April 28, 2005

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”)
Transmission System-Capital Plan F 2006 to F2015
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-33-05, please respond by Friday, May 20, 2005.

Yours truly,

Original signed by:

Robert J. Pellatt

RJP/rt
Attachment
c: Registered Intervenors/Interested Parties
1.0 Reference: BCTC, TSCP, pp. 3, 4, re: Commission Directives

The Commission expected that the Baseline Study would be considered by BCTC in its future Capital Plans. BCTC has stated that this study will be filed in Mid April 2005 and that the preliminary results from the study will be considered in the development of this capital plan.

1.1 If the Baseline Study and the State of the Transmission system report have not been filed by the time BCTC receives this IR, please advise the Commission when BCTC expects to file these reports and if BCTC expects these reports to be examined as part of this written proceeding.

1.2 Please explain how BCTC has included the preliminary results in the development of this Capital Plan. Has the Baseline study altered BCTC’s view of the work needed on the system? If so, please explain how and what the cost impact is.

The Commission at pages 27 to 28 of the Reasons for Decision attached to Order No. G-103-04 required BCTC to answer a number of questions regarding the proposed supply to Vancouver Island and a comparison of HVDC alternatives. BCTC responded to these questions in reports dated December 20, 2004 and April 8, 2005 (“HVDC Report”).

In those responses, BCTC on page 2 of the December 20, 2004 report states that “preliminary results from this analysis (HVDC light option) confirm that the 230 kV supply option remains the best transmission option to reinforce Vancouver Island.” The report filed on April 8 acknowledged that HVDC light can control the reactive power independently at each terminal (page 8) but dismissed this advantage because reactive supply for Vancouver Island is not currently a problem (page 8 and page 13). The report provides a Capital cost comparison of HVDC light and the 230 kV option on pages 11 and 12 but does not provide an economic analysis of the life cycle or integrated benefits of the two technologies. For example, we note that BCTC predicts the need for a Static VAR Compensator at Ingledow Substation is required for 2008 at a cost of $38 Million (page 49 of BCTC TSCP). Further, we note the continuing uncertainty with respect to the use of Burrard (BCTC TSCP, p. 50 and BC Hydro, March 2005, REAPS p. 3-21) all of which indicate that VAR support in the Lower Mainland will require some integrated planning.

1.3 Please provide a life cycle economic analysis, which compares the total costs of the two options (230 kV and the HVDC Light options) on an integrated system basis. Please provide all assumptions and sources of estimates and all spreadsheets used in the analysis.

1.4 Please provide an analysis (perhaps an EENS study) which compares the level of reliability delivered by the two options.

2.0 Reference: HVDC Report, general

A report entitled Evaluation of HVDC Light™ as an Alternative for the Vancouver Island Transmission Reinforcement Project (“HVDC Report”) was prepared for BCTC by TransGrid Solutions Inc.

2.1 Please provide the Terms of Reference that was given to TransGrid.
2.2 Please provide a statement of TransGrid’s experience with other HVDC projects.

2.3 Was consideration given to having ABB (the manufacturer of HVDC Light™ systems) provide the report? Please explain.

2.4 Please explain TransGrid’s familiarity with the various options for Vancouver Island transmission. Did that familiarity come solely from a review of BCTC documents?

2.5 Was TransGrid asked to review any transmission options other than the replacement of the existing HVDC system from Arnott to VIT with an HVDC Light system between the same two points?

3.0 Reference: HVDC Report, p. 3 and Appendix 1

TransGrid notes that Technical Justification Report Number SPA2004-10 and Project Planning Report Number SP2003-04 concluded that a 230 kV ac upgrade is the technically and economically superior option for the Vancouver Island Transmission Reinforcement (“VITR”) Project. TransGrid also notes that the BCTC reports concluded that the 230 kV project had lower risk and uncertainty.

3.1 Please provide copies of the cited BCTC reports.

3.2 Was TransGrid asked to review and comment on the recommendations made in the BCTC reports?

3.3 In the BCTC reports it was assumed that the existing HVDC submarine cables would be reused after performing some repairs. Please clarify whether this assumption was carried over to TransGrid’s economic analysis, as given in Appendix 1 of the report.

4.0 Reference: HVDC Report, p. 5

Please clarify what is meant by the statement, “HVDC Light™ can operate in a passive load or a dead grid.”

5.0 Reference: HVDC Report, pp. 6-7

Please confirm that the section of the report entitled “Review of the Present and Future Load/Generation Requirements on Vancouver Island” is based entirely on the aforementioned BCTC reports. If not confirmed, what other sources or analysis did TransGrid rely on, particularly with respect to the dependability of the existing HVDC system?

6.0 Reference: HVDC Report, p. 8

The reactive power supply on Vancouver Island and its control is not currently a problem in part because there are four existing synchronous condensers providing dynamic VAr support from -250 to +300 MVArs. The report states that, if the aim is to transmit 600 MW, then the reactive power control range is severely limited by the total MVA rating of the dc circuit.

6.1 What commercial and technical arrangements are in place between BCTC and the supplier(s) of the dynamic reactive support?

6.2 What is the annual cost of dynamic reactive support from the Vancouver Island facilities?
6.3 Please provide copies of the cited BCTC reports.

6.4 Please provide a load duration curve for the expected circuit loading (in both ac and dc cases if they are different).

6.5 Please provide a MW/MVAR capability diagram for the HVDC option.

7.0 Reference: HVDC Report, p. 9

The estimated transmission losses for the 230 kV ac option are 17 MW based on BCTC Briefing Note 2004-10-13. Please provide a copy of the note.

8.0 Reference: HVDC Report, pp. 9-10

The section of TransGrid’s report on reliability compares the reliability of HVDC Light™ with conventional line commutated HVDC. How would the reliability of HVDC Light™ compare with the reliability of the 230 kV ac option. In the response, please consider the fact that the former consists of two 300 MW bipolar blocks.

9.0 Reference: HVDC Report, p. 10 and Appendix 1

The TransGrid report discusses the likely cable configurations for the dc and ac options.

9.1 Please clarify, preferably with the aid of a diagram: (a) the assumed cable configurations; (b) the rationale for those configurations; (c) the burial requirements; (d) the lengths of overhead, underground, and submarine sections; and (e) the assumptions about the re-use (or not) of existing cables.

9.2 What is the basis for the figure of $700,000/km for submarine cables?

9.3 Has the same figure been used for underground cables? What is the basis for that figure?

9.4 Was the option of using alternate sites, with the potential to reduce underground cable costs, investigated? Please explain.

10.0 Reference: HVDC Report, p. 11

Please compare the environmental impacts of the dc and ac options, as opposed to comparing HVDC Light™ and conventional line commutated HVDC.

11.0 Reference: HVDC Report, p. 12 and Appendix 1

The economic evaluation of the dc option is based on several assumptions.

11.1 The price per kW of line commutated HVDC is readily available based on evidence of awarded projects worldwide. Please provide a list of the projects examined to arrive at the figure of $236/kW.

11.2 The price per kW of HVDC Light™ is either the same or even higher than conventional HVdc based on discussions with utilities that evaluated the former. Please provide a list of the utilities and the associated project evaluations on which this conclusion - and the 20% adder shown in Appendix 1 - is based.
11.3 Were the cost assumptions used in this analysis vetted by the manufacturer? If not, would it be possible to do so?

12.0 Reference: BCTC, TSCP, p. 4

BCTC states that it is in the process of reassessing its role in evaluating and contracting for specific long-term DSM measures where these may be appropriate to avoid or delay “wires” solutions in light of the Commission’s comments in the Reasons for Decision on BCTC’s F2005 Capital Plan.

12.1 Please describe the activities that have taken place on this subject.

12.2 When does BCTC expect to finalize this assessment and develop a policy with respect to DSM?

13.0 Reference: BCTC, TSCP, pp. 6, 32

BCTC states that it is not seeking Commission approval for the precise amount associated with each capital program or project identified in the Application (p. 6). “Where variance from the project plan beyond defined thresholds cannot be avoided, the project plan will be revised, and presented for internal re-approval” (p. 32).

13.1 Does this apply to the actual expenditures for 2006 and 2007 or simply to the total project costs?

13.2 Please provide an estimate of the bounds within which BCTC would expect actual costs to fall relative to the estimates provided in this Application. If appropriate, indicate the error bounds’ dependence on a project’s development stage and/or the number of years into the future the project is expected to start.

13.3 What are the defined thresholds referred to in the above quote?

13.4 Acknowledging that projects estimates are only estimates, what criteria does BCTC apply when monitoring projects to indicate that a project may be experiencing problems such as serious cost over-runs?

13.5 Under what conditions, if any, does BCTC feel it would be appropriate to re-apply to the Commission for approval to continue a project?

14.0 Reference: BCTC, TSCP, p. 7

BCTC states that the Master Agreement requires BCTC to allocate a contingency component in its capital plan to cover unforeseen capital expenditures.

14.1 For each category of unforeseen capital expenditures, please explain how the cost amount was arrived at. Please show a historical comparison for the past several years for these categories.

15.0 Reference: BCTC, TSCP, p. 8

BCTC notes that the Commission Panel expects that, as a rule of thumb, approximately 15 percent of transmission projects should be subject to CPCN review. BCTC also states that it is reasonable to expect significant variance from the 15 percent level.

15.1 Please provide a list of those projects included in the Capital Plan for which CPCN applications will be made to the Commission.
15.2 Please provide a table indicating the number and total estimated cost for CPCN and non-CPCN projects for which approval is sought via this application. Please categorize the projects according to whether the start date is F2006, F2007, or beyond F2007.

16.0 Reference: BCTC, TSCP, p. 11

BCTC discusses NERC/WECC planning standards, and states that the system performance criteria “are based on many years of experience by utilities across North America as to the general level of reliability expected by customers, relative to the cost of achieving this reliability.

16.1 Does BCTC accept that there is frequently a trade-off between cost and reliability?

16.2 If yes, how does BCTC evaluate the reliability benefit that customers will receive from an infrastructure investment against the cost of that investment? Does BCTC have specific rules, guidelines, or standards in that regard?

16.3 How does the cost/reliability trade-off affect BCTC’s interpretation and/or application of the NERC/WECC reliability criteria?

17.0 Reference: BCTC, TSCP, p. 14

BCTC has adopted, for internal impacts only, a less-stringent-than-WECC standard for frequency dip following the loss of the BC-to-US tie when importing from the United States.

17.1 What are the NERC/WECC rules regarding which standards can be relaxed and which cannot?

17.2 What are BCTC’s own rules regarding which NERC/WECC standards can or cannot be relaxed?

17.3 What processes—both internal and external—does BCTC follow if it wishes to relax a NERC/WECC standard?

18.0 Reference: BCTC, TSCP, p. 15

BCTC states that its policy is to avoid the use of generation shedding for first contingency events except if the amount of shedding is less than the largest unit on line and the cost to avoid shedding is considered to exceed the value using generation shedding.

18.1 What action does BCTC take when the amount of shedding is larger than the largest unit on line?

18.2 How does BCTC compare the cost to avoid shedding with the value of Generation shedding?

19.0 Reference: BCTC, TSCP, p. 16

The Commission has requested BC Hydro to provide a copy of its latest NITS application.

19.1 Please explain how the NITS application is acted on by BCTC? If there are further planning reports produced please provide them.
20.0 **Reference: BCTC, TSCP, p. 18**

“The coincident overall BC Hydro service area system peak demand load responsibility (including the BC Hydro domestic load and firm exports to FortisBC, New Westminster, Alberta and the US) is used to determine the system reinforcements for the bulk transmission system. … The coincident regional peak demand forecast is used to determine the regional or area system transmission requirements. Non-coincident station peak demand forecasts are used to determine local or substation reinforcement requirements.”

20.1 Please provide the forecasts (along with five years’ historical data) that support the capital projects for which approval is sought in this Application.

21.0 **Reference: BCTC, TSCP, p. 19**

BCTC has initiated a dialogue with stakeholders on whether to expand its role to include forecasting future customer requirements in advance of service contracts, and then planning to meet these requirements.

21.1 What is the status of these discussions?

21.2 When does BCTC anticipate completing the discussions and developing a related policy?

22.0 **Reference: BCTC, TSCP, p. 20**

To identify a need to resolve future congestion on the transmission system, the system is tested under stressed conditions such as worst-case generation patterns and load levels during normal and first-contingency conditions.

22.1 What level of transmission congestion, if any, does BCTC allow?

22.2 What policies or procedures are in place to establish the allowable levels of congestion?

22.3 How does BCTC evaluate the trade-off between the cost of congestion and the cost of relieving that congestion?

23.0 **Reference: BCTC, TSCP, pp. 21-22**

BCTC outlines the process of developing technical and economic justifications for projects. It notes that losses may be studied if they are expected to be a significant financial factor. It also notes that a discounted cash flow method is used to determine the present value of each alternative. When one alternative creates more capacity than the others, a capacity credit is applied to this alternative to reflect the value of the residual capacity.

23.1 What prices are used in losses forecasts?

23.2 How is the capacity credit calculated?

24.0 **Reference: BCTC, TSCP, p. 22**

BCTC states that discretionary projects are reviewed in detail and judged worthwhile investments.
24.1 What criteria does BCTC use to determine what are worthwhile investments?

24.2 How does BCTC prioritize discretionary projects?

25.0 Reference: BCTC, TSCP, pp. 22, 92

Most projects in the Growth Portfolio are categorized as Mandatory because either BCTC has a legal, regulatory, or contractual obligation to undertake the project or the absence of an upgrade will result in a violation of BCTC’s Planning Standards.

25.1 Please provide a copy of the Planning Standards.

25.2 When were the Planning Standards last reviewed by the Commission or BCTC’s stakeholders?

25.3 Is the degree to which Planning Standards may be violated a consideration in requesting approval of a capital expenditure, or is the interpretation of the Planning Standards “black and white” (that is, either they are violated or they are not)?

25.4 In BCTC’s view, does a classification of “Mandatory” imply that the Commission has no alternative but to approve the project? Please elaborate.

25.5 Were the Commission to determine that it is not in the public interest to approve every Mandatory project because of the rate impact on BCTC customers, how would BCTC or the Commission decide which Mandatory projects must proceed and which could be deferred?

25.6 Does it make sense to use the same classification (Mandatory) for a project that must be completed to address immediate security and reliability concerns and a project to address load growth that will exceed firm substation capacity in 2012 (p. 92)?

26.0 Reference: BCTC, TSCP, pp. 22-23

Certain additional studies, such as System Application Studies, Setting Studies, and Operating Studies are completed during the implementation phase of a capital project. Please provide an example of each type of study for a recent project.

27.0 Reference: BCTC, TSCP, p. 23

BCTC’s asset management planning process “balances reliability, managed risk, social, financial, and environmental factors. … BCTC’s maintenance and replacement guidelines are specific to individual assets or asset groups and are part of a comprehensive set of maintenance standards.”

27.1 Please provide a copy of the maintenance standards.

28.0 Reference: BCTC, TSCP, pp. 24-25, 27

Discretionary programs may not be essential in the short term, but address longer-term issues such as sustaining or improving service and reliability to meet targets (e.g., SAIDI).

28.1 Please state the service and reliability metrics, and the associated target values, used by BCTC.
28.2 At present, BCTC does not have sufficient data regarding individual assets’ contributions to SAIDI to fully utilize such a measure in project/program prioritization. Is there a plan to acquire such data? If so, what is the plan? If not, why not?

29.0 Reference: BCTC, TSCP, p. 26

“Baseline asset performance forecasts are prepared and risk management and value assessments are conducted to confirm the suitability of the proposed solution.”

29.1 Please provide an example illustrating this process.

30.0 Reference: BCTC, TSCP, p. 26

Sustaining Capital Program prioritization.

30.1 Please provide an example of a program prioritization (e.g. Reactive Equipment Program) explaining the rationale for the various criteria scores.

30.2 How does BCTC determine what the total expenditures for the Sustaining Capital programs will be and at what priority level is the cut off for any particular program or project.

31.0 Reference: BCTC, TSCP, p. 27

BCTC states that it does not have sufficient data regarding individual assets contributions to SAIDI to fully develop this measure.

31.1 Is BCTC aware of any other utility companies that have developed SAIDI measures for individual assets? If so, please describe the measures they use and how they have developed them.

31.2 Does BCTC have any programs in place that would eventually lead to developing these types of measures? If so, please describe them and how long it will take to complete the development for those specific assets.

32.0 Reference: BCTC, TSCP, p. 36

BCTC is involved in a variety of inter-jurisdictional regional planning initiatives including the Northwest Power Pool Transmission Planning Committee and the WECC Planning Coordination Committee.

32.1 Please describe the main issues that these groups are trying to address, and describe their potential impact on BCTC’s capital planning process.

33.0 Reference: BCTC, TSCP, p. 39

BCTC was to conduct a survey of key stakeholder groups to gain a better understanding of their views and values associated with transmission issues.

33.1 Has the survey planned for March 2005 been completed?

33.2 If so, please provide a copy of the survey results.
34.0 Reference: BCTC, TSCP, p. 46

BC Hydro submitted an application to BCTC for NITS in September 2004 that includes four scenarios. “The base scenario consists of the base generation resource plan and the load forecast with one-in-two probability. The three alternate scenarios indicate three alternate generation resource plans along with one-in-ten probability load forecasts. Additional studies to identify necessary upgrades are expected to be completed in May 2005. It is not expected that the outcome of these studies will affect the projects for which approval is sought in this Application.” The “key assumptions” for the purposes of the bulk transmission elements of the Capital Plan are then listed.

34.1 The Commission interprets this statement to mean that there is a base scenario with an assigned probability of 0.50 and three alternate scenarios, each having probability 0.10. Is this interpretation correct? If not, please clarify the quoted statement.

34.2 If the Commission’s interpretation is correct, it would appear that one or more scenarios - with a total probability of 0.2 - are missing. Please clarify.

34.3 Please elaborate on each key assumption. State the primary effect(s) on the Capital Plan in two cases: (a) the assumption turns out to be correct; (b) the assumption turns out to be incorrect.

35.0 Reference: BCTC, TSCP, p. 49

230 kV Static VAR Compensator

35.1 Please describe the present and future VAR requirements for the Lower Mainland. (What is the projected VAR forecast)?

35.2 BCTC states that a possible alternative is a mechanically switched capacitor. Are there other alternatives? Has BCTC investigated the purchase of VAR’s from a third party? Please provide any analysis that BCTC has prepared to compare the alternatives.

36.0 Reference: BCTC, TSCP, p. 50

BCTC states that an SVC at Ingledow can provide the same dynamic reactive power as Burrard generators and does not consume any natural gas.

36.1 Are the reactive power capabilities of an SVC identical to those of a generator? If not, what are the advantages and disadvantages of an SVC compared to the generators?

37.0 Reference: BCTC, TSCP, p. 52

BCTC notes that, during periods of high South Interior generation (and possibly import from Alberta), a significant portion of the transmission system’s total power supply flows through the Nicola 500 kV station. The low probability outage of a large part of the station could open several of the 500 kV lines at Nicola, causing a serious impact on the transmission system and BCTC’s customers.

37.1 What is the “serious impact”?

37.2 Does the existence of a single station that handles a significant portion of BC’s power supply lead to concerns about the possibility of intentional damage?
37.3 Has the potential for malicious damage been reassessed in recent years? If so, what were the results of that reassessment?

37.4 If Revelstoke Unit #5 or any other large generator east of Nicola did not proceed, would the station upgrades still be necessary?

38.0 Reference: BCTC, TSCP, pp. 54, 56

BCTC describes the need for 5L91/98 Series Compensation and Breaker Replacements and the addition of another 500/230 kV Transformer as being driven by Generation increases in the Selkirk Area.

38.1 Please describe the Generation sources which BCTC anticipates coming on line.

38.2 How will these system upgrades be funded?

39.0 Reference: BCTC, TSCP, p. 57

Series capacitors are proposed for 5L71/5L72. The project start date is in F2007, but the in-service date is in toll September, 2012. The project is based on one of the NITS scenarios requested by BC Hydro.

39.1 Why is a lead-time of five years required?

39.2 Given that the project will only proceed if generation is added at Mica, when will the “final” NITS scenario be known to BC Hydro and BCTC?

40.0 Reference: BCTC, TSCP, p. 59

The need and timing of the Ashton Creek capacity bank addition will be established by the confirmation and timing of new BC Hydro Network Resources east of Nicola, or by additional east-to-west point to point transfers.

40.1 Given that the need and timing have not yet been firmly established, should the approval sought for this project be only for the definition phase of the work? If not, why not?

41.0 Reference: BCTC, TSCP, p. 60

RAS project for double and triple Contingency events on 2L288, 2L295 and 2L299.

41.1 BCTC refers to a May 2004 event that caused frequencies to rise to 93 Hz. Please describe the consequences of this extreme over frequency event.

41.2 What changes in the system caused the need for this RAS?

41.3 Given the number of studies that are undertaken as part of the implementation of a project (see Section 2,3,4, for example), what is BCTC’s view as to why to potential for significant over-frequency was not anticipated?

42.0 Reference: BCTC, TSCP, p. 61
Please comment on the assignment of a Mandatory rating to the provision for as-yet unidentified RAS additions to be initiated through F2015.

43.0 **Reference:** BCTC, TSCP, p. 62

A cost estimate of $1083k is provided for GMS Generation Shedding RAS modifications, but the project description is “Under development.” Please provide a description of the project.

44.0 **Reference:** BCTC, TSCP, p. 63

An amount of $300 k per year for ten years is sought for the Definition Phase of future, as-yet unidentified area reinforcement projects.

44.1 Are the amounts intended to cover planning for all areas of the province, and for both the growth and sustaining portfolios?

44.2 Are there funds in BCTC’s operating budget that are also intended to fund area planning activities?

44.3 Are these funds ultimately allocated to specific capital projects? If so, how?

45.0 **Reference:** BCTC, TSCP, p. 64

BCTC proposes to construct a new substation north of Fort St. John together with a 55 km transmission line tap into the existing 1L364 line. The existing Fort St. John 138/25 kV substation has two 50/56 MVA transformers feeding eight 25 kV feeders. Based on the December 2004 NITS load forecast, the area load is forecast to exceed the station firm capacity of 74.5 MVA in 2006.

45.1 Please provide the relevant load forecast.

45.2 Please provide the BCTC planning standards that relate to the allowable loading of substation transformers, feeder length, power quality, and reliability. Where the standards are those of BC Hydro, please so indicate.

45.3 How is the firm capacity of a station served by a single transformer determined?

45.4 How is the firm capacity of a station served by multiple transformers determined?

45.5 For what length of time can the load at a substation typically exceed the firm capacity of the substation before equipment damage becomes a possibility?

45.6 Were reports and/or detailed costs estimates prepared on any of the alternatives that are described under the Discussion of Alternatives section on page 64?

45.7 Were the power quality issues raised by customers or discovered through an inspection/monitoring process? If the former, how many complaints were received, and are those complaints becoming more frequent?

45.8 Please provide a detailed list of which components of this project will be categorized as substation distribution assets.
BCTC proposes to build a new 60/25 kV substation at Haney, Maple Ridge. The project was included in the F2005 capital plan but was identified as 100 percent SDA. It has now been determined that this project includes transmission assets with an estimated cost of $4271k.

Has the project design changed to include transmission components, or was this a simple oversight in the F2005 plan?

Please describe which portions of the project will be transmission and which will be SDA.

BCTC proposes to construct a new 69 kV switchyard at the Clayburn substation and secure a site for a new 100 MVA substation to serve forecast load growth in the Abbotsford/Sumas Way/Clayburn service areas. The project also involves a new 69 kV circuit between Clayburn and Mission substations to alleviate north Fraser River circuit overloading.

Please provide any reports prepared on the alternatives set out under the heading Discussion of Alternatives on page 70.

Please provide a detailed breakdown of the transmission-related cost of $30,244 k.

A future project involves increasing the proposed Mt. Lehman substation capacity by 100 MVA to supply forecast load growth in the area. What other projects are proposed for the area?

Would it make sense for the Commission to consider the area projects, which have a combined capital cost in excess of $50 million, in a CPCN application? If not, why not?

BCTC proposes to install a 230/138 kV transformer at Goward substation for service in October 2008. Five alternatives to off-load or reinforce the 138 kV system are given.

Are the alternatives listed still under consideration?

If the answer to Part 1 is yes, what approval is being sought from the Commission?

If the answer to Part 1 is no, why were these alternatives rejected? Please provide any reports prepared on these options.

BCTC proposes improving the reliability and security of Rainbow substation by disconnecting the substation from 2L1 and looping 2L2 into it with a line-sectionalizing circuit breaker.

What reliability criteria are being violated?

What are the reliability statistics for this substation?

Why is the project rated “Discretionary” if, as stated, the status quo is “unacceptable”? 

Reference: BCTC, TSCP, p. 67

Reference: BCTC, TSCP, pp. 69-70, 94

Reference: BCTC, TSCP, pp. 74-75

Reference: BCTC, TSCP, pp. 75-76
50.0 Reference: BCTC, TSCP, p. 76

East Kootenay 230 kV reinforcement (discretionary). BCTC states that the Load Growth in the upper Columbia Valley has exceeded the supply Capability for many years.

50.1 Please explain what is meant by the above statement. How has the load been served if the loading exceeds the supply capability?

50.2 For how many years has this situation existed?

50.3 Why is this project considered discretionary?

51.0 Reference: BCTC, TSCP, p. 78

Valleyview Transformer RAS.

51.1 What are the alternatives to this RAS scheme?

51.2 What changes in reliability can customers expect with the installation of the RAS scheme?

51.3 If there is an increase in EENS with the installation of the RAS scheme how does BCTC determine what is acceptable?

52.0 Reference: BCTC, TSCP, p. 80

Cambie Substation 230/25 kV transformer addition SDA capital cost $6,139 K.

52.1 Please describe why the Bushings have been derated. Is the replacement of the bushings an alternative? If so what are the relative costs of this alternative?

Re: Projects with an SDA sharing:

52.2 Please explain how the costs of the Transmission portion and Distribution portion are determined.

52.3 Please provide a list of all SDA projects and reconcile this to the list of SDA projects in BC Hydro’s 2005 REAP. Please also explain any variances between the two lists.

53.0 Reference: BCTC, TSCP, p. 81

BCTC proposes to add a third 230/12 kV transformer at Cathedral Square substation.

53.1 Is it conceivable that the entire Cathedral Square substation could suffer an outage? Under what conditions could this occur?

53.2 Was the option of backing up Cathedral Square loads from other metro substations considered? If yes, why was it rejected? If no, why was it not considered?

53.3 Is this project related to the Metro 230 kV Supply described on page 68 of the Application?
53.4 Are there any reasons why the Commission should not consider this project in conjunction with the CPCN application that is to be filed for the Metro 230 kV Supply project?

54.0 Reference: BCTC TSCP, p. 83

Fort St James Mobile Transformer.

We note that for this project there is some uncertainty that the project will proceed as discussed.

54.1 Please list all projects which for which there is uncertainty in proceeding but for which BCTC is requesting approval of funds in 2006 or 2007. Please also describe whether the funds are only for studies associated with the project or there are funds allocated to the actual project.

55.0 Reference: BCTC, TSCP, p. 84

BCTC proposes to replace an existing transformer with a 230/12 kV dual winding unit at Horne Payne substation. The Application seeks approval for the definition phase of the projects, which amounts to about 60 percent of the total transmission capital cost of $870 k.

55.1 Why is the definition-phase cost such a large percentage of the transmission-related cost?

55.2 Will any of the definition-phase costs be allocated to the SDA component of the project?

56.0 Reference: BCTC, TSCP, p. 85

BCTC proposes to replace the 230/12 kV, 56 MVA T2 with a 230/12 kV, 150 MVA dual winding unit at Mainwaring.

56.1 Is this project related to the Metro Vancouver Supply/Mainwaring Substation T1 project on page 86?

56.2 Could the design of, or need for, this project be affected by the results of the BCTC/BC Hydro study of the Metro Vancouver Supply? (The latter is discussed at page 87 of the Application.)

56.3 Is there any reason why the Commission should not consider this project in conjunction with the CPCN application for metro supply?

57.0 Reference: BCTC, TSCP, pp. 87-88

BCTC proposes to install a new RTU at Mission substation to allow energy and reactive power coordination with the Ruskin/Stave Falls generation complex.

57.1 How often is the Mission substation itself expected to drive energy and/or reactive power production by the generators?

57.2 Could the linking of generation to the station load lead to possible water-level concerns? If so, what would happen were water levels to drop too far?
58.0  Reference:  BCTC, TSCP, p. 98

58.1  How has BCTC estimated the cost of future IPP connections?

59.0  Reference:  BCTC, TSCP, Section 4

59.1  How are the individual maintenance programs managed?

59.2  How are the programs coordinated so that, for example, multiple problems at a single site can be addressed with a minimal amount of resources and service disruption?

59.3  The Commission notes that the total sustaining capital portfolio cost is estimated to be over $1 billion (last line, page 103). It would be helpful, when evaluating BCTC’s request for such an amount, to have an indication of what the cost and reliability risks would be given (for example) 3, 5, or 10-year deferrals of the requested projects. Please comment on the feasibility of providing such an assessment for each project, or for each “major” project.

59.4  A number of Sustaining Capital Programs are identified as “recurring.” For each such program, please provide a 5-year history of program expenditures and a 5-year-forward forecast of expenditures.

60.0  Reference:  BCTC, TSCP, pp. 100,101,

In the Sustaining Capital Project Table BCTC states, that for several programs BCTC is requesting approval for prior year’s expenditures.

60.1  Were these expenditures previously approved by other applications (i.e. the BC Hydro Rev. Req. application?  

60.2  What is meant by “Prior years”?  

60.3  Please explain why BCTC is now requesting approval for these expenditures.
61.0 Reference: BCTC, TSCP, p. 104

For planning and management purposes, the Sustaining Capital Portfolio is divided into asset groups. Different maintenance and replacement criteria apply to each asset group based on the asset’s importance, the asset group’s inherent aging process, and other influences such as geography and environment.

61.1 Please provide the criteria by asset group.

62.0 Reference: BCTC, TSCP, p. 107

“BCTC will continue to impose reliable and effective controls around the best practices of P&C [protection and control] philosophy, application, design, configuration, installation, and testing.”

62.1 What are these controls?

62.2 How does BCTC determine that they are reliable and effective?

63.0 Reference: BCTC, TSCP, p. 108

“BCTC expects to see a reduction in OMA costs as a result of the P&C capital investment in digital, microprocessor-based technology. The new technology offers the opportunity to apply revised P&C maintenance strategies, with increased maintenance intervals and reduced job site times, which will result in reduced costs.”

63.1 Does BCTC have actual operating experience, or knowledge of others’ operating experience, to support the savings being attributed to the P&C program?

63.2 How will BCTC evaluate the success of the program on an ongoing basis?

64.0 Reference: BCTC, TSCP, p. 109 & various

The P&C Stations SCADA RTU Program involves multiple stages of replacements of station remote supervisory control, alarming, and telemetry systems at “carefully pre-selected stations” based on BCTC Station RTU Replacement Criteria and Strategy; and the installation of RTU assets for new or expanded stations as required by BCTC Real Time Operations Station RTU Addition Criteria and Strategy.

64.1 Please provide a copy of the two Criteria and Strategy documents.

64.2 How will this program be coordinated with the SCMP?

64.3 Given that this is a recurring program, please provide historical expenses on this program for the last five years and expected expenditures for the next five years.

65.0 Reference: BCTC, TSCP, pp. 110-111

BCTC proposes to install single pole trip-and-reclose controls to pre-selected system critical lines. It also proposes to replace line teleprotection tone equipment that is incompatible with recently installed digital microwave communication channels.

65.1 What are the criteria by which the “system critical” lines are selected? How many lines are there in this category?
65.2 Given their incompatibility with the digital microwave communication channels, what is the current operational status of the line teleprotection tone equipment, and what has been the effect on power system operations?

65.3 Assuming that the incompatibility was known prior to installing the digital microwave communications channels, what was the original plan for dealing with the line protection tone equipment?

66.0 Reference: BCTC, TSCP, pp. 112-115

BCTC describes the maintenance practices for circuit breakers, disconnect switches, circuit switchers, surge arrestors, transformers, instrument transformers, shunt reactors, and shunt capacitors. The general maintenance strategy varies by device type, and (at least in some cases) Reliability Centred Maintenance (“RCM”) is employed. In addition, BCTC has negotiated a number of long-term supply contracts for various device types.

66.1 Please provide the maintenance standards and strategies for each device type.

66.2 Were these strategies developed from, or have they been influenced by, the Asset Baseline Study? Please elaborate.

66.3 Please describe the nature of the long-term supply contracts. Without revealing confidential information, describe the contract provisions around term, termination, pricing, delivery requirements, minimum or maximum order quantities, etc.

66.4 How were the successful suppliers chosen in each case?

66.5 Is having multiple suppliers for each device type likely to result in spare-parts incompatibility and increased inventories? If not, why not?

66.6 BCTC has initiated a program to review its spare parts inventory. What is the status of that program? Please provide a copy of the report if it has been completed.

66.7 It is noted (p. 114) that BCTC has commissioned a more detailed assessment of issues regarding the high voltage disconnect population and is presently analyzing the recommendations from this assessment. Please provide a copy of the assessment report.

66.8 Please describe the “defined Health Index” that is used for shunt reactors. Are similar indices used with other device types?

67.0 Reference: BCTC, TSCP, pp. 119-120

In connection with the spill containment program, BCTC states, “The target acceptable risk index, used as a measure of risk, is 40.”

67.1 Is this risk index the same as the Project Priority Rating?

67.2 If not, please describe the risk index. Is it a BCTC-specific measure or an industry measure?

67.3 How is the 10 percent probability over a 10 year period derived from a risk index of 40, and what is the index scale?
68.0 Reference: BCTC, TSCP, p. 121

The Station Security Program is designed to address concerns around exposure to trespass, vandalism, or sabotage.

68.1 Has a general assessment of transmission infrastructure vulnerability to these threats been conducted within the last few years? If so, what were the results of that assessment?

69.0 Reference: BCTC, TSCP, pp. 123-124

BCTC notes that the telecommunications system contains 240 microwave repeater sites and 196 PLC terminals.

69.1 The BC Hydro program to replace the analog microwave system with new digital equipment appears to have addressed 105 of the 240 microwave sites. Is this correct and, if so, what is the status of the other sites?

69.2 Of the 196 PLC terminals, 110 require replacement. Phases 1 through 4 will address 104 of those. What is the status of the 6 still requiring replacement and the 86 that do not require replacement?

70.0 Reference: BCTC, TSCP, p. 125

The Power Line Carrier Program is intended to reduce incidents where station protection and control fails to operate correctly due to PLC problems.

70.1 What statistics are kept on incorrect operations, and how are they derived?

70.2 Has there been a noticeable up-trend in the number of failures in recent years? Please elaborate.

71.0 Reference: BCTC, TSCP, p. 126

The replacement of diesel generators and air conditioning units is required at microwave repeater sites to avoid equipment problems due to inadequate cooling. Many of the existing diesel generators cannot support the existing load at the microwave sites.

71.1 Would the power requirements associated with new equipment normally be evaluated during the design phase of a microwave equipment upgrade?

71.2 Why was new equipment installed at the sites without upgrading the power supplies?

71.3 How often are the overheating problems occurring, and what has been the associated repair cost?

71.4 Are there problems other than overheating resulting from the undersized diesel generators?

71.5 What is the effect on telecommunication services when the diesel generator at a microwave site fails?

72.0 Reference: BCTC, TSCP, p. 127

WECC requirements are cited as a driver for unidentified telecom equipment upgrades.
72.1 What are the relevant WECC requirements?

73.0 Reference: BCTC, TSCP, pp. 129-130

There are nineteen projects in the Underground and Submarine Cable Life Extension and Rating Restoration Program. Seven projects are scheduled to start in F2006, and six are multiyear projects.

73.1 What are the projects?

74.0 Reference: BCTC, TSCP, p. 130

Grillage foundations on metal support structures are being assessed using a procedure involving half-cell measurements. BCTC is evaluating field tests to directly measure remaining wood pole strength that would be significantly more accurate than current tests.

74.1 Please describe the tests involving the half-cell measurements?

74.2 Please describe the new wood pole testing procedure. How does it compare with existing tests in terms of time and cost?

74.3 When does BCTC expect to complete its evaluation of the field tests?

75.0 Reference: BCTC, TSCP, p. 135

In connection with the Overhead Reliability Improvement Program, BCTC notes that transmission lines were sometimes located in a fashion that resulted in less than standard line-to-ground clearances. A number of clearance deficiencies have already been identified on several 500 kV circuits.

75.1 What was the rationale for not meeting standard line-to-ground clearances?

75.2 What steps is BCTC proposing to address this issue?

75.3 To what extent are the non-standard ground clearances affecting transmission line capacity?

76.0 Reference: BCTC, TSCP, Tab 7, p. 158

76.1 Are any of the projects listed under Paragraph 7.2 SDA projects? If so, please identify which ones are SDA’s.

76.2 If there are SDA’s listed here please explain why BCTC and not BC Hydro should apply for approval of those projects.

77.0 Reference: BCTC, TSCP, Section 5

Why are there no project priority rankings in this section?

78.0 Reference: BCTC, TSCP, p. 145

BCTC notes that effective asset management is critical to the success of its business, and states that the One Asset One View vision for asset management has allowed for asset data to be integrated and made available to asset managers in a timely, accurate, and reliable manner.
78.1 Please explain what the “One Asset One View” vision is.

78.2 Has BCTC fulfilled that vision? If not, what remains to be done?

78.3 Does the Asset Management Information System incorporate all of the requirements of RCM?

79.0 Reference: BCTC, TSCP, p. 146

BCTC is seeking approval of $500k for a financial modelling tool to support BCTC’s organizational structure.

79.1 How will the financial modelling tool support BCTC’s organizational structure?

79.2 What methods does BCTC currently use for financial modelling, and how do they fail to meet BCTC’s requirements?

79.3 What is the priority of this project relative to other projects in the BCTC capital portfolio?

80.0 Reference: BCTC, TSCP, p. 146

How does the IMAX project relate to the Asset Management Information System?

81.0 Reference: BCTC, TSCP, pp. 146-147

“BCTC currently faces significant risks with its current OASIS provider. These risks relate to reliability of service, and potentially, discontinuation of service.”

81.1 Has there recently been a change in circumstances that leads BCTC to its conclusions about the level of risk? Please explain.

81.2 If the answer to Part 1 is no, why are the risks greater now than in the past?

81.3 Has the option of an alternate supplier been investigated? If not, why not, and if so, what were the results of the investigation?

81.4 Do other transmission providers typically contract their OASIS systems or maintain them in-house?

81.5 Please describe the relationship between the following projects: OASIS Replacement (including TSS Interface); OASIS Phase II; TSS Tariff Changes, Market Business Systems; OASIS Future Upgrades.

82.0 Reference: BCTC, TSCP, p. 152

BCTC proposes an Interactive Customer Forum (“ICF”) where either Market Operations or WTS/OATT customers can raise or respond to issues. Currently, when Market Operations posts a bulletin soliciting customer feedback, the response rate is less than desirable.

82.1 Have BCTC’s customers been polled to determine why the response rate is typically low?
82.2 Has BCTC confirmed with its customers that developing the ICF is the correct solution to the low-response-rate concern?

82.3 The project is entitled Customer-Driven Website Improvements. Which customers have specifically asked BCTC for these improvements?

83.0 Reference: BCTC, TSCP, p. 155

The status report on the Financial Systems Project states that the system’s objective is to develop the financial and business management tools that BCTC requires to support its Phase 2 business model and to function as an independent entity.

83.1 How does this project relate to the Financial Modelling project (p. 146)?

83.2 Why were the requirements of the Financial Modelling tool not incorporated into the Financial Systems Project?

83.3 The statement is made that Stage 2 of the Financial Systems Project “will deliver additional, high-value functionality.” How does BCTC measure the value of its information systems?