



SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

ROBERT J. PELLATT
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
web site: <http://www.bcuc.com>

Log No. 10140

VIA E-MAIL
marcel.reghelini@bctc.com

September 7, 2005

BCTC – VITR Exhibit No. A-13

Mr. Marcel Reghelini
Director, Regulatory Affairs
British Columbia Transmission Corporation
10th Floor, Four Bentall Centre
1055 Bentall 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. 2

Attached please find Commission Information Request No. 2 to BCTC. Please provide a hard copy and e-mail copy in response. Pursuant to Commission Order No. G-72-05, BCTC is to respond to the Information Request by Tuesday, September 27, 2005.

Yours truly,

Original signed by:

Robert J. Pellatt

JBW/rt
Attachment
cc: Registered Intervenors/Interested Parties

**British Columbia Transmission Corporation
Certificate of Public Convenience and Necessity Application
for the Vancouver Island Transmission Reinforcement Project**

112.0 Reference: Exhibit B-6, Response to IR 62.5; IR 78.1

The Responses to IRs state that BCTC plans the system based on the generation load provided to it by BC Hydro in the NITS Application; BCTC does not have an opinion on what a reasonable generation addition assumption should be for Vancouver Island following 2009-2010.

112.1 BC Hydro submitted a Resource Options Report (“ROR”) on June 13, 2005 to the Commission. According to BC Hydro, the information resulting from the ROR will aid in making decisions about what level of transmission service should be contracted. For the purposes of filing the VITR application, has BCTC reviewed the ROR? If no, why not.?

112.1.1 If yes, does the information in ROR inform BCTC as to the level of transmission services before and following 2009-2010?

112.1.2 Is the information in ROR comparable to that in the NITS?

112.1.3 Does BCTC have an analyst in charge of independently reviewing BC Hydro’s load demand forecasting and supply/demand outlook? If no, what are BCTC’s internal assessment procedures upon receipt of information from BC Hydro?

113.0 Reference: Exhibit B-6, Response to IR 62.4

The Response to IR 62.4 states that as part of a coordinated effort to select resources to serve load, BCTC provides BC Hydro with the transmission reinforcements required for resource scenarios proposed by BC Hydro. In BC Hydro’s 2004 NITS Application, BC Hydro chose not to specify generation resources on Vancouver Island after 2009/10.

113.1 BC Hydro filed with the Commission in July 2005 Supplemental Call Evidence as part of its 2005 Resource Expenditure and Acquisition Plan (“REAP”) application. For the purposes of making prudent preparations for later construction of a second 230 kV circuit, has BCTC been coordinating with, and providing input to, BC Hydro over evaluation factors for generators on Vancouver Island that would potentially defer transmission capital improvement costs and reduce or increase losses in the regional network? If no, why not? If yes, please provide documentation of the coordination efforts and inputs to BC Hydro.

114.0 Reference: Exhibit B-1, Appendix J, p. 5; Exhibit B-6, Response to IR 82.1

Whereas BCTC is not investigating any other industrial load shedding proposals than the Norske proposal, it was consulted recently regarding an industrial load expansion plan on Vancouver Island. Please comment on the probability that the expansion plan would proceed and the potential impact of the expansion on load demand if it proceeds.

115.0 Reference: Exhibit B-6, Response to IR 83.1; Exhibit B-1, Tab J, Table 1 & Appendix 3

The “VI Dependable Gen” in Table 1 was duplicated from Appendix 3 from the row labeled “VI Sum” with the exclusion of the VI CFT generation (252 MW). The “VI Dependable Gen” is calculated at 714 MW for F2007 and is expected to remain at 744 MW from 2009/10 until 2024/05.

115.1 In the Commission Decision for VIGP CPCN application, the Commission concluded that BC Hydro’s supply additions should be adjusted upwards by 5 MW for 2007/08 and by 15 MW for 2011/12 to reflect the on-going development of green energy resources. Table 3.2 and Table 4.1 of the Decision summarize the adjusted dependable capacity at 2,045 MW that includes 30 MW from E-plus, Resource Smart and Green Energy for 2007/08. In BCTC’s view, is it appropriate to not take note of the E-plus, Resource Smart and Green Energy capacity when calculating the supply balance in Table 1?

115.2 Given that the Duke Point Power project is not proceeding as planned, should the Vancouver Island Contingency Plan which includes small dependable capacity calls, etc. (Reference: 2005 REAP BC Hydro Response to BCUC IR 1.23.0) be referenced by BCTC in transmission scheduling and planning?

116.0 Reference: Exhibit B-6, Response to IR 83.2

In calculating the difference in demand data between Table 1 and Exhibit B-98 of the BC Hydro CFT application, BCTC calculated that the difference for F2007 is 0, based on 2,283 MW from Exhibit B-98. Please confirm that the demand for F2007 from Exhibit B-98 is in fact 2,293 and not 2,283 and that the difference is not 0 but 10.

116.1 Please comment if the new data in the response to IR 83.2 would change BCTC’s response to IR 79.1.

117.0 Reference: Exhibit B-6, Vol. 1, BCUC IR 1.4.2

117.1 Further to the response to BCUC IR 1.4.2, please clarify if the estimate of \$0.800 million to abandon in place portions of the 138 kV cables is in addition to the \$4.42 million estimate to remove the cables, or is the total cost related to taking the old cables out of service.

117.2 If abandonment of the cables in place is environmentally acceptable and the cost would be considerably lower than removal, please explain whether BCTC’s preferred plan would be to abandon them in place.

118.0 Reference: Exhibit B-6, BCUC IR 1.19.4, Exhibit B-1, Appendix L (C. HVDC Operational Reliability Improvement)

“Despite a planned rating of zero MW at the end of 2007, the system will not perform at zero capability 100 % of the time. There will be levels of capacity and availability that will contribute to reliability of service to Vancouver Island.”

118.1 Please indicate the levels of capacity expected to be available.

118.2 What are the expected capital costs and on-going incremental operating and maintenance costs to improve the reliability of the existing HVDC system?

119.0 Reference: Exhibit B-6, Vol. 1, BCUC IR 1.19.2, 1.30.1

119.1 Further to the expected energy not served (“EENS”) numbers in the response to BCUC IR 1.19.2, if possible please provide the dollar value of each EENS index in terms of value to BC Hydro and to customers, and identify the basis of the unit energy value used in the calculation.

119.2 In the responses to BCUC IR 1.30.1, the Executive Summary of the attached report “Probability Distribution of HVDC Capacity and Impacts of Two Key Components” states that replacing the Pole 2 reactor at VIT in 2005 will bring the HVDC failure probability in 2009 back to its failure probability level in 2007 and replacing the Pole 2 filter capacitor at VIT in 2005 will bring the HVDC failure probability in 2008 back to its failure probability level in 2007. Does the reference to replacing those components in 2005 have significance? That is, would substantially the same effect result if the components were replaced in 2007?

119.3 From an operational point of view, please discuss whether after replacement of the two components, the HVDC system would be expected to be able to fulfill the same supply role to Vancouver Island in 2009 that it currently is expected to provide in 2007.

120.0 Reference: Exhibit B-6, Vol. 3, BCUC IR 1.36.11, 1.36.21 and 1.80.2

120.1 The response to BCUC IR 1.80.2 indicates a shortfall in dependable capacity to Vancouver Island and the southern Gulf Islands of 282 MW in 2007/08. Appendix M in Exhibit B-1 and the response to BCUC IR 1.36.1 identify several bridging measures, including:

- there is a high probability that the short term overload rating of the 500 kV cables can be increased by 120 MW;
- the reduction in reliability of the aging HVDC system can be delayed;
- the 138 kV circuits can be used to supply 60 MW to the southern Gulf Islands;
- a demand side management arrangement may be negotiated with Norske.

Near the end of the response to BCUC IR 1.36.1, BCTC states that it “plans to select the amount of load shedding necessary to meet the requirements for serving the firm loads on Vancouver Island in 2006.” Does BCTC mean 2006, 2007, or 2008? Please explain.

120.2 As several of these bridging measures involve incremental expenditures, please explain the process and criteria that BCTC will use to select the prudent amount and mix of bridging measures for winter 2007/08.

120.3 Further to the response to BCUC IR 36.2, please discuss the basis for BCTC’s desire to not depend on bridging measures after 2007/08, including consideration of both the cost of the bridging measures and potential increases in the cost of the VITR Project in order to keep the project on schedule.

121.0 Reference: Exhibit B-6, BCUC IR 1.39.4, 1.102.4

- 121.1 The response to BCUC IR 1.39.4 states that the HVDC Pole 3 cost estimate is a P90 estimate, with a confidence level that actual costs will be within the overall estimate 90 percent of the time. The response to BCUC IR 1.102.4 states that the contingency for the VITR project should provide a cost estimate that is predicted to be within +10 percent of the actual cost eight times out of ten. Please explain how the confidence level and contingency for the VITR cost estimate relate to P90 and P50 estimates.
- 121.2 Please identify P90 and P50 contingency amounts and total cost estimates for the proposed VITR project.

**122.0 Reference: Exhibit B-1, p. 74;
Exhibit B-6, Vol. 3, BCUC IR 1.95.9, 1.96.2**

- 122.1 The proposed VITR project (Route 2) has an estimated cost of \$244.985 million, plus \$10 million to retire one 138 kV circuit (Exhibit B-1, p. 74, Figure 3-35). Revised Table 4-3 in the response to BCUC IR 1.95.9 indicates that the Stage 1 (2008) capital costs of Route 1 (overhead in Tsawwassen) would be \$13.69 million less expensive. Please confirm that the Route 1 capital cost would be \$231.295 million plus \$10 million retirement costs, or provide the correct figures.
- 122.2 Please provide a table similar to that in the response to BCUC IR 1.96.3 that compares the costs for Route 1 and Route 2.
- 122.3 Referring to Revised Table 4-3, please confirm that Route 2 (undergrounding in Tsawwassen) commits BCTC to an increased future expenditure estimated at \$12.6 million in 2017, in the event it proceeds with the second 230 kV circuits. If the amount does not include contingency, overhead and IDC, please provide a cost estimate that does include them.
- 122.4 What is the incremental net present value (“NPV”) cost of advancing the undergrounding of the second 230 kV circuit in Tsawwassen from 2007 to 2008?
- 122.5 In order to proceed with undergrounding the second circuit as part of the VITR project, does BCTC propose that community funding would cover the \$12.6 million additional cost, or the increment NPV cost of advancing the undergrounding of the second 230 kV circuit. Please explain the reasons for your response.

123.0 Reference: Exhibit B-6, Vol. 1, BCUC IR 1.17.3; Vol. 3, BCUC IR 1.44.1, 1.97.3, 1.98.2

- 123.1 In response to BCUC IR 1.17.3, and 1.97.3, BCTC indicates that in the event of multiple 138 kV cable failures, the southern Gulf Islands load would be converted to 230 kV supply. The response to BCUC IR 1.98.2 states that the cost of advancing construction of a 230 kV substation on Salt Spring and decommission both 138 kV lines in 2008 would increase NPV costs by approximately \$3.5 million. Please confirm that the \$3.5 million covers the NPV cost difference of converting service to both Salt Spring and Galiano Islands for 2008, or provide the incremental NPV cost for both islands.

- 123.2 The response to BCUC IR 1.44.1 provides reasons why BCTC believes that retaining one 138 kV circuit “as is” is not the best solution in the long run. Another low cost option may be to build a single 230 kV circuit, advance the conversion of Salt Spring and Galiano Islands and take both 138 kV lines out of service, all for 2008. Please provide estimates of the cost of this option (for the cases of underground and overhead construction in Tsawwassen) relative to the Route 1 and Route 2 options, in the form of the table in the response to BCUC IR 1.96.2.
- 123.3 Please provide a comparison of the NPV cost of installing two 230 kV circuits under the foregoing option relative to the Route 1 and Route 2 options, in the form of Revise Table 4-3 in the response to BCUC IR 1.95.9, assuming the 230 kV line is overhead in Tsawwassen and
- (a) a single circuit 230 kV line is built for 2008 and a second 230 kV line is built for 2017.
 - (b) the on-land portion of the new 230 kV line is built as a double circuit line, but the conductors for only one circuit are installed for 2008.
 - (c) completing the on-land construction of a double circuit 230 kV line.
- 123.4 Please compare the foregoing option for complete removal of the 138 kV lines in 2008 to the proposed VITR project, in terms of reliability, public impact during construction and subsequently, and operating and maintenance costs.

124.0 Reference: Exhibit B-6, Vol. 3, BCUC IR 1.56.4, 1.56.6

- 124.1 The response to BCUC IR 1.56.4 states that Route Option 1 has a Return Period of 1/1850 and Route Option 2 has a Return Period of 1/1700. The response to BHCUC IR 1.56.6 states that the current IEEE code requires that critical electrical installation be designed for a return period of at least 2475 years. Please explain whether either Route 1 or Route 2 would be in compliance with IEEE requirements.
- 124.2 Has BC Hydro confirmed that the proposed Route 1 and Route 2 designs will meet its revised Seismic Performance criteria? If it has not, what additional measures may BCTC need to incorporate into the project, and what would they cost?

125.0 Reference: Exhibit B-1, BCUC IR 1.91.2, 1.99.7

- 125.1 Further to the response to BCUC IR 1.91.2, the Inquiry Report dated May 26, 1995 related to Undergrounding of the Overhead Transmission Lines along Boundary Road in the City of Vancouver at page 16 states that BC Hydro expressed concern that undergrounding the Boundary Road lines would set a precedent that could lead to undergrounding nearly 300 kilometers of high-voltage transmission lines in urban or suburban areas, at a cost of over \$3 billion. Please discuss whether undergrounding the new 230 kV line in Tsawwassen would establish a precedent for other lines.
- 125.2 Please provide an update on the length of undergrounding and cost that would result from a Commission decision that led to a major undergrounding of transmission lines.

- 125.3 In the response to BCUC IR 91.2, BCTC notes that the Tsawwassen situation arises from a proposal to replace and upgrade existing facilities. If BCTC does not anticipate undergrounding except for new or upgraded lines in urban or suburban areas, and assuming all such new or upgraded high-voltage lines would be undergrounded, what would be the incremental cost of such undergrounding over the next 20 years?
- 125.4 In response to BCUC IR 1.99.7, BCTC states that it did not apply formal weighting criteria to conclude that the Tsawwassen section should be undergrounded. In the absence of a formal decision-making mechanism to determine which transmission lines should be undergrounded at ratepayer expense, please explain how the Commission can have confidence in estimates of the likely future total cost of undergrounding transmission lines, or that the public along different transmission lines will be treated equitably.

126.0 Reference: Exhibit B-6, BCUC IR 1.11.3, 1.100.2, 1.110.1

- 126.1 The response to BCUC IR 1.110.1 provides changes in Transmission Revenue Requirements and rate impacts based on BC Hydro's current equity and debt levels, but notes that the VITR project would be funded 100 percent by debt. For purposes of comparison, please also provide the response showing change in Transmission Revenue and rate impact on the basis that the project is financed 100 percent by debt. Please include the scenario where both 230 kV circuits are installed underground in Tsawwassen and completed for 2008 (Route Option 7), and assuming the cost is recovered from all ratepayers.
- 126.2 The responses to BCUC IR 1.11.3 and 1.100.2 note that Special Direction No. HC2 requires that ratepayers pay a return on equity on unamortized contributions in aid of construction. Please provide a schedule similar to that in the response to BCUC IR 1.110.1 that shows the change in Transmission Revenue Requirements and the rate impacts for the following cases:
- (a) Route Option 2, where community funding pays for the incremental cost of undergrounding in Tsawwassen.
 - (b) Route Option 7, where community funding pays for the incremental cost of undergrounding the second circuit in Tsawwassen for 2008.
 - (c) Route Option 7, where community funding pays for the incremental cost of all undergrounding in Tsawwassen.

Please show or explain how the calculation was done.

- 126.3 Based on the response to the previous question, please identify and discuss the net benefits to other ratepayers if community funding is provided for incremental project costs.

127.0 Reference: Exhibit B-6, BCUC IR 1.111.1

- 127.1 The response to BCUC IR 1.111.1 notes that Option 1 has less Temporary Construction Impacts than Option 2 which in turn has lower impacts than Option 7. Please provide a concise comparison of the construction impacts of Options 1 and 2 and the expected duration of these impacts. If a second 230 kV line is built for 2017, how will this affect the comparison of construction impacts for Tsawwassen?

- 127.2 Does the assessment that Option 2 has lower impact than Option 7 only consider impacts through 2008? Please provide a concise comparison of construction impacts and their expected duration for these Options.
- 127.3 Further to the response to BCUC IR 1.111.1 that it is difficult to monetize non-financial criteria, please attempt to monetize those criteria where it is possible to do so, such as OMA cost and Property Values.
- 127.4 In order to provide better differentiation of the rankings of the Options, please provide a table similar to that in the response to BCUC IR 1.111.1 where the criteria for each Option are ranked on a scale of perhaps 1 to 10 (e.g. a ranking of 6 for each of two Options would indicate they have similar impact, while 8 for the other Option would indicate it is somewhat better or worse than the other two).

128.0 Reference: Exhibit B-6, BCUC IR 1.82.1

“BCTC is not investigating any other industrial load shedding proposals than the Norske proposal.”

- 128.1 Please describe other potential industrial demand side management programs for Vancouver Island.
- 128.2 Why is BCTC or BC Hydro not investigating any other demand side management programs at the present time?
- 128.3 What is the expected impact of the new stepped rates introduced for conservation and energy efficiency?

129.0 Reference: Exhibit B-6, BCUC IR 1.84.1

“There are existing 138 kV, 230kV and 500 kV overhead lines throughout suburban communities in the Lower Mainland and in a few places elsewhere in the province. This includes North Vancouver, Coquitlam, Pitt Meadows, Burnaby, New Westminster, Surrey and Delta among others.”

- 129.1 Please indicate in which Lower Mainland communities BCTC has existing 230 kV overhead lines, and specifically describe:
- a) Where the right-of-way traverses residential properties or school grounds;
 - b) What year those transmission lines were built;
 - c) How many homes approximately are affected;
 - d) Was the undergrounding option considered for any of those residential areas at the time of construction; and
 - e) If it was, why was it rejected?

130.0 Reference: Exhibit B-6, BCUC IR 1.84.1, 1.99.1

- 130.1 Further to the response to BCUC IR 1.84.1, please provide a schedule showing the lengths of BCTC 138 kV, 230 kV and 500 kV transmission lines in each municipality in B.C., identifying the portions that are underground in each case. If it is possible to do so, please also identify the portions of the lines that are in built-up urban and suburban communities.

130.2 Please provide a map showing the BCTC lines in the Vancouver area, identifying the portions that are underground and, if possible, the voltage of each line.

130.3 In the response to BCUC IR 1.84.1, BCTC states that it has no intent to release any existing ROW and that it will take measures to preserve its existing ROW for future upgrades or additions. Further to the response to BCUC IR 1.99.1, please discuss whether BCTC considers that adequate steps have been taken to preserve the ROW in Tsawwassen for transmission lines (noting that the ROW does not provide for underground lines). If adequate steps have not been taken, should any incremental costs that result be the responsibility of ratepayers?

131.0 Reference: Exhibit B-6, BCUC IR 1.87.0

The memorandum dated July 20, 2005 from Raymond Penner to Donna McGeachie, when addressing participants' key responses, list eight statements.

131.1 Please summarize BCTC's position regarding each one of the eight statements.

132.0 Reference: Exhibit B-6, BCUC IR 1.87.0

The memorandum dated July 20, 2005 from Raymond Penner to Donna McGeachie lists materials distributed and presentations made.

132.1 Please provide references to the Application or a copy of the materials and presentations for each of the items listed as attachments to the memorandum.

133.0 Reference: Exhibit B-6, Responses to BCUC IR 1.84.1 and 1.90.3

In its response to IR 84.1, BCTC states that BCTC and BC Hydro have had difficulty accessing the existing 138 kV lines for many years. The response to IR 90.3 states that BCTC and BC Hydro have the right to pass and re-pass over the land (including land outside the ROW).

133.1 Please explain the nature of the difficulties that BCTC and BC Hydro have encountered while exercising their right to pass and re-pass over the land in question, when accessing the existing lines for vegetation management and other maintenance. How would the situation be improved following the implementation of the 230 kV project?

134.0 Reference: Exhibit B-6, Response to BCUC IR 1.111.1

On the second page of its response, BCTC provides a table summarizing the evaluation of three options.

134.1 Please explain how BCTC arrived at the Overall Rankings shown on line 13. If weightings were applied to the various factors, please provide them. If the Overall Rankings were affected by factors not listed in the first column, please provide information on those additional factors.

134.2 Which three of the Rankings did BCTC consider the most significant in the determination of the Overall Ranking?

135.0 Reference: Exhibit B-6, BCUC IR 1.5.2

“The benefits will include a wider range of permitted uses of the legal right-of-way because of the larger edge distances.”

135.1 Please provide examples of the wider range of permitted uses of the legal right-of-way because of the larger edge distances for both lands publicly owned and privately owned.

136.0 Reference: Exhibit B-6, BCUC IR 1.88.1

“BCTC also believes that reaching agreement on a funding proposal by November 2005 is also important to ensure the proposal is adequately considered by the Commission as part of its deliberations.”

136.1 Should the agreement be filed prior to the commencement of the hearing?

137.0 Reference: Exhibit B-6, BCUC IR 1.92.1

“Currently, the design is frozen pending the immediate BCUC process and completion of a view shed analysis being conducted as part of the environmental assessment process. The final tower spotting and design process can begin once the BCUC proceeding has been completed.”

137.1 Does BCTC require BCEAA approvals, particularly of the Environmental Management Plan, prior to final tower spotting?

138.0 References: Exhibit B-1, p. 52; Exhibit B-6, BCUC IR 1.14.1

“BCTC has prepared a list of potential encroachments on the existing ROW. However, no assessment has been undertaken at this time to confirm the extent to which the structures or improvements are conforming or non-conforming. BCTC intends to conduct this assessment as part of the detailed design phase of the Project scheduled for early 2006” (Exhibit B-6, BCUC IR 1.14.1).

“All lands and conforming improvements will be restored to previous condition following construction” (Exhibit B-1, p. 52).

138.1 Does the distinction between conforming and non-conforming turn on the Company’s opinion of whether or not the encroachment might interfere with the safe and efficient operation of its works, as provide for in clause 2 of the agreement attached to BCUC IR 1.3.2?

138.2 Will the designation of encroachments as either conforming or non-conforming need to be made after completion of the final structure spotting?

138.3 Please confirm that BCTC intends to restore to previous condition only conforming improvements. If confirmed, does BCTC intend to notify property owners of non-conforming improvements that will not be restored to previous condition? When will BCTC notify the property owners?

138.4 Please provide examples, if any, of conforming structures or improvements that will need to be restored. For each example, please explain how the structure or improvement will be restored to previous condition?

139.0 Reference: Exhibit B-6, BCUC IR 1.17.1, BCUC IR 1.18.4

BCTC notes that, with both 500 kV circuits out of service, the HVDC at full operational output, and the 138 kV circuits transferring 200 MW of load, there would still be a significant amount of load curtailment required on Vancouver Island.

- 139.1 How often, and for how long, must the 500 kV circuits be taken out of service for planned maintenance?
- 139.2 Are there operational considerations that would prevent the 500 kV circuits from being taken out for maintenance during periods when Vancouver Island loads are at their lowest? If yes, please explain.
- 139.3 What is the distribution of the repair times for the 500 kV circuits following unplanned outages?
- 139.4 Is the probability of a 500 kV circuit failing roughly constant throughout the year, or are there seasonal or other factors that materially change that probability?
- 139.5 Please provide probability distributions for the amount of load curtailment (both MW and MWh) that would be required on Vancouver Island when:
 - (a) one 500 kV circuit fails (the other remains in service);
 - (b) the second 500 kV circuit fails while the first is out of service for planned maintenance;
 - (c) the 500 kV circuits fail simultaneously.

140.0 Reference: Exhibit B-6, BCUC IR 1.17.2

BCTC states that, if it proves economically feasible, it will maintain the HVDC system in an operable condition beyond 2008, and will load the HVDC system as much as possible during emergency conditions. BCTC further states that emergency capacity depends on the pre-emergency condition of the HVDC equipment and cables, the ambient air temperature being less than 7.2 °C, and restricting Pole 1 to two hours per day of overloading.

- 140.1 How will BCTC determine whether the reliability benefits of an operational HVDC system outweigh the costs of maintaining the operational status? Please state any assumptions that BCTC expects to have to make in its evaluation.
- 140.2 When does BCTC expect to be able to make such a decision?
- 140.3 What is the likelihood that the ambient temperature is less than 7.2 °C during Vancouver Island's heaviest load hours?
- 140.4 Does the temperature restriction mean that no emergency capacity would be available if the ambient air temperature were 7.3 °C or above? Please elaborate.

141.0 Reference: Exhibit B-6, BCUC IR 1.19

BCTC describes the amount and nature of the projected capacity shortfall and provides EENS values with and without the proposed 230 kV line for each of three years.

- 141.1 Please update the EENS values shown in BCUC IR 1.19.2 under the assumption that the Norske demand management proposal is in place in all three years. For clarity, energy not provided to Norske because of demand reductions under its DSM proposal is not to be counted as energy not served.
- 141.2 For both the original EENS data and the data provided in response to the previous question, please provide the probability distributions for lost MW and lost MWh.
- 141.3 The capacity of each 500 kV circuit is reported in 1.19.3 to be 1200 MW, but is stated to be 1300 MW elsewhere in the Application (e.g., BCUC IR 1.36.3). Please clarify whether the EENS calculations assumed 1200 MW or 1300 MW and, if necessary, update the EENS values so they are based on the latter.
- 141.4 What is the effect on the EENS values of assuming that the 500 kV circuits' ratings can be increased to 1300 MW plus five percent (i.e., 1365 MW) at low ambient temperatures?
- 141.5 What is the effect on the EENS values of assuming that the short-term overload rating of the 500 kV circuits can be increased by 120 MW (BCUC IR 1.36.1)?
- 141.6 Please describe in detail the simulation process used to arrive at the EENS values. In your response, please state the number of simulations performed and discuss the process used to model Vancouver Island load (including its temperature dependence, if applicable).
- 141.7 Are the repair times stated under Assumption 2 in BCUC IR 1.19.3 assumed to be fixed, or is there an associated probability distribution?
- 141.8 Assumption 3 in BCUC IR 1.19.3 states that both ageing and repairable failures on HVDC Poles 1 and 2 were modeled. Please describe the modeling process and state any assumptions made.
- 141.9 Assumption 4 in BCUC IR 1.19.3 shows a repair time for JHT-1 of more than 900 hours compared to 2 hours for JHT-2. Please explain, and indicate whether using that value in simulations is reasonable.
- 141.10 Please explain how the bridging measures noted in the response to BCUC IR 1.19.4 were incorporated into the EENS calculations. If the bridging measures were not modeled, please indicate the time and effort that would be required to do so.

142.0 Reference: Exhibit B-6, BCUC IR 1.19.4 and 1.19.5; Excel File "BCUC IR 1.19.5.xls"

In its discussion of bridging measures, BCTC makes the assumption (see Bridging Measure F) that the Norske DSM trial will be successful and that a load-shedding mechanism will be in place for October 2007. Presumably, the Norske DSM mechanism would be "unarmed" under certain system operating conditions, "armed" under certain other operating conditions, and "triggered" under a subset of the armed conditions and/or in response to certain events.

- 142.1 Please provide an update on the results of the trials to date.
- 142.2 Please describe the system operating conditions under which the DSM scheme would be armed.
- 142.3 Please describe the system operating conditions and/or events under which Norske load would be curtailed.
- 142.4 Please add column(s) to the spreadsheet provided in the response to BCUC IR 1.19.5 that indicate what the state of the Norske load would have been (unarmed, armed, or curtailed) in each hour, assuming that the HVDC system capacity had been zero in all hours.

143.0 Reference: Exhibit B-6, Excel File “BCUC IR 1.19.5.xls”

- 143.1 The columns entitled “Status: Pole 1” and “Status: Pole 2” contain the values “IN”, “OUT”, and “AVAIL.” Please confirm that “IN” means in service and “OUT” means out of service.
- 143.2 Please confirm that “AVAIL” means available for service. Please explain why most hours in which the status of both poles is “AVAIL” have HVDC flows of less than 2 MW (in absolute value) but a few such hours have flows over 200 MW in absolute value.
- 143.3 The Commission calculates the following hours for 2004 from the worksheet.

Status	Pole 1	Pole 2
AVAIL	367	81
IN	7745	8201
OUT	672	502
Total	8784	8784

Outage Type	Pole 1	Pole 2
Forced	16	29
Planned	656	473

Please confirm that these values are correct, and reconcile them with the statements on page 2 of the report attached to BCUC IR 1.30.1 that the availability of Pole 1 in 2004 is only 38.9 percent and the availability of Pole 2 in 2004 is only 84 percent.

144.0 Reference: Exhibit B-6, BCUC IR 1.20.2

BCTC states that any new circuit (HVDC Light or ac) along the southern corridor is expected to run at a relatively high level for most of the year.

- 144.1 Please quantify this statement.

145.0 Reference: Exhibit B-6, BCUC IR 1.22.2

- 145.1 Why does BCTC expect that construction costs for duct banks should be lower than normal?
- 145.2 Please set out the “Aboriginal accommodation costs” for this project.

146.0 Reference: Exhibit B-6, BCUC IR 1.24.1

146.1 Which structures, if any, have been identified as requiring ground densification, caissons, or other special foundation treatment?

147.0 Reference: Exhibit B-6, BCUC IR 1.29.4

147.1 Please describe the circumstances of the N-1-1 and N-2 500 kV circuit outages. In the response, please include the date and time of the failures, the time to restore the first circuit, and (if applicable) the time to restore the second circuit.

148.0 Reference: Exhibit B-6, BCUC IR 1.30.1

BCTC is currently reviewing the options presented in the report entitled *Probability Distribution of HVDC Capacity and Impacts of Two Key Components* to determine if there are more economic methods to achieve the same outcomes. BCTC is also looking at other cost-effective ways to enhance the availability of the HVDC system.

148.1 Please provide the EENS values for the cases shown in the response to BCUC IR 1.19, this time under the assumption that the old reactor and filter capacitors on HVDC Pole 2 are replaced. The HVDC failure probabilities should be adjusted accordingly.

148.2 On page 2 of the aforementioned report, it is noted that the in-service date of the 230 kV ac line will be October 2008 as an “accelerated” plan or October 2009 as a “non-accelerated” plan. Please define the term “accelerated” in this context, and comment on any risks associated with accelerating the project.

148.3 What would be the financial and rate impacts of deferring the VITR for one year? Two years?

149.0 Reference: Exhibit B-6, BCUC IR 1.37.1

BCTC indicates that, in the extremely unlikely event of conductor contact between the 230 kV and 138 kV systems, high-speed protection would clear the fault within a few cycles. However, on June 13, 2005, a major outage occurred when lightning struck a transmission line connecting FortisBC facilities to BCTC’s transmission system. Customers complained of equipment damage from overvoltages that resulted from the failure of protective equipment to operate as intended.

149.1 How will BCTC ensure that a similar protection system failure does not result in equipment damage should the 230 kV and 138 kV conductors come into contact?

150.0 Reference: Exhibit B-6, BCUC IR 1.39.4; BCUC IR 1.102.4

BCTC has produced cost estimates and set confidence levels for those estimates based on Monte Carlo simulations.

150.1 Please describe the inputs and assumptions involved in the simulations, the processing that takes place on the input data, and the outputs.

150.2 Please describe any checks that were performed on the simulation outputs.

151.0 Reference: Exhibit B-6, BCUC IR 1.48.1

The BC Hydro Transmission Engineering Technical Standards, Procedures, and Guidelines for certain clearances are more stringent than CAN/CSA Standard C22.3-No. 1-01.

151.1 What is the rationale for the larger clearances required by BC Hydro?

151.2 What effect do these more stringent standards have on project costs?

152.0 Reference: Exhibit B-6, BCUC IR 1.51.2

BCTC intends to manage the risk of sunk costs arising from the environmental assessment (“EA”) process through tender options and prudent contract language with regard to contract amendment or termination.

152.1 BCTC’s risk management proposal appears to transfer the EA risk to BCTC’s suppliers. Please comment on whether that is likely to result in higher prices.

153.0 Reference: Exhibit B-6, BCUC IR 1.97.6

153.1 Did BCTC examine options for controlling the flow on the 138 kV system during operation in parallel with the 500 kV circuits to Vancouver Island? Please explain.

154.0 Reference: Exhibit B-6, BCUC IR 1.2.4

154.1 If only a single 230 kV AC circuit is approved at this time, and with the assumption that future Vancouver Island supply will not be served from Arnott, please describe the advantages and disadvantages of serving Gulf Island Load with two circuits from VIT versus a single circuit between ARN and VIT.

154.2 Can the power flow on a remaining 138 kV circuit between ARN and VIT be controlled with a phase-shifting transformer?

154.3 With additional investments, what is the practical maximum transfer capability of the 138 kV AC circuit between ARN and VIT. Please assume additional investments for phase-shifting transformers (if required), replacement of submarine cables (to practical single conductor maximums), and additional de-bottlenecking have taken place.

155.0 Reference: Exhibit B-6, BCUC IR 1.18.1

155.1 If the WECC RMS agreement does not address compliance with planning or operating to meet N-1 or N-1-1 criteria for operations internal to one’s own system, what are the procedures necessary to seek relaxation of or exceptions to the NERC/WECC planning standards for effects and responses to single contingencies contained with one’s own system? Please describe these in detail.

- 155.2 In the BCTC 2005 Transmission System Capital Plan proceeding, Exhibit B-1, Appendix K and Exhibit B-8, BCUC IR 2.108.3 refer to “System Planning Withstand Performance Criteria.”

Please supply a copy of the “System Planning Withstand Performance Criteria,” and identify those criteria that differ from the NERC/WECC Planning Standards.

156.0 Reference: Exhibit B-6, BCUC IR 1.18.6

- 156.1 Please list and describe the other instances in the BC transmission system for 230 kV AC and above where the N-1-1 criterion is not met.

157.0 Reference: Exhibit B-6, BCUC IR 1.21.1

- 157.1 Please describe BCTC’s understanding of the characteristics of the supply deficiency associated with the Olympic Peninsula?
- 157.2 Please prepare a single line diagram showing the Juan de Fuca project’s transmission connection south to the first common point with the transmission path from the Ingledow-Custer interconnection, including ratings and voltages of the interconnecting transmission lines.
- 157.3 Does the Juan de Fuca project offer a potential return path for Downstream Benefits, and if so, can it potentially lower the flows on the Ingledow-Custer interconnection when power flows are south-to-north?

158.0 Reference: Exhibit B-6, BCUC IR 1.28.1

- 158.1 Although the 138 kV AC line between VIT and ARN will still satisfy N-1 criteria at GLS and SAL, what is the expected probability of having both the VIT and ARN connections unavailable compared to the probability of unavailability of supply in the present configuration?

159.0 References: Exhibit B-6, BCUC IR 1.30.1; BCUC IR 1.34.1 (Response to BCUC IR 2.44.1 in VIGP Hearing)

- 159.1 Please confirm that a fundamental conclusion of the “Probability Distribution of HVDC Capacity and Impacts of Two Key Components” report is that the level of reliability and availability of the HVDC system presently anticipated for 2007 could be extended to 2009 with the investment of \$3.7 million.
- 159.2 What determines the interpretation of this enhanced reliability and availability as a “bridging measure” rather than a preservation of “dependable capacity”?
- 159.3 Does BCTC still support BC Hydro’s earlier conclusion stated in the response to the BCUC Information Request 2.44.1 of the VIGP Hearing that “the HVDC Life Extension Alternative is not a viable alternative”?

160.0 References: Exhibit B-6, BCUC IR 1.36.1; BCUC IR 1.69.1

- 160.1 Please provide the rationale and criteria that determine the difference between a “bridging measure” and an increase in “dependable capacity.”
- 160.2 Is the probability of the increase in the rating of the 500 kV cables at least as high as the probability that the HVDC will be unavailable for dependable capacity in 2007?
- 160.3 What enhancement or incremental capability is necessary to consider the 500 kV cable rating increase as firm capability rather than contributing simply to operational flexibility?

161.0 References: Exhibit B-6, BCUC IR 1.39.1; BCUC IR 1.43.1; BCUC IR 1.109.1

- 161.1 Please show the effects of Overheads in both the 2002 and 2004 estimates.
- 161.2 Please reconcile the apparent discrepancy in the row and column designation in the response to BCUC IR 1.43.1. In the row summary, Overheads are shown as \$12,023,000, and in the column summary as \$6,269,000. Are Overhead and IDC reversed in one location?
- 161.3 Whatever value is correct, please reconcile this against the 2.56% capitalized overhead rate stated in the response to BCUC IR 1.109.1.

162.0 Reference: Exhibit B-6, BCUC IR 1.40.1

- 162.1 Please describe any other recent DC technologies that BCTC is aware of that are potential competitors to HVDC Light™?

163.0 Reference: Exhibit B-6, BCUC IR 1.44.4

- 163.1 Please prepare projected cash flows for the two alternatives identified in BCUC IR 1.44.4, and include a NPV analysis. Also, please show the effect on the NPV of an advancement of 5 years and a delay of 5 years of adding the second line in 2017.
- 163.2 Please describe how BCTC attributes value for the visual impact of varying circuit designs in an economic evaluation.

164.0 References: Exhibit B-6, BCUC IR 1.45.2; BCUC IR 1.46.1

- 164.1 Please reconcile the statements in the responses to the two referenced Information Requests. One statement provides a base cost of \$400,000 for keeping the 138 kV cables as spares, while the other statement contends that leaving six 138 kV cables is not feasible.

165.0 Reference: Exhibit B-6, BCUC IR 1.56.6

- 165.1 If the revised BC Hydro Seismic Performance Criteria result in the need for additional capital investments, will the criteria be submitted to the Commission for review prior to adoption?

166.0 Reference: Exhibit B-6, BCUC IR 1.59.1

166.1 The Structure Modification costs are described as “not a significant figure”. Is this not significant compared to the cost of the structures, or the cost of the rest of the fibre installation, or both?

166.2 The Terminal Equipment costs are not separated from other station costs. Is the cost associated with Terminal Equipment also not significant (less than 5%) compared to the rest of the fiber installation costs?

167.0 Reference: Exhibit B-6, BCUC IR 1.71.3

167.1 Please identify any instances on the BC transmission system that relies upon RAS for single contingencies.