1.0 Reference: Exhibit B-5-1, Page 3-2 & BCUC IR #1, Question 151

1.1.1 Why is the change from 2006 Forecast to 2007 RRA as shown not equal to the difference between the columns?

RESPONSE:

Please refer to the responses to BCUC IR 1.148.1 and BCUC IR 1.151.1.

1.0 Reference: Exhibit B-5-1, Page 3-2 & BCUC IR #1, Question 151

1.1.2 Is the difference really between the 2006 RRA and 2007 RRA?

RESPONSE:

Please refer to the responses to BCUC IR 1.148.1 and BCUC IR 1.151.1.

2.0 Reference: Exhibit B-5-1, Page 3-3, Lines 17 to 20

1.2.1 Given that water inflows are 93% of average versus the 2006 RRA assumption of average water, what is the cost of energy increase solely related to compensating for the drop in the assumption from 100% to 93%?

RESPONSE:

The energy equivalent of a 7 per cent reduction in F2007 water inflows for the BC Hydro system is approximately 3900 GWh (F07/F08 RRA p.3-8, lines 9-10). If this reduction in water inflows were totally offset by market purchases during F2007, then the corresponding increase in cost of energy for F2007 is estimated, very roughly, at $175 million.

This calculation makes the simplifying assumptions that:

- **there is no change in end of F2007 system storage levels or F2007 system spill;**
- **incremental market purchases of only 3640 GWh (instead of 3900 GWh) are required to offset the reduced inflows due to an approximate 7 per cent reduction in transmission losses within BC;**
- **all of the incremental purchases, estimated at $194 million, are made at the expected F2007 average purchase price of $53.4 CDN/MWh (F07/F08 RRA p.2-4, line 7);**
- **water licence fees estimated at $19 million [at $5.1 CDN/MWh (F07/F08 RRA p.3-13, line 12)] are reduced due to the lower hydroelectric generation within BC; and**
- **any change in maintenance costs due to the reduced hydroelectric generation is negligible.**

It should be noted that as system inflows change, the system operating plan is continually re-optimized to account for the changing conditions. Assuming that everything but the substitution of inflows and imports would remain static is therefore a gross simplification.

2.0 Reference: Exhibit B-5-1, Page 3-3, Lines 17 to 20

1.2.2 Please provide the calculation of the difference due to the change in assumption in terms of both volume and price.

RESPONSE:

Please refer to the response to CEC IR 1.2.1.

No change in market purchase price was assumed – all incremental market purchases were assumed to be made at the forecast average purchase price for F2007.

2.0 Reference: Exhibit B-5-1, Page 3-3, Lines 17 to 20

1.2.3 If the assumptions for determining cost of energy were based on normal water inflows, what would the cost of energy be?

RESPONSE:

Please refer to the response to CEC IR 1.2.1.

2.0 Reference: Exhibit B-5-1, Page 3-3, Lines 17 to 20

1.2.4 If the assumptions for determining cost of energy were based on normal water inflows, would there be any other costs such as increased assumed water rentals and what would be appropriate estimates for those costs if any?

RESPONSE:

Yes, if water inflows for F2007 were normal (100 per cent) instead of 93 per cent, and if the additional inflows resulted in a corresponding increase in hydroelectric generation in the BC Hydro system, then there would be additional costs related to increased water rentals. There would also be increased transmission losses within BC associated with the additional generation. While maintenance requirements may change, it is expected that the net change due to the increased generation would be negligible.

Please refer to the response to CEC IR 1.2.1 for more details.

2.0 Reference: Exhibit B-5-1, Page 3-3, Lines 17 to 20

1.2.5 Please provide the historical water inflow information and the calculation of the average water inflow.

RESPONSE:

The historic total hydro system inflow energy equivalent as percent of normal for F1995 through F2006 is provided in the table below.

Fiscal Year	Percent of Normal
1995	93.6%
1996	100.1%
1997	101.0%
1998	116.9%
1999	94.2%
2000	108.6%
2001	93.2%
2002	88.4%
2003	100.3%
2004	95.0%
2005	95.2%
2006	99.5%

Note that F2005 actual and F2006 forecast are reported in the F07/F08 RRA as 90 per cent and 97 per cent of normal *weighted system inflow (Feb through Sep)*. The values provided in the table above are for the total system, April through March period, and for F2006 represent the actual, not forecast, value.

Because the energy equivalent of the inflows depends on the production capability of the system into which the inflows are received, the actual value of the energy produced under average inflow conditions varies. In other words, as resources are added to the system, the average energy production capability increases. A simple average of the historic inflow energy equivalent would produce a number that was too low for the current system configuration. For this reason, the values in the table are listed as a percent of normal.

Normal total system hydro energy production is calculated as the sum of: Heritage Contract average hydro energy; Arrow Lakes Hydro Entitlement energy; Canal Plant Agreement Entitlement energy, and Resource Smart additions post-Heritage Contract.

2.0 Reference: Exhibit B-5-1, Page 3-3, Lines 17 to 20

1.2.6 If one assumes that the historical average water inflows are a reasonable basis for predicting future water inflows, please provide the variability uncertainty with respect to each potential time period over which water inflows could be averaged (i.e. 2,3,4,5,6,7,8,9,10… years) showing decreasing uncertainty as the time period extends.

RESPONSE:

The standard deviation of the total hydro system inflow energy equivalent is estimated based on historic records to be approximately 3900 GWh. Assuming that the total hydro system inflow energy equivalent has a probability distribution that is normal, and that values for successive years are uncorrelated, then the standard deviation of the average over any n years is:

$$\frac{3900}{\sqrt{n}}$$

A 95 per cent confidence interval on a normal distribution represents values within 1.96 standard deviations of the mean. The following table gives the 95 per cent confidence interval limits on variation in the total hydro system inflow energy equivalent averaged over n years, rounded to the nearest 100 GWh.

No of Years	^{h} Percentile Limits (GWh)
1	± 7600
2	± 5400
3	± 4400
4	± 3800
5	± 3400
6	± 3100
7	± 2900
8	± 2700
9	± 2500
10	± 2400
20	± 1700
50	± 1100
100	± 800

2.0 Reference: Exhibit B-5-1, Page 3-3, Lines 17 to 20

1.2.7 Does BC Hydro believe that the historical average water inflows are a reasonable basis for predicting future water inflows? If not why not?

RESPONSE:

Yes.

2.0 Reference: Exhibit B-5-1, Page 3-3, Lines 17 to 20

With all other data being equal, what would BC Hydro anticipate the required rate increases or decreases for the next 20 years or 10 revenue requirement applications to be assuming:

1.2.8.1 future water inflow long term averages are highly correlated to past water inflow long term averages

RESPONSE:

BC Hydro expects the average required rate increase or decrease over the long-run to be the same under both of the methods described in CEC IR 1.2.8.1 and CEC IR 1.2.8.2.

By using the current method of adjusting Year 1 inflows based on the prevailing forecast, BC Hydro is better able to forecast the cost of energy for Year 1. With this better forecast, BC Hydro is then able to more accurately predict its short-term revenue requirements and, therefore, reduce the amounts placed into the related deferral accounts.

However, over the long-run, BC Hydro expects the Year 1 inflow forecast to be approximately normally distributed with an average of 100 per cent. This implies that, over the long-run, there should be no difference in the average required rate increase or decrease.

2.0 Reference: Exhibit B-5-1, Page 3-3, Lines 17 to 20

With all other data being equal, what would BC Hydro anticipate the required rate increases or decreases for the next 20 years or 10 revenue requirement applications to be assuming:

1.2.8.2 rates are set every two years using the assumption pattern BC Hydro now uses of adjusting to current experience for year 1 and assuming normal water for year 2.

RESPONSE:

Please refer to the response to CEC IR 1.2.8.1.

2.0 Reference: Exhibit B-5-1, Page 3-3, Lines 17 to 20

1.2.9 Does BC Hydro have any better predictor of future water inflows than historical water inflows?

RESPONSE:

BC Hydro does not have any better predictor of future water inflows other than historical water inflows.

Please also refer to the response to CEC IR 1.2.7.

2.0 Reference: Exhibit B-5-1, Page 3-3, Lines 17 to 20

1.2.10 Has BC Hydro analyzed its water inflow patterns to determine if there are any effects from global warming evident in its existing data?

RESPONSE:

BC Hydro has examined the annual inflow data at a number of BC Hydro's facilities and has not found any statistically significant long-term trends in the inflows.

3.0 Reference: Exhibit B-5-1, Table 2-26, Page 2-63

1.3.1 Please explain the 'Net sales to Powerex (displaced hydro generation)' on line 25 and why the energy difference does not have an equivalent cost entry in the section above?

RESPONSE:

Net sales to Powerex (displaced hydro generation) refers to energy sold by BC Hydro to Powerex, previously allocated to the trade account under the Transfer Pricing Agreement. The revenue is recorded under "Intersegment Revenues". These transactions are described in section 2.2.10, page 2-16 of the application. "Intersegment Revenues" are shown as a line item on the Pro Forma Consolidated Statement of Operations, schedule 2-1, line 11, page 2-38. A detailed schedule of "Intersegment Revenues" is shown on schedule 2-25, page 2-62. This energy is assumed to come from hydro resources and is recorded as part of Heritage Energy.

3.0 Reference: Exhibit B-5-1, Table 2-26, Page 2-63

1.3.2 Please explain the 'Exchange net' on line 28 and why the energy difference does not have an equivalent cost of energy entry in the section above?

RESPONSE:

Please refer to the response to BCUC IR 1.122.0.

4.0 Reference: Exhibit B-5-1, Page 2-15, lines 12 to 16, Exhibit B-5-1, Page 2-38, Schedule 2-1, & BCUC IR #1, Question 284

Please quantify each of the reasons given for anticipating higher Powerex net income regarding the assumptions in the 2006 RRA and those in the 2007 RRA:

1.4.1.1 Higher electricity prices;

RESPONSE:

Please refer to the response to BCUC IR 1.284.0.

4.0 Reference: Exhibit B-5-1, Page 2-15, lines 12 to 16, Exhibit B-5-1, Page 2-38, Schedule 2-1, & BCUC IR #1, Question 284

Please quantify each of the reasons given for anticipating higher Powerex net income regarding the assumptions in the 2006 RRA and those in the 2007 RRA:

1.4.1.2 Higher returns on long term deals;

RESPONSE:

Please refer to the response to BCUC IR 1.284.0

4.0 Reference: Exhibit B-5-1, Page 2-15, lines 12 to 16, Exhibit B-5-1, Page 2-38, Schedule 2-1, & BCUC IR #1, Question 284

Please quantify each of the reasons given for anticipating higher Powerex net income regarding the assumptions in the 2006 RRA and those in the 2007 RRA:

1.4.1.3 Long term deals not held before;

RESPONSE:

Please refer to the response to BCUC IR 1.284.0.

4.0 Reference: Exhibit B-5-1, Page 2-15, lines 12 to 16, Exhibit B-5-1, Page 2-38, Schedule 2-1, & BCUC IR #1, Question 284

Please quantify each of the reasons given for anticipating higher Powerex net income regarding the assumptions in the 2006 RRA and those in the 2007 RRA:

1.4.1.4 Growth in Eastern North American markets; and

RESPONSE:

Please refer to the response to BCUC IR 1.284.0

4.0 Reference: Exhibit B-5-1, Page 2-15, lines 12 to 16, Exhibit B-5-1, Page 2-38, Schedule 2-1, & BCUC IR #1, Question 284

Please quantify each of the reasons given for anticipating higher Powerex net income regarding the assumptions in the 2006 RRA and those in the 2007 RRA:

1.4.1.5 Increased gas activity.

RESPONSE:

Please refer to the response to BCUC IR 1.284.0.

4.0 Reference: Exhibit B-5-1, Page 2-15, lines 12 to 16, Exhibit B-5-1, Page 2-38, Schedule 2-1, & BCUC IR #1, Question 284

Please quantify each of the reasons given for anticipating higher Powerex net income regarding the assumptions in the 2006 RRA and those in the 2007 RRA:

1.4.2 Please provide estimates of the uncertainty involved in the forecast of Powerex net income in terms of expected standard error and confidence intervals.

RESPONSE:

Please refer to the response to BCUC IR 1.284.0.

4.0 Reference: Exhibit B-5-1, Page 2-15, lines 12 to 16, Exhibit B-5-1, Page 2-38, Schedule 2-1, & BCUC IR #1, Question 284

Please quantify each of the reasons given for anticipating higher Powerex net income regarding the assumptions in the 2006 RRA and those in the 2007 RRA:

1.4.3 Did BC Hydro consider forecasting Powerex trade income higher (at $160 million or 185 million) for the purpose of this revenue requirements application? If not why not?

RESPONSE:

Please refer to the response to BCUC IR 1.284.0.

4.0 Reference: Exhibit B-5-1, Page 2-15, lines 12 to 16, Exhibit B-5-1, Page 2-38, Schedule 2-1, & BCUC IR #1, Question 284

Please quantify each of the reasons given for anticipating higher Powerex net income regarding the assumptions in the 2006 RRA and those in the 2007 RRA:

1.4.4 Please provide all schedules and reports if any that formed the basis for BC Hydro's estimate of Powerex trade income.

RESPONSE:

Please refer to the response to BCUC IR 1.284.0.

4.0 Reference: Exhibit B-5-1, Page 2-15, lines 12 to 16, Exhibit B-5-1, Page 2-38, Schedule 2-1, & BCUC IR #1, Question 284

Please quantify each of the reasons given for anticipating higher Powerex net income regarding the assumptions in the 2006 RRA and those in the 2007 RRA:

1.4.5 Did BC Hydro consider asking BCUC for disposition of the deferred Powerex trade income to fill in any short fall if necessary for a higher forecast level of Powerex trade income?

RESPONSE:

No.

4.0 Reference: Exhibit B-5-1, Page 2-15, lines 12 to 16, Exhibit B-5-1, Page 2-38, Schedule 2-1, & BCUC IR #1, Question 284

Please quantify each of the reasons given for anticipating higher Powerex net income regarding the assumptions in the 2006 RRA and those in the 2007 RRA:

1.4.6 With $224 million in income deferred in the TIDA is there any reason for BC Hydro not to take the risk of higher trade income forecasts, given that the Powerex trade income performance has been significantly higher than forecast in the past if BCUC were prepared to approve disposition of the TIDA at least in part on the basis of trade income stabilization.

RESPONSE:

The TIDA was established pursuant to HSD #2.

Please also refer to the response to BCUC IR 1.284.0.

5.0 Reference: Exhibit B-5-1, Page 2-44 & Page 2-45, Schedules 2-7 and 2-8 & BCUC IR #1, Question 228

1.5.1 What is BC Hydro's estimate of the probability in any given year that the cost of energy as a consequence of water inflows will be greater or lesser than the forecast based on average expected water inflows?

RESPONSE:

Inflows may vary considerably from year to year, and within any one year from basin to basin, but the impact of these temporal and spatial variations may not translate directly to an impact on the cost of energy in each particular year. There are two reasons for this. First, BC Hydro operates a physical system with large reservoirs that provide the opportunity to shape energy between years to maximize the value of the system to the ratepayers. The optimal operational strategy for any given year may result in a carry over of the inflow variation into future years. Second, BC Hydro uses financial hedges in the market to mitigate a portion of the risk of inflow (and market) variations.

Ignoring the impact of physical (i.e. storage operation) and financial hedges, and estimating the impact of a change in inflows alone, it is not unreasonable to assume that there is a 50 per cent probability that the costs will be either higher or lower than forecast due to the impact of variability of inflows.

This assumption ignores the following:

1. **Due to system capability constraints, upper tail of inflow distribution (i.e. outliers) cannot be fully converted to energy due to spill.**

2. **For large inflow deficits, the cost associated with offsetting market purchases will be higher than the cost reductions associated with large inflow surpluses due to the nature of market prices (bound by 0 on the low end and unlimited on the high end) and market depth impacts.**

5.0 Reference: Exhibit B-5-1, Page 2-44 & Page 2-45, Schedules 2-7 and 2-8 & BCUC IR #1, Question 228

1.5.2 What is BC Hydro's estimate of the probability in any given year that the cost of energy as a consequence of average degree-day temperatures will be greater or lesser than the forecast based on the average expected in the forecasts?

RESPONSE:

The load response to temperature variation is most significant in colder months due to increased heating load, and less so, although still measurable, in the summer due to increased cooling load. Different load segments also have a different responsiveness to temperature variation.

The timing of any temperature differences during the year is critical. For example, a year with much colder temperatures in the winter and warmer in the summer, although average overall, will have a higher load.

The actual impact on cost of energy for the particular fiscal year when temperature variation is experienced depends on the optimized operation of the system. The actual operation may result in the load variance being served by increased hydro production from storage withdrawals or from market purchases, or some combination thereof. As a result, a portion of the cost of energy associated with the temperature variation may be shifted to other fiscal year(s).

Ignoring the complexities associated with monthly distribution of temperature variations and the impact of operational strategies, as noted above, it is not unreasonable to assume that there is a 50 per cent probability that the costs of energy will be either higher or lower than forecast due to the impact of temperature degree-days.

5.0 Reference: Exhibit B-5-1, Page 2-44 & Page 2-45, Schedules 2-7 and 2-8 & BCUC IR #1, Question 228

1.5.3 Please calculate and identify from the Heritage Deferral Account balances the costs deferred that are a direct consequence of water inflows being less than those anticipated in the RRA estimates.

RESPONSE:

In response to the changes in water inflows, market conditions, loads and generation unit availability, BC Hydro continuously re-optimizes its operations and purchasing strategy to maximize the value of the system to the ratepayers. These resulting operations and purchasing strategy may shift some of the impact of these changes to future year(s). As a result there is no direct relationship of a change in inflows and the cost of energy in any given fiscal year. Therefore, there is no direct offsetting relationship between the amount placed in the Heritage Deferral Account and the change in water inflows from those estimated in the RRA in any given fiscal year.

Ignoring the optimized operation implications noted above and the potential concomitant changes to transmission losses and water license fees, if variations to inflows compared to the F05/F06 RRA forecasts were to be directly offset by market purchases at the average purchase price within the individual fiscal years, the resulting impact on cost of energy is estimated to be as follows:

	Inflow variance from F05/F06 RRA (GWh)	**Average FY purchase price ($/MWh)**	**Impact on cost of energy ($ million)**
F2005	**+80**	**57.0**	**-4.6**
F2006	**-380**	**59.5**	**+22.6**

Note that the inflow variance with respect to the F05 RRA forecast is due to the measured total system inflows being slightly higher than was forecast, but still significantly below normal (95 per cent).

The costs associated with the impacts of transmission losses and water license fees were ignored because the inflow variance in the two years F2005 and F2006 was small.

5.0 Reference: Exhibit B-5-1, Page 2-44 & Page 2-45, Schedules 2-7 and 2-8 & BCUC IR #1, Question 228

1.5.4 Please calculate and identify from the Non-Heritage Deferral Account the costs deferred that are a direct consequence of water inflows being less than those anticipated in the RRA estimates.

RESPONSE:

For the reasons noted in the response to CEC IR 1.5.3, there is not a direct link between inflows and the Non-Heritage Deferral Account balance.

Appendix C Schedule 4 shows transfers of $18.3 million in F2005 (actual) and $110.2 million in F2006 (forecast) from Heritage Energy to Non-Heritage Energy, because of actual energy production exceeding both forecast and 49,000 GWh.

5.0 Reference: Exhibit B-5-1, Page 2-44 & Page 2-45, Schedules 2-7 and 2-8 & BCUC IR #1, Question 228

1.5.5 Please calculate and identify from the Heritage Deferral Account the costs deferred that are a direct consequence of average degree-day temperatures being greater than those anticipated in the RRA estimates.

RESPONSE:

There is not a direct link between the costs deferred and average degree-day temperatures.

5.0 Reference: Exhibit B-5-1, Page 2-44 & Page 2-45, Schedules 2-7 and 2-8 & BCUC IR #1, Question 228

1.5.6 Please calculate and identify from the Non-Heritage Energy Account the costs deferred that are a direct consequence of average degree-day temperatures being less than those anticipated in the RRA estimates.

RESPONSE:

There is not a direct link between the costs deferred and average degree-day temperatures.

5.0 Reference: Exhibit B-5-1, Page 2-44 & Page 2-45, Schedules 2-7 and 2-8 & BCUC IR #1, Question 228

1.5.7 Has BC Hydro considered disposition of the account balances in the Heritage Deferral Account and the Non-Heritage Deferral Account based on the timeframes over which water inflows and average degree day temperature variances may be expected to normalize, at least for the portions of these accounts directly caused by weather variability.

RESPONSE:

Please refer to the response to BCUC IR 1.228.4.

5.0 Reference: Exhibit B-5-1, Page 2-44 & Page 2-45, Schedules 2-7 and 2-8 & BCUC IR #1, Question 228

1.5.8 Please calculate and identify the portions of the Heritage Deferral Account and Non-Heritage Deferral Account balances, which are not directly affected by the water inflow and average degree-day temperature variability and disaggregate and attribute them to the specific causes of the variability.

RESPONSE:

It is not possible to disaggregate causes of Heritage Deferral Account and Non-Heritage Deferral Account balances in this way.

5.0 Reference: Exhibit B-5-1, Page 2-44 & Page 2-45, Schedules 2-7 and 2-8 & BCUC IR #1, Question 228

1.5.9 Where the cause of the variability giving rise to deferral of costs into the Heritage Deferral Account and the Non-Heritage deferral account is due to estimating uncertainty regarding economic parameters (such as market prices, hedging market outcomes, foreign exchange rates, economic growth etc.) does BC Hydro expect that its estimating ability over time will consistently over estimate or consistently under estimate costs or will bounce between over estimating sometimes and under estimating some times?

RESPONSE:

BC Hydro considers there is an equal likelihood that the actual cost of energy will be above or below forecast.

5.0 Reference: Exhibit B-5-1, Page 2-44 & Page 2-45, Schedules 2-7 and 2-8 & BCUC IR #1, Question 228

1.5.10 Has BC Hydro considered amortizing deferral account balances caused by estimating uncertainty regarding economic parameters back into future rate applications based on a period of time for amortization, which might be expected to smooth out the estimating uncertainty as BC Hydro adjusts its estimating bases.

RESPONSE:

Please refer to the response to BCUC IR 1.228.4.

6.0 Reference: Exhibit B-5-1, Page 2-18, Section 2.3.2 & BCUC 63 & BCUC IR #1, Question 95.5

1.6.1 Has BC Hydro considered deferral account disposition policies based on the causes of the variability 'Cause Based Deferral Disposition' as opposed to the proposed 'Risk Based Deferral Account Disposition'?

RESPONSE:

BC Hydro does not know what is meant by the terms "Cause Based Deferral Disposition" and "Risk Based Deferral Account Disposition".

Please refer to the response to BCUC IR 1.228.4 for more information on BC Hydro's proposal to dispose of the deferral account balances.

6.0 Reference: Exhibit B-5-1, Page 2-18, Section 2.3.2 & BCUC 63 & BCUC IR #1, Question 95.5

1.6.2 Has BC Hydro in making its proposal for deferral account disposition reviewed and analyzed its estimating variability by source of variability for each cost estimate subject to deferral?

RESPONSE:

No. Please refer to the response to BCUC IR 1.228.4.

6.0 Reference: Exhibit B-5-1, Page 2-18, Section 2.3.2 & BCUC 63 & BCUC IR #1, Question 95.5

1.6.3 In addition to rate smoothing as an over riding purpose of the deferral accounts, does BC Hydro also see another over riding purpose as being to avoid transferring risks of estimating to the shareholder and thus having the customers bear the risks of uncertainty based on actual results?

RESPONSE:

BC Hydro agrees that deferral accounts transfer the risk to customers of actual results for these items subject to deferral account treatment being higher or lower than forecast.

7.0 Reference: Exhibit B-5-1, Page 2-71, Schedule 2-34

1.7.1 Please explain the basis on which DSM costs are allocated only 10% to transmission, none to generation and 90% to distribution, when allocating finance charges.

RESPONSE:

The allocation of DSM costs was determined by the BCUC in its 1998 decision on BC Hydro's Wholesale Transmission Services application.

7.0 Reference: Exhibit B-5-1, Page 2-71, Schedule 2-34

1.7.2 Does this allocation result in DSM costs and finance charges related to DSM costs being charged largely to rate classes taking service from the distribution system?

RESPONSE:

Yes.

8.0 Reference: Exhibit B-5-1, Page 6-3, Table 6-1

1.8.1 The FTE growth for Corporate Groups appears to be on the order of 40%. Have the Corporate Groups in BC Hydro's history ever grown as much in such a short period of time? Is this unprecedented?

RESPONSE:

The increase in FTEs in the Corporate Groups is due in part to the hiring of employees to replace contractors.

As shown on Table 6-2, total operating costs for the Corporate Groups are forecast to increase from $68.1 million in F2005 to $99.6 million in F2008. However this increase in operating costs is largely due to the incremental charges to the Corporate Groups from ABSU due to the implementation of the Permanent Pricing Methodology. Excluding these incremental charges from ABSU, operating costs for the Corporate Groups are forecast to remain approximately the same from F2005 to F2008.

Further information on operating costs and FTEs for the Corporate Groups is provided in Chapter 6.

8.0 Reference: Exhibit B-5-1, Page 6-3, Table 6-1

1.8.2 Did BC Hydro management in approving this growth conduct any cost benefit analysis or prepare any business case to support the growth of the staffing and of the concomitant costs? If so please provide the review and analysis documents and if not why not?

RESPONSE:

Please refer to the response to CECBC IR 1.8.1.