Schedule C. List of Errata

Title	Remove	Insert	Note
Volume I, Summary Table of Contents	Original, page i	Revision 1, pages i and i-1	1
Volume I, Chapter 2	Original, page 2-49	Revision 1, page 2-49	9
Volume I, Chapter 2	Original, page 2-85	Revision 1, page 2-85	16
Volume I, Chapter 4	Original, page 4-5	Revision 1, page 4-5	6
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Volume II, Appendix I	Original, page 8	Revision 1, page 8	5
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BCUC IR #1.1.3	Original, page 1	Revision 1, page 1	7
BCUC IR #1.2.10	Original, page 1	Revision 1, page 1	15
BCUC IR #1.2.20	Original, page 1	Revision 1, page 1	13
BCUC IR #1.5.10	Original, page 4	Revision 1, page 4	12
BCUC IR #1.18.3	Original, schedule 18-3-2	Revision 1, schedule 18-3-2	2
BCUC IR #1.75.6	Original, Schedule 75-6-16, first page	Revision 1, Schedule 75-6-16, first page	4

Notes:

1. Added Chapter 2A – Evidentiary Update Consolidated Revenue Requirements and Financial Schedules and Chapter 2B – BC Hydro Deferral Accounts
2. Corrected Distribution Expansion and Improvements for F1994; corrected Deferred Power Smart for F1995 to F1998.
3. Corrected upper limit of free rider range from 12% to 22% as per IPPBC IR #1.24.2
4. Corrected Interior YTD Actual CAIDI from 2.92 to 2.76 as per PRRD IR #1.13.0

5. Corrected misalignment of headings column as per SIERRA IR #1.24.0
6. Line 21, corrected as "cost of conserved energy" as per SIERRA IR #1.1.0
7. Corrected Distribution OMA for F2003 Actual
8. Corrected description of Figure 7-3 in line 7; corrected range labels on x-axis of Figure 7-3.
9. Corrected fiscal year reference in line 22.
10. Corrected classification of Aboriginal Relations charge as per BCUC IR #1.20.3 and BCOAPO IR #1.47.0(b).
11. Corrected classification of Aboriginal Relations charge as per BCUC IR #1.20.3 and BCOAPO IR #1.56.0(c).
12. Corrected assignment of $1.9m under Regional Facilities for F2001 from G&A, Coastal Region to Operations, Coastal Region.
13. Corrected values for NTSA and Other Net Exchanges for F2003 and F2004.
14. Reclassification of ARD expenditures ($5.0m) from SS&I to "Other".
15. Reclassification of ARD expenditures ($5.0m) from SS&I to "Other".
16. Headcount mix restated as per BCUC IR #2.184.0

Volume 1. Summary Table of Contents

SCHEDULE A-9

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

	A F2003 Actual	B F2004 Forecast	C F2005 Plan	D F2006 Plan	Sched.	Reference	Chapter
Domestic cost of energy :							
Water rentals	$258	$246	$265	$281	D1-2	Gen (HC)	Ch 5
Independent Power Producers and long-term purchase commitments	290	378	378	397	C2	En. Supply Cost	Ch 4
Market electricity purchases	54	249	105	55	D1-2	Gen (HC)	Ch 5
Net Purchases from Powerex	50				D1-2	Gen (HC)	Ch 5
Natural gas for thermal generation[1]	28	28	28	24	D1-2	Gen (HC)	Ch 5
Domestic cost of energy - Non-integrated Areas	14	13	14	15	C4	Dist &NIA	Ch 7
Domestic transmission	5	16	16	16	D1-2	Gen (HC)	Ch 5
Gas transportation	5	10	13	13	C2	En.Supply Cost	Ch 4
Cost of market[2]	1	1	1		C3	Transmission	Ch 6
Other	3	3	4	7	D1-2	Gen (HC)	Ch 5
Total Domestic cost of energy	$708	$944	$824	$808			

	F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan
Domestic energy:				
GW·h's				
Water rentals	47,665	44,759	46,130	46,293
Independent Power Producers and long-term purchase commitments	4,950	6,229	6,598	7,003
Market electricity purchases	896	4,930	2,316	1,506
Net Purchases from Powerex	1,113			
Thermal generation	251	242	258	194
Non-integrated Areas	96	98	107	105
Exchange net	(1,605)	(1,179)	560	660
	53,366	55,079	55,969	55,761
Less: Line loss and system use	(4,689)	(5,325)	(5,422)	(5,457)
Net sales to Powerex		(623)	(1,260)	(700)
Domestic sales volumes	48,677	49,131	49,287	49,604
$/MW·h				
Water rentals	$ 5.413	$ 5.496	$ 5.745	$ 6.070
Independent Power Producers and long-term purchase commitments	58.586	60.684	57.290	56.690
Market electricity purchases	60.268	50.507	45.337	36.521
Net Purchases from Powerex	44.924			
Natural gas for thermal generation	111.554	115.702	108.527	123.711
Domestic cost of energy - Non-integrated Areas	145.833	132.653	130.841	142.857
Total weighted average cost[3]	$ 14.545	$ 19.214	$ 16.718	$ 16.289

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Notes:

1. This includes fixed transportation costs of approximately $10 million related to the Bypass Transportation Agreement between Terasen and BC Hydro.
2. Domestic cost of energy transmission which includes congestion management cost.
3. Relates to total cost divided by sales volumes.

SCHEDULE D4

Resource Usage - Transmission
($ millions)

Line		F2003 Actual	F2004 Forecast	F2005 Plan	F2006 Plan BC Hydro	F2006 Plan BCTC
	Operations, Maintenance and Administration Expenses by Resources					
	Labour					
1	Direct	17.5	23.0	28.1		28.6
2	Indirect	7.4	9.9	11.2		11.4
3	Materials	8.2	5.2	4.4		4.4
	BC Hydro Services					
4	Engineering	12.7	13.1	14.2		14.2
5	Field Services	63.0	73.4	69.2		69.2
6	BC Hydro Corporate Direct Charges	3.0	3.9	5.7	4.8	0.9
7	Other BC Hydro Billings	5.9	4.6	3.8		4.9
	External Services					
8	ABS*	7.9	10.3	10.0		10.6
9	Other	16.7	31.4	29.5		28.0
10	Buildings & Equipment	1.6	2.1	2.9		2.8
11	Vehicles	0.1	0.1	0.1		0.1
12	Corporate Allocation	28.0	22.7	15.4	16.2	
13	Less: Capitalized Overhead	(5.2)	(5.2)	(5.2)		(5.2)
	Less: Recoveries					
14	Internal	(6.8)	(6.3)	(6.3)		(5.0)
15	External	(1.8)	(0.1)	(0.1)		(0.1)
16	Total OMA Expenses	158.2	188.1	182.9	21.0	164.8
	Operations, Maintenance and Administration Expenses by Category					
17	Direct	123.7	142.0	154.0	4.8	151.1
18	Support	20.3	35.0	25.1		24.0
19	Corporate Allocations	28.0	22.7	15.4	16.2	
20	Less: Capitalized Overhead	(5.2)	(5.2)	(5.2)		(5.2)
21	Less: Recoveries	(8.6)	(6.4)	(6.4)		(5.1)
22	Total OMA Expenses	158.2	188.1	182.9	21.0	164.8
	Capital Expenditures					
23	Sustaining	99.1	143.0	155.0	104.0	43.0
24	Growth	68.0	53.0	89.0	162.0	
25	CIA	(12.2)	(8.0)	(8.0)	(9.0)	
26	Total Capital Expenditures	154.9	188.0	236.0	257.0	43.0
	Headcount					
27	M&P	100	171	181	-	181
28	IBEW	86	98	98	-	98
29	OPEIU	42	47	47	-	47
30	Total Headcount	228	316	326	-	326

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

F2004 includes $11.1 million relating to restructuring costs.

2. Power Smart

The costs associated with Power Smart programs before and since F2002 are summarized in Table 4-2. This table summarizes the Power Smart cost expensed for each of the periods identified; the Power Smart deferred capital expenditures are detailed in chapter 8, section 1.5.

Table 4-2. Power Smart Costs

($ millions)	F2003	F2004	F2005	F2006
OMA	$12.8	$19.1	$22.6	$22.4
Amortization of Power Smart before F2002	23.4	18.0	13.3	8.4
Amortization of Power Smart from F2002	1.5	6.3	17.7	28.1
Amortization subtotal	**$24.9**	**$24.3**	**$31.0**	**$36.5**
Finance charges	5.0	4.3	4.6	6.0
Allowed ROE	4.0	3.8	4.3	4.7
Total	**$46.7**	**$51.5**	**$62.5**	**$69.6**

2.1.1. Power Smart Before F2002

BC Hydro initiated a significant Power Smart program in 1989. As of the end of F2001, it yielded energy savings of 2,459 GWh/year at a portfolio total resource cost (TRC) of 3.8 cents/kWh and a portfolio utility cost of 2.0 cents/kWh. The amortization of BC Hydro's costs amounts to $13.3 million and $8.3 million for F2005 and F2006, respectively. This amount is decreasing rapidly each year as the initial programs are fully amortized.

2.1.2. Power Smart Since F2002

In F2001, BC Hydro forecasted that approximately 10,000 GWh of new electricity supply was required to meet the projected increase in load over the following 10-year period. BC Hydro assessed the achievable potential for incremental electricity savings from Power Smart, drawing on the 1993-1994 Conservation Potential Review (CPR). The CPR was an in-depth analysis of where, how and at what cost electricity consumption in BC could be reduced through energy efficiency and behavioural changes. The CPR indicated that there was about 6,000 GWh/yr of electricity savings potentially achievable between 1990 and 2010 at a cost of less than 6 cents/kWh (cost of conserved energy). As noted above, the Power Smart programs initiated before F2002 achieved an estimated 2,459 GWh/year of electricity savings. Therefore, approximately 3,500 GWh/yr of the CPR's estimated

Table 6-1. Total Transmission Revenue Requirement Summary

($ millions)	F2005 Plan	F2006 Plan	
Operations, Maintenance & Administration			
System Operations	$44.2	$45.7	
Asset Management & Maintenance	106.4	106.8	
General & Administration	18.6	17.5	c
BC Hydro Corporate Allocation	15.4	16.2	
BC Hydro Rights Management, Properties, and Asset Retirement Obligation	4.8	4.8	c
Total Operations, Maintenance & Administration	$189.3	$190.9	
Cost of Market	1.0	5.8	
Asset Related Expense			
Finance Charge	131.0	141.5	
Depreciation & Amortization	151.9	159.4	
Grants & Taxes	89.5	90.8	
Allowed Return	123.0	129.9	
Total Cost	**$685.8**	**$718.3**	
Less Non-WTS Revenues and Recoveries			
Non-WTS Revenues:			
Generation Related Transmission Assets	(43.3)	(43.3)	
Substation Distribution Asset Management	(69.6)	(70.4)	
Aquila General Wheeling Agreement	(3.8)	(3.8)	
Secondary Revenues	(4.2)	(5.6)	
	(120.9)	**(123.1)**	
Cost Recoveries:			
Generation Dispatch Services	(1.1)	(1.1)	
Distribution Dispatch Services	(2.6)	(2.6)	
Control Centre Leases	(1.4)	-	
Other Recoveries	(1.4)	(1.4)	
	(6.5)	**(5.1)**	
Total Non-WTS Revenues and Recoveries	**$(127.4)**	**$(128.2)**	
Total Transmission Revenue Requirement	**$558.4**	**$590.1**	

F2005 reflects Phase 1 of BC Hydro and BCTC's relationship. During Phase 1, BC Hydro has retained BCTC to administer the WTS tariff and BCTC has been given the responsibility for planning, operating, and maintaining the transmission system. All costs associated with providing transmission service, including those related to BCTC, are paid by BC Hydro. BC Hydro is seeking to recover the net amount of these costs of $558.4 million (Table 6-1).

3 Gross Operating and Maintenance Expenditures

Table 6-2 shows transmission operations, maintenance, and administration expenses for F2003 to F2006. These are comprised of:

- system operations expenses;
- asset management and maintenance;
- general and administration expenses; and
- BC Hydro rights management, properties, and asset retirement obligations.

Table 6-2. Operations, Maintenance, and Administration Costs Summary

($ millions)	F2003 Actual *(Note 1)*	F2004 Forecast	F2005 Plan	F2006 Plan
Transmission System Operation		$37.7	$44.2	$45.7
Asset Management and Maintenance		103.0	106.4	106.8
General and Administration		27.5	18.6	17.5
BC Hydro Rights Management, Properties, and Asset Retirement Obligation		3.2	4.8	4.8
BC Hydro Corporate Allocation		22.7	15.4	16.2
Total Cost		**$194.1**	**$189.3**	**$190.9**
Deduct: Cost Recoveries		(6.0)	(6.5)	(5.1)
Total per Financial Statements	**$158.2**	**$188.1**	**182.9**	**$185.8**

Notes:
1. F2003 Costs are not available in the same categories as subsequent years due to accounting and restructuring changes that occurred post-F2003.

The increase in Operations, Maintenance, and Administration costs from F2003 to F2004 is explained in Table 6-3.

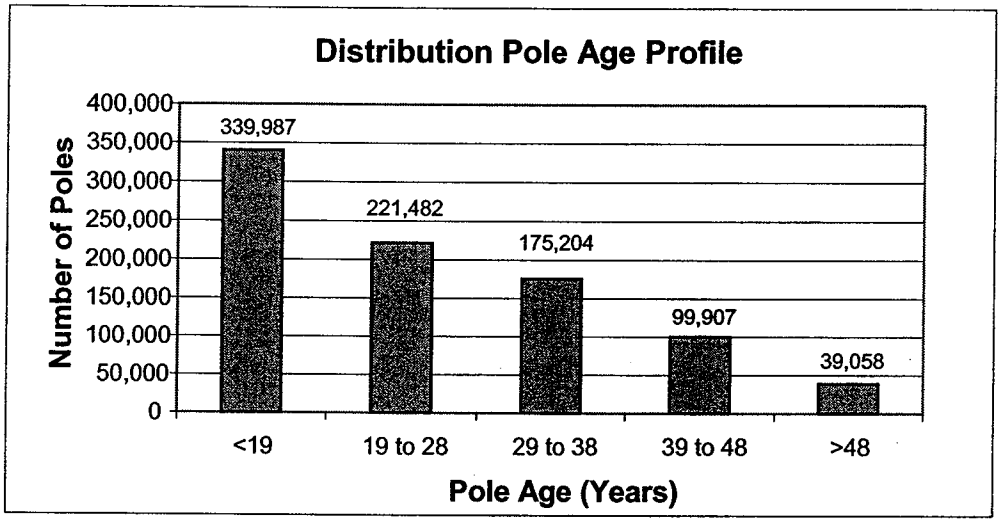
Table 6-3. Reconciliation of Operations, Mtce, and Admin Costs, F2003 to F2004

	($ millions)
F2003 Actual	**$158.2**
Accounting Changes	14.9
One-time BCTC establishment cost	11.1
Additional operating costs	0.4
Ex-plan forest fire repair cost	3.9
Ex-plan maintenance cost	5.4
Ex-plan cyberspace security review	0.4
Corporate Allocation Reduction	(5.3)
Intra-SBU budget transfers	(0.9)
F2004 Forecast	**$188.1**

2.7.1.2 Overview of Asset Health

Asset health is a direct driver of operating, maintenance, and capital expenditures. The distribution network asset health is generally good, meaning that in the near term it is able to continue to provide the service that it was designed for. The major caveat is that an increasing proportion of the facilities is at or approaching end of life, which means increasing maintenance efforts and expenditures will be required.

Figure 7-3 shows an age profile for poles, one of the major asset categories, for F2003. | C



| C

Figure 7-3. Distribution Pole Age Profile

The age profile of distribution poles is considered typical for other asset categories. The average life expectancy for poles is 40 years. As noted in Figure 7-3, 15% of poles are older than the average life expectancy, and with an additional 20% reaching that threshold within 10 years, a disproportionately high number of poles is nearing the end of their expected lives. Age is a major factor influencing asset health and this age profile indicates that additional sustaining investments (maintenance or replacement) will be necessary to manage asset failures and equipment-related outages.

BC Hydro conducts an annual assessment of the condition of its distribution assets. The following is a summary of the current condition of the assets, as well as BC Hydro's response to asset condition.

Future capital spending requirements are identified within the operating plans presented in chapters 3 to 9. Table 11-2 identifies the forecast capital additions by expenditure category for F2004 to F2006.

Table 11-2. Capital Expenditure Forecast, F2004 to F2006

Expenditure Category ($ millions)	F2004			F2005			F2006			
	S	G	Total	S	G	Total	S	G	Total	
Generation Hydro	$95	$22	$117	$96	$13	$109	$123	$12	$135	
Generation Thermal	6	33	39	3	58	61	3	193	196	
Transmission - Lines	71	16	87	41	9	50	44	12	56	
Substations	34	37	71	45	80	125	53	150	203	
Distribution	75	118	193	84	123	207	86	130	216	
Computers	65	2	67	60	4	64	50	4	54	
Land & Buildings	10	0	10	8	0	8	6	0	6	
Surveys & Investigations (incl Aboriginal Negotiations)	9	0	9	10	0	10	5	0	5	C_2
Vehicles	21	0	21	17	0	17	19	0	19	
Power Smart	0	116	116	0	105	105	0	94	94	
Other	27	0	27	18	0	18	5	0	5	C_2
BCTC *(Note 2)*	12	0	12	47	0	47	0	0	0	
Gross Expenditures	$425	$344	$769	$429	$392	$821	$394	$595	$989	
CIA - Specific	0	-8	-8	0	-8	-8	0	-9	-9	
CIA - Recurring	-3	-37	-39	-4	-38	-42	-4	-41	-45	
Net Expenditures incl BCTC *(Note 3)*	$422	$299	$722	$425	$346	$771	$390	$545	$935	

Notes:
1. S = Sustaining Capital Expenditures; G = Growth Capital Expenditures
2. Includes expenditures on BCTC-owned assets only.
3. BCTC Capital Expenditures are consolidated for F2004 and F2005 only (see section 3.10, page 2-21).
4. Some columns do not total due to rounding.

This remainder of this chapter includes lists of historical (since F1994), in-progress, or planned capital projects, by line of business or service organization, with capital cost greater than $2 million. Descriptions are provided for projects with capital cost greater than $5 million.

As discussed in chapter 6, BCTC has responsibility for planning and justifying capital projects relating to BC Hydro's transmission assets. As a result, historical, in-progress, and planned capital expenditures relating to transmission assets are identified in chapter 6.

Note: application of the cost of new supply to the energy savings by region is beyond the scope of this analysis (note: the only exception is a few specific programs in the residential sector that target residents on Vancouver Island). In addition, for the purpose of conservatism, capacity savings were not estimated or valued in this analysis, thus making the analysis conservative.

Resource Supply Cost of Natural Gas

Some of the programs in the residential sector include the conversion of electric appliances to natural gas appliances. The kWh savings are converted to GJ and then multiplied by the forecast resource supply cost of natural gas. This figure is then multiplied by the relative efficiency rating of the energy efficient equipment.

Source: BC Hydro's Long Run Natural Gas Price Forecast (January 2003).

Greenhouse Gas Emissions

Each GWh of electricity that Power Smart saves is assumed to eliminate the production of electricity from new sources. It is assumed that these new sources of electricity would generate 360 tonnes of green house gases per GWh. Each tonne of green house gases is valued at $3 per tonne (i.e. $1,080 per GWh saved). For the purpose of conservatism, the green house gas valuation of $3 per tonne is assumed to be constant in all 20 years (i.e. 0% inflation is assumed).

Source: Green house gas emissions and values estimated by BC Hydro's Green House Gas Staff (J. Duffy and T. Ferguson), May 2003.

Customer Electricity Tariff Rates

Outlined below is a summary of the tariff rates that were assumed in the analysis (note: this rate is used to compute the customers' electricity savings as well as BC Hydro's forgone revenues):

- *Residential Sector:* the analysis assumes the trailing step (1101) tariff of 5.77 cents per kWh.

Source: BC Hydro Rates Department, "Electricity Service – Residential (1101) – Zone I".

- *Commercial/Government Sector:* the analysis assumes a blended tariff of 5.34 cents per kWh based upon the weighted average consumption of General 35 KW and over and Under General 35 KW customers in fiscal 2002/03.

Source: BC Hydro, Power Smart Business Systems Group (H. Bains), May 2003.

- *Industrial Sector:* the analysis assumes a blended tariff of

3.61 cents per kWh. This is based upon the following assumptions: 85% of the industrial sectors' electricity consumption is at the 1821 tariff of 3.30 cents per kWh and 15% of the industrial sectors' electricity consumption is at the blended tariff of 5.34 cents per kWh for the commercial/government sector (i.e. 3.61 cents per kWh is the weighted average). | c

Source*:* The 1821 tariff is based upon a billing analysis of the industrial sector's accounts within the 1821 tariff. The 85%/15% allocation of the energy savings within the industrial sector is based upon Power Smart's estimate of the achievable energy savings in the industrial sector giving consideration to the Conservation Potential Review's achievable energy savings targets.

Discount Rate

A nominal discount rate of 8% is used to discount the streams of benefits, costs and energy savings back to fiscal 2002/03. This includes the estimated inflation of 2.0% per year.

Source: Discount rate provided by BC Hydro's Controller's Division, May 2003.

Line Losses

For the purpose of calculating TRC and utility cost, line losses were used to gross-up the energy savings at the customers' meters to reflect the actual electricity generation savings that BC Hydro will realize. The following line losses were applied to each sector:

- *Residential Sector:* line losses of 7%.
- *Commercial/Government Sector:* line losses of 7%.
- *Industrial Sector:* line losses of 3.6%. This is based upon the following assumptions: 85% of the industrial sectors' electricity consumption is at the 1821 tariff with line losses of 3% and 15% of the industrial sectors' electricity consumption is at the 12xx tariffs with line losses of 7% (i.e. 3.6% is the weighted average).

Source: BC Hydro's Resource Planning and Load Forecasting Divisions, May 2003. The 85%/15% allocation of the energy savings within the industrial sector is based upon Power Smart's estimate of the achievable energy savings in the industrial sector giving consideration to the Conservation Potential Review's achievable energy savings targets.

Free Riders, Free Drivers and Monitoring & Verification

The programs in each sector have individual assumptions for free riders, free drivers and Monitoring and Verification (M&V). A free rider is defined as someone who participates in the Power Smart program and receives the incentive/rebate but would have undertaken the energy efficient project without the incentive/rebate. The assumption for free riders range from 3% to 22% for individual

1.0 Reference: Volume 1, p. 1-15, Cost Drivers

1.1.3 Please provide a cost summary of requirements needed to maintain the reliability of the system.

RESPONSE:

Table 1 shows the overall OMA and capital expenditures, by function required to maintain the reliability of the system.

Table 1 Expenditures Required to Maintain Reliability of the System

($ millions)	F1994 Actual Estimated	F2003 Actual	F2004 YEF	F2005 Plan	F2006 Plan	
Distribution						
OMA	61.4	71.8	70.5	77.4	77.5	C
Capital	39.4	50.9	62.9	63.7	67.0	
Sub-Total	100.8	122.7	133.4	141.1	144.5	C
Generation						
OMA	53.0	49.9	48.3	53.4	53.5	
Capital	53.9	95.5	98.1	101.1	125.3	
Sub-Total	106.9	145.4	146.4	154.5	178.8	
Transmission						
OMA	99.8	84.2	100.7	105.1	105.1	
Capital	30.0	88.0	120.0	98.0	90.0	
Sub-Total	129.8	172.2	220.7	203.1	195.1	
Total OMA	214.2	210.6	219.5	235.9	236.1	
Total Capital	123.3	234.4	281.0	262.8	282.3	
Total OMA and Capital	337.5	440.3	500.5	498.7	518.4	C

Notes:

- **While the above OMA and capital expenditures do impact reliability, they may also impact other drivers e.g., safety.**
- **The OMA costs consist of direct maintenance spending only.**
- **The F1994 OMA costs for distribution, transmission and generation are estimated.**

2.0 Reference: Application, Volume I, Chapter 2, Consolidated Revenue Requirements and Financial Schedules

1.2.10 Page 2-16, Table 2-13: What projects have been abandoned or studies capitalized over F2003 and F2004, and which are forecast over F2005 and F2006?

RESPONSE:

The abandoned projects and studies capitalized over F2003 to forecast F2006 are listed in the table below.

Summary of SSI Project Expenditures for F2003 to F2006
(in millions)

Project Name	Brief Project Description	Expenditures Capitalized F2003	F2004	F2005	F2006	
Site Studies, Aboriginal Negotiation & Settlement Projects and Other Deferred Project costs capitalized						
Dam Safety Deficiency Investigations						
WAC Bennett Dam Project DI		0.3				
Ruskin Dam DI		1.0				
Coquitlam Dam DI		1.8				
Hugh Keenleyside Earthfill Dam DI		0.2				
Ruskin Dam - Stave Falls Dam - Deficiency Investigations			0.5			
LaJoie Dam Shotcrete & Seismic Resistance			0.3			
John Hart Dam - Deficiency Investigation			0.1			
Seton Dam - Deficiency Investigations (Power Canal, Spillway)			0.1			
Hugh Keenleyside Dam - Remediation Options			0.1			
Spillway Gate Operation After Seismic Event			0.1			
Mica Dam - Flood & Seismic Capacity, Slopes			0.1			
Strathcona Dam - Deficiency Investigation			0.1			
Peace Canyon - Seismic Stability				0.5	0.6	
Strathcona - Embankment Dam and Power Outlet Works				0.5	-	
Revelstoke - Seismic Performance and Other Issues				0.2	0.3	
Mica - Performance Assessment (Embankment Dam)				0.3	0.2	
GM Shrum - WAC Bennett Fines Mitgration DI				0.4	-	
Strathcona - PMF and Spillway Capacity, Campbell R. System				0.3	0.1	
Clowhom - Seismic Stability				0.2	0.1	
Seton - Seismic Stability of Dam & Canal				0.2		
Aberfeldie Dam Spillway & River Bank Stability				0.1		
Spillimacheen - Structural Stability				0.1		
Hugh Keenleyside - Safety Case				0.1		
Hugh Keenleyside - Reliability of Discharge Facilities				0.1		
Total Dam Safety Deficiency Investigations		3.3	1.3	2.8	1.3	
Aboriginal Negotiation and Settlement Projects [1]						
Capitalized Aboriginal Negotiation and Settlement costs		7.5	7.2	6.8	3.6	C
Other Deferred Project Costs Capitalized						
ABS start-up - deferred RFEI costs	Cost of ABS transaction structuring, legal, and other advisory services associated with the transaction. These deferred transaction costs will be amortized on a straight-line basis over the initial term of the agreement.	10.0	-	-	-	
Total Studies and deferred costs capitalized		20.8	8.5	9.6	4.9	C
Abandoned Projects Written-Off						
Wind Energy	10MW wind farm project on VI	1.3		-		
Wave Energy	Testing of 20 MW wave technology on the west coast of VI.	0.1	-	-	-	
Wave Energy	Testing of 4 MW wave technology on Vancouver Island.	0.4	-	-	-	
Wind Energy	Wind Energy - Energy Futures	0.2				
Wind Energy	Wind Site Identification - Wind Energy Development	0.8	-	-	-	
Total write-down of abandoned projects		2.8	-	-	-	

Note 1: Aboriginal negotiation, litigation and settlement costs are capitalized and amortized over 10 years pursuant to BCUC Order Number G-53-02.

2.0 Reference: Application, Volume I, Chapter 2, Consolidated Revenue Requirements and Financial Schedules

1.2.20 Page 2-49, Schedule A-9, Line 33: Receipt of Non-Treaty Storage in F2003 (Exchange net) appears to drive Market purchases and Purchases from Powerex. Please explain.

RESPONSE:

The item labelled "Exchange net" in Chapter 2, Page 2-49, Schedule A-9 and Chapter 4, Page 4-18, Table 4-7 includes net energy deliveries under the Non-Treaty Storage Agreement (NTSA), the Canal Plant Agreement, the Keenleyside Entitlement Agreement and several shorter-term Treaty Operating Agreements. The table below shows the NTSA component of Exchange net:

Fiscal	NTSA	Other Net Exchanges	Total Net Exchanges
F2003	**(65)**	**(1,540)**	**(1,605)**
F2004	**(301)**	**(878)**	**(1,179)**
F2005	**515**	**45**	**560**
F2006	**499**	**161**	**660**

There is no direct relationship between the NTSA component of Exchange Net and either "Market electricity purchases" (energy purchased from Powerex that is needed to economically serve domestic load) or "Net Purchases from Powerex" (energy purchased by Powerex for the purpose of electricity trade).

The NTSA, which is attached in its entirety to BC Hydro's response to BCUC IR # 1.4.13, provides significant benefits of additional stream flow regulation to both BC Hydro and the Bonneville Power Administration (BPA) through the co-operative use of reservoir storage (primarily at Mica) and generation at Mica, Revelstoke and Keenleyside and at the eleven projects downstream in the United States.

Under the NTSA, use of non-treaty reservoir storage at Mica is shared equally by BC Hydro and BPA. BC Hydro is obligated to send electricity to BPA when:

- **BPA releases water from their account resulting in increased generation at Canadian projects; or**
- **BC Hydro stores water into its account, causing a reduction in generation at downstream projects in the United States.**

Similarly, BPA is obligated to send energy to BC Hydro when:

- **BC Hydro releases water from its account resulting in increased generation at downstream projects in the United States; or**
- **BPA stores water into its account, causing a reduction in generation at Canadian projects.**

Operating Costs and Headcount - Organizational View

ORGANIZATION	F2001 Actual		F2002 Actual		F2003 Actual		F2004 Forecast		F2005 Plan		F2006 Plan	
	$Millions	Headcount	$Millions	Headcount	$Millions	Headcount	$Millions	Headcount	$Millions	Headcount	$Millions	Headcount
Peace Region	13.4	95	13.8	97	12.7	94	13.2	100	14.2	100	14.4	101
Columbia Region	19.2	149	18.0	149	18.9	142	19.7	143	23.9	142	24.2	140
Coastal Region	47.7	246	55.4	291	48.2	284	40.5	228	39.7	224	40.0	224
Total Regions	80.3	490	87.3	539	79.8	520	73.4	471	77.8	466	78.6	465
Engineering Services	(1.5)	242	12.1	232								
Resource Management	15.3	84	20.3	76	13.4	73						
Business Integration	0.4	-	0.5	-								
Operations & Energy Purchasing							13.3	65	12.6	63	13.1	64
Dam Safety	5.6	5	1.6	5	4.5	19	4.2	21	4.3	22	4.3	21
Sustainability/Aboriginal Relations							7.9	57	6.8	53	6.6	52
Aboriginal Relations							-	-	-	-	-	-
Strategic Projects					1.0	-						
Strategic Asset Management					5.5	29						
Business Development							3.4	15	2.8	15	2.8	15
Subtotal	21.3	89.0	22.5	81.0	24.3	140.0	28.8	158	26.5	153	26.8	152
Controller's Office	5.2	76	8.6	80	2.7	32	7.6	55	7.9	52	7.6	50
Human Resources	1.3	10	0.9	7	1.2	7	1.1	7	1.3	7	1.3	7
Other	7.0	21	0.1	57	11.4	61	15.1	65	11.9	57	11.7	53
Total Line of Business Support	13.5	107	9.7	144	15.4	100	23.8	127	21.1	116	20.6	110
Total BC Hydro Generation Operating Costs	113.5	928	131.6	996	119.5	760	126.0	756	125.4	735	126.0	727
RESOURCE MANAGEMENT	15.3	84	20.3	76	13.4	73						
OPERATIONS & ENERGY PURCHASES												
Operations and Maintenance												
Real Time Operations							2.3	14	2.1	14	2.1	14
Operations Planning							4.2	28	4.0	27	4.4	28
Hydrology							3.5	16	3.3	16	3.4	16
General and Administration												
Environmental Program							0.4	2	0.4	2	0.4	2
Information Technology							2.9	5	2.8	4	2.8	4
Total Operating Costs							13.3	65	12.6	63	13.1	64
ENGINEERING SERVICES	(1.5)	242	12.1	232								
BUSINESS INTEGRATION	0.4	-	0.5	-								
STRATEGIC PROJECTS					1.0	-						
STRATEGIC ASSET MANAGEMENT					5.5	29						
BUSINESS DEVELOPMENT and ASSET MANAGEMENT												
General and Administration												
Planning Generating Systems							3.4	15	2.8	15	2.8	15
REGIONAL FACILITIES												
Operations (O)												
Peace Region	5.0	N/A	2.3	N/A	1.0	N/A	0.5	6	0.5	6	0.5	6
Columbia Region	5.1	N/A	3.9	N/A	5.9	N/A	1.4	7	1.3	7	1.3	7
Coastal Region	19.1	N/A	9.0	N/A	10.3	N/A	6.3	47	6.2	47	6.4	47
Subtotal (O)	29.2	N/A	15.2	N/A	17.3	N/A	8.2	60	8.0	60	8.2	60
Maintenance (M)												
Peace Region	8.3	N/A	7.2	N/A	9.7	N/A	10.5	77	10.8	77	11.1	78
Columbia Region	14.1	N/A	8.7	N/A	8.9	N/A	11.3	107	15.4	106	15.8	105
Coastal Region	28.6	N/A	28.9	N/A	22.8	N/A	23.2	131	22.6	131	23.0	136
Subtotal (M)	51.0	N/A	44.8	N/A	41.4	N/A	45.0	315	48.8	314	49.9	319
General and Administration												
Peace Region	0.1	N/A	4.4	N/A	2.0	N/A	2.2	17	2.9	17	2.8	17
Columbia Region	0.0	N/A	5.4	N/A	4.0	N/A	7.0	29	7.2	29	7.1	28
Coastal Region	0.0	N/A	17.5	N/A	15.1	N/A	11.0	50	10.9	46	10.6	41
Subtotal General and Administration	0.0	N/A	27.3	N/A	21.1	N/A	20.2	96	21.0	92	20.5	86
Total Operating Costs	80.3	490	87.3	539	79.8	520	73.4	471	77.8	466	78.6	465

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[Revision 1, March 29, 2004]

Capital Expenditure Summary
For the Years ended March 31
(in millions)

Gross Capital Expenditures	F1994	F1995	F1996	F1997	F1998	F1999	F2000	F2001	F2002	F2003 S	F2003 G	F2003 Total	
Electric System													
Generation - Hydro	29	35	34	37	52	76	48	37	87	88	58	146	
Generation - Thermal	18	19	22	25	21	28	70	38	63	6	76	82	
Transmission	117	131	78	55	42	51	90	91	93	88	68	156	
Subtotal	**164**	**185**	**134**	**117**	**115**	**155**	**208**	**166**	**243**	**182**	**202**	**384**	
Distribution													
Expansion and Improvements	198	178	182	164	148	142	140	146	154	49	121	170	
Total Electric System	**362**	**363**	**316**	**281**	**263**	**297**	**348**	**312**	**397**	**231**	**323**	**554**	c
General													
Computers	13	11	11	20	22	55	60	46	70	82	6	88	
Land & Buildings	14	5	10	8	6	9	5	13	12	4	0	4	
Surveys & Investigations	13	12	7	7	11	7	8	4	10	11	0	11	
Tools & Equipment	7	4	3	2	2	1	4	4					
Vehicles	9	12	11	6	8	14	13	14	10	14	0	14	
Other	10	4	7	2	4	5	7	13	32	25	0	25	
Subsidiaries	1	3	1	1	0	2	2	4					
Under (over) applied overhead	1	(2)	(2)	1	3	(4)	(1)	2					
Total General	68	49	48	47	56	89	98	100	134	136	6	142	
Subtotal Capital Expenditures	**430**	**412**	**364**	**328**	**319**	**387**	**446**	**412**	**531**	**367**	**329**	**696**	
Deferred Power Smart	54	59	33	23	6	5	3	1	14		45	45	c
Total Gross Capital and DSM Expenditures	**484**	**471**	**397**	**351**	**325**	**392**	**449**	**413**	**545**	**367**	**374**	**741**	
Less Contributions in Aid													
Specific									(16)			(17)	
Recurring									(38)			(45)	
Total CIA	(56)	(51)	(51)	(48)	(47)	(39)	(41)	(44)	(54)			(62)	
Total Net Capital and DSM Expenditures	**428**	**420**	**346**	**303**	**278**	**353**	**408**	**369**	**491**	**367**	**374**	**679**	c

Notes:
1. Figures restated to reflect presentation in F2003.

FIELD SERVICES

The monthly Field Services Management Report is the key document for identifying variances at the Key Business Unit (KBU) level. The report contains the recovery statements for each KBU along with performance against both financial and non-financial targets. This report is reviewed monthly at the Field Services management committee meetings. At that time, any variances in performance and associated corrective actions are discussed. In turn, each KBU manager would discuss their individual recovery statements with their own management teams and take corrective actions as necessary. In addition, the monthly management report is updated with a current annual forecast in order to identify trends against plan. The Field Services performance targets and actual results for F2003 and year-to-date December actual results for F2004 are provided in the following tables.

Summary of Performance KPI as March 31, 2003

Performance KPI's	Interior		LMVI/Stations		LMVI/Distribution		LMVI/Trans & Veg		CBU	
	YTD Actual	YTD Target	YTD Actual	YTD Target	YTD Actual	YTD Target	YTD Actual	YTD Target	YTD Actual	YTD Target
# of Disabling Injuries/Medical Aids	20	32	4	8	22	28	15	12	22	34
% of Total Planned Work Completed - Stations	98%	98%	102%	98%						
% of Preventative Maintenance Work Completed - Stations	99%	100%	100%	100%						
% of Planned Work Completed - Distribution										
% of Annual Inspections Completed							92%	92%		
% of Annual Corrective Maintenance Completed							94%	92%		
% of Scheduled Vegetation Maintenance Completed - Distribution							100%	95%		
% of Scheduled Vegetation Maintenance Completed - Transmission							104%	95%		
Preventable Outages										
CAIDI	2.76	2.15			2.48	2.15				
IBEW Labour Utilization	69.0%	69.0%	69.0%	69.0%	70.6%	69.0%	79.1%	69.0%	85.6%	80.0%
Vehicle Utilization	50.1%	50.0%	46.3%	50.0%	59.9%	50.0%	47.8%	50.0%		
Total Chargeable Hours									484.9	365.0

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