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VIA E-MAIL
marcel.reghelini@bctc.com

August 5, 2005

BCTC – VITR Exhibit No. A-4

Mr. Marcel Reghelini
Director, Regulatory Affairs
British Columbia Transmission Corporation
Suite 1100, Four Bentall Centre
1055 Dunsmuir Street
PO Box 49260
Vancouver, B.C. V7X 1V5

Dear Mr. Reghelini:

Re: British Columbia Transmission Corporation ("BCTC")
Certificate of Public Convenience and Necessity
for the Vancouver Island Transmission Reinforcement ("VITR") Project Application
Commission Information Request No. 1

Attached please find Commission Information Request No. 1 to BCTC. Please provide a hard copy and e-mail copy in response. Pursuant to Commission Order No. G-70-05, BCTC is to respond to the Information Request by Friday, August 26, 2005.

Yours truly,

Original signed by:

Robert J. Pellatt

JBW/rt
Attachment
cc: Registered Intervenors/Interested Parties

Application for Certificate of Public Convenience and Necessity ("CPCN") for Vancouver Island Transmission Reinforcement ("VITR") Project

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1.0 Reference: VITR Application, Exhibit B-1, pp. 6-7, 108-9

BCTC states that the regulatory, technical, and construction risks are reasonably manageable, and notes some key milestone dates.

1.1 If the items listed on p. 7 do not constitute a complete list of the tasks on the project's critical path, please provide such a list (including float time, where applicable).

1.2 In BCTC's view, are there certain aspects of its application that the Commission could rule on in advance of others to mitigate the regulatory risks and/or to facilitate any of the critical-path tasks?

2.0 Reference: VITR Application, Exhibit B-1, pp. 25, 40, 69-70

BCTC states that it proposes to make prudent preparations for later construction of a second 230 kV line currently forecast for a requirement in 2017.

2.1 Please list all incremental facilities proposed now in preparation for a second 230 kV line.

2.2 How will Tsawwassen Substation be served when the second line is converted to 230 kV?

2.3 Please provide an estimate of the costs that will be incurred to convert Tsawwassen and the Gulf Islands to their ultimate (post-2017) configurations.

2.4 How would these configurations differ if one of the HVDC options were to be selected over the 230 kV option?

2.5 Have BCTC or BC Hydro assessed the ultimate potential for renewable energy production on Vancouver Island? Please provide a copy of any reports that have been prepared.

3.0 Reference: VITR Application, Exhibit B-1, p. 32

3.1 BCTC states that only selected areas of Segment 2 will have a second set of underground conduits installed to facilitate the potential installation of a second 230 kV underground circuit.

What criteria will BCTC use to determine which portions will have a second underground conduit?

3.2 BCTC also states that the existing rights-of-way on this corridor include the ability to construct and operate 230 kV overhead lines, but that the existing rights do not permit BCTC to install and operate underground cables through most of Segment 2.

Please provide an example of a typical existing Right of Way agreement on the corridor BCTC is referring to.

3.3 Please provide an example of a typical Right of Way agreement that includes underground rights.

3.4 Please clarify BCTC's usage of the terms "corridor" and "most of Segment 2." Do they mean the same thing?

3.5 Will BC Hydro be required to acquire the underground rights?

3.6 How will BC Hydro/BCTC value these rights?

3.7 How has the need to acquire these rights been factored into BCTC's risk assessment for the project?

3.8 By what date must the rights be acquired to avoid project delays?

3.9 What plans do BCTC/BC Hydro have if these rights need to be expropriated, and how much time is likely to be required for such a process?

3.10 Instead of expropriation, would BCTC consider reverting to overhead construction through this segment?

4.0 Reference: VITR Application, Exhibit B-1, p. 32

BCTC suggests that there may be different solutions for the removal of 138 kV cables.

4.1 Please describe the requirements for abandoning the cable in place.

4.2 Please provide cost estimates for the removal of the cables and for abandoning the cables in place.

5.0 Reference: VITR Application, Exhibit B-1, p. 39

BCTC proposes to remove both existing 138 kV single-circuit lines and install one new 230 kV double-circuit steel pole line on the existing ROW in Segment 8.

5.1 Are there facility maintenance and/or vegetation management benefits to reducing the number of lines on this and other segments?

5.2 Does BCTC expect public land-use benefits as a result of a reduction in the number of lines in this and other segments? Please explain.

5.3 Would it be possible and, if so, desirable, to reduce the width of the ROW on this or any other segment as a result of the reductions in the number of lines?

6.0 Reference: VITR Application, Exhibit B-1, p. 41

BCTC notes that narrow configuration single-circuit steel poles may be considered in a few locations as a means of reducing structure heights, where desirable.

6.1 What criteria are used to determine whether a reduced structure height is desirable?

6.2 Has BCTC designated particular locations where reduced structure heights are desirable? If so, please provide a list.

6.3 What is the incremental cost of the alternate structures?

7.0 Reference: VITR Application, Exhibit B-1, pp. 43-44, and Appendix E, p. 4

BCTC states that structural loading criteria have been defined to meet established design standards and expected weather loading due to ice and wind. BCTC also notes that the entire project is in a seismically active zone. In Appendix E, assumed maximum ambient temperatures are quoted for various cable zones.

Current models of climate change suggest that, due to natural and/or human-induced global warming, sea levels may rise. The Intergovernmental Panel on Climate Change cites research suggesting that the rise in global mean sea level could be as large as 32 cm by 2050, with significant local variation (see *Climate Change 2001: Synthesis Report—Summary for Policymakers [p. 8]*, available at http://www.ipcc.ch/pub/un/syreng/spm.pdf). The report notes (p. 33) that "Many physical systems are vulnerable to climate change (e.g., the impact of coastal storm surges will be exacerbated by sea-level rise…)." And while there is as yet no consensus, some models suggest an increase in the intensity of mid-latitude storms with attendant increases in property and infrastructure losses.

Further, in a report entitled *An Assessment of the B.C. Tsunami Warning System and Related Risk Reduction Practices—Tsunamis and Coastal Communities in British Columbia* (Public Safety and Emergency Preparedness Canada, 2004, available at http://www.ocipep-bpiepc.gc.ca/research/resactivites/CI/2003D001_Anderson_ENG_FINAL.pdf), it is stated that "Although usually associated with earthquakes, tsunamis can also be triggered by many other types of phenomena, including submarine or terrestrial landslides, submarine and terrestrial volcanic eruptions, explosions and even bolide (e.g. asteroid, meteor, comet) impacts. … The west coast of Canada is particularly vulnerable to earthquake-induced tsunamis due to the presence of both nearby and distant subduction source zones at the margin of the Pacific basin."

7.1 To what extent has BCTC assessed the risks to the project, and/or altered its design standards (such as those associated with transmission structures), to account for potential changes to ambient temperatures, storm frequency and intensity, and sea-level changes, or to specific events such as tsunamis?

7.2 What would be the impact of a rise in local sea level of 0.7 cm/year, as suggested by a potential rise of 32 cm by 2050?

7.3 If it were certain that a sea level rise of this magnitude would occur, would BCTC's route selection or engineering design for the project change? Please explain.

8.0 Reference: VITR Application, Exhibit B-1, p. 44

BCTC makes the observation that the entire route is subject to seismic activity, but in the evaluation of alternative routes, BCTC discusses two areas of particular seismic concern: the substation site at Arnott and the existing HVDC cable routes.

8.1 Please compare the relative seismic risk for all sections of the proposed and alternative routes (including the present cable routes).

9.0 Reference: VITR Application, Exhibit B-1, p. 44

BCTC states that overhead structures and systems, as proposed, are "not especially vulnerable" to seismic events.

9.1 Please clarify the meaning of "not especially vulnerable" and state the likely consequences of a seismic event on overhead structures and systems.

9.2 What components of the 230 kV project are most vulnerable to seismic events, and what risk management strategies (both for damage prevention and after-event response) are in place?

10.0 Reference: VITR Application, Exhibit B-1, p. 45

BCTC states that a corridor access assessment was conducted for the entire terrestrial corridor except between TSW and EBT.

10.1 Please explain why that particular access assessment was not done.

10.2 Will there be additional cost and/or schedule risks without this assessment? If so, of what magnitude?

10.3 How many new accesses are required along the ROW, and where are they?

11.0 Reference: VITR Application, Exhibit B-1, pp. 32, 52

BCTC has committed that, if alternative sources of funding or financing can be put in place to cover the additional costs, it is prepared to undertake underground construction in public streets and/or advance the replacement of the second 138 kV line.

11.1 Please discuss the alternative funding mechanisms that BCTC has explored.

11.2 Has BCTC considered options, such as rate riders, that would allow the financing of the alternatives to occur over time? Please elaborate.

11.3 If community funding or financing is arranged for additional capital costs, please describe how on-going incremental operating and maintenance costs would be addressed. Also, please describe the effects of this external funding of capital costs on the project's contribution to rate base, equity and customer rates.

12.0 Reference: VITR Application, Exhibit B-1, p. 55

Figure 3-23 shows the configuration of the buried cable system.

12.1 What impact does the choice of cable layout have on EMF and radio-frequency interference?

12.2 Have considerations of EMF and RFI influenced the duct bank design?

13.0 Reference: VITR Application, Exhibit B-1, p. 55

BCTC states that the transition from the underground cable system to the submarine cable system will be made using either back-to-back cable terminations or transition joints, and that the choice will be made following the public tendering process.

13.1 What are the criteria by which BCTC will make the choice?

13.2 Will the choice have a material impact on the public through, for example, visual impacts?

14.0 Reference: VITR Application, Exhibit B-1, pp. 56-57

BCTC states that construction work will be planned to minimize, to the extent practical, the disruption and time span for overhead line removal, new underground construction, and site restoration on individual properties. BCTC also notes that surface improvements will be restored, except for non-conforming structures or deep-rooted trees located within 5 m of the duct-bank centerline.

14.1 What constitutes a non-conforming structure? If an assessment of non-conforming structures on Segment 2 has been performed, please provide it.

14.2 What restorations will take place in lieu of restoring the exceptions?

15.0 Reference: VITR Application, Exhibit B-1, pp. 60 & 62

BCTC states that the new 230 kV cables will be installed in the existing ROW, and that it is proposed that they be located south of the existing cable locations for the first 4 km west of EBT.

15.1 How wide are the ROWs in question?

15.2 For the first 4 km, how far south of the existing ROW will the new cables be installed?

15.3 Is a new ROW required for the first 4 km?

16.0 Reference: VITR Application, Exhibit B-1, p. 85

BCTC states that it follows the regulatory standards and guidelines for EMF of the ICNIRP, and that this standard has been endorsed by the World Health Organization ("WHO").

16.1 Please provide the ICNIRP precautionary guideline. How was this guideline arrived at?

16.2 Please provide the WHO endorsement of the ICNIRP guideline.

17.0 Reference: VITR Application, Exhibit B-1, p. 90

BCTC states that, while the 138 kV cables remain suitable as local supply circuits to serve the southern Gulf Islands, they are no longer used for bulk power transfers to Vancouver Island. BCTC also notes that the HVDC system will still be available for emergency capacity beyond 2008 as long as it is economically feasible to maintain the system in an operable condition.

17.1 What capacity could the 138 kV system provide to Vancouver Island under emergency conditions, and what restrictions would there be on such usage?

17.2 What capacity could the HVDC system provide to Vancouver Island under emergency conditions, and what restrictions would there be on such usage?

17.3 Please describe the uncertainty associated with the ageing 138 kV circuits and their ability to provide long term supply of electricity to the southern Gulf Islands. In the absence of the proposed Project, please identify what measures would have to take place to reduce this uncertainty and the cost of those measures.

18.0 Reference: VITR Application, Exhibit B-1, p. 92

BCTC states that it plans the bulk transmission system to meet NERC/WECC standards which include an N-1 criterion. BCTC also states that N-1 and N-1-1 standards dictate the Vancouver Island system planning and operation.

18.1 If BCTC is unable to meet either of these standards, is BCTC in violation of its Reliability Management System ("RMS") agreements with WECC? If so, what would be the sanction for the violation?

18.2 If a violation of the RMS agreement does or will exist, what period is allowed for the violation to be remedied?

18.3 If the RMS agreement is not applicable to the path to Vancouver Island, please explain why.

18.4 Does BCTC use the N-1-1 standard for planning purposes for Vancouver Island? If so, please explain how this standard is achieved.

18.5 Does BCTC use the N-1-1 standard for any other part of the bulk transmission system? If so, please state where it is used and how it is achieved.

18.6 If BCTC uses the N-1-1 standard selectively, what criteria are used to decide when to employ it?

19.0 Reference: VITR Application, Exhibit B-1, p. 93, Appendices J and L

19.1 Please describe both the amount and the nature of the capacity shortfall expected in 2007, which is illustrated by Figure 4-3.

19.2 Please provide BCTC's estimates of expected energy not served ("EENS") for 2007/08, 2008/09, and 2009/10 with and without the proposed 230 kV.

19.3 Please state all assumptions made about the factors that materially influence the EENS values, such as generator availability, the planning and emergency capabilities of the 138 kV, 500 kV, and HVDC links to Vancouver Island, weather conditions, temperature sensitivity of load, etc.

19.4 Please state all assumptions regarding the bridging measures outlined in Appendix L.

19.5 Please provide hourly data for the previous three years for: (a) Vancouver Island load, including losses; (b) Vancouver Island generation; (c) the flows on the 138 kV, 500 kV, and HVDC circuits. In your response, please identify any hours in which the facilities in question were out

of service and state whether the outages were planned or unplanned.

20.0 Reference: VITR Application, Exhibit B-1, p. 95, Table 4-5, Appendix J

BCTC states on p. 95 that the HVDC replacement option would continue to use all serviceable elements of the existing HVDC systems including the existing cables.

20.1 For the estimates in Table 4-5, did BCTC consider that the cables would be reused for the HVDC Light option? If so, please explain the difference in cable costs between options for conventional HVDC and HVDC Light. If not, please explain why.

20.2 In Appendix J (p. 9 and Appendix 4), BCTC calculates the NPV of various options and includes an evaluation of HVDC Light with a VAr Credit.

Please explain how BCTC determined the value of this credit.

20.3 Has BCTC considered the value of a VAr credit based on the probabilistic use of an HVDC Light system for supply to Vancouver Island? (The credit would be on the basis that the full capacity requirement for the supply to Vancouver Island is only required for a short period of time, and therefore the full VAr capability of HVDC Light would be available the rest of the time.) If so, please supply this analysis. If not, please comment on whether this would be a valid analysis.

21.0 Reference: VITR Application, Exhibit B-1, p. 99
Sea Breeze Power Corporation website (http://seabreezepower.com/projects/sbprts/)

BCTC states that it continues to believe that the long-term supply solution for Vancouver Island should include a combination of additional on-island generation and transmission connections to the mainland.

21.1 Sea Breeze Pacific Juan de Fuca Cable, LP proposes to construct a 550 MW HVDC Light system between Victoria and Port Angeles, Washington. Please describe in detail how this line (assuming it is built and commissioned) would affect the timing and need for the 230 kV project. Please comment on adequacy, reliability, and stability, and include any relevant studies or reports in your response.

21.2 Has the capability of Sea Breeze Pacific's Juan de Fuca Cable Project been evaluated against the Vancouver Island load and system requirements in Appendix J of Exhibit B-1?

21.3 If it is BCTC's assessment that this project does not affect the 230 kV project's timing or need, please explain.

21.4 Is the Juan de Fuca Cable Project a possible substitute for the proposed Project? Why or why not?

21.5 If it is BCTC's opinion that this project will not be built, please explain and provide any evidence that supports that opinion.

21.6 Does BCTC consider the use of merchant transmission in the execution of its mandate? By what process does the use of merchant transmission enter BCTC's long range planning?

21.7 Are the costs of utilizing the Juan de Fuca Cable Project's merchant transmission capability known?

21.8 Assuming this line is constructed, what effect will it have on the need and timing for the second 230 kV circuit?

22.0 Reference: VITR Application, Exhibit B-1, p. 103 (Table 4-3) and p. 108

22.1 How was the $1000/m estimated overhead line installation cost developed?

22.2 How was the $8000/m cost for both underground and submarine cable installation costs developed?

22.3 How was the estimate of $1,632,000 for seismic upgrade costs for ducts developed?

22.4 What is the basis for the cost estimate of $2 million for two new terminals and $4 million/km for underground construction on the Gulf Islands?

23.0 Reference: VITR Application, Exhibit B-1, Appendix C, p. 24

A footnote to the table of loaded masses suggests that ice has a density of 0.9 kg/m^3.

23.1 Please confirm that this value is a typographical error, and that the ice density used in the analysis was actually close to 920 kg/m^3.

24.0 Reference: VITR Application, Exhibit B-1, Appendix C, p. 46

In the discussion of load factors for use in PLS-CADD steel pole structure models, BC Hydro Engineering notes that seismic loads were not considered.

24.1 Why?

25.0 Reference: VITR Application, Exhibit B-1, Appendix E, p. 1; Appendix M, p. 10, Section 9

BCTC notes that the first-stage work will replace the three most southerly cables in Georgia Strait (1L18 cables 1, 2, and 3) and the three most northerly cables in Trincomali Channel (1L17 cables 12, 13, and 14).

25.1 On what basis were the cables selected for replacement?

25.2 Please describe more fully which circuit's assets remain in service and why, and the designation given to the remaining 138 kV circuit.

26.0 Reference VITR Application, Exhibit B-1, Appendix E, p. 2

BCTC notes that provisions have been made for making a transition from sea cable to larger land cable near the high-water mark to accommodate the more severe thermal conditions between there and the cable terminals. Later design activities will investigate methods to avoid the need to install two different cable

sizes, since the transition joints may have a negative impact on reliability. It is also stated that the transition from submarine to underground cables will be done using back-to-back cable terminations at EBT.

26.1 What is the status of this work on avoiding the need for two different cable sizes?

26.2 In the absence of a resolution of the cable-size issue, does this imply that there will be one type of cable under the Georgia Strait, a transition to a second cable type at the high water mark, and a transition to a third type of cable at EBT?

27.0 Reference: VITR Application, Exhibit B-1, Appendix H, p. 1

BCTC notes that two 230 kV breakers may be replaced if it is decided to have single-pole reclosing for the 230 kV line to achieve the lowest possible outage rate, but that such an option is not proposed at this time.

27.1 Please provide estimates of the incremental cost and incremental reliability associated with single-pole reclosing.

28.0 Reference: VITR Application, Exhibit B-1, Appendix H, pp. 2 & 3

BCTC notes that GLS and SAL, which currently tap both 138 kV circuits, will have only one 138 kV circuit looping through them in the future.

28.1 Please describe any reliability implications of this change.

29.0 Reference: VITR Application, Exhibit B-1, Appendix J, p. iv

BCTC states that, compared to the HVDC replacement or the HVDC Light® option, the 230 kV has higher transmission efficiency (including lower losses). BCTC also notes that the 230 kV option will reinforce the synchronous interconnection between the Mainland and Vancouver Island, which is desirable to deal with power frequency excursion when the loss of both 500 kV circuits to the island occurs.

29.1 Please provide a detailed assessment of the losses associated with the each of the three options. Include an assessment of the losses in all system components, including lines, cables, shunt reactors, phase-shifting transformers, etc.

29.2 Please provide copies of the reports prepared by BCTC that demonstrate the benefits of the 230 kV option over the dc options with respect to frequency excursions.

29.3 Do the frequency excursions occur on both N-1-1 and N-2 events on the 500 kV circuits? Please explain.

29.4 Please state BCTC's assumptions concerning the probability of losing both 500 kV circuits to Vancouver Island.

30.0 Reference: VITR Application, Exhibit B-1, Appendix J, p. 3

BCTC states that the HVDC life extension is adequate to serve as a stop-gap measure in case of delays in meeting supply deficits on Vancouver Island.

30.1 Please describe the HVDC life extension project (including its cost). Please state the amount of additional capacity and the degree of reliability it can deliver, and indicate how long BCTC expects the additional capacity to be available.

30.2 Please describe any restrictions that are likely to be imposed on the operation of the HVDC system following the life extension project.

30.3 Are there differing amounts of capacity that can be achieved from this project at different levels of investment? If so, please describe them.

31.0 Reference: VITR Application, Exhibit B-1, p. 68; Appendix H, p. 2; Appendix J, p. 6; Appendix M; p. 9

On page 2 of Appendix H, BCTC notes that two 245 kV, 75 MVA shunt reactors are required for the VITR project. On page 6 of Appendix J, BCTC states that reactors will be added on Vancouver Island and Galiano Island, each with 66.1 MVAr at 230 kV.

31.1 Please describe more fully the final sizing selection of the shunt reactors, and the cost differences between a 66.1 MVAr shunt reactor and a 75 MVAr shunt reactor.

32.0 Reference: VITR Application, Exhibit B-1, Appendix J, page 6

BCTC describes mitigating the seismic risk at Arnott by temporarily connecting the circuit to one or two of the 230 kV circuits between ING and ARN in a short period of time.

32.1 Please explain this option more fully.

32.2 Please state whether any other seismic mitigation measures are appropriate at Arnott, whether directly linked to the proposed 230 kV line or not, given the large number of circuits connected at that substation.

33.0 Reference: VITR Application, Exhibit B-1, Appendix J, p. 8

33.1 Please add a column to the table showing the applicable values for the most recent HVDC Light® offering, the 700 MW, ±300 kV system noted on p. 97 of the Application.

34.0 Reference: VITR Application, Exhibit B-1, Appendix J, p. 11

34.1 Please provide copies of any of the reports listed here that have not already been provided as part of the Application.

35.0 Reference: VITR Application, Exhibit B-1, Appendix J, p. 13

The Vancouver Island distribution substation peak for 2003/04 is shown as 1703 MW, and has been adjusted to 1660 MW. Certain other adjustments are shown in the table. Footnote 10 states that the adjustments are for weather and transmission curtailment.

35.1 Please describe the methodology used for each of the adjustments.

35.2 Please provide the data that establishes the sensitivity of Vancouver Island load to temperature.

35.3 Please provide the source document(s) from which this table is derived.

36.0 Reference: VITR Application, Exhibit B-1, Appendix L

36.1 For each of the bridging measures listed in Appendix L, please describe its rationale, its expected cost, and the capacity and reliability (on a short time frame) it can provide.

36.2 Do these measures (excluding the RAS scheme) cover the capacity shortfall described above?

36.3 If BCTC fails to meet the scheduled in-service date, will these measures be able to cover any capacity shortfalls? Are there additional measures available? If so, at what cost? Specifically, please explain any material differences between winter 2007/08 and winter 2008/09, if the 230 kV line is delayed.

36.4 Please describe the nature and cost of the pilot project with Norske that is planned for this summer.

36.5 What rated capacity (between the 138 kV and HVDC systems) is available to accommodate a one-year delay in the 230 kV project?

37.0 Reference: VITR Application, Exhibit B-, Appendix M, p. 9

In the project's first stage, when parallel circuits are operated at 230 kV and 138 kV, there is the possibility of severe temporary overvoltage conditions on the 138 kV circuit. Under certain circumstances, some surge arrestors are expected to fail.

37.1 Is there a possibility of damage to customer equipment as a result of an over-voltage prior to the failure of one or more surge arrestors? Please explain.

38.0 Reference: VITR Application, Exhibit B-1, Appendix M, p. 12

Please provide copies of any of the reports listed here that have not already been included with the Application.

39.0 Reference: VITR Application, Exhibit B-1, Appendix P

The $49.2 million dollar rise in the Pole 3 cost estimate between 2002 and 2004 has been attributed to the Euro's value against the Canadian Dollar.

39.1 Please provide line item costs estimates from both 2002 and 2004 that demonstrate which project components have risen in cost. Please separately identify project management, engineering and contingency amounts.

39.2 Please reconcile the statement (p. iii) that the main reason for cost increases between 2002 and 2004 is the increase in value of the Euro relative to the Canadian dollar with the fact that Pole 3 costs rose 28 percent while Pole 4 costs rose only 5 percent.

39.3 The value of the Euro used in the estimates was $1.62 Cdn (p. A5). As of July 29, 2005, that value was $1.4968 Cdn. Please update the estimates based on the revised exchange rate.

39.4 Please provide the rationale for the inclusion of an 18 percent contingency in the estimates (p. 2).

39.5 Please provide the basis for the annual operating cost of each pole being $550,000 (p. 2).

39.6 The Substations Planning Department recommended escalating 1997 costs by ten percent (e.g., p. A2) to bring the estimate to 2004 dollars, while the Overhead Department recommended adding 50 percent (e.g., p. A3). Please explain the difference.

39.7 Please provide copies of any of the references cited on page A9 that have not already been included with the Application.

40.0 Reference: VITR Application, Exhibit B-1, Appendix Q

The report included in this Appendix was included as part of BCTC's F2006-F2015 Transmission System Capital Plan Application.

40.1 For the record in this proceeding, please provide the information requests and responses related to this report.

41.0 Reference: VITR Application, Exhibit B-1, Appendix R, p. 4

41.1 Route 4 is shown to have a high impact on First Nations lands. Please provide a map showing First Nations lands that are or may be affected by the choice of routes.

41.2 Please explain the basis for the assumption that there would be an improvement in property values if underground construction is used in Tsawwassen, given that one of the 138 kV lines will remain for at least ten years. Has this assumption be validated by realtors?

41.3 BCTC states that the cost and schedule uncertainties with respect to Route 2 are low, even though there is opposition by some to granting underground access rights. Please explain BCTC's assessment of the schedule risks associated with negotiating underground access rights.

42.0 Reference: VITR Application, Exhibit B-1, Appendix R, p. 6

42.1 Please provide the basis for the impact on First Nations interests of each of the possible Gulf Islands routes.

42.2 With respect to the "very high" degree of difficulty for ROW acquisition, which segments of the routes does BCTC believe will be the most difficult, and why?

43.0 Reference: VITR Application, Exhibit B-1, p. 4, Table 1-1

43.1 For each column in Table 1-1, please provide a comprehensive scope description, and a detailed estimate that identifies that amount of contingency and embedded capitalized overhead costs allocated to each column.

44.0 Reference: VITR Application, Exhibit B-1, pp. 28-39, Section 3.2

44.1 Is the option of retaining 1L18 as-is and confining this project to a single circuit (2L129) construction feasible, and if so, would it constitute the lowest-cost "stage 1" option? If not, why not?

44.2 Has an analysis of the option of retaining 1L18 as-is and confining this project to a single circuit (2L129) construction been performed? If so, please provide the analysis that identifies costs, technical requirements and other project characteristics. Please provide this analysis for each segment of overhead line.

44.3 Why has the option of retaining 1L18 as-is and confining this project to a single circuit (2L129) construction not been evaluated as a "base case" option?

44.4 Please provide a cash flow and NPV cost comparison between: (a) a single-circuit 230 kV line and a second line added in 2017; and (b) BCTC's proposal for incurring costs for portions of a second line now and adding the rest of the second line in 2017.

45.0 Reference: VITR Application, Exhibit B-1, p. 32, Section 3.2.3

45.1 What work would be necessary to retain the 1L17 submarine cables (cables 1, 2, 3, 12, 13 and 14) for use as "installed spares" for 1L18?

45.2 What one-time and annual costs would be encountered in keeping the 1L17 submarine cables available as "installed spares"?

46.0 Reference: VITR Application, Exhibit B-1, p. 39, Section 3.3.1.1

46.1 Is there a feasible method to increase 1L18's 100 MW rating by utilizing the spare cable, or cables from 1L17?

47.0 Reference: VITR Application, Exhibit B-1, p. 40, Table 3-2

47.1 If a single 230 kV AC circuit was considered, could any of the existing steel lattice structures in segments 4, 6 or 8 be retrofitted for 230 kV use? If so, would a cost savings be realized, and if not, why not?

48.0 Reference: VITR Application, Exhibit B-1, p. 44, Section 3.3.1.2.7

48.1 Please provide the instances where BC Hydro Transmission Engineering Technical Standards, Procedures and Guidelines for vertical and operating clearance criteria exceed those of CAN/CSA Standard C22.3-No.1-01.

49.0 Reference: VITR Application, Exhibit B-1, p. 58, Section 3.3.4.1

49.1 Please describe various cable technologies suitable for submarine high voltage AC installations, and the relative cost associated with each technology. Is extruded or non-oil filled cable available for such applications?

50.0 Reference: VITR Application, Exhibit B-1, p. 63, Section 3.3.4.3

50.1 Please provide an engineering drawing showing typical installations for protective split pipe covers, including cross-sections.

51.0 Reference: VITR Application, Exhibit B-1, p. 73, Section 3.6.1

51.1 Please provide the basis for BCTC's assessment that there is little risk of changes to the Project's design as a result of the EA process.

51.2 If changes to the Project's design that result from the EA process cause sunk costs from designs or tenders released prior to obtaining the EA certificate, please describe how those sunk costs will be recovered.

52.0 Reference: VITR Application, Exhibit B-1, p. 74, Figure 3-35

52.1 Please provide the project cash flow in terms of a time based "S" curve, with links back to the project milestone schedule. Please include the $10 million of 138 kV retirement/dismantling cost, or provide a separate diagram for this amount.

53.0 Reference VITR Application, Exhibit B-1, p. 90, Section 4.1.1.2

53.1 Please provide a table of monthly operating hours and associated energy for the last 3 years for Pole 1 and Pole 2.

54.0 Reference: VITR Application, Exhibit B-1, p. 99, Section 4.2.6

BCTC states that a separate corridor from the 500 kV northern connection results in full N-1 compliance.

54.1 Please describe BCTC's interpretation of the multiple lines in a single corridor situation with respect to NERC/WECC's N-1 full compliance and other contingency criteria. For example, would another line in any of the referenced corridors result in less than full N-1 compliance?

54.2 Please describe those situations for Vancouver Island where BCTC's interpretation of the single corridor language in the NERC/WECC reliability criteria results in less than "full N-1 compliance."

55.0 Reference: VITR Application, Exhibit B-1, p. 100, Section 4.2.6

55.1 Please provide the emergency and short-term overload capability of 2L123, 2L128, 1L17, 1L18 and the proposed 2L129, and when and for how long these ratings can be employed.

56.0 Reference: VITR Application, Exhibit B-1, p. 102, Table 4.2

56.1 Please describe the specific First Nations impacts associated with Option 4.

56.2 Please describe the specific implementation risk associated with Option 4.

56.3 Please separate the seismic risk from the other factors contributing to reliability for Option 4 for both the submarine and underground sections.

56.4 Please describe the seismic risk of each option in terms of its ability to withstand seismic events that have a period of once every X years.

56.5 Please describe the issues associated with using an overhead transmission line for the 2550 meter underground cable section associated with Option 4, including cost, environmental, social, First Nations and reliability impacts. Is this underground section entirely adjacent to the Highway 17 corridor?

56.6 Please describe the seismic risk of the ARN HVDC converter facilities in terms of their ability to withstand seismic events that have a period of once every X years.

57.0 Reference: VITR Application, Exhibit B-1, p. 104, Section 4.3.2

57.1 Please describe the considerations that lead to the decision of rebuilding the remaining 138 kV line as part of a 230 kV line rather than leaving it as-is, on Salt Spring and Galiano Islands. Would cost savings be realized by building a single circuit 230 kV AC line, and leaving the remaining 138 kV line as is, and if so, what are they?

58.0 Reference: VITR Application, Exhibit B-1, p. 111, Table 4-7

58.1 Please provide a summary line that shows the annual Revenue Requirement.

59.0 Reference: VITR Application, Exhibit B-1, Appendix C, p. 9

59.1 What are the incremental costs associated with the installation of the fiber? Please break this out for at least the fiber cost, the installation, the structure modifications, and the termination equipment.

59.2 What communication infrastructure will be used if fiber is not installed, and how much spare capacity exists on this infrastructure?

60.0 Reference: VITR Application, Exhibit B-1, Appendix F, p. 56, Table10-5

60.1 Can the 0.014 Total Annual Failure Probability associated with Option C be interpreted as a one in 71 year occurrence?

60.2 The appendices to Appendix F do not appear to show any boreholes in the waters between the causeway and the existing submarine cables that exit EBT. Please comment on why not, and how the assessment of Option C assigned characteristics to this area.

61.0 Reference VITR Application, Exhibit B-1, Appendix H, Drawing SK-VI230-101

61.1 Are the devices shown connected to ground at various terminals on 2L129 lightning arrestors, and what are their characteristics?

62.0 Reference: VITR Application, Exhibit B-1, Appendix J, p. 4

62.1 Please confirm that incremental dependable capacity additions of approximately 40 MW will defer the need for a second 230 kV AC line by one year in the 2017-2018 period.

62.2 What will the 1L18 load from VIT be in the 2017-2018 period, and will this load be capable of being supplied from ARN?

62.3 For how many hours every year (starting in 2017-2018, and at least out to 2024-2025) would the 1L18 load be required to be fed from ARN in order to contribute to deferring the need for the second 230 kV AC line? Please describe this also in terms of Expected Energy Not Served (EENS). In later years, please consider this load shift to be acting in combination with other resource options or load shifts, but always as the first one dispatched.

62.4 Please comment on the lack of any dependable generation addition on Vancouver Island after 2009-10. Recognizing the division of responsibilities that exists between BC Hydro being responsible for identifying resources and BCTC being responsible for connecting resource to load, please comment on whether one could submit there is an apparent lack of co-ordination exhibited in Table 1.

62.5 In BCTC's opinion, is it reasonable to assume no addition of dependable generation on Vancouver Island for the 15 years following 2009-10, given the F2006 Call described in BC Hydro's 2005 REAP? What dependable generation addition assumptions would be reasonable?

62.6 Please comment on the respective capabilities of dependable generation additions in the North Island, mid-Island and South Island to defer the next stage of transmission reinforcement, assuming that is the second 230 kV AC circuit.

63.0 Reference: VITR Application, Exhibit B-1, Appendix J, p. 5, Section 4

63.1 What is the practical maximum size (transfer capability) of a single 230 kV AC circuit, and if greater than 600MW, what cost increment would be required to achieve this?

64.0 Reference: VITR Application, Exhibit B-1, Appendix J, p. 7

64.1 Please provide the engineering analysis of extruded insulation cables.

65.0 Reference: VITR Application, Exhibit B-1, Appendix J, p. 9

65.1 Please describe and quantify the capability of the 230 kV AC circuits to transmit dynamic VARs from the VIT synchronous condensers to the Lower Mainland.

66.0 Reference: VITR Application, Exhibit B-1, Appendix J, p. 15

66.1 Please supply the detailed line item cost estimates to support each of the four projects listed in Appendix 4.

66.2 Please supply the NPV comparison analysis for Stage 1 projects only.

66.3 Please provide the total amount of contingency in each project, as well as the total engineering, project management, and allocated overhead costs associated with each project for Stage 1 only and both Stage 1 and 2.

66.4 What is the total installed cost for the ING SVC? Please explain and quantify how the 50% credit has been applied towards the HVDC Light evaluation.

67.0 Reference: VITR Application, Exhibit B-1, Appendix K, p. 7

It is stated the BCTC's policy is to avoid the use of generation shedding for first contingency events.

67.1 In a system with a large component of hydrogeneration, please comment on the percentage of time that the system is at peak generation capacity.

67.2 If a system only reaches peak generation capacity for a small percentage of time, is it unacceptable to use probabilistic or economic analysis to allow for some amount of generation shedding based on either the infrequent occurrence of contingencies or low value of potentially lost generation, versus the cost of upgrading the system to allow for no generation shedding at all?

67.3 Does BCTC consider total hourly generation profiles when performing system studies, or simply the peak possible values for various seasons?

68.0 Reference VITR Application, Exhibit B-1, Appendix K, p. 7

It is stated the BCTC's policy is that line over voltage protection schemes will not be triggered by N-1 or N-2 events.

68.1 Please describe the requirements of the NERC/WECC reliability and planning standards with respect to these criteria.

69.0 Reference: VITR Application, Exhibit B-1, Appendix L, p. 1

69.1 If the short-term emergency ratings of the 500 kV cables can be increased by 120 MW, will this delay the need for the second stage of Vancouver Island transmission reinforcement by about 3 years?

70.0 Reference: VITR Application, Exhibit B-1, Appendix M, p. 7, Section 6

70.1 Please describe more fully the out-of-step tripping phenomenon and associated RAS.

71.0 Reference: VITR Application, Exhibit B-1, Appendix N, p. 5, Table 1

71.1 Please provide the number of hours in each year, commencing in 2008, that the 2L129 is exposed to overloading without a phase shifter for both the N-0 and 2L128 contingency cases (pre-SAT conversion). Please describe this also in terms of Expected Energy Not Served (EENS). Also, please provide these results with 1L18 load fed from ARN.

71.2 Would the SAT conversion eliminate the need for the 230 kV phase shifter?

71.3 What Remedial Action Schemes would need to be put in place to segment load at VIT or SAT in order to prevent overloading of 2L129 in the event of a 2L128 contingency?

71.4 Would single pole reclosing on 2L123 and 2L128 reduce the likelihood of overloading 2L129, and if so, by how much?

72.0 Reference: VITR Application, Exhibit B-1, Appendix N, p. 6, Figure 2

Figure 2 appears to show a power flow of about 500 MW for zero phase shifter angle and a VI load of 2100 MW.

72.1 Please reconcile figure 2 with the value in Table 1 on Page 5 of Appendix N, which shows that a power flow of 608 MW is expected for a bypassed phase shifter and a VI load of 2144 MW.

73.0 Reference: VITR Application, Exhibit B-1, Appendix O, p. 5, Section 4.3

73.1 Please explain why the 0.2% reduction in bus voltage at VIT230 and PIK230 is significant.

74.0 Reference VITR Application, Exhibit B-1, Appendix O, p. 6, Section 6

74.1 Please summarize the Green Call generation additions on Vancouver Island. Are any generation additions expected after 2010?

75.0 Reference: VITR Application, Exhibit B-1, Appendix P, p. A1

The Pole 3 and Pole 4 cost estimates are shown to be carrying 18 % contingency.

75.1 Please compare this to the amounts of contingency included in the Proposed project, and the HVDC Light option and explain the differences.

76.0 Reference: VITR Application, Exhibit B-1, Appendix Q, p. 14

76.1 Please provide additional information regarding the cost savings, the reliability impacts, and the feasibility of using overhead lines in place of underground cables for the HVDC Light option.

77.0 Reference: Exhibit B-1, p. 50, Figure 3-19

Please confirm that the caption for Figure 3-19 should read “Okana Creek, Salt Spring Island (After)

instead of "(Before)".

78.0 Reference: Exhibit B-1, p. 88, lines 12-17; p. 94, Table 4-1; p. 99, lines 12-13

The Application states that a capacity deficiency is forecast for the winter peak season in 2007/08 and that deficiency will continue to grow in subsequent years. It also states that there are no specific generation options currently planned that could meet the forecast capacity deficits on Vancouver Island.

78.1 Please provide the major assumptions for the forecast of the growth in capacity deficiency in years subsequent to 2007/08. For example, is BCTC assuming that there will no generators on Vancouver Island between now and 2017?

79.0 Reference: Exhibit B-1, p. 91, lines 11-13, p. 100, line 13; Appendix J, p. 3

The Application refers to the reliance by BCTC on BC Hydro's October 2004 Load Forecasts for Vancouver Island's peak demands.

79.1 BC Hydro issued a revised forecast subsequent to its October 2004 Load Forecast that is referred to as the December 2004 Load Forecast (Reference: Exhibit B-67 of the BC Hydro CFT Application for Energy Supply on Vancouver Island). Please explain why BCTC is relying on the October 2004 forecasts instead of the revised December 2004 forecasts.

79.2 Is BCTC aware of any other updates to the October 2004 Load Forecasts apart from the one mentioned above?

79.3 The Application states on page 69 lines 21-22 that the installation of one 230 kV circuit will provide sufficient capacity to supply the forecast Vancouver Island shortfall for approximately 10 years. In BCTC's view, will this installation lower the transmission distribution losses that are embedded in BC Hydro's forecast for Vancouver Island?

79.4 If the existing transmission loss factor will not still apply to the Vancouver Island load, please quantify the savings in energy losses.

80.0 Reference: Exhibit B-1, p. 91, lines 13-14; Appendix J

"The Vancouver Island peak demand (~2300 MW) during January 2005 is supportive of the most recent load forecast."

80.1 Please provide the actual F2005 recorded peak demand and the weather-adjusted peak demand for Vancouver Island, showing with and without the Gulf Islands load.

80.2 Does "VI Demand" in Table 1 in Appendix J include forecast loads on the Gulf Islands? Where possible, please provide a separate column for peak demand forecasts for the Gulf Islands.

81.0 Reference: Exhibit B-1, Figures 4-2 and 4-3

81.1 Please provide the data in the two Figures in tabular format.

82.0 Reference: Exhibit B-1, p. 93, lines 4-7; Appendix L

BCTC has been developing a series of measures to bridge the 2007/08 winter capacity shortfall.

82.1 In addition to the various measures described in Appendix L, are BCTC and BC Hydro currently exploring other industrial demand side management proposals in addition to the one from Norske Canada? Please describe any other current initiatives.

83.0 Reference: Exhibit B-1, Appendix J, Table 1; Appendices 2 & 3

The Appendices 2 & 3 containing the Vancouver Island load forecast and dependable generation data were prepared on October 18, 2004 and November 26, 2004 respectively.

83.1 Please update these two tables where possible.

Please cross reference Table 1 with data contained in Appendices 2 and 3.

83.2 Table 1 shows that the Vancouver Island peak demands include 5.5% power losses. The Application states that the data are based on the BC Hydro October 2004 load forecast after Power Smart.

Please reconcile the numbers in Table 1 on VI Demand (MW) with the December 2004 Load Forecast for "Vancouver Island Load with PowerSmart and Transmission Losses" as shown in the table in Exhibit B-98 of the BC Hydro CFT for Energy Supply for Vancouver Island.

83.3 Please reconcile the 5.5% power losses used in the Application with the 8.7% system transmission loss factor used by BC Hydro (Reference: BC Hydro December 2004 Load Forecast, p. 54).

84.0 Reference: Exhibit B-1, Project Justification, Section 4, p. 104

The Application refers to Tsawwassen as an area where many homes adjacent to the ROW have been built with their foundations literally on the ROW boundary. While this is the case in few locations elsewhere on the BCTC transmission ROW, in no case it is so widespread or confining to system operations.

84.1 Please provide examples of neighborhoods similar to Tsawwassen within the BCTC system, where there is a potential future requirement to replace overhead lines with underground construction and indicate the total number of these neighborhoods.

84.2 What processes has BCTC undertaken to ensure that circumstances similar to those in Tsawwassen will not be allowed to develop in the future?

85.0 Reference: Exhibit B-1, Project Overview and Executive Summary, Section 1, p. 5

BCTC is requesting approval of this balanced approach including acceptance, subject to prudent control of costs through project development and construction, that the estimated $ 16 million additional cost of underground construction on the 3.7 km section through Tsawwassen is appropriate for recovery in rates once the project comes into service.

Please provide examples of regulatory precedents, in terms of cases where regulators in B.C. or other jurisdictions in Canada or the US have allowed the proposed "balanced approach" premium to be recovered in rates charged to all rate payers.

86.0 Reference: Exhibit B-1, Project Description, Section 3, p. 32

The existing rights do not permit BCTC to install and operate underground cables through most of Segment 2 through Tsawwassen. These underground rights will have to be acquired as part of the Project.

86.1 Please provide the estimated cost of the underground rights and confirm whether or not they have been included in the project costs.

87.0 Reference: Exhibit B-1, Project Justification, Section 4, p. 104

Although Option 1 has the lowest cost, BCTC proposes to proceed with Option 2 as the best solution, balancing the interests of all stakeholders.

Please describe all key commitments, if any, that BCTC has made to the residents of Tsawwassen and other communities along the power line route during the consultation process.

88.0 Reference: Exhibit No. B-1, Section 1.4, p. 5-6

88.1 The Order Sought includes a request for approval, contingent upon confirmation of external funding and upon notice to the Commission, to underground the Project in public streets or to advance the underground replacement of the second 138 kV line in this area.

Please identify when BCTC requires a decision from the Tsawwassen community regarding the funding proposal for undergrounding on public streets and the installation of the second underground circuit, so that BCTC can meet the VITR Project schedule.

89.0 Reference: Exhibit No. B-1, Section 1.4, p. 6

89.1 Given the number of detailed environmental processes, including socio-economic processes, BCTC states that it would not be appropriate for the Commission "to carry out a detailed review of the potential environmental and socio-economic effects of the Project."

Please comment on whether or not BCTC is of the view that the above quoted reference to "a detailed review of the environmental and socio-economic effects", includes consultations with First Nations and any environmental impact differences of the various route options, particularly for Segment 2 in Tsawwassen, set forth in the Application.

90.0 Reference: Exhibit No. B-1, Section 3.2, p. 28

90.1 Please identify the legal interest held (i.e., either a registered ROW or fee simple interest) by either BC Hydro or BCTC for the use of land between ARN and VIT. Please also identify permitted uses of the land, for example, does the legal interest held permit third party use? Please also identify third party use, if any.

90.2 Please also identify technological restrictions, if any, in the interests held that may be relevant to the VITR project. Are there any restrictions for the use of land, other than overhead versus underground?

90.3 What are the permitted uses by property owners of land on which the transmission line corridor is located through Segment 2 in Tsawwassen? Does the legal interest held permit public access on the transmission line corridor? Please describe the rights of ingress and egress held by BC Hydro or BCTC to and from the transmission line corridor.

91.0 Reference: Exhibit No. B-1, Section 3.2.2, p. 32

91.1 Please explain why BCTC is not recommending funding for Segment 2 in Tsawwassen similar to the funding conditions found in Commission Order G-48-95 dated June 9, 1995.

91.2 Please provide an explanation for BCTC proposals for the funding of costs for undergrounding on the transmission line corridor, undergrounding in public streets, and for the installation of the second underground circuit. For each explanation, BCTC should describe the differences between the transmission line corridor considered in Commission Order G-48-95 and the transmission line corridor on Segment 2 that form the basis for the different funding approaches. Please include the basis for the different funding arrangements that are being recommended for undergrounding on the transmission line corridor, for undergrounding in public streets, and for the installation of the second underground circuit.

92.0 Reference: Exhibit No. B-1, Section 3.3.1.2.3, p. 42

92.1 The Application suggests that the final structure spotting is subject to detailed line design.

Please describe the process, including the consultation process with affected landowners, from detailed line design to final structure spotting and provide an expected schedule for each step in that process. Please identify the process for each segment, and if the process is different for each alternative route option for Segment 2, please identify the process for each alternative route for Segment 2. Please also state the approvals expected from the Commission, if any, regarding structure locations.

93.0 Reference: Exhibit No. B-1, Section 4.3.1, p. 102, Table 4-2

93.1 Please describe the assessment process/criteria for determination of each of the numeric rankings in the cells in Table 4-2.

94.0 Reference: Exhibit B-1, pp. 62, 101; Appendix F, pp. 56-8, Figure 1.1

94.1 The Golder Associates study in Appendix F of Exhibit B-1 concludes that Route A is preferred for the new cable installation. Comparing Figure 4-4 on page 101 of Exhibit -1 and Figure 1-1 in Appendix F, please confirm the recommended route for the new cables is generally consistent with Option A of the Golder Associates study, lying south of the existing 138 kV cables and near the southern boundary of the cable corridor.

94.2 Please explain the reasons for any material deviations from the Option A routing.

94.3 As BCTC indicates that it likely will propose the installation of additional 230 kV circuit in approximately 10 years time, please discuss whether it will be possible to install the cables for two 230 kV circuits within the existing cable corridor while realizing the lower geohazard risk benefits of the Option A routing.

94.4 To what extent will it be necessary to remove the existing 138 kV cables in order to install the first and second 230 kV circuits within the existing cable corridor.

95.0 Reference: Exhibit B-1, pp. 103, 107; Appendix J, pp. 5-10, Appendix 4

95.1 Further to the description of the 230 kV AC Option on page 5 of Appendix J, please clarify whether the direct cost of $207 million for the first phase includes the cost of undergrounding the Tsawwassen section. Please identify the amount of contingency in the estimate and reconcile the Appendix J estimate with that in Table 4-5 of Exhibit B-1.

95.2 The description of the HVDC Light option on pages 6 and 7 of Appendix J refers to using the 138 kV right of way and placing the cables submarine or underground. What would be the impacts on the first and second phases of the HVDC Light option of placing the on-land sections of the cables above ground?

95.3 If the cost reductions identified in response to the preceding question are material, please provide an analysis similar to that in Appendix 4 that is based on cost estimates assuming above ground construction.

95.4 Please explain the basis for the estimates of overhead for each Option in Appendix 4 of Appendix J, and clarify the reference to use of an 8 percent discount factor for this item.

95.5 Please explain the basis for the estimates of O&M for each Option in Appendix 4 of Appendix J.

95.6 Please explain the basis for the estimate of Losses for each Option in Appendix 4 of Appendix J, separately addressing the quantity of losses and the unit cost of such losses.

95.7 Please clarify whether the not-bold-face numbers in Appendix 4 of Appendix J are in as-spent dollars, real 2005/06 dollars or on some other basis.

95.8 Further to the response to the preceding question, please clarify if 6 percent is a real or nominal discount factor and explain why this factor is appropriate. Would the conclusion that BCTC draws from the comparison be different if it used a discount factor that is 2 percent higher or lower than 6 percent?

95.9 Table 4-3 in Exhibit B-1 refers to NPV at 7 percent. Please explain why BCTC used 7 percent in Table 4-3.

95.10 If the NPV in Table 4-3 includes any costs or benefits other than the capital costs shown in the table, please explain what they are.

96.0 Reference: Exhibit B-1, pp. 104-8

96.1 Page 104 of Exhibit B-1 identifies Option 2 as 230 kV AC underground construction in selected areas on Galiano and Salt Spring Islands, at a cost ranging from $280 to $332 million. Please provide a map outlining the sections that would be under grounded for each of the $280 million

and $332 million scenarios.

96.2 Please provide detailed cost information for the $280 million scenario for the 230 kV AC line, preferably in the form of an expanded Table 4-5.

96.3 Table 4-4 indicates that Option 3 (HVDC Light an existing 138 kV corridor) has lower Community Impacts than Options 1 or 2 (230 kV AC in 138 kV corridor). Please explain how BCTC arrived at this conclusion. Are the differences between the Options material?

97.0 Reference: Exhibit B-1, pp. 39-40, 69-70

97.1 Exhibit B-1 at pages 39 and 40 describe the 138 kV circuits, lines 1L17 and 1L18. Please provide an outline of the present condition of the major components of each line including differentiation between the submarine and on-land portions.

97.2 What does BCTC estimate to be the remaining useful life of each line (or major segment of each line, if different)?

97.3 In the event that the installation of the second 230 kV AC line to Vancouver Island is delayed materially past 2018, please explain whether the reconstructed 138 kV line will be adequate to supply the southern Gulf Islands for this extended period.

97.4 Noting from page 7 of Exhibit B-1 that BCTC proposes to install the new submarine cables in summer 2008, please outline the schedule of activities for reconstruction of the remaining 138 kV line in a way that will maintain reliable service to the southern Gulf Islands.

97.5 Appendix L in Exhibit B-1 states that the reconstructed 138 kV circuit may be available some time during the 2007/08 winter to meet the peak load of 60 MW. Please explain why the reconstructed 138 kV line will be materially more reliable than the present line.

97.6 Exhibit B-1 at pages 39 and 90 states that the 138 kV circuits are each rated at 100 MW, and that they are no longer used for bulk power transfer to Vancouver Island. Please explain in detail whether they are no longer suitable for this purpose, if they are suitable for supplying "local" power and why BCTC is not prepared to rely on the two of them for at least 100 MW of reliable transmission to Vancouver Island and the southern Gulf Islands.

98.0 Reference: Exhibit B-1, pp. 28-9, 70

98.1 Exhibit B-1 refers to Tsawwassen Distribution substation. Please describe the role of lines 1L17 and 1L18 in supplying the Tsawwassen Substation. If one 138 kV line is taken out of service, how will supply to this substation be affected?

98.2 Exhibit B-1 indicates that, when the second 230 kV AC line is installed, the Salt Spring substation will be converted to 230 kV and the 138 kV circuit will be decommissioned. What would be the NPV cost difference to advance construction of a 230 kV substation on Salt Spring and to decommission both 138 kV lines in 2008?

98.3 What savings, including reduced O&M expense and sustaining capital expenditures would be realized if the second 138 kV line was taken out of service in 2008 rather than 2018?

99.0 Reference: Exhibit B-1, pp. 5, 52

99.1 Exhibit B-1 at page 55 states that development of residences has been allowed to enclose a portion of the existing ROW, severely limiting access for maintenance or vegetation managements. Please explain the nature of the encroachment on the ROW and identify who allowed this to happen. If BC Hydro or BCTC, why was this permitted? What rights does BCTC have to now rectify the situation?

99.2 Please confirm the extent to which the development and encroachments are conforming and non-conforming.

99.3 With respect to the 3.7 km that BCTC proposes to underground, please explain how the development or other encroachment has hampered activities related to the two 138 kV lines to date, and provide a comparison in both qualitative and dollar terms of how it is expected to impact future operations and maintenance under each of the following scenarios:

- two existing 138 kV lines
- one existing 138 kV line plus proposed 230 kV line underground
- double circuit 230 kV/138 kV lines on single poles above ground
- two underground circuits.

99.4 What would be the impact on the appraised or assessed value of a typical detached residential property that is adjacent to the ROW (in dollars and percent) under each of the scenarios identified in the preceding question?

99.5 How many detached houses, other dwellings, schools and other buildings are immediately adjacent to the ROW on the 3.7 km that BCTC proposes to underground? How many were there prior to construction of the first 138 kV line?

99.6 What problems will the constrained access to the 3.7 km of ROW cause when it comes time for BCTC to install the second set of 230 kV cables underground, and remove the segment of 138 kV overhead line?

99.7 On page 5 of Exhibit B-1, BCTC states that it believes that its proposal to underground the 3.7 km of the new line at a cost of $16 million represents a balanced approach for stakeholders. Please explain how BCTC weighted the monetary and other considerations in coming to this conclusion, and provide the criteria that it used to determine that undergrounding at the expense of all ratepayers was appropriate in this circumstance.

99.8 Please explain whether BCTC intends to apply the same criteria to decide whether other transmission lines should be installed underground. What is expected to be the expected impact on BCTC capital expenditures over the next 10 years from the use of these criteria?

100.0 Reference: Exhibit B-1, pp. 5, 6

100.1 On page 6 of Exhibit B-1, BCTC requests approval, contingent upon confirmation of external findings and upon notice to the Commission, to underground the Project in public streets or to advance the underground replacement of the second 138 kV line in this area. Please confirm that the request is specific to the 3.7 km section in Tsawwassen, and that BCTC seeks prior approval for either or both of these scope changes.

100.2 For greater certainty, please confirm that other ratepayers of BCTC will not be responsible for any costs that result from these scope changes.

100.3 Exhibit B-1 at page 6 states that BCTC anticipates any CPCN for the VITR project will be granted subject to the receipt of other necessary permits and approvals. Please clarify whether BCTC proposes that a CPCN Order should anticipate that other permits and approvals are also necessary for the project to proceed, or whether the receipt of such other permits and approvals should be made an explicit condition of the CPCN.

101.0 Reference: Exhibit B-1, pp. 70-3

101.1 Further to the description of installation of marine cables on pages 60 to 62 of Exhibit B-1, please describe the constraints on the submarine cable schedule that relates to such needs as availability of a suitable cable-laying vessel, weather or calendar season.

101.2 Please discuss whether there are aspects of the VITR project which are not on the critical path and where a Commission decision could be delayed some months without materially impacting project schedule (e.g., whether or not to underground the 3.7 km section through Tsawwassen, or whether to retain one existing 138 kV line between Arnott and Tsawwassen).

101.3 On page 73 of Exhibit B-1, BCTC states it considers there is little risk that the EA process will not be completed successfully or will result in changes or conditions that will affect decisions on the submarine cables or phase shifting transformer. Please discuss whether BCTC expects that the EA process will be completed successfully if the approved routing is for overhead lines through Tsawwassen. If not, please explain.

102.0 Reference: Exhibit B-1, pp. 74-5

102.1 Please clarify if the VITR project cost estimate in Figure 3-35 on page 74 is in real or as-spent dollars. If the estimate is not in as-spent dollars, please provide the estimate on this basis.

102.2 Please explain how the $10 million estimate for retirement/dismantling was determined and provide a breakdown of the costs. To what extent does the estimate include charges for the premature decommissioning of 138 kV lines or other facilities?

102.3 Why has BCTC not included the $10 million in project costs?

102.4 Please explain the basis for $18.99 million of contingency.

102.5 On page 75 of Exhibit B-1, BCTC states that it anticipates environmental or socioeconomic effects can be avoided or minimized through appropriate design or mitigation measures. What information can BCTC provide to substantiate that the cost of such measures can be accommodated within the cost estimate, including the contingency amount?

102.6 Further to pages 77 and 79 of Exhibit B-1, please provide an update on approval of the Terms of Reference for the EAC Application.

103.0 Reference: Exhibit B-1, pp. 28, 39, 40

103.1 Please provide the estimated remaining book value of each of the eight sections of each of the

138 kV lines as of 2008 when some sections of the lines will be taken out of service.

103.2 Please describe the accounting treatment that BCTC proposes for the remaining book value of the portions of the 138 kV lines that are taken out of service.

104.0 Reference: Exhibit B-1, p. 86

104.1 Further to the information on page 86 of Exhibit B-1, please provide maximum edge of right of way and ground level centre-of-ROW EMF levels for the 3.7 km of line through Tsawwassen for each of the following scenarios. If the EMF levels are not based on maximum loadings on the lines, please explain.

a) existing two 138 kV lines
b) proposed one existing 138 kV line and one underground 230 kV line
c) double circuit 230 kV lines on single poles, with one circuit operating at 138 kV (similar to the Arnott to Tsawwassen section).
d) double circuit 230 kV line on single poles with both circuits operating at 230 kV.

104.2 If figures are available that show the profile of calculated EMF levels on cross-sections across the ROW and extending beyond the ROW, please provide them.

104.3 Please repeat the foregoing two questions for typical sections of line in South Delta, Salt Spring Island, Galiano Island and North Cowichan.

105.0 Reference: Exhibit B-1, p. 41; Appendix B

105.1 Section 6.0 of Appendix B in Exhibit B-1 appears to confirm the use of a double-circuit, braced-post steel pole design. Please confirm that this is the configuration referred to as "Double Crcuit Steel Pole, 2 x 3 Braced Post Arrangement" in Section 3.0 of Appendix B, and that this is the design that BCTC generally intends to use for overhead lines for this project (or set out the correct information).

105.2 Appendix B indicates that the compact nature of the braced post arrangement produces the least field effects and least area impacts of all the types compared. Please discuss whether these factors were the main considerations in selecting the design.

105.3 Appendix B indicates that the cost of $560,000 per km for braced post structures is somewhat higher than $470,000 per km for the davit arm arrangement. What would be the cost savings to the project of using the davit arm design for the project, and why did BCTC not choose this arrangement?

105.4 Would either double circuit pole design be compatible with installing one 230 kV circuit now and a second 230 kV circuit at a future date?

105.5 Please provide a diagram drawn to scale that shows a typical cross-section of the ROW in Tsawwassen for each of the following scenarios.

a) existing two 138 kV lines
b) proposed one existing 138 kV line plus an underground 230 kV line
c) one double circuit 230 kV line (similar to the new line between Arnott and Tsawwassen)

105.6 Please repeat the proceeding question for a typical cross-section of the ROW on Salt Spring Island.

106.0 Reference: Exhibit B-1

106.1 Exhibit B-1 at page 86 states that Health Canada has indicated that it does not consider EMF guidelines necessary. Please provide a copy of the Health Canada document or other communication that sets out this position.

107.0 Reference: Exhibit B-1, Appendix R

107.1 In Appendix R, the Tsawwassen Route Alternatives Evaluation states that Route 1 (overhead lines) has a Visual Impact of "Neutral Change – Fewer and narrower, but higher structures." The Gulf Islands Alternatives Evaluation states that Option 1 (230 kV overhead lines) has a Visual Impact of "Reduced – Fewer and narrower structures, farther from edge of ROW." Please explain in detail why BCTC considers that the change to a new double-circuit 230 kV line would not have a reduced visual impact in the Tsawwassen area.

108.0 Reference: Exhibit B-1, p. 109

108.1 On page 109 of Exhibit B-1, BCTC identifies the need to obtain underground rights in Tsawwassen as a risk factor. Please provide the Action Plan and timelines that BCTC is using to negotiate and, if necessary, expropriate underground rights.

108.2 Please provide a schedule and cost estimate for a "worst case" scenario, where perhaps one-half the residents along the Tsawwassen ROW refuse to negotiate underground access.

109.0 Reference: Exhibit B-1, p. 74

109.1 Further to the cost estimate on page 74 of Exhibit B-1, please explain how BCTC calculated Overhead and IDC.

110.0 Reference: Exhibit B-1, p. 110

110.1 Further to Table 4-6 on page 110 of Exhibit B-1, please provide similar Rate Impact assessments for each of the following alternatives.

a) Option 1 as set out in Table 4-3
(all on-land lines overhead)

b) Option 6 as set out in Table 4-3
(Submarine cable around Pt. Roberts)

c) Conventional HVDC, Existing ROW, reuse existing HVDC OH line, as set out in Table 4-5

d) HVDC Light – Northern Bypass, as set out in Table 4-5

111.0 Reference: Exhibit B-1, pp. 75, 76

Commissioner Ken Hall prepared an Inquiry Report dated May 26, 1995 regarding BC Hydro, entitled "Undergrounding of the Overhead Transmission Lines along Boundary Road in the City of Vancouver."

111.1 The Boundary Road Inquiry Report at page 25 refers to a Multiple Account Evaluation that BC Hydro filed as Exhibit 22 in that Inquiry. Such an evaluation attempts to identify, quantify and, where practical, monetize the full spectrum of costs and benefits of a project to society at large. The accounts normally evaluated include:

Financial;
Environmental;
Societal; and
Economic Development.

Please provide a Multiple Account Evaluation that compares the full spectrum of costs and benefits for:

a) installing the 3.7 km section of new 230 kV line in Tsawwassen underground (with one existing 138 kV line left in place)

b) installing two new lines underground (to operate at 230 kV and 138 kV initially)

c) installing two new lines overhead on double-circuit poles (as between Arnott and Tsawwassen, to operate at 230 kV and 138 kV initially).

111.2 Exhibit B-1 at page 76 states that environmental assessments provide a single integrated framework to address a broad range of environmental, health, heritage, socioeconomic, community and First Nations issues. Please provide a summary comparison of these impacts for the Tsawwassen section of the new 230 kV line that compares the full, broad range of the effects of installing the line underground or overhead under each of the scenarios set out in the preceding question. Please include an overall assessment of the impacts, and describe briefly how the factors were weighted to arrive at the overall conclusion.