial situation. BC Hydro also
19 proposes that by June 30 of each year, commencing in 2005, that it publicly report to the
20 Commission the variances for the previous fiscal year in the components of the Heritage
21 Payment Obligation Deferral Account, and its balance.

22 Regarding the Trade Income Deferral Account, BC Hydro proposes that it be used to record
23 differences between forecast and actual Trade Income, as that expression is defined in
24 HSD #2. In this way any losses on the year or any extraordinary windfalls that would cause
25 Powerex audited net income to exceed \$200 million dollars would not be carried forward to
26 future periods, consistent with the government's response to the Heritage
27 Recommendations. As with the Heritage Payment Obligation Deferral Account, the Trade
28 Income Deferral Account would be cleared through an adjustment to BC Hydro's revenue
29 requirement, upon application, and each year BC Hydro would publicly report to the
30 Commission the variance for the previous fiscal period in Trade Income, and the balance of
31 the Trade Income Deferral Account.

1 **4.3 BCTC Transition Deferral Account**

2 As summarily described above and as elaborated on in chapter 6, BCTC will be providing
3 wholesale transmission services on behalf of BC Hydro and under BC Hydro's existing tariffs
4 until April 1, 2005 (phase 1). At that time it expects to begin providing WTS on its own
5 behalf under its new tariffs, and on behalf of BC Hydro under BC Hydro's new tariffs (phase
6 2). This application assumes that the total net cost to BC Hydro of providing and purchasing
7 WTS services in phase 2 will be the same as the total net cost of providing those services in
8 phase 1, and that in consequence BC Hydro's transmission revenue requirement for F2006
9 will remain as it is presented in this application, and that no further adjustment to BC Hydro's
10 rates will be required other than as applied for in this application. That assumption will not
11 be tested until BCTC applies for and receives Commission approval for its first independent
12 revenue requirement for F2006. In consequence BC Hydro applies in this application for
13 approval to record any variances between its current forecast of net WTS costs in F2006
14 and its adjusted forecast of its net WTS costs in F2006 based on the outcome of BCTC's
15 revenue requirement proceeding, and for approval to carry that adjustment forward to
16 subsequent rate periods.

5 Reconciliation of Consolidated and Functional Costs

5.1 Introduction

Sections 2 and 3 of this chapter presented the cost and revenue components of BC Hydro's revenue requirements consolidated across lines of business, service organizations, and subsidiaries, without distinguishing between the particular costs incurred by business units, or by function performed. However, most of the detail in this application regarding costs and revenues is described in the chapters that follow, which are organized on the basis of the functions performed by the business units. Thus, it is necessary to reconcile the consolidated financial schedules in sections 2 and 3 with the functional costs and revenues of the functions described in chapters 3 to 9. That is the purpose of the remainder of this chapter.

The primary purpose of this section 5 is to summarize those functions.

5.2 Definitions of Functions

Chapters 3 to 9 of this application describe the following functions, which generally follow standard CEA industry definitions.¹

- Chapter 3: BC Hydro Corporate Functions. This chapter describes, in part, the various corporate functions performed by BC Hydro, and their expected costs, in F2005 and F2006. Corporate functions include financial management, regulatory affairs, information technology and human resources. The corporate office and BC Hydro Distribution perform these functions. Of the various corporate groups, two directly charge their costs to the functions based on volume of service provided, being Legal Services and Property Services. The remaining corporate costs that BC Hydro expects to incur to perform the corporate functions are allocated to the lines of business, service organizations and subsidiaries using the allocation methodology described in section 7.2.
- Chapter 4: Energy Supply Costs. This chapter provides an overview of the overall cost to supply energy to meet expected domestic load in the test periods, which includes the

¹ Canadian Electricity Association, Committee on Corporate Performance and Productivity Evaluation (COPE), COPE Data Submission Reference Manual, May 2003.

1 Heritage Payment Obligation and costs of acquiring energy from third parties. Also
2 included in the overall supply cost are OMA and amortization expenses related to
3 demand side management programs. To some extent this chapter overlaps with
4 chapters 5 and 8.

- 5 • Chapter 5: Heritage Contract. This chapter describes the cost of maintaining and
6 operating the Heritage Resources, a function performed by BC Hydro Generation.
7 Included in this chapter is a detailed explanation of BC Hydro's forecast of the Heritage
8 Payment Obligation.
- 9 • Chapter 6: Transmission. This chapter describes BC Hydro's anticipated cost of
10 operating, maintaining, and expanding its transmission system. It also describes the role
11 of BCTC in F2005 (while it is expected to provide service under BC Hydro tariffs) and
12 F2006 (when it is expected to provide service, in part, under its own tariffs).
- 13 • Chapter 7: Electricity Distribution and Non-Integrated Areas. This chapter describes the
14 expected cost of operating the distribution system, and managing, maintaining, and
15 expanding distribution assets, functions performed by BC Hydro Distribution. Included in
16 this chapter is a discussion of operations in non-integrated areas.
- 17 • Chapter 8: Power Smart, Customer Care, and Energy Management. This chapter
18 describes the cost of customer-related functions such as billing, meter-reading, credit
19 collection, key account management and advertising, the cost of acquiring and
20 managing energy from IPPs, and costs of the Power Smart program.
- 21 • Chapter 9: Service Organizations, Subsidiaries and Outsourcing. This chapter provides
22 an explanation of the different service organizations within BC Hydro, BC Hydro's
23 subsidiaries and BC Hydro's outsourcing arrangements with ABS. The service
24 organizations and ABS charge the costs described in this chapter back to the lines of
25 business, and those costs are included in the costs described in chapters 3 to 8. The
26 costs described in chapter 9 are presented on an aggregated basis to make fully
27 transparent the costs the lines of business are expected to incur in F2005 and F2006.
28 BC Hydro's subsidiaries are also described in this chapter, for the purpose of elaborating
29 on the overall financial impact of their operations on BC Hydro's consolidated revenue
30 requirement.

6 Definition of Financial Schedules

This section is intended to explain the purpose of each type of functional schedule and to allow the reader to track the functional costs described in chapters 3 to 9 to the consolidated financial schedules. A careful review of this chapter and the financial schedules within it ought to reassure the reader that, among other things, no cost item described in chapters 3 to 9 has been “double-counted” or omitted.

Section 6.1 provides a description of the ‘A’, ‘B’, ‘C’, ‘D’, and ‘E’ schedules, including an example of how they are linked. Section 6.2 identifies the approach used to assign corporate-wide consolidated costs such as finance costs identified in the consolidated statements to the functions. Section 7 describes the allocation of corporate OMA costs to the different functions.

6.1 Description of Schedules

6.1.1 ‘A’ Schedules: Supporting Consolidated Schedules

In section 2, Table 2-2 and Table 2-3 identify the need for a rate increase based on the pro forma consolidated statements of operations. The ‘A’ schedules located at the end of this chapter provide additional breakdown of the consolidated cost and revenue elements in these tables.

6.1.2 ‘B’ Schedules: Breakdown of Expense Categories by Function

The ‘B’ schedules disaggregate the consolidated costs shown in Tables 2 and 3 of this chapter by function (chapter by chapter) using the approach identified in section 6.2 below.

6.1.3 ‘C’ Schedules: Cost of Service by Function

The ‘C’ schedules restate the ‘B’ schedule costs to provide a nominal “cost of service” of each function. Fiscal years F2003 to F2006 are presented for each function. OMA as stated in chapters 3 and 9 as “direct”, “support”, and “corporate allocations” correspond with the total OMA costs in the ‘C’ schedules.

It was necessary to calculate a nominal cost of service for the generation and transmission functions for the purposes of defining the Heritage Payment Obligation and to provide a

1 means to calculate the reduction in WTS rates described in chapter 6. Costs of service for
2 the remaining functions fall out naturally from these necessary calculations, but are not
3 intended to be utilized for rate design purposes. BC Hydro will be undertaking a new cost of
4 service study for rate-design purposes.

5 6.1.4 'D' Schedules: Resource Usage by Function

6 The 'D' schedules provide additional breakdown of the OMA costs presented in the 'B' and
7 'C' schedules. These costs include the costs arising from the use of service organizations
8 within BC Hydro and the services of ABS. F2003 to F2006 are presented for each function.

9 The 'D' schedules provide a more detailed view of OMA by providing both OMA by resource
10 (e.g., labour, materials) and OMA by cost category (e.g., direct and support costs). These
11 schedules also identify staffing levels and summarize capital spending necessary in the
12 tests periods to perform the functions. Note that:

- 13 • Labour costs are fully-loaded and are shown for direct and indirect activities within the
14 function. CEA definitions are used for "direct" and "indirect". Direct costs relate to
15 workers directly performing the function, as well as direct supervision of those workers.
16 Indirect costs related to workers within the functional area but who are not directly
17 performing work, such as higher levels of management and those providing HR and
18 Finance support.

19 All corporate labour is shown as direct. Indirect costs for corporate relate to BC Hydro
20 non-current service employee future benefit costs.

- 21 • Materials are goods procured from external firms or internal services (such as Materials
22 Management Business Unit).
- 23 • "Internal services" are services that are procured internally from service organizations
24 such as Field Services and corporate groups such as Legal.
- 25 • "External services" are services that are procured from outside BC Hydro. These
26 include services from ABS.
- 27 • "Buildings & equipment" costs are associated with building rent, communications, etc.
- 28 • "Vehicles" includes employee-owned vehicle costs and equipment rentals.

- 1 • “Corporate allocations” relate to the allocation of corporate costs as per the rules defined
2 in section 7.2 of this chapter.
- 3 • “Capitalized overheads” relate to those resources that perform work related to capital
4 activities not readily identified with a specific project. The cost is recorded in OMA and
5 then allocated to capital projects. This is treated as an offset to OMA expense for the
6 function.
- 7 • “Recoveries” are offsetting costs from either internal or external sources. This category
8 does not include revenues.

9 Capital additions are described in terms of “sustaining”, “growth”, and “deferred capital.”
10 Sustaining capital relates to investments such as equipment replacements made to existing
11 infrastructure to continue the current level of service. Growth capital relates to investments
12 required to expand service capability (e.g., distribution network expansion). Deferred capital
13 relates to DSM expenditures that will be amortized rather than expensed.

14 Headcount relates to active staff² recorded or forecast at March 31 of the applicable fiscal
15 year. Headcount is further identified as either Management & Professional or bargaining
16 unit (International Brotherhood of Electrical Workers and Office & Professional Employees
17 International Union).

18 For service organizations, resource schedules identify the total level of work performed
19 regardless of whether it is defined as OMA or capital. Recoveries are also identified,
20 consistent with the cost-recovery model utilized by them.

21 Capital and headcount totals in chapters 3 to 9 correspond to capital expenditures and
22 headcount in the ‘D’ schedules.

23 6.1.5 ‘E’ Schedules: Summary of Billings by Service Organizations and ABS

24 The ‘E’ schedules summarize the work performed by Field Services and Engineering
25 Services, and OMA allocations from BC Hydro’s corporate office.

² Active headcount refers to full-time or part-time employees who are actively involved in the operations of the company. Employees on leave (e.g., disability, pre-retirement, maternity) are not considered active employees.

1 For Field Services and Engineering Services, the 'E' schedule outgoing charges to a
2 function do not necessarily correspond with the incoming OMA charges identified by the
3 function in the applicable 'D' schedule. This is because a portion of services provided are
4 recorded as capital by the lines of business and service organizations receiving the service.
5 As a result, the total resource cost identified by Field Services or Engineering Services will
6 be greater than the total of incoming OMA charges identified by the lines of business and
7 service organizations.

8 6.1.6 Example Schedules 'B' to 'D'

9 The 'B' and 'C' schedules provide different views of the costs incurred by each function.
10 This is shown as an example for F2005 in Table 2-18. This table also identifies how costs
11 are aligned with the discussions in chapters 3 to 9.

12 The 'B' schedules show the information from each row in Table 2-18 for F2003 to F2006.
13 The total of the category applicable to the row (e.g., OMA) is equivalent to the reported
14 value of that category in the consolidated statement.

15 The 'C' schedules show the information from each column in Table 2-18 for F2003 to F2006.
16 The total of the column for a specific function (e.g., Electricity Distribution and Non-
17 Integrated Areas) is equivalent to the cost of service of that function.

18 Table 2-19 provides an example of a 'D' schedule for Generation (Heritage Contract) for
19 F2005. As is seen, the total OMA identified within this schedule is equivalent to the OMA
20 identified for Generation (Heritage Contract) in schedules 'B' and 'C'.

21 Table 2-20 provides an example of an 'E' schedule for the Field Services organization for
22 F2005. A comparison of the tables shows that the total charge to Generation (Heritage
23 Contract) in the 'E' schedule does not equal the corresponding Internal Services charge
24 from Field Services in the Generation (Heritage Contract) 'D' schedule, and the difference is
25 explained in section 6.1.5 above.

1 **Table 2-18. Example of 'B' and 'C' Schedules, F2005**

		Schedule B-2 Functionalized Costs F2005							
(\$ millions)		Corporate	Energy Supply	Generation	Transmission ⁷	Electricity	Customer	Service	Consolidated
			less Heritage Payment Obligation ¹	(Heritage Contract) ²		Distribution & NIA ⁸	Care ¹	Orgs and Subsidiaries	
		Chapter 3	Chapter 4	Chapter 5	Chapter 6	Chapter 7	Chapter 8	Chapter 9	
B1	Domestic cost of energy		391.6	417.4	1.0	14.1			824.1
	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	(131.0)	12.8	42.9	15.4	25.9	8.5	25.5	-
B2	Adjusted OMA including Corporate Allocations	(60.6)	35.4	168.3	182.9	133.3	110.0	7.8	577.1
B4	Depreciation	54.2	27.9	130.2	151.9	89.6		16.0	469.8
B3	Taxes	7.4		28.6	89.5	18.8		1.1	145.4
B5	Finance charges	9.5	4.6	208.0	131.0	109.4		-	462.5
B6	Allowed net income (return on equity)		4.3	196.0	123.0	103.7		-	427.0
C3	Other ³			43.3		69.6			112.9
A-1	Restructuring costs	-	-	-	-	-	-	-	-
A-8	Miscellaneous external revenues	(10.5)		(107.4)	(120.9)	(4.5)	(4.2)	(21.6)	(269.1)
	Cost of Service by Function	-	463.8	1,084.4	558.4	534.0	105.8	3.3	2,749.7
A-8	Transmission 3rd party wheeling revenues ⁴								(5.5)
A-1	Intersegment revenues ⁵								(124.0)
	Total Revenue Requirement⁶								2,620.2
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)

1 **Table 2-19. Example of 'D' Schedule, Generation F2005 (from schedule D1-1)**

(\$ millions)	2005 Forecast
Operations, Maintenance, and Administration Expenses by Resources	
Labour	
Direct	\$43.5
Indirect	24.5
Materials	6.7
Internal Services	
Engineering	6.5
Field Services	11.2
BC Hydro Corporate Direct Charges	3.9
Other BCH Billings	1.0
External Services	
ABS	16.7
Other	21.3
Buildings & Equipment	0.8
Vehicles	0.2
Corporate Allocation	42.9
Less: Capitalized Overhead	(8.0)
Less: Recoveries	
Internal	(2.8)
External	(0.1)
Total OMA Expenses	\$168.3
Operations, Maintenance, and Administration Expenses by Category	
Direct	\$75.8
Support	60.5
Corporate Allocations	42.9
Less: Capitalized Overhead	(8.0)
Less: Recoveries	(2.9)
Total OMA Expenses	\$168.3
Capital Additions	
Sustaining	\$116.4
Growth	71.4
Deferred Capital	-
Total Capital Gross of CIA	\$187.8
CIA	
Total Net Capital	\$187.8
Headcount	
M&P	207
IBEW	323
OPEIU	205
Total Headcount	735

1 **Table 2-20. Example of 'E' Schedule, Field Services (from schedule E3)**

Summary of External Charges (\$ millions)	F2005 Plan
Corporate	\$1.8
Engineering Services	0.3
Field Services	-
Generation	20.4
Transmission	101.4
Energy Portfolio Management	
Distribution	168.3
Customer Care	-
Power Smart	-
Other Internal	-
Total Internal OMA Recoveries	\$291.8
Less Services Charged to OMA <i>(Note 1)</i>	\$170.2
Less Services Charged to Capital	121.6
Total Internal OMA Recoveries	\$291.8

2 **6.2 Approach to Functionalization**

3 The following describes the relationship between consolidated costs and the costs of the
 4 functions described in chapters 3 to 9, and methods used to allocate costs that are incurred
 5 on a corporate-wide basis.

6 6.2.1 Operations, Maintenance, and Administration Expense

7 OMA costs are expensed as incurred by each business group. OMA expenses also include:
 8

- 9 • internal billings from service organizations, and from the direct charge of some corporate
 10 services as described in section 7.1; and
- 11 • charges from ABS, including corporate loadings, as described in chapter 9.

12 OMA costs are applicable to all functional schedules.

13 6.2.2 Finance Charges

14 Finance charges are allocated to the functions based on the ratio of average Rate Base
 15 balance of the individual function to the total average Rate Base of all the functions
 16 combined. As mentioned above, this exercise was necessary to establish the Heritage

1 Payment Obligation and to reset WTS rates. Rate Base is defined as Net Book Value of
 2 capital assets in service including demand-side management programs, less contributions in
 3 aid of construction.

4 Schedule B7 identifies the total Rate Base for BC Hydro, Rate Base by function, and the
 5 percentages used for allocations.

6 The finance charges allocated to the functions noted above exclude finance charges relating
 7 to the deemed interest charges on the assets of BCH Service Asset Corporation. This wholly
 8 owned subsidiary of BC Hydro holds the assets used in providing services to BC Hydro by
 9 ABS. The deemed interest charges of approximately \$10 million/year are loaded onto the
 10 charges from ABS to reflect the full cost of service to the users of services from ABS.

11 6.2.3 Allowed Net Income (Return on Equity)

12 The allowed net income is the net income needed to meet the allowed return on equity of
 13 13.91% as calculated in chapter 10. The allowed net income is allocated to the functions
 14 based on the proportionate share of Rate Base, as shown in Table 2-21.

15 **Table 2-21. Allowed Net Income**

(\$ million)	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Allowed ROE %	15.47%	14.33%	13.91%	13.91%
Ending Equity Balance	\$2,700	\$2,726	\$3,069	\$3,180
Allowed Net Income	\$418	\$391	\$427	\$442

16 6.2.4 Domestic Cost of Energy

17 Domestic cost of energy is the sum of certain amounts found in chapter 4 (Energy Supply
 18 Costs), chapter 5 (Heritage Contract), chapter 6 (Transmission), and chapter 7 (Electricity
 19 Distribution and Non-Integrated Areas), as shown in schedule B1.

20 6.2.5 Depreciation and Amortization Expenses

21 Depreciation and amortization allocations are based on the assets that are owned by each
 22 function and the corresponding depreciation rates of the assets. Generally, assets used for
 23 the generation of energy fall within the generation (Heritage Contract) function, assets used

1 in the distribution of energy fall within the distribution functions, and assets used for
2 transmission fall within the transmission function.

3 Power Smart manages the demand side management program. However, 10 per cent of
4 the asset's book value and annual amortization is allocated to the asset owner component
5 of the transmission revenue requirement (i.e., BC Hydro Transmission), based on the
6 Commission's decision regarding BC Hydro's 1997/98 WTS application. See chapter 6 for a
7 discussion of the transmission revenue requirement.

8 In BC Hydro's financial systems, BC Hydro Transmission is the owner of most substation
9 assets and records the depreciation expense associated with these assets. BC Hydro
10 Transmission charges BC Hydro Distribution and BC Hydro Generation for use of these
11 assets.

12 6.2.6 Taxes

13 School taxes are assigned on the basis of actual charges. Grants-in-lieu are allocated to the
14 functions based on the ratio of assessed values.

1 **7 Allocation of Corporate Costs**

2 Costs incurred by BC Hydro's corporate office, and costs allocated to BC Hydro's corporate
3 office from BC Hydro Distribution's corporate business units, are either charged directly by
4 usage to the lines of business and service organization, or allocated to them using allocation
5 factors. These costs are shown in the financial schedules to this chapter and in chapter 3.
6 Corporate allocations are also shown throughout chapters 4 to 9.

7 **7.1 Direct Charges**

8 Legal, Property Services, Regulatory, and Corporate Communications directly charge all or
9 a portion of their costs. In addition, the depreciation and finance costs associated with the
10 assets owned by BCH Services Asset Company are charged out to the lines of business
11 and service organizations via a loading on the direct charges from ABS.

12 The charges from Legal, Property Services, Regulatory, and Corporate Communications are
13 recorded by them as OMA recoveries, and by the recipient lines of business and service
14 organizations as either OMA or capital, depending on the nature of work performed.
15 Because Legal, Property Services, and Regulatory recover their full OMA costs (as well as
16 depreciation expense), their net total costs (excluding property taxes) are zero.

17 **7.2 Allocated Costs**

18 The costs of all remaining corporate groups, including some residual costs of Legal and
19 Property Services, are allocated to the lines of business and service organizations.³ The
20 rationale for the allocation of the costs of the various corporate groups is provided below.

21 7.2.1 General Costs

22 General costs include the costs of the Corporate Executive Office, Corporate
23 Communications and Public Affairs, Finance, Sustainability (except for Strategic Research
24 and Development), BC Hydro Distribution's corporate costs, and other corporate costs
25 described in chapter 3, section 12. For the test years these costs are allocated based on
26 the ratio of OMA and sustaining capital expenditures of the BC Hydro Generation and

³ The lines of business included BC Hydro Transmission in F2003 and F2004.

1 BC Hydro Distribution to the total OMA and sustaining capital expenditures of these groups,
2 as this best represents the relative value of the services to those business units.

3 None of the general costs is directly allocated to Powerex or BC Hydro Transmission (test
4 years only), as Powerex and BCTC have their own corporate offices.

5 7.2.2 Corporate HR

6 Corporate Human Resources costs are allocated based on the headcount of each line of
7 business and service organization, as HR work is performed on behalf of employees
8 throughout the organization.

9 None of the costs is directly allocated to Powerex or BC Hydro Transmission (test years
10 only), as Powerex and BCTC have their own, stand-alone human resources departments.

11 7.2.3 Strategic Research and Development Costs

12 Strategic research and development costs are allocated evenly between BC Hydro
13 Generation and BC Hydro Distribution as the program is expected to provide equal benefits
14 to both lines of business.

15 7.2.4 Employee Benefit Costs

16 Employee benefit costs include the costs of extended health and dental plans; the
17 employer's portion of Canada Pension Plan and Employment Insurance payments; group
18 life insurance premiums; income continuance allowances; pension costs; and other post
19 retirement benefit costs. Employee benefit costs are classified as either current service
20 costs or non-current service costs. Current service costs are charged to the lines of
21 business and services organizations as a loading on employee payroll costs. Non-current
22 service employee future benefit costs are allocated to the lines of business and service
23 organizations based on their proportionate share of payroll costs.

24 A portion of non-current service benefit costs are directly allocated to BC Hydro
25 Transmission since a portion of these costs relate to BCTC employees when they were
26 employed by BC Hydro. The allocation for the test years is based on F2003 payrolls.

1 7.2.5 Catastrophic Risk Insurance Costs

2 Catastrophic fire risk insurance costs are allocated 100% to BC Hydro Generation as the
3 policies cover the risks of catastrophic events primarily associated with generation assets.

4 7.2.6 Corporate Taxes and Depreciation

5 Corporate taxes and any residual depreciation on corporate assets are allocated to the lines
6 of business and service organizations based on their proportionate share of space occupied
7 in BC Hydro's Dunsmuir and Edmonds buildings, the primary assets associated with
8 corporate taxes and depreciation.

9 7.2.7 Allocation of Corporate Costs Directly Allocated to Service Organizations

10 Service organizations are directly allocated costs based on the above allocation process.
11 Corporate costs allocated to the service organizations are not included in their charge out
12 rates to the lines of business and other service organizations. Therefore, these costs are
13 allocated to the lines of business based on their proportionate share of consumption of the
14 service organization services.

15 **7.3 Change in Allocation Methodology with ABS Implementation**

16 In F2003, a portion of depreciation expense on capital assets used in the provision of
17 support services was charged via loadings to the applicable business unit. With the
18 implementation of the ABS contracts, the full depreciation cost of these assets has been
19 loaded on to the base cost in order to provide a rate that reflects the full cost of service
20 delivery. Other asset-related expenses such as finance charges were also added to the
21 loading in F2004. As a result of this change in the costing method, all functional areas are
22 showing an increase in their OMA costs from F2003 to F2004.

1 Table 2-22 identifies the total OMA and capital expenditures on ABS service by the lines of
 2 business and service organizations. Note that loadings comprise a significant portion of
 3 ABS costs to the lines of business and service organizations, and as shown in the 'D'
 4 schedules.

5 **Table 2-22. Fully Loaded ABS Costs, Organizational View**

(\$ millions)	F2004 Forecast			F2005 Plan			F2006 Plan		
	Base	Loading	Total	Base	Loading	Total	Base	Loading	Total
Distribution	\$92.3	\$31.6	\$123.9	\$85.3	\$34.8	\$120.1	\$80.9	\$33.3	\$114.2
Generation	12.9	6.9	19.8	10.8	7.4	18.2	10.3	6.8	17.1
BCTC	7.8	3.3	11.1	9.6	3.8	13.4	9.2	3.5	12.7
Engineering Services	8.6	4.6	13.2	7.9	4.6	12.5	7.6	4.3	11.9
Field Services	12.4	8.6	21.0	11.8	9.0	20.8	11.3	8.5	19.8
Corporate	11.2	4.9	16.1	9.8	5.2	15.0	9.4	4.9	14.3
Powerex	2.0	2.3	4.3	2.5	2.3	4.8	2.3	2.3	4.6
Powertech	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
	\$147.3	\$62.0		\$137.9	\$66.9		\$131.0	\$63.7	
Fully Loaded ABS Cost			\$209.3			\$204.8			\$194.7

6 Notes:

7 1. This table includes both OMA and capital expenditures.

8 The asset-related loadings are eliminated from OMA upon consolidation and appear as
 9 finance charges, depreciation, etc. in the consolidated schedules.