BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

BRITISH COLUMBIA TRANSMISSION CORPORATION
Transmission System Capital Plan
F2006 to F2015 Application

DECISION

September 23, 2005

BEFORE:

Robert H. Hobbs, Chair

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1.0 INTRODUCTION

1.1 Application

On March 23, 2005 the British Columbia Transmission Corporation ("BCTC") filed its F2006 to F2015 Transmission System Capital Plan ("the F2006 TSCP") with the Commission. The Application was filed under Sections 45(6) and 45(6.1) of the Utilities Commission Act. This application is the second Transmission System Capital Plan. The first was filed in May 2004 and subsequently approved by Order G-103-04. The first plan requested approval for capital expenditures beginning in F2005. This plan describes projects within the period F2006 to F2015; however, BCTC only requests approval for capital expenditures beginning in F2006 and F2007. BCTC will continue to file annual capital plans and, in the next plan, BCTC will request approval for any new projects identified for F2007 and for F2008.

1.2 Regulatory Requirements

BCTC is required by Section 45 of the Utilities Commission Act to file annual capital plans. Under a Master Agreement between BCTC and British Columbia Hydro and Power Authority ("BC Hydro"), BCTC is responsible for planning, constructing and obtaining regulatory approvals for enhancements, reinforcements, and sustaining and growth investments to BC Hydro's transmission system. BCTC has therefore filed for approval of capital investments for BC Hydro's transmission system as well as for capital investments directly funded and owned by BCTC.

1.3 Orders Sought

In its Application BCTC seeks:

- An Order that its capital plan meets the requirements of Sections 45(6) and 45(6.1) of the Act;
- An Order approving this capital plan under Subsection 45(6.2)(a) of the Act; and
- Certain Orders under Subsection 45(6.2)(b) of the Act as set out in Section 7 of the BCTC Transmission System Capital Plan (F2006-F2015).

The order(s) sought with respect to Subsection 45(6.2)(b) of the Act pertain to the projects listed in the Growth and Sustaining Capital Portfolios for the BC Hydro transmission system and for the BCTC Capital Portfolio for business support systems, control centre technologies, facilities management, and information technology.

1.4 The Nature of Commission Approvals

Beginning on page 6 of the TSCP, BCTC states:

> It should also be noted that, as with BCTC's F2005 Capital Plan, BCTC is not seeking Commission approval for the precise amount associated with each program or project identified in this Application. The amounts identified for each program or project are estimated costs and actual expenditures will vary from these estimates in some cases. If BCTC were limited to expenditures in the precise amounts set out in this Capital Plan it would need to re-apply to the Commission in those cases where actual project spending exceeds estimates. BCTC does not believe this is a practical approach. Accordingly, for those projects that are identified in Section 7, BCTC is seeking the Commission's approval that capital expenditures on these projects are in the public interest rather than for a precise expenditure. BCTC recognizes and accepts that these expenditures will be subject to a later prudency review.

Section 45(6.2) states that the Commission "may determine that any expenditure referred to in the plan is, or is not at that time, in the interests of persons within British Columbia" and may "determine the manner in which any expenditure referred to in the plan can be recovered in rates." For the projects identified in Section 7.2, the Commission Panel wishes to clarify that, when it "grants approval" for a project, it is "determining that the expenditure is in the interests of persons within British Columbia." The Commission Panel acknowledges that the expenditures are normally based on planning or engineering estimates and that it is reasonable to expect that actual expenditures may vary from such estimates, and does not expect BCTC to seek re-approval of every project that goes over the estimate. The Commission Panel does expect BCTC to provide explanations for any projects whose actual costs do not vary significantly from the estimate provided to the Commission, and it agrees with BCTC that in some cases a prudencey review may follow for such projects. However, the Commission Panel expects that most projects will not be subject to a prudencey review. It is more likely that actual expenditures will be considered when the amount to be recovered in rates will be determined, in most cases during a revenue requirements proceeding.

2.0 BCTC'S RESPONSES TO PREVIOUS DIRECTIVES

In the Reasons for Decision attached to BCUC Order No. G-103-04 ("F2005 Reasons for Decision"), which approved BCTC's F2005 Capital Plan, the Commission Panel provided a number of directives. BCTC's responses to those directives were set out in BCUC IR 2.84. In this section, the Commission Panel provides additional comments and directives relating to some of the F2005 directives.

2.1 State of the Transmission System Report

At page 8 of the F2005 Reasons for Decision, the Commission Panel directed BCTC to provide a "state of the transmission system" report ("STSR") in future capital plans. The Commission Panel intended that the report provide stakeholders with a "big picture" of the issues BCTC is attempting to address with projects proposed in its capital plans, and was to include sections on, among other things:

- bulk system issues (e.g., changing path usage patterns, import/export capacity limitations);
- regional issues (e.g., regional path capacity limitations, must-run generation issues);
- local issues (e.g., local reliability problems, specific environmental problems, stakeholder concerns);
- problems with specific types of equipment;
- relationships among projects and between projects and strategic issues (e.g., if Project X is cancelled, should Project Y still go ahead?).

In its response to BCUC IR 2.84.1, BCTC noted that it filed the first STSR on May 6, 2005 as Exhibit B-3A in this proceeding.

Commission Findings

The Commission Panel notes that the STSR was the first such report filed by BCTC, and finds that it provides a good general overview of the British Columbia transmission system. The Commission Panel notes, however, that the report does not contain sufficient "hard" data to give the Commission and interveners an adequate sense of the issues that BCTC is attempting to resolve through its F2006 TSCP. For example, the report states (page 6), "The Transmission System from Selkirk to Nicola is currently limited to approximately 1700 MW. The existing surplus generation capacity in the Selkirk area plus imports from the US or Alberta can at times exceed this level." There is no indication in the STSR of the amount by which the 1700 MW has been exceeded, how often that has occurred, or what circumstances precipitated the excess line flows. Some additional data on the Selkirk to Nicola path was provided in both the F2006 TSCP (page 54) and IR responses (e.g., BCUC IRs 1.28.1 and 2.105.2). However, in the Commission Panel's view, the information provided by BCTC was still insufficient to give the Commission and interested parties an adequate understanding of the constraints, solution options, and timing requirements associated with the proposed Selkirk-to-Nicola (South Interior system) capital projects.

As another example, on page 7 the report briefly discusses load in the Lower Mainland, the capacity of the Interior to Lower Mainland ("ILM") transmission system, the requirement for reliability must-run ("RMR") generation, and the fact that the ILM system is congested at both peak and "other" times. However, there were no historical data illustrating Lower Mainland load growth, there was no indication of the cost or other implications of RMR generation, and there was no discussion of why an increase in ILM transfer capability may be preferable to increased imports or coastal generation. There was a limited discussion of how ILM requirements could be affected by additional generation in the Lower Mainland and on Vancouver Island, no discussion of the possible effect of the Juan de Fuca HVDC connector between Vancouver Island and Washington State, and no discussion of how sensitive the ILM requirements are to forecast errors or changing assumptions. Some additional data was provided in response to IRs (e.g., BCUC IR 2.106.2), but here again, the Commission Panel finds that BCTC has provided insufficient information to justify all ILM capital projects.

The Commission Panel appreciates that some of the larger projects in BCTC's F2006 TSCP will be subjected to detailed reviews by the Commission and interveners through future CPCN applications, and that some projects submitted for approval include only definition-phase work. Nevertheless, the Commission Panel would find it helpful to have additional information, including data that shows how often and to what extent congestion is occurring or is expected to occur on the transmission system, presented in the STSR. The Commission Panel provides additional views on the information that should accompany future capital plans in Section 5.1.3.

2.2 Project Evaluation Framework

On page 8 of the F2005 Reasons for Decision, the Commission Panel stated:

> "The Capital Plan contains evidence that BCTC has various processes in place to properly evaluate capital projects. However, the evidence is generally in the form of generic descriptions of project planning and evaluation criteria rather than numeric data or descriptions of specific instances of the application of those criteria. For example, the Capital Plan contains descriptions of specific projects, but there is often no description of how these projects were selected from among alternatives, no statement of how the projects relate to other proposed projects (if at all), and no statement of the priority of one project relative to others. ... In addition, it is not always clear which set(s) of criteria have been applied to which projects, and there is often little discussion of how the projects fit into BCTC's overall plan for the transmission system."

On page 9 of the F2005 Reasons for Decision, the Commission Panel accepted the suggestion that a common framework for the evaluation of transmission capital projects would be useful. The framework was to incorporate some of the suggestions of interveners as well as the criteria noted by BCTC throughout its F2005 Capital Plan. In addition, BCTC was directed to address several questions relating to both the capital planning process (standards, stakeholder interests, and management processes) and individual projects or groups of projects (objectives, assumptions, alternatives, and the consequences of not proceeding). The Commission Panel also expected that each project included in the next capital plan would have an associated priority ranking (F2005 Reasons for Decision, p. 19).

In its response to BCUC IR 2.84.1, page 2, BCTC stated that Section 2 of the F2006 TSCP provided an overview of the planning process, and that the details surrounding individual projects were provided in the project descriptions for the Growth, Sustaining, and BCTC Capital Portfolios in Sections 3, 4, and 5, respectively. BCTC also stated (ibid., p. 4) that Sections 2.3 and 2.4 of the F2006 TSCP address the capital project evaluation processes for the Growth and Sustaining Capital Portfolios. With respect to the growth planning process, BCTC stated that the "planning studies" step identifies a need to resolve future congestion on the system (Exhibit B-1, p. 20). Then, "Once a need is identified, most large projects are planned and implemented using a two-phase approach in order to minimize the financial risks. The first, or Definition Phase, comprises detailed engineering studies carried out in order to develop the exact scope of the project, the project implementation plan, and detailed cost estimates. The second, or Implementation Phase, consists of detailed design, procurement of materials, construction and commissioning of the facilities" (Exhibit B-1, p. 17).

Within the F2006 TSCP, most Sustaining Capital projects were assigned a numeric priority rating (some were ranked "n/a"), while Growth Capital projects were ranked as either "mandatory" or "discretionary." A growth project was rated as mandatory if BCTC has a legal, regulatory, or contractual obligation to undertake the project or if the absence of an upgrade will result in a violation of BCTC's Planning Standards (F2006 TSCP, p. 22). BCTC clarified that the growth project classifications are for internal prioritization purposes and are not meant to limit or expand the Commission's authority to approve or not approve those projects (BCUC IR 1.25.4). Priority rankings were not provided for BCTC Capital projects, though BCTC expects to provide such rankings in its F2007 Capital Plan (BCUC IR 2.84.1, p. 4).

Commission Findings

Some of the deficiencies noted in the F2005 Reasons for Decision have been remedied in BCTC's F2006 TSCP and the accompanying STSR. However, the Commission Panel remains concerned that the information being provided by BCTC in its capital plans and related documents is not sufficient to give the Commission and interveners a sense of the need for, and urgency of, particular projects. This concern is reflected in the Commission Panel's comments in Section 2.1 regarding the STSR, and in its findings on several growth capital projects in Section 5.1.3 below.

The Commission Panel notes that, for several capital projects, BCTC is seeking approval for definition-phase expenditures only. Given the limited information provided in the F2006 TSCP and the STSR, it might be expected that the need for those projects is to be established through their definition phases. If this is the case, the Commission Panel is concerned at the level of effort and expenditure that may precede a determination that a project is necessary. For example, BCTC proposes to spend in excess of $600,000—presumably on detailed engineering studies leading to option selections, implementation plans, and detailed cost estimates—for the definition phase of the proposed Selkirk-to-Nicola path upgrade. However, the Commission Panel has not yet accepted this upgrade as necessary.

While the acceptance-follows-definition phase concept is supported by the relative lack of information provided by BCTC in support of several large capital projects in both the current and F2005 capital plans, that concept is not supported by the direct evidence of BCTC in this Application. In the list of major steps in the growth planning and implementation process (Exhibit B-1, p. 17), Step 1 is "determining the need for system reinforcements," while Step 2 is the project definition phase. The nature of the definition phase steps noted above also suggests a definition phase-follows-acceptance model. Further, BCTC stated that, "for those projects that are identified in Section 7, BCTC is seeking the Commission's approval that capital expenditures on these projects are in the public interest" (Exhibit B-1, p. 7). Clearly, the Commission Panel cannot find a project to be in the public interest before the need for it is established.

Given the foregoing, it is the Commission Panel's view that there is some uncertainty about exactly what approval BCTC is seeking for definition phase-only projects. **To avoid such uncertainty in the future, the Commission Panel directs BCTC to provide a clear statement of where, in the overall identification, design, and construction process, it expects the Commission's approval of the need for a Growth Capital project. BCTC is at liberty to propose different processes for different types of projects, but if it does so, it must identify which process is being followed by each project in the capital plan. In particular, the**

Commission Panel notes that there may be differences between CPCN and non-CPCN projects, and between large and small projects, in this regard.

The Commission Panel notes that it approved definition phase funding for 5L83 and the Metro Vancouver 230 kV Supply in the F2005 Capital Plan. In doing so, the Commission Panel adopted the view, based on the evidence available at the time, that project need would be established through the definition phase. (In both cases, the Commission Panel directed BCTC to submit CPCN applications, and in the case of 5L83, the Commission Panel explicitly stated that it was not offering an opinion on whether 5L83 is in the public interest.) However, the additional details on the planning process provided by BCTC in the present Application suggest that it may be more appropriate to address the need for a Growth Capital project in advance of the definition phase. The Commission Panel expects BCTC to carefully consider these points when complying with the direction given immediately above.

With respect to the Growth Capital project ratings, the Commission Panel does not accept that (for example) a project needed to comply with legal, regulatory, or contractual obligations, a project needed to avoid violating planning criteria next winter, and a project needed to avoid violating planning criteria ten years into the future should all have the same rating. Further, as discussed in Section 3.2, the Commission Panel does not accept BCTC's strictly deterministic interpretation of the planning standards of the North American Electric Reliability Council ("NERC"), the Western Electricity Coordinating Council ("WECC"), and BCTC. Consequently, the Commission Panel finds that a Growth Capital rating system consisting only of the ratings "mandatory" and "discretionary" is inadequate. **The Commission Panel therefore directs BCTC to refine the Growth Capital ranking system to better discriminate between growth capital projects. The ranking system should consider the factors that BCTC has set out in Section 2 of the F2006 TSCP, but should also consider factors such as lead-time, forecast uncertainty, and probabilistic measures such as Expected Energy Not Served ("EENS") (see Section 3.2).** The Commission Panel expects that a refined ranking system will provide the Commission and stakeholders with better information about project drivers and facilitate the determination of the need and timing for the projects.

2.3 Forecasting

On page 12 of the F2005 Reasons for Decision, the Commission Panel noted its expectation that BCTC would include certain components of the transmission usage forecast in future capital plan applications. In its response to BCUC IR 2.84.1, page 3, BCTC reiterated the statement it made on page 18 of the F2006 TSCP that it's role is to plan the transmission system in response to customer requests, and that an aggregation of the service under the BC Hydro NITS agreement plus all other transmission service contracts forms the BCTC Transmission Usage

Forecast. In this role, BCTC does not carry out detailed evaluations of the assumptions and inputs used in the contributing forecasts and service requests.

Commission Findings

The Commission Panel notes that BCTC did not include transmission usage forecasts in its Application. Further, in its response to BCUC IR 2.105.3, BCTC stated that it could not provide a forecast of flows on the Selkirk-to-Nicola path because such flows are mostly generation dependent. The Commission Panel acknowledges that the generation and load forecasts upon which Growth Capital requirements are based originate with parties other than BCTC—predominantly with BC Hydro. However, in the Commission Panel's view, it is incumbent upon BCTC to translate its customers' requests for service into forecasts of transmission path usage, and to provide those forecasts in its capital plan applications. In the absence of such forecasts, it is much more difficult, if not impossible, for the Commission and interveners to properly assess whether projects to increase transmission capacity on particular paths are in the public interest. **The Commission Panel therefore directs BCTC to include path utilization forecasts in its capital plans whenever transmission capacity upgrades are proposed. The Commission Panel expects that, in providing such forecasts, BCTC will comply with the directions given on page 12 of the F2005 Reasons for Decision.**

The Commission Panel notes that 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 (Exhibit B-1, p. 19). **The Commission Panel directs BCTC to report on the status and outcome of those discussions in its next capital plan application.**

2.4 Reliability Indices

In the F2005 Reasons for Decision (page 15), the Commission Panel noted its expectation that BC Hydro and BCTC would present their reliability indices (SAIFI, SAIDI, CAIDI, ASAI, SARI, MAIFI, generation forced outages, availability, and the generation outage rates), both combined and disaggregated (where applicable), on an annual basis with comparisons to CEA averages. The Commission Panel directed BCTC to report these indices, as applicable, in its annual capital plan.

In its response to BCUC IR 2.84.2, BCTC stated that the period between Order No. G-103-04 and the Application was insufficient to respond to all of the directives in the F2006 TSCP application. BCTC also stated that it is working on the reliability indices and expects to provide the requested reliability information in future capital plans. It noted that SAIDI and Annual Customer Hours Lost metrics are being developed and tracked for individual parts of the system, and provides F2006 targets for these metrics (BCUC IR 1.28.1; BCUC IR 2.91.1).

Commission Findings

The Commission Panel is concerned that the reliability indicators identified in Order No. G-103-04 have not yet been prepared, especially for trends from recent-past data. BCTC proposes significant capital expenditures over the coming years. Without reliability indicators it is difficult to determine whether the worst-performing areas of the system are being targeted, or whether the projects, once implemented, have improved system performance. **The Commission Panel directs BCTC to report the indices applicable to it from Order No. G-103-04 and their associated trends for at least the past five years in the next capital plan. The reporting of these indices should also state the targets for the specific years against which each indicator was measured.**

2.5 Performance Indices

On page 17 of the F2005 Reasons for Decision, the Commission Panel directed BCTC to submit, with its next capital plan, performance indices that are capable of providing an indication of when and where Growth Capital spending may be necessary. The Commission Panel provided several examples of such indices, including:

- the fraction of time an intertie is congested;
- measures (frequency and duration) of events requiring emergency operating actions including shedding interruptible load, system voltage reductions, or appeals for public load reduction;
- measures of events of bulk system alert or emergency states such as exceeding security limits on transmission interfaces or losing significant transmission lines or substations;
- measures of the costs of remedial actions, including off-economic operation of generation (because of transmission constraints), suspension or curtailment of economic interchanges, or emergency assistance from adjacent control areas; and
- system utilization measures such as load factors on significant transmission paths, regional and system-wide load duration curves, and peak line flows and/or flow duration curves in comparison with path capacities.

In its response to BCUC IR 2.84.2, BCTC stated that it does not feel that such measures would be useful in aiding BCTC's growth planning. There is little congestion on the system since BCTC does not allow congestion to occur for firm transmission service, and any congestion that does occur is generally related to outages (either planned or forced) or short-term market conditions that affect the interties. With regard to the latter, BCTC is collecting statistics on intertie usage.

BCTC stated that Sections 2.1, 2.2 and 2.3 of the F2006 TSCP summarized the criteria BCTC employs and the method by which BCTC determines where and when Growth Capital spending is necessary. Key drivers for Growth Capital projects are the service agreements with BCTC's customers and ensuring compliance with the deterministic standards of NERC, WECC and BCTC. In the case of discretionary projects, BCTC would take into consideration actual and predicted performance metrics such as failure rates, repair times, project costs, and restrictions and curtailments on customers.

BCTC stated that it has initiated a dialogue with stakeholders through its Transmission Planning Advisory Committee ("TPAC") into the possibility of building in advance of service contracts (Exhibit B-1, p. 19, and BCUC IR 1.21.1). The TPAC concluded that BCTC, as the entity responsible for planning for the growth of the transmission system, should consider developing an investment policy that goes beyond addressing reliability requirements and specific customer requests. This would result in BCTC proposing expansions of the system considered to have a future benefit. At the TPAC meeting on June 8, 2005, BCTC presented a draft evaluation framework for comment, along with two case studies. BCTC will incorporate the TPAC's commentary into its draft and bring back a finalized investment policy for TPAC review.

Commission Findings

The Commission Panel does not accept BCTC's view that the performance indices suggested by the Commission Panel in the F2005 Reasons for Decision are of no use. The Commission Panel has already provided directives with respect to the provision of historical data and forecasts for transmission paths on which capacity upgrades are proposed (see Section 2.3). BCTC's responses to these directives must include such utilization measures as peak line flows and/or line flow duration curves in comparison with path capacities. The Commission Panel has also provided directives elsewhere in this Decision (see Section 3.3) with respect to addressing transmission capacity limitations through Demand Side Management ("DSM"). In such cases, the frequency and duration of events requiring the shedding of interruptible load (for example) become important to customers. BCTC acknowledged that, at least with respect to discretionary projects, it would take into consideration restrictions and curtailments affecting customers (BCUC IR 2.84.2, p. 10).

The Commission Panel has provided directives elsewhere in this Decision (see Section 3.2) with respect to BCTC's use of discretion in the application of deterministic planning criteria and the use of probabilistic planning. Given these directives, some of the performance metrics suggested by the Commission Panel in the F2005 Reasons for Decision become more important.

For all of the reasons stated above, the Commission Panel directs BCTC to comply with the directive given on page 17 of the F2005 Reasons for Decision in its next capital plan. The Commission Panel also directs BCTC to submit the investment policy that it is developing in conjunction with TPAC for Commission review before such policy is implemented. The Commission Panel expects that, at the time the investment policy is submitted, BCTC will be prepared to discuss its "no congestion for firm transmission" policy and DSM options, both of which may affect the policy.

2.6 Directive Compliance Reporting

The Commission Panel found BCTC's discussion of the status of its compliance with each Commission directive, which was provided in BCUC IR 2.84, to be helpful. The Commission Panel also notes that BCTC continues to work on complying with the following directives (page references are to the F2005 Reasons for Decision):

- reliability indices (page 15);
- classification of transmission failures and the associated statistics (page 16);
- project evaluation and prioritization processes (page 19), including presentation of revenue impacts according to project priority (page 20); and
- congestion statistics (page 37).

In addition, as discussed in Sections 2.1 through 2.5 of this Decision, additional work is required on previous directives related to the STSR, forecasting, and performance indices. **The Commission Panel therefore directs BCTC to provide, in each future capital plan, a section describing its response to Commission directives from previous capital plans. The status of compliance with each directive is to be reported in each capital plan until such time as BCTC has complied with the directive.**

3.0 PLANNING STANDARDS

BCTC's transmission planning process was described in some detail in Section 2 of the F2006 TSCP Application. The applicable transmission planning standards were also introduced in that section, and the interpretation of these standards was explored in a number of subsequent information requests.

In its response to BCUC Information Request 1.25.1, BCTC submitted copies of the WECC Reliability Criteria, the BCTC Planning Standards, and the NERC Reliability Standards for the Bulk Electric Systems of North America. BCTC noted that the documentation of planning standards is currently in transition within both NERC and WECC. The WECC Reliability Criteria contain the NERC/WECC Planning Standards, the Power Supply Assessment Policy, and the Minimum Operating Reliability Criteria ("MORC").

3.1 Applicable NERC/WECC Standards

As stated in the F2006 TSCP (Exhibit B-1, p. 10), BCTC is a member of the WECC, which in turn is a regional member of the NERC. As a WECC member, BCTC plans and operates the transmission system in accordance with NERC planning and operating standards as augmented by WECC. The NERC/WECC Planning Standards establish the envelope within which members plan and operate their electric systems.

In addition to the Planning Standards, WECC members are subject to the MORC, a document that sets out obligations for control area operators regarding reliable system operation. For example, the MORC establish operating reserve requirements, such as the amount of spinning reserve and non-spinning reserve that must be available to respond to system contingencies. The MORC also establish requirements in other areas of system operations, including transmission, interchange, system coordination, emergency operations, and telecommunications. The transmission requirements include, among other things, the use of automatic voltage control equipment, power system stabilizers, undervoltage load shedding, and reactive reserves. WECC also has a number of policies and programs (which are similar to standards) that address matters such as the use of remedial action schemes and the operation of power system stabilizers on generating units. The NERC/WECC Planning Standards and the WECC MORC policies and programs have never been explicitly reviewed or approved by the Commission (BCUC IR 1.25.2).

3.2 BCTC Application and Interpretation of NERC/WECC Standards

As described above, BCTC plans and operates the electric system in accordance with planning and operating standards set by NERC and augmented by WECC. These standards accommodate differences in the planning and operating standards of individual utilities while still requiring that each utility's standards conform to the NERC/WECC standards. As noted by BCTC (Exhibit B-1, p. 11), WECC members have mutually agreed to apply performance standards with respect to the impacts that each system can have on its neighbours. Specifically, the WECC Planning Standards state:

> "WECC Member Systems shall comply with the WECC Disturbance-Performance Table of Allowable Effects on Other Systems... To the extent permitted by NERC Planning Standards, individual systems or a group of systems may apply standards that differ from the WECC specific standards ... for internal impacts. If the individual standards are less stringent, other systems are permitted to have the same impact on that part of the individual system for the same category of disturbance. If these standards are more stringent, these standards may not be imposed on other systems. This does not relieve the system or group of systems from WECC standards for impacts on other systems."

The F2006 TSCP (Exhibit B-1, pp. 10-14) reviews the system performance criteria and describes transmission equipment thermal limits, system voltage limits and voltage stability, underfrequency limits, transient stability, and dynamic stability. The use of "safety nets" such as underfrequency load shedding, generation shedding, and over-voltage line tripping is also described.

As allowed by the NERC/WECC Planning Standards, BCTC has adopted, for internal impacts only, a less stringent standard for the frequency-dip limit under various contingencies (Exhibit B-1, p. 14; BCTC Planning Standards [attached to BCUC IR 1.25.1], p. 3). This exception is solely for the loss of the US to BC interties when importing from the United States. The exception was adopted because using the higher standard for internal purposes would result in a significant reduction in the historical import limit of 2000 MW from the U.S. The risk associated with the event that would trigger an excessive frequency dip is very low, and BCTC is in a position to selectively reduce the import limit during high-risk conditions.

BCTC has also adopted a policy to avoid the use of generation shedding for first contingency events when all facilities are in service (Exhibit B-1, p. 15; BCTC Planning Standards, p. 2). Exceptions to this general policy are allowed if the amount of shedding is less than the largest unit on the BC system and the cost to avoid shedding is considered to exceed its value. BCTC accepts generation shedding for double contingencies and for single contingencies if one element is already out of service. The NERC/WECC Planning Standards are silent on whether generation shedding is allowed for single contingencies (NERC/WECC Planning Standards [attached to BCUC IR 1.25.1], pp. 9-25).

NERC/WECC Planning Standards allow planned or controlled interruption of radially supplied customers during single contingency outages. These standards do not place any limits on the amount of load or type of customer that may be interrupted. BCTC interprets the standard in the following manner, although some exceptions may occur (BCTC Planning Standards, p. 3):

(a) Redundancy is not required for small loads supplied by a radial transmission system or local network.

(b) Service to areas with significant total area loads, where transmission distances are not excessive, will have transmission supply redundancy for improved security.

(c) For small substations, transformer backup, if provided, will be by mobile transformer, system spare transformer, and/or a distribution feeder from another substation. For larger substations, firm transformer capacity will be provided to prevent loss of load on single contingency.

(d) The decision to implement firm supply (i.e., redundancy) is a function of several factors, such as the size of load, location, and cost of implementation, historical performance, risk, cost and feasibility of maintaining the non-redundant facilities.

All other metrics established by the NERC/WECC Planning Standards are followed by BCTC for planning local area networks.

BCTC notes that most projects in the Growth Capital Portfolio are categorized as "mandatory" because BCTC has a legal, regulatory, or contractual obligation to undertake the project or because the absence of an upgrade will result in a violation of BCTC's Planning Standards (Exhibit B-1, p. 22). In BCTC's view, the degree to which Planning Standards are violated is not a consideration in requesting approval of a capital expenditure; the standards are deterministic (BCUC IR 1.16.1), and they are either violated or they are not (BCUC IR 1.25.3). While BCTC accepts that there is an inherent trade-off between cost and reliability, it does not generally weigh these trade-offs because "the development of these standards has already taken [them] into consideration" (BCUC IR 1.16.1). Further, BCTC believes it is appropriate to use the "mandatory" classification for both projects needed to address immediate security and reliability concerns and projects to address load growth that will exceed firm substation capacity seven years from now (BCUC IR 1.25.6).

BCTC states that it does not allow congestion to occur on the system for firm transmission service (BCUC IR 1.22). If the loading on a transmission facility is greater than 100 percent of its rating, the path or cut plane is congested. When studies indicate that the Planning Standards will not be met, various reinforcement options are developed to relieve the congestion and the least cost, long-term system reinforcement that is technically and environmentally acceptable is chosen to reinforce the system. BCTC does not calculate a cost of congestion.

Commission Findings

As noted above, BCTC has proposed certain capital projects based on avoiding violations of the NERC/WECC Planning Standards. Consequently, the interpretation of these standards is important in assessing the need for capital projects. The interpretation of the standards becomes especially important for contingency events because the standards specify that, for most single-element outages, there should be no loss of firm load except on radial portions of the system and local networks served by the affected facility. The ability of the system to withstand the loss of a single element without loss of load is commonly referred to as "N-1" capability.

Among the questions to be addressed when interpreting the NERC/WECC Planning Standards are whether they are deterministic or probabilistic in nature and whether economic considerations play a role in assessing the need for a project. As noted above, BCTC contends that the standards are deterministic. This contention is reinforced by BCTC's statement that congestion occurs when the loading on a transmission element exceeds 100 percent of its rating, the response to which is planning a system reinforcement to relieve the congestion. As also noted above, BCTC takes the position that explicit economic considerations are unnecessary because they have already been taken into account, a stance reinforced by the fact that BCTC does not consider the cost of relieving congestion when proposing capital projects to increase transmission capacity.

The Commission Panel does not support BCTC's stated positions on either avoidance of economic considerations or strict adherence to the deterministic system performance criteria specified by the NERC/WECC Planning Standards in all instances. The Commission Panel is concerned that doing so will drive "mandatory" capital investment requirements to have an unacceptable and unsustainable impact on rates. The Commission Panel therefore encourages BCTC to define areas of the system where relaxed system performance criteria could be employed to delay the need for capital investment requirements, and to carefully consider cost/reliability trade-offs in its project proposals.

The Commission has previously approved, by Order No. G-61-04, BCTC's Reliability Management System Agreement ("RMS Agreement") and Reliability Criteria Agreement with the WECC. These agreements specify the formal performance requirements of the transmission system that, if not met, could result in sanctions. The Commission Panel notes that these agreements specify compliance with applicable NERC/WECC standards only for specific system-to-system interconnection points ("Transfer Paths"), where interconnection power transfer limits are established and published. System improvements to maintain interconnection transfer limits are classified as mandatory, both to protect the transfer limit capability and to refrain from impacting neighbouring systems beyond what is allowed by the NERC/WECC Planning Standards (BCUC IR 1.89.2).

The Commission Panel notes that relaxations of the NERC/WECC criteria are allowed when the effects are contained within an individual system. Indeed, BCTC has already taken advantage of such relaxations and employed probabilistic and economic considerations in doing so. For example, it has relaxed the frequency-dip limit for contingencies on the US-BC tie because the event that would trigger such a dip has a very low probability of occurrence. Strict adherence to purely deterministic planning standards would limit import capability on the tie, which in turn would (presumably) have undesirable economic consequences for British Columbia electricity consumers. Other examples involving economic considerations include BCTC's evaluation of the cost of avoiding generation shedding and its examination of the cost to implement firm supply (redundant transmission) for certain loads. The Commission Panel commends BCTC for augmenting its deterministic planning with probabilistic and economic assessments and suggests that it look for additional opportunities to do so in the future. The Commission Panel will provide additional guidance to BCTC with respect to employing economic considerations in evaluating transmission projects in the next section, which deals with alternatives to transmission.

In relaxing strict adherence to deterministic system performance criteria, probabilistic methods (for instance, calculating EENS) should be used to help define risks and consequences. In particular, for capital projects to relieve congestion on non-WECC-rated transmission paths (non-Transfer Paths), future project evaluation and justification should include an analysis that identifies the duration and amount of congestion that would be incurred absent the project. The analysis should compare the cost of that congestion against the cost of relieving it (BCUC IR 1.22.3).

With respect to BCTC's comment that economic considerations have already been incorporated into the NERC/WECC Planning Standards, the Commission Panel notes that it is not aware of any explicit review of the economic and reliability trade-offs inherent in the standards, particularly in British Columbia (BCUC IR 1.25.2). While the standards have evolved through many years of experience with the development and operation of power systems, it is unreasonable to expect that it will be economically rational to remedy every conceivable violation of deterministic NERC/WECC planning criteria through the addition of new transmission capacity. Fundamentally, a transmission upgrade is economically rational if the marginal benefit of the upgrade exceeds its marginal cost; that determination cannot be made based on what are essentially purely engineering criteria. Note that the Commission Panel is not suggesting that economics is the only driver, or even necessarily the most important driver, for every transmission upgrade. **However, economic considerations are important, and the Commission Panel directs BCTC to consider economics in its assessment of whether transmission**

upgrades should proceed. The Commission Panel does not consider that the simple existence of a NERC/WECC Planning Standards violation is sufficient justification for transmission upgrades in every case.

The Commission Panel acknowledges that accounting for economic/reliability trade-offs and using some probabilistic (rather than solely deterministic) methods for system planning may result in a small but non-zero level of transmission congestion, even for firm customers. The Commission Panel also notes that BCTC will be required to make some assumptions about the cost of congestion (which will be tested in future Applications). However, the Commission Panel expects that the result will be a closer-to-optimal transmission system. Thus, the Commission Panel does not support BCTC's policy of not allowing congestion to occur on the system for firm transmission service (BCUC IR 1.22.1). The Commission Panel will provide additional guidance to BCTC with respect to employing economic considerations in evaluating transmission projects in the next section, which deals with alternatives to transmission.

The Commission Panel notes that Attachment J to the BCTC's Open Access Transmission Tariff refers to violations of applicable reliability criteria. **The Commission Panel directs BCTC to review Attachment J to determine whether any changes are warranted, given the Commission Panel's directives herein on system planning and the interpretation of reliability standards.**

BCTC's F2006 TSCP is silent on system capability during maintenance outages of system elements. Section I.A.M2 of the NERC/WECC Planning Standards states:

> "The systems must be capable of meeting Category B requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed."

It is necessary for BCTC to control and confine planned maintenance outages on individual system components to periods when the next uncontrolled outage will still allow the system to conform to Section I.A.M2. This level of coordination between maintenance planning and system planning was not apparent in the Application. Future applications should identify whether any capital projects are driven by the need to conform to Section I.A.M2 during maintenance outages.

3.3 Alternatives to Transmission

The Growth Capital investments proposed in BCTC's Capital Plan are driven by the need to expand and reinforce the transmission system to meet the forecast requirements of BC Hydro and other customers over a ten-year planning period. Sometimes, however, there are viable alternatives to transmission capacity increases, including locating generation resources near loads, reducing demand either generally or during specific periods, or establishing remedial actions schemes ("RAS") that can immediately shed load or generation in the event of a contingency (see Exhibit B-1, pp. 48 and 59-60). In addition, there may be alternatives to BCTC-funded investments for increasing transmission capacity, such as merchant transmission lines (e.g., the proposed Port Angeles-Juan de Fuca HVDC project [Schedule A1 to Exhibit C2-4]) and market-provided services (e.g., reactive power provision [BCUC IR 2.93.1]).

In its final submission (Exhibit C9-2, pp. 2 and 4) the CEC notes that, while the load forecast used by BCTC incorporates PowerSmart programs as planned by BC Hydro, there are no programs directed at demand reduction or demand response to reduce BC Hydro's peak load requirements. The CEC believes there is an opportunity for electric-system-wide efficiency improvements through negotiated arrangements with customers for alternative levels of service and service quality. It believes that: (a) tariffs for these alternatives should be established; (b) negotiations with customers should be carried out to determine the extent to which alternative service levels could be achieved; and (c) regulatory approval of the alternatives and prices should be sought. To that end, the CEC recommends that the Commission require BCTC to:

- ask BC Hydro to provide appropriate assumptions regarding what could be achieved with demand response programs directed at customers;
- provide the Commission with its estimate of the potential transmission system cost savings achievable through demand response arrangements with customers;
- consult and coordinate with BC Hydro throughout the Integrated Electricity Plan ("IEP") and rate design process to ensure that there are no expenditures where demand side options may defer the need for projects.

The CEC notes that BC Hydro is expected to file its long-term IEP and general rate design applications by December 2005, and that some of the issues concerning DSM and demand response could be dealt with in the context of those applications.

In its Application, BCTC noted that it is in the early stages 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, and that it expects to incorporate a finalized policy on DSM into its next capital plan. In the meantime, BCTC is working with Norske Canada and BC Hydro to test, evaluate, and potentially implement a DSM program with Norske loads on Vancouver Island (BCUC IR 1.12).

BCTC believes that the DSM-related requests presented by the CEC are premature. It submits that BC Hydro, through processes such as the load forecast and the IEP, is in a better position to identify the need for, and put in place, broadly based DSM initiatives. Further, any assumptions regarding what could be achieved with a new DSM initiative would be much better informed following BC Hydro's upcoming IEP and rate design processes. In BCTC's view, the Growth Capital projects for which approval is sought are driven by immediate, well-defined needs, whereas DSM initiatives of any magnitude would take time to conceive, be developed, be approved, go to market, get taken up, and ultimately manifest themselves in the system load (Exhibit B-11, pp. 3-5).

Commission Findings

The Commission Panel accepts BCTC's statement that the CEC's requests related to DSM are premature in the context of the present Application. The Commission Panel does not believe that BCTC's efforts on DSM are far enough along, for example, to develop meaningful estimates of the transmission cost savings that could be achieved in the F2006 TSCP through demand response programs. Consequently, the Commission Panel will not provide any DSM-related directions to BCTC with respect to the F2006 TSCP projects.

Notwithstanding the Commission Panel's comments with respect to DSM-related directions for F2006 projects, the Commission Panel appreciates the willingness of customers to provide solutions to transmission constraints and to discuss such solutions with BCTC and BC Hydro. **The Commission Panel therefore directs BCTC, if it has not already done so, to initiate discussions with customers (including BC Hydro) on potential customer-provided solutions to transmission constraints, and to report to the Commission on the outcome of those discussions in its next capital plan. Without limiting the scope of the discussions, the Commission Panel expects BCTC will examine the following in conjunction with BC Hydro:**

- **options for general (i.e., system- or area-wide) demand reductions, to the extent they are not already covered by existing DSM initiatives such as PowerSmart;**
- **options for location- or area-specific demand reductions, either planned or in response to system events (e.g., by arming customer-specific remedial action schemes);**
- **demand reduction timing requirements (e.g., all hours, peak months or hours, or only when armed);**
- **mechanisms for compensating customers, such as reduced rates, direct payments through commercial contracts, or investment deferral credits;**

- **options for customer-supplied transmission services, such as reactive power or reliability must-run generation.**

The Commission Panel further notes that, as the entity responsible for developing solutions to transmission constraints, BCTC is in the best position to identify the extent to which customer- or third-party-provided solutions could defer or eliminate the need for Growth Capital investments. Without pre-judging whether BCTC or BC Hydro (or both) should ultimately contract for non-wires solutions, the Commission Panel expects that BCTC will identify potential non-wires solutions in future studies and capital plan applications.

4.0 THE CONDITION OF TRANSMISSION ASSETS: THE ASSET BASELINE STUDY

As part of the F2006 TSCP, BCTC filed an Asset Baseline Study ("ABS," Exhibit B-3B). The study was conducted to fulfill an obligation to BC Hydro under Article 7 of the Asset Management and Maintenance Agreement ("AMMA"), one of the key agreements establishing BCTC as an independent transmission company. The AMMA required that an independent engineering company conduct the ABS. Acres International Ltd. ("Acres") was selected through a competitive process as the independent engineering firm to conduct the assessment and establish a baseline for asset health. An ABS will be performed every three years (BCUC IR 1.1.1). There were no intervener comments or information requests on the ABS.

4.1 Reasons for the Asset Baseline Study

BCTC stated that the key objectives for the ABS were to:

- Assess the current state of health of the transmission system assets in order to establish a baseline for measuring the performance of BCTC;
- Satisfy the requirements of the AMMA between BCTC and BC Hydro, which requires an independent expert audit opinion of asset condition every three years;
- Document the methodology and define a repeatable process that can be used in future audits;
- Develop best-practice asset health indices for the transmission system assets; and,
- Use the asset health indices as inputs to planning and decision-making for present and future capital replacement and expensed maintenance requirements.

(See Exhibit B-3B, Introduction and Context For the Baseline Study ["ICBS"], p. 3).

In addition to using the asset health indices, BCTC stated that it will bring a lifecycle approach to planning and decision-making for present and future capital replacement and expensed maintenance requirements. Specifically, BCTC has committed to (Exhibit B-3B, p. 7):

- Pursue an economic balance between maintenance and replacement to achieve the lowest lifecycle cost for the function of a particular asset without impacting the required level of performance. This balance will be supported by a rigorous financial analysis that will include calculations of Net Present Value ("NPV") and benefit/cost ratio. BCTC will look for opportunities to make one-time capital investments that result in larger offsetting reductions in lifecycle OMA costs without negatively impacting performance.

- Apply an "evergreen" process for asset replacement, meaning that it will replace individual assets when it makes sense for that asset, rather than waiting for an entire generation of assets to degrade before replacing.

- Adopt new technologies as they become available and are proven, rather than replacing like for like.

- Focus on the overall system rather than individual components.

- Focus on asset health rather than defects. Historically, the objective was to track defects in order to drive repair activity. However, individual defects do not provide a view of the health of the entire asset or clear feedback on the effectiveness of the asset management strategy.

- Define appropriate asset management processes and manage the processes to drive efficiencies over time.

BCTC's planning and decision making for present and future capital replacement and expensed maintenance requirements will be guided by (Exhibit B-3B, p. 8):

- A moving ten-year planning horizon for sustaining capital programs in order to ensure a long-term perspective, provide for smoother revenue requirements, and focus on the highest priority work;

- Compliance with (rather than the exceeding of) applicable reliability targets and standards;

- Asset management strategies that support the new safety management and environment management programs implemented by BCTC;

- Asset management strategies that include looking for partnership opportunities with suppliers and other utilities to improve effectiveness and lower costs; and,

- Reliability Centred Maintenance ("RCM") philosophies.

4.2 Methodology

The AMMA specified that the ABS had to be completed within a 12-month window following commencement. Comprehensively assessing the health of the transmission system assets would include assessing over:

- 1000 circuit breakers;
- 4000 disconnect switches;
- 230 transformers and 4200 instrument transformers;
- 2900 relay systems with nearly 8000 relays;
- 2600 surge arrestors;

- 11,500 km of rights of way;
- 97,000 spans of overhead conductor (~18,000 circuit km);
- 20,000 metal support structures;
- 67,000 wood pole structures;
- 1.3 million support structure insulators;
- 338 km of underground and submarine cable; and,
- many other assets and critical sub-components.

For purposes of analysis and reporting, the transmission assets were categorized into 33 classes of items with similar characteristics or functions.

The ABS relied on data supplied by BCTC for each asset class. Generally, the ABS involved the following (Exhibit B-3B, Transmission Baseline Study Report ["TBSR"], p. 1):

1. Providing general descriptions of each asset class;
2. Preparing demographic profiles of each type of asset in the transmission system;
3. Describing typical degradation processes and condition assessment techniques for each asset class;
4. Formulating a health index for each asset class by developing end-of-life criteria;
5. Calculating a numerical condition score for members of each asset class to indicate their suitability for continued service;
6. Using those condition scores to make relative comparisons about the health of common asset class members and reach conclusions about the overall health of each asset class; and,
7. Ensuring repeatability by documenting the methodology and data sources used in the ABS.

The ABS did not involve the monitoring, sampling or testing of any assets. Results reflect the analysis of existing electronic data from BCTC plus information obtained in a limited field survey. In some cases, additional data may have existed in hard copy at substations or field offices, but collection and transformation of that data was not included in the scope of the study.

End-of-life criteria were developed for each of the 33 asset classes to aid in determining a component's condition relative to potential failure. Where information was available for a particular asset, that asset was given a ranking of "A" to "E" against each criterion, and each ranking was given a value according to the following scale:

- "A" means the component is in "as new" condition (value = 4);
- "B" means the component has some minor problems or evidence of ageing (value = 3);
- "C" means the component has many minor problems or a major problem that requires attention (value = 2);
- "D" means the component has many problems and the potential for major failure (value = 1); and
- "E" means the component has completely failed or is degraded beyond repair (value = 0).

Each criterion was assigned a weighting factor according to the importance of that criterion to the function of the asset. Each criterion's weighting factor was then multiplied by its condition ranking. The result of these multiplications were summed together, divided by the total possible score (sum of all weighting factors multiplied by a ranking of 4) and then multiplied by 100 to get a normalized health index that was scaled between 0 and 100 (Exhibit B-3B, TBSR, p. 4).

If an asset exhibited what was considered to be a "fatal flaw" in either its own condition, or was part of a population known to possess a "fatal flaw" characteristic, the calculated health index was divided by a previously defined factor. For instance, if the "fatal flaw" factor were 2, the resulting normalized health index would have a range between 0 and 50. A "fatal flaw" factor was applied for portions of the populations in 11 of the 33 asset classes (BCUC IR 2.139.4).

Incomplete condition data sets for a given asset were considered adequate if the maximum normalized health index of the criteria for which data existed within the incomplete data set yielded a score of at least 70 percent of the maximum possible score for a full data set (the 70 Percent Rule). If an incomplete condition data set for a given asset failed to satisfy the 70 Percent Rule, but the maximum normalized health index of the criteria for which data existed within the incomplete data set yielded a score of at least 50 percent of the maximum possible score for a full data set, then that asset's health index was presented in the overall results, but not included as a sample when determining the statistical condition of a particular population of assets (the 50 Percent Rule) (BCUC IR 2.101.3).

The results of the normalized health index evaluations were segregated into five standard categories of asset condition as shown in the table below. As previously mentioned, the health index is only one input into the overall decision-making process for maintenance and capital replacement planning.

Health Index	Condition	Description	Requirements
85 - 100	Very Good	Some ageing or minor deterioration of a limited number of components	Normal maintenance
70 - 85	Good	Significant deterioration of some components	Normal maintenance
50 – 70	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 – 50	Poor	Widespread serious deterioration	Start planning process to replace or rebuild considering risk and consequences of failure
0 - 30	Very Poor	Extensive serious deterioration	At end-of-life, immediately assess risk; replace or rebuild based on assessment

The baseline asset condition results for 15 of the 33 asset classes have sample sizes greater than 50 percent of the population, and this is with the inclusive effects of the 70 Percent Rule and the 50 Percent Rule. Of those 15 asset classes, complete population data sets were available for 8 asset classes, 5 of which had populations less than 10 (BCUC IR 2.101.7).

Commission Findings

The Commission Panel commends BCTC for its efforts in preparing the ABS, which is the first such study prepared by BCTC. The Commission Panel notes that, as acknowledged by BCTC and the report's authors, there were some limitations on the study. It did not involve the monitoring, sampling or testing of any assets, and only a very limited field survey was conducted. The collection and transformation of data that may exist in hard-copy form was not within the scope of the study, and there were many assets for which the condition could only be inferred from the application of adjustment mechanisms or from the condition of other members of that asset class. No data at all was available for three classes of assets (station insulators, access roads and civil works), because data to support a health index has simply never been recorded. For a fourth class, wood pole structures, some data was available, but it was deemed by Acres to be too inconsistent to report a meaningful result (Exhibit B-3B, p. 8).

The Commission Panel finds that the three-year interval between asset condition audits is appropriate. However, increasing amounts of asset data should be available at each interval. BCTC's data monitoring, collation and analysis activity should be sufficient to ensure that an adequate data-based condition assessment is available for at least 90 percent of the assets within each class meeting the 70 Percent Rule by the third audit.

The Commission Panel encourages the preparation and use of a rigorous financial comparison of continued maintenance versus equipment replacement as a key driver in asset management planning. Where possible and practical, this analysis should be done for individual pieces of equipment, with maintenance costs for that piece of equipment based on its actual condition and its required reliability in its specific application. The Commission Panel expects that such financial evaluations will include a comparison against options that were considered but not selected, rather than only an evaluation of the selected option (BCUC IR 2.112.3).

The Commission Panel is concerned that an overly aggressively approach to equipment replacement that is based on asset health indicators rather than experienced defects or failures may be prone to premature capital investment if the health indicators are too conservative. Thus, the Commission Panel is reassured by BCTC's use of the condition rating as an indicator for further investigation rather than as a basis upon which to proceed to immediate equipment replacement (BCUC IR 2.139.1). If there is a sufficient population of a certain type of asset, then some limited amount of defect-driven failure should be tolerated to validate the corresponding asset health indicator and avoid premature capital investment.

The Commission Panel is also concerned with the application of "fatal flaw" factors to entire portions of asset populations. The "fatal flaw" factor is either 2 or 4, which would make an otherwise near-perfect asset either Poor or Very Poor (BCUC IR 2.101.2). **The Commission Panel recommends that the "fatal flaw" factor only be used on individual assets that meet the 70 Percent Rule, and not be applied to entire populations for which valid data may not exist.** Even in this circumstance, the application of the "fatal flaw" factor should be used sparingly. If the equipment is still operating acceptably then the rigorous economic analysis of equipment replacement versus OMA costs should drive equipment replacement decisions. Poor or Very Poor condition characterizations based on the application of a somewhat arbitrary factor should trigger further investigation rather than investment or maintenance decisions (BCUC IR 2.139.1).

The Commission Panel notes that clear correlations have not yet been established among asset classes' health index values, failure rates, expected remaining lifetimes, and impacts on reliability indicators such as SAIDI. Notwithstanding the Commission Panel's concerns about the use of the ABS as a driver of Sustaining Capital programs today, if such correlations exist and can be detected, health indices could become useful predictors of asset maintenance and replacement requirements, and therefore important drivers of Sustaining Capital programs, in the future. On the other hand, a lack of correlation among the aforementioned variables may highlight necessary changes to asset scoring criteria or other aspects of the ABS methodology. **The Commission Panel therefore recommends that, during the design and development of its asset management information systems, BCTC consider the data collection and analysis processes necessary to establish the correlations described above.**

4.3 Asset Baseline Study and Sustaining Capital Portfolio Impacts

As discussed earlier, BCTC stated that the condition rating of an asset will be used as an indicator for further investigation rather than as a basis upon which to proceed to immediate equipment replacement, although replacement may be the final result.

BCTC states that the recommendations from the ABS validated existing policies and initiatives. One new initiative has been attributed to the health findings associated with certain Gas Insulated Switchgear ("GIS") installations (BCUC IR 2.110.1). These findings have prompted the new initiative to refurbish the BBC GIS hydraulic installations.

Commission Findings

The Commission Panel recognizes the usefulness of the ABS for validating existing policies and initiatives. The Commission Panel sees the ABS as a measurement tool that reflects the effectiveness of Sustaining Capital Portfolio activities, rather than as a primary driver around which programs are defined. Therefore, the Commission Panel is concerned that without further supporting data such as impact on operability or reliability indices, basing the BBC GIS refurbishment initiative (Exhibit B-3B, TBSR, p. 11-31) on the health findings may not be consistent with the concept of using the ABS as a measuring tool rather than a program driver. The Fair rating of all the BBC GIS assets raises questions regarding this initiative's priority relative to other proposed Sustaining Capital Portfolio projects.

As yet, the Commission Panel is not convinced that the ABS has validated BCTC's existing maintenance policies and practices. This is neither a criticism of BCTC nor a suggestion that the ABS calls into question its policies and practices. Rather, it is a recognition of the acknowledged limitations inherent in this first ABS and of the fact that it is not possible, at this stage, to relate health index scores to variables such as failure rates or remaining lifetimes. The Commission Panel provided guidance to BCTC in this regard in the previous section.

5.0 THE CAPITAL PORTFOLIOS

In this Application BCTC requests approval for projects beginning in both F2006 and F2007. In next year's F2007 Plan, BCTC will request approval for any additional projects that have been identified for F2007, as well as projects commencing in F2008 (Exhibit B-1, page 1).

5.1 Growth

BCTC stated that its Growth Capital portfolio is comprised of the capital investments required to expand and reinforce the transmission system to meet the forecast requirements of BC Hydro and other customers over the 10-year planning period (Exhibit B-1, p. 46). The system expansion and reinforcement reflected by the Growth Capital portfolio is driven by service requests made pursuant to BCTC's WTS tariff. Such service requests include:

- the Network Integration Transmission Service ("NITS") Agreement between BCTC and BC Hydro, which covers the supply of domestic load in BC Hydro's service area from all BC Hydro supply sources (both generation and imports);
- point-to-point ("PTP") contracts with BC Hydro and other customers, which cover the wheeling of power from BC Hydro and other generation entities to wholesalers and utilities over sections of the transmission system;
- interconnections; and
- other service requests, such as the General Wheeling Agreement with FortisBC.

BCTC notes (Exhibit B-11, p. 1) that projects for which specific approval is sought are limited to all F2006 projects and projects for which spending will begin in F2007. The projects are listed beginning on page 158 (Tab 7) of the Application.

5.1.1 General

In its final submission, the CEC expresses concern about the uncertainty associated with the capital planning process and the effect such uncertainty could have on BCTC's ability to minimize planning costs. In that regard, it provides two general recommendations. First, BCTC should be required to provide the Commission and BC Hydro with appropriate planning time-frames for major transmission system upgrades and expansions so that BC Hydro can advance its resource planning and regulatory approvals to minimize transmission planning costs.

Second, the Commission should approve the Growth Capital Portfolio subject to change based on the developments flowing out of BC Hydro's IEP and general rate design (Exhibit C9-2, p. 4).

BCTC, in its final response to intervener comments, states that there are always uncertainties with any planning process, and that those uncertainties often cannot be resolved other than through the passage of time (Exhibit B-11, p. 3). BCTC also states that it continues to refine both its planning processes and the manner in which its capital plan is presented (Exhibit B-1, p. 1), and that the capital planning process is flexible enough to accommodate changes in assumptions by advancing or deferring projects (Exhibit B-11, p. 5). BCTC is also of the view that, from a transmission perspective, uncertainty is usually reflected in exactly when a solution will be required, not whether a solution is required or in the solution itself (Exhibit B-11, p. 3).

With respect to the CEC's first recommendation, BCTC notes that its F2006 TSCP is for a ten-year period, and that planning studies are often performed over an even longer period. BCTC only seeks approval for those projects that it has determined are needed to meet System Performance Criteria and that it believes are in the public interest, or for definition-phase projects necessary to initiate detailed planning activities (Exhibit B-11, p. 5). With respect to the second recommendation, BCTC states that it has reviewed the F2006 TSCP in response to the CEC's submission, and that all of the projects in the Application are necessary. Accordingly, in BCTC's view, the planning and implementation of these projects should not be delayed until the outcomes of BC Hydro's processes are known (Exhibit B-11, p. 6).

In addition to its comments about uncertainty, the CEC also expresses concern about the "massive peaking of expenditure in F2007, F2008, and F2009." It states that it is likely that certain projects put forward in the planning stages will be deferred, and therefore that the revenue requirement upon which rates are set may be overstated. The CEC therefore recommends that the Commission require BCTC to prepare, in preparation for any future revenue requirements driven from this planning data, an analysis of past deferrals of planned projects so that an appropriate adjustment may be made to the schedule of expenditures (Exhibit C9-2, p. 4).

In response to the CEC's recommendation, BCTC states that its revenue requirements applications are based on the best information available at the time of filing. In the case of capital additions, this information reflects those capital projects that are forecast to come into service during the period covered by the application. If there is a risk that a Growth Capital project will not come into service as forecast, the issue can be dealt with during the revenue requirements proceeding. BCTC therefore submits that the CEC's requested direction is not necessary (Exhibit B-11, p. 7).

Commission Findings

The Commission Panel acknowledges the CEC's concerns about uncertainty, and supports efforts by BC Hydro and BCTC to reduce uncertainty to minimize planning and infrastructure costs. However, the Commission Panel also accepts BCTC's view that there are always uncertainties with any planning process, and that those uncertainties often cannot be resolved other than through the passage of time. Further, the Commission Panel notes that BC Hydro makes its transmission requirements known to BCTC through applications for transmission service (e.g., the September 2004 NITS application) and, in response, BCTC provides BC Hydro and the Commission with information on necessary infrastructure reinforcements and the associated timelines through system impact studies, facilities studies, and the capital plan. Thus, the Commission Panel believes that the mechanisms necessary for the exchange of planning information already exist, and that any required changes to BCTC's capital plan would arise naturally through that information exchange. The Commission Panel therefore does not accept that the directives recommended by the CEC are necessary.

The Commission Panel also accepts BCTC's submission that no specific direction concerning the preparation of revenue requirements applications is warranted, for the reasons given by BCTC. However, the Commission Panel supports the concept that knowledge of how the capital plan evolves is of benefit to interested parties. **Consequently, the Commission Panel directs BCTC to file, with each future capital plan, a table showing the changes from one capital plan to the next. The table may be in a form to be determined by BCTC, but must note any projects that have been accelerated, deferred, or cancelled, and must show any changes in expenditure patterns.**

5.1.2 Key Drivers

BCTC cited four key drivers for the Growth Capital Portfolio: the interconnection of new generation provided for in BC Hydro's NITS application, load growth, customer-requested projects, and independent power producer ("IPP") connections (Exhibit B-1, pp. 46-47).

Interconnection of New Generation

The key generation assumptions for the purposes of the bulk-transmission-system components of the Growth Capital Portfolio were provided by BC Hydro in the NITS Application submitted to BCTC in September 2004 and finalized in December of that year. The resource assumptions and the consequences for the F2006 TSCP if those assumptions turn out to be wrong are as follows (see Exhibit B-1, p. 46, BCUC IR 1.34.3, and pp. 5-7 of the System Impact Study attached to BCUC IR 1.19.1).

- In 2008, the IPPs identified by BC Hydro as Network Resources will provide additional generation capacity of 140 MW in the Peace River basin, 140 MW in the Columbia River basin, 300 MW in the Lower Mainland, and 160 MW on Vancouver Island. If this assumption turns out to be wrong, the impact on the F2006 TSCP will simply be a deferral of IPP-related projects. No IPP interconnections are made until agreements are reached with the respective IPPs.

- In 2008, the Duke Point Power project will be in service (293 MW on Vancouver Island). This assumption is already known to be wrong and, as a result, there will be a planning capacity shortfall on Vancouver Island until the Vancouver Island Transmission Reinforcement Project is commissioned. However, BCTC anticipates no capital expenditures outside the proposed F2006 TSCP to address the shortfall.

- By 2010, the GM Shrum ("GMS") Resource Smart program will increase the output of GMS (by 246 MW according to the aforementioned System Impact Study, and by about 200 MW according to the response to BCUC IR 1.34.3). BCTC noted that there may be a need to increase the ILM capacity by increasing reliability must run ("RMR") generation or by advancing the 5L83 project, but that such changes do not alter the present F2006 TSCP. Should the capacity increase not materialize, there is no F2006 TSCP change because generation capacity would be as it is today.

- In 2010, Alcan's contract to supply generation to BC Hydro will expire and Alcan will switch from a 147 MW resource to a 175 MW load. If this assumption turns out to be wrong, there is no impact on the plan because things will be as they are today. In the absence of new local generation to supply the load (see the next item), transmission reinforcements would be required.

- In 2010, the gas turbine at Kitimat will be in service, providing 180 MW of generation to serve the Alcan load.

- In 2011, 2013, 2014, and 2015, various calls for tenders will be held throughout BC, adding a total of 705 MW of capacity in the Peace River basin, 646 MW in the Columbia River basin, and 664 MW in the Lower Mainland. BCTC noted that, while the F2006 TSCP includes an allowance for IPP connections, actual amounts may be more or less than these values.

- By 2012, the Mica Resource Smart program will increase the output of Mica by 130 MW. The F2006 TSCP includes project definition work for series capacitors on 5L71/5L72 to accommodate the increase, though the work is not scheduled to begin until after confirming the requirements with BC Hydro.

- In 2014, the Burrard Thermal Station will be retired, reducing Lower Mainland capacity by 960 MW. The retirement will reduce the availability of RMR generation in the coastal region, but if 5L83 is built in 2013, enough RMR generation is available without Burrard. However, the reactive power capability of Burrard must be replaced, so the F2006 TSCP includes definition phase work for the Ingledow SVC. An earlier retirement of Burrard would necessitate addition RMR generation or an advancement of 5L83, and the Ingledow SVC would have to be advanced. BCTC has not studied the effect of a deferral of Burrard's retirement.

The CEC is the only intervener that commented on the resource assumptions. It notes that the assumption that the Duke Point Power project will be in service is now clearly not applicable. The CEC also states that there is considerable uncertainty with regard to other assumptions such as the retirement of the Burrard plant, the locations and in-service dates from the current call for generation resources, and the timing and location of the future calls. In the CEC's view, it would be valuable for BC Hydro to resolve a number of these uncertainties sooner rather than later so that transmission planning expenditures can be minimized (Exhibit C9-2, p. 1).

Commission Findings

The Commission Panel accepts the CEC's view that it would be valuable for BC Hydro to resolve a number of planning uncertainties sooner rather than later, and is of the view that some assistance in this regard will be provided with the future filing of BC Hydro's IEP. However, as noted in Section 5.1.1, the Commission Panel accepts BCTC's view that there are uncertainties with any planning process, and that those uncertainties often cannot be resolved other than through the passage of time.

Given that no intervener has suggested alternative resource assumptions, the Commission Panel accepts that the assumptions used by BCTC in developing this F2006 TSCP, with the obvious exception of the Duke Point assumption, are reasonable. With respect to the Duke Point cancellation, the Commission Panel accepts BCTC's statement that there is no resulting change to any of the projects in the Application (Exhibit B-11, p. 4).

Load Growth

BCTC used BC Hydro's October 2004 Electric Load Forecast 2004/05 to 2024/25 as the basis for its F2006 TSCP load projections. The coincident peak demand (including losses, domestic load, and firm exports to FortisBC, New Westminster, Alberta, and the United States) was used to determine the reinforcement requirements for the bulk transmission system. That peak demand is expected to grow by 1120 MW over the next 10 years. The Coincident Regional Peak Demand Forecast is used to determine regional or area reinforcement requirements, while the Non-Coincident Substation and Industrial Load Peak Demand (MW) Forecast is used to determine local area and substation expansion or modification requirements (Exhibit B-1, p. 47).

The only intervener to comment on BCTC's use of load forecasts was the CEC. While submitting that the BC Hydro forecast may be overstated because it does not contain any allowance for negotiated arrangements with customers for different levels of service and service quality (which might allow planning for lower peak demand load forecasts), it notes that BCTC has no choice, at this time and in this application, but to rely on the forecasts and assumptions it has been given (Exhibit C9-2, p. 2).

In its Final Response to Interveners' Submissions, BCTC states that it does not believe it is in the ratepayers' interest for it to duplicate BC Hydro's forecasting process (Exhibit B-11, p. 3), in particular because BC Hydro has the data and the detailed knowledge of its residential, commercial, and industrial customer base and of distribution system reconfigurations that can impact substation loading (BCUC IR 2.86.4).

Commission Findings

The Commission Panel accepts that the load forecasts used by BCTC in the preparation of this F2006 TSCP are reasonable, and that, subject to the comments on DSM in Section 5.3, it is appropriate that BCTC use the load forecasts prepared by BC Hydro.

Customer-Requested Projects

From time to time, a BCTC or BC Hydro customer may request changes to the transmission system for its own benefit. These types of requests may include increased service levels beyond that which is normally provided or relocation of transmission system equipment. While BC Hydro continues to own the assets, the customer requesting the project pays the costs (Exhibit B-1, p. 47). The Commission Panel notes, therefore, that BCTC's forecast of customer-requested projects is not a significant factor in its approval of the F2006 TSCP.

Independent Power Producer Interconnections

From time to time, BC Hydro will issue various calls for tender for electricity supply from IPPs. The successful proponents under these calls will sign Electricity Purchase Agreements with BC Hydro and will have to be connected to the transmission system. In addition, IPPs from time to time may request interconnection to the system to make sales to purchasers other than BC Hydro. IPP connections typically include direct assignment facilities, which are fully paid for by the IPP, and Network Upgrades, which are funded in accordance with the WTS/OATT tariff (Exhibit B-1, p. 47).

The CEC's comments on the uncertainty around the location and timing of resources, including IPP resources, was noted previously in this section under the heading Interconnection of New Generation. In its response to BCUC IR 2.92.1, BCTC acknowledged that predicting the likelihood of a particular IPP proceeding is difficult, but that of the 23 IPPs included in the F2006 TSCP, ten are in service or under construction, five have started interconnection impact and facilities studies, and eight have not started interconnection impact and facilities studies. BCTC also noted that if IPPs do not enter into interconnection service agreements, then the IPP projects would be deferred in the F2006 TSCP. BCTC could not comment on what the impact on BC Hydro's Resource Plan might be.

Commission Findings

The Commission Panel acknowledges the CEC's concerns about forecasting IPP interconnections, but notes that no alternative assumptions regarding resource interconnections were provided. The Commission Panel therefore accepts the IPP assumptions used by BCTC in developing the F2006 TSCP.

5.1.3 Bulk Transmission System Reinforcements

The bulk transmission system includes the 500 kV facilities together with portions of the 230 kV grid, the Vancouver Island transmission circuits, and the interconnections with FortisBC, Alcan, Alberta, and the United States. Typical reinforcement projects on the bulk system include (Exhibit B-1, p. 48):

- the installation of reactive power compensation devices such as capacitors, reactors, and static VAr compensators ("SVCs") to prevent voltage instability, control transient voltage fluctuations, and regulate steady-state bus voltages;
- the addition or replacement of transformers to increase the capacity and/or reliability of substations;
- the installation of Remedial Action Schemes ("RAS"), which are automated, logical control systems that activate pre-programmed actions in response to identified power system contingencies to enhance power system performance and protect equipment, especially in response to high-impact, low-probability ("HILP") events.

Interior to Lower Mainland ("ILM")

The ILM system delivers power from the Northern and Southern Interior regions, as well as power imported from Alberta, to the major load centres in the Lower Mainland and to the 500 kV BC-US tie for export. Several 500 kV lines move power from the Kelly Lake and Nicola Substations to a number of substations in the Lower Mainland. A 500 kV line from Kelly Lake to Nicola connects the Peace and Columbia systems together and provides the ability to transfer power flows to the remaining lines during certain single-contingency outages.

BCTC noted that the ILM system is voltage-stability and thermally limited during winter peak periods. It is also congested at other times, depending on Lower Mainland load, exports, generation dispatch, and facilities out of service. The thermal limitation is presently the main driver for reinforcement of the ILM system, and the potential solutions (such as the proposed 5L83 line between Nicola and Meridian Substations, the definition phase of which was approved in BCTC's F2005 Capital Plan) tend to require long lead times. Such reinforcements will be required as new generation resources are developed in the Peace and Columbia regions, and/or imports from Alberta are increased, to serve growing Lower Mainland and Vancouver Island load. Alternatively, new generation resources could be developed closer to load centres, deferring the need for transmission upgrades (Exhibit B3-A, p. 8).

BCTC has proposed the following Growth Capital projects on the ILM portion of the transmission system.

Project	F2006/F2007 Costs	Transmission Capital Cost
Ingledow 230 kV SVC (Definition Phase)	524,000	37,879,000
Meridian Land Purchase	160,000	160,000
Nicola Station Reconfiguration (Definition Phase)	214,000	5,955,000
Interior to Lower Mainland Total	898,000	43,994,000

In this and subsequent tables, the column "F2006/F2007 Costs" contains BCTC's estimate of the cost of each project for which BCTC is seeking approval through the F2006 TSCP. BCTC stated that it is seeking approval for projects to be initiated in F2006 or F2007 (Exhibit B-1, p. 1). Because work initiated in F2006 or F2007 may not be completed until after F2007, the amount shown is not necessarily the anticipated F2006/F2007 expenditure. The "Transmission Capital Cost" is BCTC's estimate of the total cost to complete the work, excluding Substation Distribution Asset ("SDA") costs (Exhibit B-1, p. 6).

BCTC states that the Ingledow SVC project is being driven by increasing power transfers across the ILM system, which leads to an increase in the reactive power needed to meet WECC standards, maintain a proper voltage profile, and ensure that the system can withstand a critical contingency. In addition, there is uncertainty about the continued operation of the Burrard plant, which currently provides dynamic reactive power to the system. An SVC at Ingledow can provide the same dynamic reactive power as Burrard (Exhibit B-1, p. 50).

BCTC has indicated that there are alternatives to an SVC, including synchronous machines and variations on the type of SVC. While synchronous machines have some advantages (and disadvantages) compared to SVCs, BCTC has not investigated the possibility of purchasing reactive power from third parties (BCUC IRs 1.35.2 and 1.36.1). BCTC stated that, if its plans identify a need for reactive power in an area with IPP activity, or a project sponsor comes forward and demonstrates that it can supply reactive power cost-effectively, BCTC would investigate the potential for outsourcing (BCUC IR 2.93.1).

IRAHVOL submits that the Commission Panel should deny both the proposed definition-phase expenditure on the Ingledow SVC and the Meridian land purchase on the grounds that they might not be necessary or might be deferred if BCTC were to select the HVDC Light® alternative for VITR (Exhibit C2-4, p. 3). In reply, BCTC states that there are no projects for which approval is sought in the F2006 TSCP that would be made unnecessary if the HVDC Light® option were to be used (Exhibit B-11, p. 12).

Commission Findings

The Commission Panel accepts BCTC's statement that there are no projects for which approval is sought in the F2006 TSCP that would be made unnecessary if the HVDC Light® option were to be selected for VITR, and therefore does not accept IRAHVOL's recommendation that the Meridian land purchase be denied. The Commission Panel accepts BCTC's submissions that Meridian substation is strategically located on the ILM transfer path, and that additional equipment may be required in the future to support increased power transfers (Exhibit B-1, p. 51). **The Commission Panel therefore approves the Meridian land purchase.**

The Commission Panel notes that no party opposed the definition-phase work on the Nicola reconfiguration project, which had already been approved as part of BCTC's F2005 Capital Plan. **That definition-phase work is therefore approved.** Given the uncertainty discussed in Section 2.3 around the timing of the Commission's approval of need relative to the definition phase, it is worth noting that BCTC will complete a reliability study in the fall of 2005 as part of the definition phase; that study will establish the need for the upgrade at present and future loading levels (BCUC IR 1.37.4). Therefore, in granting approval of the definition phase for this project, the Commission Panel is not expressing an opinion on whether the project is or is not in the public interest.

The last of the three proposed ILM Growth Capital projects is the Ingledow SVC. The Commission Panel is concerned with the lack of information on this project and the associated reinforcement requirements and options. Some of the concerns were stated in Section 2.1. The Commission Panel further notes that BCTC uses "uncertainties about the continued operation of Burrard" (Exhibit B-1, p. 50) as partial justification for the project, whereas in the F2005 Capital Plan, a possible shutdown of Burrard was not considered. The Commission Panel is not suggesting that a change in the assumption about Burrard is not appropriate, but notes that no justification for such an important change was provided by BCTC. In addition, BCTC acknowledged that it has not yet investigated the purchase of reactive power from sources other than BC Hydro (BCUC IR 1.35.2), though such purchases could significantly affect the proposed project. The Commission Panel notes that BCTC's initiative to purchase Interconnected Operations Services such as reactive power was accepted in Decision G-58-05 (p. 86) on BCTC's Open Access Transmission Tariff.

Based on the foregoing, the Commission Panel is unable to find at this time that the Ingledow SVC is in the public interest. **The Commission Panel therefore rejects BCTC's application for definition-phase funding. BCTC is at liberty to re-file its request whenever it chooses, but if it does so, it must provide either: (a) a justification for the project that addresses the issues raised by the Commission Panel; or (b) a plan to develop the justification and a statement as to why the associated costs should be capitalized.** If BCTC files a justification for the Ingledow SVC and the Commission Panel accepts that it is in the public interest, the project can proceed to implementation without further review by the Commission. The economic justification for the Ingledow SVC may be based on planning estimates.

Lower Mainland to Vancouver Island ("LM-VI")

Power is supplied to Vancouver Island and the Gulf Islands through a combination of 500 kV and 138 kV ac lines and 260 kV and 280 kV DC lines. The two 138 kV circuits that supply the Gulf Islands are ageing and are considered to have zero dependable capacity for planning purposes, though BCTC intends to keep them in service as long as it is economic to do so. The DC system is also ageing, and it has been de-rated over time to its present dependable capacity of 240 MW. It will be further de-rated to zero in 2007 but, like the 138 kV circuits to the Gulf Islands, will be kept operational as long as it is economic to do so (Exhibit B-3A, p. 9). BCTC recently submitted an application for a CPCN for the Vancouver Island Transmission Reinforcement ("VITR") project, which (if approved) will see the replacement of the existing 138 kV circuit with a new 230 kV circuit (Exhibit B-1, p. 52). The Commission approved VITR definition-phase expenditures for F2005 in Order No. G-03-04, and in this Application BCTC is seeking approval for additional expenditures to complete the definition-phase. The $5,182,000 requested by BCTC is to cover engineering studies, public consultation, the CPCN application and approval process, the environmental assessment process, and the United States permitting process (Exhibit B-1, p. 53).

In its final comments, IRAHVOL states its belief that BCTC has not allowed for effective public consultation and participation, has not responded satisfactorily to its requests and, by planning to submit an application for a CPCN unchanged from its original plans, appears to not have considered the compelling evidence submitted by IRAHVOL and other interveners during the 2005 capital plan proceedings. IRAHVOL therefore believes that the only way to see that efforts and public money are directed to the best option available is to ask the Commission not to approve funding to complete the definition phase for VITR. IRAHVOL further recommends that the Commission request BCTC to engage in a multi-stakeholder evaluation of alternatives using multiple account evaluation methods to address Vancouver Island's increased electricity requirements in a cost effective, reliable manner that satisfactorily addresses all stakeholders' needs (Exhibit C2-4, p. 2).

In its response to intervener comments (Exhibit B-11, pp. 10-11), BCTC states that it does not agree with IRAHVOL on a number of points. It further suggests that IRAHVOL's submissions are more properly dealt with in the context of the CPCN application for VITR. BCTC further states that, if definition-phase funding were to be denied, then BCTC, the Commission, and other regulatory authorities would be prevented from assessing VITR. BCTC also states that it should not carry significant OMA funding to undertake definition-phase work.

Commission Findings

The Commission Panel accepts BCTC's view that IRAHVOL's issues are more properly dealt with in the context of the CPCN application for VITR. The Commission Panel also accepts the view that definition-phase funding through the F2006 TSCP is necessary to properly assess the need for the VITR project and to select among alternatives. The Commission Panel is of the view that funding VITR definition-phase work through the F2006 TSCP provides for better management and public review of the costs than would funding through the OMA budget. **The Commission Panel therefore approves BCTC's request for definition-phase funding for VITR.**

The Commission Panel acknowledges that its treatment of definition-phase funding for VITR may be different from what might be expected given the concerns raised in Section 2.2. However, the VITR project is already at the CPCN stage, and it would make little sense to alter the treatment of that project now. Further, the Commission Panel notes that there may be inconsistencies in how projects are treated during the transition to the process(es) to be proposed by BCTC in accordance with the directives given in Section 2.2 (as ultimately approved by the Commission).

South Interior System

The South Interior bulk system consists of a network of 500 kV lines that deliver power from the Columbia and Kootenay area generating stations west to the central interior and east to Alberta. It also provides power to loads in the South Interior and transfers power to FortisBC. BCTC has proposed the following Growth Capital projects for the South Interior bulk transmission system:

Project	F2006/F2007 Costs	Transmission Capital Cost
5L91/5L98 Series Compensation (Definition Phase Only)	630,000	87,162,000
Ashton Creek Neutral Reactor & Surge Arrestor	551,000	551,000
Selkirk 500/230 kV Transformer Addition	14,628,000	14,628,000
5L71/5L72 Series Capacitors (Definition Phase Only)	219,000	35,726,000
Ashton Creek Capacitor Bank Addition	6,321,000	6,321,000
South Interior Total	22,349,000	144,388,000

BCTC proposes to undertake the definition-phase for adding three series capacitor stations—one each on 5L98, 5L96 (the eastern portion of 5L98 between Selkirk and Vaseux Lake Substations), and 5L91—as well as possible circuit breaker replacements at Selkirk and Ashton Creek substations. The series capacitors are required to accommodate the increased transfers from Selkirk to Nicola due to expected generation increases in the Selkirk area (BCUC IR 1.38.1), committed transfers from Alberta, and committed transfers through the eastern interconnection with the United States. The capacitors would also reduce the need for generation shedding in response to contingencies. BCTC stated that the current path transfer capacity is 1700 MW, and that it expects the total transfer on the path will reach 2150 MW in 2010. In its response to BCUC IR 2.105, BCTC provided graphs of the flows across 5L91 and 5L98 in 2002 and 2003 that showed that the path capacity had already been exceeded for a few hours.

BCTC has also proposed the addition of a 500/230 kV transformer at Selkirk as an alternative to the replacement of transformer T3, which was approved in BCTC's F2005 Capital Plan. BCTC proposed the change, which has an incremental cost of about $1.3 million, based on a recent determination that a fourth transformer can be accommodated in the substation. The revised project has the advantage of avoiding the possible requirement to replace T2 soon at the same cost as replacing T3 (Exhibit B-1, pp. 56-57). BCTC stated that, if the project does not proceed, increased restrictions on generation and/or imports will be required when one transformer is out of service, and generation shedding and transfer tripping of the eastern US-BC interconnection will be required to mitigate the impact of a possible contingency.

BCTC has proposed to carry out the definition-phase for a project to install series capacitors in 5L71 and 5L72 to increase the transfer capability of the 500 kV lines from Mica to Nicola. The key drivers for this project are the Mica G5 project (500 MW of additional generation) and the Mica G1 and G2 upgrade projects (130 MW of additional generation) which may come on line as early as F2012 in one of the NITS scenarios requested by

BC Hydro (Exhibit B-1, p. 57 and BCUC IR 1.34.3). The project will only proceed if the additions to Mica generation go ahead.

The F2006 TSCP contains a project for F2007 to add a 500 kV, 250 MVAr shunt capacitor bank at Ashton Creek to provide voltage support in the area and thus increase transfer limits through the Ashton Creek substation (Exhibit B-1, p. 58). In its response to BCUC IR 1.54.1, BCTC noted that there is some uncertainty associated with this project because its need is tied to the development of Revelstoke G5 and expected increased transfers from the Selkirk area. The need will most likely be established through the BC Hydro NITS studies. BCTC further stated that approval of definition-phase expenditures only would not impact the project's in-service date (BCUC IR 1.40.1).

BCTC proposed the Ashton Creek neutral reactor and surge arrestor addition for 5L91 single-pole reclosing to improve system reliability (Exhibit B-1, p. 55). It noted that the ability to use single-pole reclosing would reduce generation shedding in response to single line-to-ground faults (which constitute about 90 percent of the disturbances) and allow the faulted phase to be recovered more quickly. Further, if 5L98 or 5L96 is out of service, single-pole reclosing on 5L91 will reduce the chance of islanding for faults on 5L91.

Commission Findings

The Commission Panel acknowledges BCTC's statements that expected increases in generation in the Selkirk area, committed transfers from Alberta, and committed transfers through the eastern interconnection will increase flows on the Selkirk to Nicola path. However, in response to a Commission Panel request to provide forecast path flows for the first and fifth years in which the path capacity is at its proposed new value of 2300 MW, BCTC replied that the path flows are mostly generation dependent and therefore cannot be predicted (BCUC IR 2.105.3). Further, while the charts provided in response to BCUC IR 2.105.2 showed that path flows exceeded path capacity in a small number of hours, there was no explanation of the circumstances that precipitated the excesses. The graphs also showed that path flows were well under path capacity in most hours.

The Commission Panel notes that there are important links between the South Interior capital projects. These links are evident in both the project descriptions and in the "Related/Dependent Projects" lists provided in the F2006 TSCP. However, it is not clear how these projects depend on each other. For example, it is unclear whether the generation shedding that will be reduced by enabling single-pole reclosing on 5L91 and adding the Selkirk 500/230 kV transformer is the same generation shedding that BCTC hopes to reduce by adding 5L91/5L98 series capacitors. The extent of generation shedding, both before and after single-pole reclosing on 5L91, is not specified. Further, the nature of the relationship noted by BCTC (Exhibit B-1, p. 58) between the

5L71/5L72 series capacitors, which are driven by the G1, G2, and G5 projects at Mica, and the Ashton Creek shunt capacitors is unclear. With respect to the capacity of the Selkirk-to-Nicola path, it is not clear from the F2006 TSCP whether the binding constraint is transformer capacity at Selkirk, the thermal capacity of the lines themselves, voltage stability limits, or some other factor.

The Commission Panel is unclear about several other aspects of the capital plan for the South Interior system as well. For example, BCTC stated that the 500/230 kV transformer (T4) addition at Selkirk is being driven by the generation increase in the area (Exhibit B-1, p. 56). However, BCTC also noted that this project is in lieu of the T3 replacement project proposed and approved in BCTC's F2005 Capital Plan, the justification for which was that "The increased transformation capability will reduce generation shedding to acceptable levels for first contingency loss of a transformer" (F2005 Capital Plan [May 31, 2004], p. 108). Consequently, it is not clear whether the primary driver of the T4 addition is increased generation or a desire to reduce generation shedding. Further, BCTC notes that, in the absence of the Selkirk transformer addition, some restrictions will be imposed on generation and imports when one Selkirk transformer is out of service. However, there are no data that would indicate the expected magnitude or frequency of such restrictions or the change in the probability thereof on going from three transformers to four. A significant difference of about 1000 MW exists in the 2014/15 timeframe between the resources being planned for (identified as the Base Case Resource Alternative on page 5 of the System Impact Study attached to BCUC IR 1.19.1) and those being invested in (as identified in Chart 2-6 on page 2-26 of BC Hydro's F2005 Resource Expenditure and Acquisition Plan). If the South Interior projects are being driven by additional generation, the Commission Panel is concerned that this may not be supported by BC Hydro's resource plans. Finally, in its System Impact Study for BC Hydro Distribution, NITS 2004 Stage 1, BCTC notes that some South Interior reinforcements can be deferred by reducing the South Interior East resource dispatch (p. 95 in Appendix 12 of the second attachment to BCUC IR 1.19.1), but provides no evaluation of this option.

In the Commission Panel's view, the foregoing paragraphs highlight the significance of the findings in Section 2.1 that BCTC has not provided the Commission and interested parties with an adequate understanding of the constraints, solution options, and timing requirements for the proposed Growth Capital projects on the South Interior bulk transmission system. The Commission Panel notes that BCTC has only applied for definition-phase funding for some of the projects but, as discussed in Section 2.2 above, such funding is for projects for which a need has already been established. **The Commission Panel therefore denies BCTC's application for approval of the Growth Capital projects on the South Interior bulk transmission system. Instead, the Commission Panel directs BCTC to submit, at the time of its next capital plan, or sooner should it so wish, a comprehensive System Development Plan ("SDP") for the South Interior bulk transmission system. The**

SDP must address the issues noted by the Commission Panel in this section and Section 2.1, and must clearly illustrate the relationship between the proposed Growth Capital projects.

With respect to BCTC's proposal to add T4 at Selkirk instead of replacing T3 as previously approved, the Commission Panel notes that the T3 replacement project was justified in the F2005 Capital Plan based on a reduction in generation shedding. No association between the T3 replacement and a requirement for additional Selkirk-to-Nicola transmission capacity was noted. In addition, the TSCP has raised the issue of the timing of the Commission's approval of need relative to the definition phase. Consequently, the Commission Panel expects that the T4 project will not proceed until the need can be confirmed through the SDP.

Remedial Action Schemes

BCTC proposes a RAS to deal with multiple contingencies on 2L288, 2L295, and 2L299 that will initiate actions (including shedding generation at Kootenay Canal and the FortisBC area plants) to prevent transient instability and severe overloading problems. The lines are in an area where lightning is frequent (Exhibit B-1, p. 60). An event in May 2004, caused by the near-simultaneous tripping of all three lines, resulted in severe over-frequency, generation shedding, and loss of load (BCUC IR 1.41).

In its Application, BCTC requested approval of a project to implement as-yet-unidentified RAS through F2015, though specific approval is sought only $500,000 in each of F2006 and F2007. BCTC states that RAS can be implemented much more quickly and at lower cost than other alternatives, and so are ideal for mitigating the effects of HILP events and increasing transfer capabilities (Exhibit B-1, p. 61). HILP events can occur at any time, revealing previously unknown weaknesses in the transmission system.

Commission Findings

In the Commission Panel's view, the advisability of the multiple-contingency RAS is clear; the project is therefore approved. The Commission Panel also accepts BCTC's view that RAS may be the appropriate solution to certain system problems, and therefore approves the Unidentified RAS Additions project for F2006 and F2007. The Commission Panel expects that actual expenditures on this project will be reported in BCTC's next capital plan application.

5.1.4 Area Reinforcements

As noted in Section 4.2, the regional transmission systems consist of portions of the 230 kV system and all of the 138 kV and 69 kV facilities. There are four main regional systems (Vancouver Island [VI], Lower Mainland [LM], Northern [N], and Southern Interior [SI]), each of which is divided into smaller geographic areas for planning purposes. Regional projects are needed mainly to ensure that the transmission system can supply the forecasted local load in an area (Exhibit B-1, p. 62). Typical regional projects consist of area reinforcements such as raising conductor height to increase transfer capacity and station expansions/modifications such as adding transformer capacity. This section deals with the area reinforcements; station expansions and modifications are dealt with in the next.

BCTC has proposed the following area reinforcements:

Project	**Region**	**Transmission Capital Cost**	*** Total Capital Cost**
Area Planning Definition Work		** 600,000	** 3,000,000
60L300 (Soda Creek to Mount Polley)	N	164,000	164,000
Fort St. John – Fox Creek Substation	N	12,590,000	17,986,000
Salmon Arm Substation – 230/138 kV Transformer	SI	5,358,000	5,358,000
Langley Area Reinforcement – Harvie Road Sub.	LM	19,802,000	28,289,000
Maple Ridge Area – Haney Substation	LM	4,271,000	14,238,000
Mission and Matsqui Area Supply	LM	30,244,000	43,205,000
Whistler Village Reinforcement – Function Junction	LM	5,462,000	13,655,000
3L3 (Wahleach to Rosedale) 230 kV Conversion	LM	6,321,000	6,321,000
60L101 (McLellan to Nikomekl) – New 69 kV Line	LM	4,946,000	4,946,000
60L43/44 (Richmond) – Undergrounding	LM	2,000,000	2,000,000
Rainbow Substation – 2L2 Loop-in	LM	1,437,000	1,437,000
Goward Substation – 230/138 kV Transformer	VI	5,539,000	5,539,000
Area Reinforcements Total		98,134,000	143,138,000

* The Total Capital Cost includes the cost of Substation Distribution Assets.

** This work is estimated to cost $300,000 per year for ten years for a total of $3,000,000. BCTC is seeking approval of the costs for F2006 and F2007, so the approval amount is $600,000.

In addition to the projects shown in the above table, BCTC noted the Metro 230 kV Supply (Sperling to Cathedral Square) 230 kV Cable Circuit 2L43; it will seek a CPCN for the project and is therefore not applying for any approval as part of this F2006 TSCP. The estimated cost of the 2L43 project is $38,029,000.

Among the future projects noted by BCTC is the East Kootenay 230 kV Reinforcement Project, a second 230 kV line from Cranbrook Substation to Invermere Substation to be in service by late fall 2011. The projected start date is F2008. BCTC notes that load growth in the Upper Columbia Valley has exceeded the supply capability of the Cranbrook-Invermere-Golden 69 kV transmission system for many years, and during outages on 2L258 (Cranbrook-Invermere), the system load between Invermere and Golden must be shed to prevent a collapse of the underlying 69 kV system. BCTC will undertake a cost/benefit study to determine the feasibility and staging for the implementation of this project.

BCTC has proposed the addition of a 230/138 kV transformer at Goward Substation (Exhibit B-1, p. 75). BCTC indicated, however, that there are several alternatives to the transformer and that these alternatives are still under consideration. BCTC is seeking approval of this F2007 project, under the assumption that the transformer option will be confirmed as the best one through the upcoming area study, so that work can proceed to implementation early in F2007 (BCUC IR 1.48).

In response to BCUC IR 1.44, BCTC clarified that the $300,000 per year for ten years under the Area Planning Definition Work project is intended to cover the relatively smaller growth reinforcement projects for all areas of the province that are identified between the completion of one capital plan and the preparation of the next. The definition-phase for a project includes system planning and engineering design work to identify the project objectives, scope, schedule, cost, and project plan. In BCTC's view, such expenses are more properly allocated to capital than to OMA, the latter being used for general planning work that identifies which projects should proceed to the definition phase.

IRAHVOL was the only intervener to comment on any of the Area Reinforcement projects. It states that the Goward transformer should not be approved because it may become unnecessary or may be deferred with the installation of an HVDC Light® system for VITR. IRAHVOL also lists the Unidentified Future Area Reinforcements project as one that may be affected by the HVDC Light® option (Exhibit C2-4, p. 3).

Commission Findings

The Commission Panel notes that the East Kootenay 230 kV project is only being investigated at this stage, and that BCTC is not seeking its approval. **However, given the projected cost, geographic extent, environmental**

issues, and range of customers affected, the Commission Panel directs that BCTC submit a CPCN application for the East Kootenay project should BCTC decide to proceed.

The Commission Panel notes that the Goward project is in response to increasing load, which will exceed the capacity of the 138 kV system south of Vancouver Island Terminal by 2008/09 (Exhibit B-1, p. 74). The Commission Panel therefore does not accept IRAHVOL's argument that the project may not be required if HVDC Light® is used for VITR. As noted above, the Commission Panel accepts BCTC's statement that none of the projects for which approval is sought would be made unnecessary or could be deferred by the HVDC Light® option (Exhibit B-11, p. 12). **The Commission Panel therefore accepts BCTC's recommendation that the Goward project be approved under the assumption that the proposed 230/138 kV transformer is the best option, and expects that BCTC will make a new application to the Commission if an alternate solution is selected.** With respect to the Unidentified Future Area Reinforcements, the Commission Panel notes that it is not possible at this time to determine whether individual future projects would or would not be affected by the choice of VITR technology. In any event, the first expenditures would not occur until F2009, by which time the technology issue will have been decided. The Commission Panel also notes that BCTC is seeking approval for only F2006 and F2007 projects at this time.

As described in Section 2.2, the Commission Panel is concerned that some of the work associated with the definition-phase of a project should be carried out only after the Commission has approved the need for that project. Consequently, some of the definition-phase activities that BCTC suggests are necessary on as-yet-unidentified area reinforcement projects may more properly be associated with the planning phase and treated as OMA expenses rather than capital expenses. **Notwithstanding that view, the Commission Panel does not wish to prevent BCTC from carrying out necessary work on area reinforcements, and therefore grants approval for the Area Planning Definition Work for F2006 only. For F2007 and beyond, area planning activities should be treated in accordance with the process(es) that BCTC proposes (and that the Commission ultimately approves) in response to the directives given in Section 2.2.**

The Commission Panel notes that no interveners commented on the other Area Reinforcement projects. **Having reviewed BCTC's F2006 TSCP and the further evidence provided through the information requests, the Commission Panel is satisfied that those projects are in the public interest, and therefore approves them.**

5.1.5 Station Expansions and Modifications

BCTC stated that station expansions and modifications include transformer additions and replacements, switchgear replacements, bus work, and voltage conversions at distribution substations and system switching stations. Transformer additions and replacements are required when the load is forecast to exceed the existing transformer capacity, that capacity being established as described in BCUC IR 1.45.3 and 1.45.4. Feeder section additions allow for the construction of more feeder positions to serve the local distribution load when there is no more room on existing feeder sections at the substation. Switchgear additions are required for reliable and secure operation, while voltage conversions enhance distribution efficiency and power quality. Generally, transmission-related expenditures associated with these projects consist of changes or additions to the transmission system to accommodate the distribution-level changes (Exhibit B-1, p. 79).

BCTC has proposed the following station expansions and modifications:

Project	Region	Transmission Capital Cost	Total Capital Cost
Fort St. James – Mobile Transformer Connection	N	55,000	549,000
Seventy Mile House – 69/25 kV Tr. Replacement	N	121,000	1,205,000
Winsor – 69/12 kV Transformer Replacement	SI	121,000	1,212,000
Annacis Island Substation – 69/12 kV Transformer	LM	302,000	3,016,000
Cambie Substation – 230/25 kV Transformer	LM	1,083,000	7,222,000
Cathedral Square – 230/12 kV Transformer	LM	1,455,000	7,275,000
Cheekeye – 60/24 kV Transformer & Feeder Position	LM	134,000	2,674,000
Horne Payne – 230/12 kV Transformer (Defn Phase)	LM	* 506,000	4,351,000
Lougheed Substation – 12 kV Breaker Replacements	LM	77,000	765,000
Mainwaring – 230/12 kV T2 Replacement	LM	534,000	5,338,000
Mission Substation – Equipment Upgrade	LM	478,000	371,000
Mission Substation – Monitoring Equipment	LM	371,000	371,000
Squamish – 69/25 kV Transformer Addition	LM	257,000	2,568,000
Como Lake – 25 kV Feeder Section Addition	LM	2,007,000	6,690,000
Station Expansion and Modifications Total		3,724,000	43,607,000

* The amount given here is for the definition phase; the project total is $870,000.

In addition to the above projects, BCTC noted the requirement to add a new feeder section and replace the existing 230/12 kV, 84 MVA transformer (T1) at Mainwaring Substation in metro Vancouver in 2006. Pursuant to Commission direction at page 31 of the F2005 Reasons for Decision, BCTC will apply for a CPCN before proceeding with this project. Consequently, BCTC is not applying for any approvals associated with this project as part of this F2006 TSCP (Exhibit B-1, p. 86).

The only intervener to comment on station expansions and modifications was IRAHVOL. As with other capital projects, IRAHVOL submits that certain station expansion/modification projects may become unnecessary or may be deferred by an HVDC Light® VITR (Exhibit C2-4, p. 2). In its view, the affected projects could include the Colwood 138/25 kV Transformer ($1 million), Unidentified Future Station Expansions and Modifications ($9 million), and Unidentified Future Transformers ($15 million).

Commission Findings

The Commission Panel notes that BCTC is seeking definition-phase only approval for the Horne Payne 230/12 kV transformer replacement. It appears to the Commission Panel that the work involved—examining the option of transferring load between substations—is more properly part of the planning phase. However, to avoid potentially delaying implementation beyond the required in-service date of September 2007, the Commission Panel approves the definition-phase expenditures. The Commission Panel directs BCTC to consider and report on the appropriate treatment of this project when complying with the directives in Section 2.2.

Because all of the projects cited by IRAHVOL will start after the technology choice for VITR has been made, and because BCTC is not seeking approval for them in this F2006 TSCP, the Commission Panel sees no reason to provide a decision on them at this time. **Based on its review of the Application and BCTC's responses to information requests, the Commission Panel approves the other substation expansion and modification projects as submitted.**

5.2 Sustaining Capital Portfolio

BCTC's Sustaining Capital Portfolio is comprised of the investments required to sustain the current and future performance capability of the transmission system, to meet customer and system requirements, and to meet industry reliability standards. These investments extend the useful life of an asset, replace an asset at the end of its useful life, or reduce the risk of asset failures or other operational problems (Exhibit B-1, p. 104). The Sustaining Capital Portfolio is divided into the following asset groups (Exhibit B-1, p. 106):

- Stations
- Protection and Control
- Telecommunications
- Underground and Submarine Cables
- Overhead Lines.

Each asset group is intended to contain a particular population of assets that can be judged as a group against criteria such as importance to operations, inherent ageing processes, geography, environment, and other factors. The assets within each asset group are further separated into equipment types in order to develop specific life-cycle plans and strategies for a particular equipment type (BCUC IR 1.61.1).

5.2.1 General

There are five key drivers of the Sustaining Capital Portfolio (Exhibit B-1, p. 24):

- Equipment end-of-life issues;
- Equipment maintainability and availability (operability);
- Equipment security and exposure to hazards;
- Obsolescence and original equipment manufacturer ("OEM") support; and,
- Legislative and regulatory compliance.

The Sustaining Capital Portfolio is characterized by four program elements (Exhibit B-1, p. 24):

- Safety – investments based on the mitigation of safety hazards to the public, employees, or contractors
- Mandatory – the minimum investments BCTC believes are necessary to keep the electric system operational in the short term
- Legal and Regulatory – investments required by statutes, contracts, licences, standards, and regulators
- Discretionary

There is also a prioritization process for each proposed investment program using a combination of the following deterministic and risk-based criteria (Exhibit B-1, pp. 26-32):

- Environmental factors (including regulatory, environmental and safety);
- Impact on reliability;
- Asset condition and sustainability;
- Financial impact; and,
- Societal and consent-to-operate implications.

Within each program, there is a further level of prioritization that categorizes individual projects into High, Medium and Low categories based on criticality, outage scheduling, and other factors. These internal program prioritizations are not comparable amongst different programs since they are done relative to the projects within the program (Exhibit B-1, p. 32).

In its final submission, the CEC observed that, although there is a significant increase in spending levels for the Sustaining Capital Portfolio over past levels of expenditure (Exhibit C9-2, p. 6), the overall Sustaining Capital program should be approved (Exhibit C9-2, p. 4). The CEC also acknowledged and commended the significant efforts by BCTC to extend asset life beyond manufacturers' conservative estimates (Exhibit C9-2, p. 6). However, the CEC also recommended that the Commission require that, prior to any revenue requirements process, BCTC make a scheduling adjustment to reflect past experience with project deferrals and/or expenditure levelizing (Exhibit C9-2, p. 6). In its final submission, BCTC submitted that this issue would best be dealt with during future revenue requirements processes (Exhibit B-11, p. 8), and that CEC's requested direction in this regard was not necessary because revenue requirement applications use the most up-to-date information available. Beyond CEC's observations, there were no other intervener comments regarding the Sustaining Capital program.

Commission Findings

The Commission Panel is concerned that pressure from multiple sources is acting to raise rates. One of these sources is the Sustaining Capital Portfolio. The Commission Panel has sought to identify correlations between large increases in various programs and the key drivers that support these large increases. By examining thresholds within the key drivers, the Commission Panel seeks to adjust the evaluative guidelines that define the overall size of the Sustaining Capital Portfolio without interfering with BCTC's expert judgement in prioritizing the projects within the individual programs. The Commission Panel's objective is to provide BCTC with sufficient evaluative guidelines to achieve reductions in the F2006 and F2007 Sustaining Capital Portfolio and to sustain those reductions in the forecast budgets for future years.

The Commission Panel expects that future revenue requirements applications will contain the best available information of the pattern and amount of expenditures. Specifically, where the information in such future applications is different than the forecasts supplied in this Application, the Commission Panel expects BCTC will provide commentary as to the source of the differences. The Commission Panel directs BCTC to report future Sustaining Capital Portfolios in a manner that preserves the ability to track and

trend annual Sustaining Capital spending as far back as F2001, and facilitates comparisons and identification of trends in spending for individual Sustaining Capital Programs.

5.2.2 Key Drivers

The following five key drivers for the Sustaining Capital Portfolio are discussed: equipment end-of-life; equipment maintainability and availability (operability); obsolescence and OEM support; equipment security and exposure to hazards; and legislative, regulatory, and contractual obligations (Exhibit B-1, pp. 104-105).

Equipment End-of-Life

BCTC states that most of the existing transmission assets were installed from the 1940s through the 1980s, and proposes that as these assets approach their end-of-life, they require increased maintenance and capital investment to continue to provide reliable transmission service. While age is an end-of-life factor, it is a better indicator of the general condition of a class of assets than of the condition of an individual asset (BCUC IR 2.156.1).

Equipment Operability

In some cases, equipment becomes unable to reliably perform its function to acceptable performance standards. This can be due to design problems, changed usage patterns, changes to other parts of the transmission system, or premature wear-out. In most instances, the equipment must be replaced to maintain the reliability of the system.

Obsolescence and Original Equipment Manufacturer ("OEM") Support

BCTC claims that equipment obsolescence and lack of OEM support (in terms of replacement parts and, in some cases, expertise) can make maintaining certain equipment impractical. Although the equipment may be in fair or good condition, the lack of replacement parts, either in stock or from suppliers, makes repair very expensive or even impossible. BCTC attempts to mitigate issues such as access to spare parts by cannibalizing equipment taken out of service to support similar equipment still in service (BCUC IR 1.122.1; BCUC IR 1.165.1).

Equipment Security and Exposure to Hazards

The transmission system is exposed to risks such as ice storms, fire, earthquakes, and weather-related events such as windstorms or lightning. Each of these risks is analysed based on the probability of the event and the expected impact. Risks are then prioritized based on the magnitude of the consequences. BCTC has ongoing risk management programs to address each of these hazards and thereby reduce retained risk (Exhibit B-3A, STSR, p. 17).

Legislative, Regulatory, and Contractual Obligations

BCTC's mandate is described in the Transmission Corporation Act and is subject to the terms of the Designated Agreements between BCTC and BC Hydro. In addition to operating under the jurisdiction of the BCUC, BCTC must also comply with requirements arising from statute, agreements and contracts, provisions in Right-of-Way or licence-of-occupation agreements, Workers' Compensation Board safety directives, public safety standards and regulations, the British Columbia and Canadian Electrical Codes, federal and provincial environmental legislation, and the WECC.

Commission Findings

In addition to recognized safety and environmental hazards, the operability of equipment is, and undoubtedly should be, a key driver of sustaining capital investments. The Commission Panel extends this interpretation of equipment operability to also address the identification of specific pieces and classes of equipment that have disproportionately degraded the reliability indices. There are several instances of insufficient data to evaluate the contribution of individual assets to reliability indices (BCUC IR 2.135.1; BCUC IR 2.135.2; BCUC IR 2.173.1; BCUC IR 2.178.2). **The Commission Panel expects BCTC to collect sufficient data to allow the identification of the worst performing asset classes by quantification of the effect of equipment failures on the reliability indices, and to present this data in support of future sustaining capital plans and programs. The Commission Panel reaffirms the following direction from Order G-103-04:**

> **The Commission therefore directs BCTC to provide, in future Capital Plans, a classification of transmission failures by equipment type and age, as well as an indication of the impact of transmission failures on reliability indices. Statistics should be included for as many years in the past as are reasonably available in order that trends may be observed. Should the requested statistics not exist, BCTC is to file a plan for collecting the necessary data in the future.**

The Commission Panel finds that equipment age is not a suitable indicator of end-of-life. In the absence of quantitative evidence demonstrating that maintenance and capital investment are no longer cost-effective means of continuing reliable operation, programs based solely on equipment age represent opportunities for reduced expenditures. Similarly, programs focused on the wholesale replacement of obsolete equipment may not always be structured in the most cost-effective manner. Equipment that is functioning acceptably may be replaced within the scope of a larger program when it may have been more cost effective to maintain that equipment with spare parts from equipment removed from service. The Commission Panel commends BCTC on the instances where such maintenance has already occurred. Furthermore, towards the objective of reducing the rate increase associated with the rapid rise in the overall Sustaining Capital Portfolio, the Commission Panel encourages the consideration of this practice as an option in the economic evaluation of alternatives for the obsolescence-driven programs.

The Commission Panel recognizes that higher expectations of conformance to various accepted standards and practices, or higher performance criteria within those accepted standards and practices, exist today than may have existed in the past. This is particularly true in the case of seismic and weather-related events (for instance, ice storms). Nevertheless, the Commission Panel expects that the inherent N-1 capability embedded within the transmission system by virtue of the NERC/WECC Planning Standards would address many instances of seismic or weather-induced failures. Consequently, in the absence of direct safety-related consequences to the public and workers, a reduced and prolonged capital expenditure profile within seismic enhancement and weather-effect reinforcement projects should be considered.

As described in Section 3.2, the NERC/WECC Planning Standards appear to have some flexibility for interpretation and application, especially with respect to system performance impacts that can remain confined to one's own system and are not on the WECC-rated bulk transmission facilities. **Again, with the objective of reducing the rate increase associated with the rapid rise in the overall Sustaining Capital Portfolio, the Commission Panel encourages the use of this flexibility to defer or eliminate the need for projects driven by a conservative application of the standards.**

5.2.3 Protection and Control Sustaining Capital Programs

BCTC has proposed the following Sustaining Capital Projects for approval within the protection and control asset class.

Programs for Approval	F2006/F2007 Costs	Transmission Capital Cost
Station Protection and Control	5,260,000	32,460,000
P&C Stations SCADA RTU Program	1,580,000	10,380,000
P&C Line Protection Program	3,869,000	44,569,000
P&C Minor Capital and Emergency Replacements Program	196,000	996,000
New Protection and Control Subtotal	10,905,000	88,405,000

Commission Findings

The Commission Panel notes a significant increase in the Station Protection and Control ("P&C") Program (BCUC IR 1.59.4) compared to the average level of expenditure over the past five years. This recurring program is driven by equipment operability and obsolescence (the equipment is described as "functional but obsolete" and past end-of-life expectancy [Exhibit B-1, p. 108]), but there is insufficient data correlated to reliability indices to support operability claims (BCUC IR 2.135.1; BCUC IR 2.135.2; BCUC IR 2.173.1). With no further support for the end-of-life economic evaluation, and significant proposed and future expenditures, this program may represent an opportunity for substantial expenditure reductions when taken in the context of the priority of other Sustaining Capital expenditures and the objective to reduce overall spending. The Commission Panel makes a similar observation for the P&C Line Protection Program, which appears to be a significant new long-term program driven by equipment operability and obsolescence criteria.

There is a further expenditure of $14,213,000 in F2006 and F2007 in programs for which approval is not being sought that may be reducible if the programs are re-evaluated against re-defined key drivers as suggested in Section 5.2.2. Specifically, the $5,082,000 of F2006 and F2007 expenditures in the Line Protection Replacement under the 500 kV – Stage 6 project may be capable of being reduced or extended.

Based on the foregoing discussion, the Commission Panel directs BCTC to implement reductions in F2006 and F2007 of $2,000,000 and $3,500,000, respectively, in the Protection and Control Sustaining Capital Programs.

5.2.4 Stations Sustaining Capital Programs

BCTC has proposed the following Sustaining Capital Projects for approval within the stations asset class.

Programs for Approval	F2006/F2007 Costs	Transmission Capital Cost
Williston - Emergency Replacement of 5CB2681	28,000	681,000
Williston - Emergency Replacement of 5CB5672	11,000	672,000
Switching Equipment Program	19,371,000	163,751,000
Surge Arrestors Program	5,076,000	14,680,000
Station Auxiliary Equipment Program	5,148,000	28,815,000
Reactive Equipment Program	530,000	41,033,000
Spill Containment Program	1,139,000	9,215,000
Fire Protection Program	1,000,000	17,000,000
Station Security Program	740,000	7,740,000
Stations Corrosion Protection Program	1,461,000	21,491,000
Stations Seismic Upgrades Program (plus F2008)	161,000	7,853,000
Stations Minor Capital Program	1,558,000	7,918,000
New Stations Projects Subtotal	36,223,000	320,849,000

Commission Findings

The majority of the individual projects listed above are driven by equipment operability or legislative concerns. However, the program that represents over 50 percent of the proposed spending in F2006 and F2007, the Switching Equipment Program, is also significantly driven by equipment end-of-life and obsolescence criteria (Exhibit B-1, p. 116). The Commission Panel commends BCTC on the efforts it has made to extend the useful life of existing equipment by utilizing spare components from salvaged equipment (BCUC IR 1.122.1; BCUC IR 1.165.1). The Commission Panel encourages BCTC to seek further opportunities to reduce the immediate and long-term costs of this program by prolonging the service life of the installed equipment instead of completely replacing a given population. The Commission Panel expects that future capital plans will contain economic evaluations that compare increased and extended maintenance against equipment replacement for such large programs.

The remainder of the proposed F2006 and F2007 expenditures in the stations asset class amounts to $27,957,000. The Stations Seismic Upgrades – Phase 5 project appears to be particularly long-running, with expenditures forecast to at least F2015. This project has base costs of $1,000,000 per year to F2008, with a related further expenditure for Murrin curtain wall seismic upgrades of $7,662,000 in F2008 being proposed for approval (Exhibit B-1, p. 122). These projects should be reviewed to ensure that the upgrades (as opposed to new installations) are being driven by public and personnel safety concerns. Equipment reliability concerns should be captured within the inherent N-1 capability of the system.

Based on the foregoing discussion, the Commission Panel directs BCTC to implement reductions in F2006 and F2007 of $2,500,000 and $4,500,000 respectively, in the Stations Sustaining Capital Programs.

5.2.5 Telecommunications Sustaining Capital Programs

BCTC has proposed the following Sustaining Capital Projects for approval within the telecommunications asset class.

Programs for Approval	F2006/F2007 Costs	Transmission Capital Cost
Power Line Carrier Program	6,821,000	15,321,000
Microwave Replacements	1,510,000	1,864,000
Unidentified Future Optical Fibre	500,000	4,500,000
Unidentified Telecom Upgrades	3,001,000	35,801,000
Telecom Minor Capital	552,000	2,933,000
New Telecommunications Projects Subtotal	12,384,000	60,419,000

Commission Findings

The Power Line Carrier ("PLC") Program is being driven by equipment operability and equipment end-of-life concerns. The older PLC equipment is still in service, and is described as functional but obsolete (Exhibit B-1, p. 125). The available data is not in a format that allows an assessment of how PLC operation is affecting reliability indices (Exhibit B-1, BCUC IR 2.178.2). However, the available data does show a downward trend in the number of failures of PLC equipment (Exhibit B-1, BCUC IR 1.70.2). This program should be reviewed for expenditure reductions based on this information.

The Unidentified Telecom Upgrades Program carries the lowest priority rating of the telecommunications programs for which approval is being sought (Exhibit B-1, p. 125). The undefined scope of these upgrades, coupled with the relatively low priority ranking, suggests that expenditures within this program could be reduced upon re-evaluation against the key drivers. The Commission Panel notes a significant increase in future costs for this program, and expects comprehensive economic evaluations of alternatives in future capital plans.

The remainder of the proposed F2006 and F2007 expenditures in the telecommunications asset class amounts to $10,062,000. Two large expenditures account for almost 75 percent of this amount. The Microwave Replacement Project is nearing completion with only the Peace-Skeena systems still to be replaced at a projected cost of $2,976,000. This overall investment of $21,768,000 has seen the replacement of soon-to-be incompliant analog microwave equipment with new digital microwave equipment across the entire transmission system (Exhibit B-1, p. 124). The Lower Mainland Network Robustness project is the other large F2006/F2007 expenditure with $4,500,000 projected in F2007.

Based on the cost reduction opportunities identified above, the Commission Panel directs BCTC to implement reductions in F2006 and F2007 of $1,000,000 and $2,500,000, respectively, in the Telecommunications Sustaining Capital programs.

5.2.6 Underground and Submarine Cables Sustaining Capital Programs

BCTC has proposed the following Sustaining Capital Projects for approval within the underground and submarine cables asset class.

Programs for Approval	F2006/F2007 Costs	Transmission Capital Cost
Cable Life Extension and Rating Restoration Program	5,300,000	37,410,000
Cable Reliability Improvements (Future)	0	12,000,000
New Underground and Submarine Cables Projects Subtotal	5,300,000	49,410,000

Commission Findings

The Commission Panel recognizes the importance of the Cable Life Extension program and the relatively high cost of failure-induced repairs as compared to the costs of corrective and preventative maintenance. In addition to the costs put forward for approval above, there are further expenditures of $7,290,000 in F2006/F2007 for projects in progress within this asset class. BCTC is commended on its management of these assets, and the Commission Panel encourages further work to maximize the utilization and life expectancy of these assets.

5.2.7 Overhead Lines and Rights of Way Sustaining Capital Programs

BCTC has proposed the following Sustaining Capital Projects for approval within the overhead lines and rights of way asset classes.

Programs for Approval	F2006/F2007 Costs	Transmission Capital Cost
Civil Protective Works Program	3,731,000	15,799,000
Highway Transmission Line Relocation Program	1,300,000	7,700,000
Transmission Recurring Capital	8,350,000	18,450,000
Overhead Life Extension Program	15,150,000	111,150,000
Overhead Reliability Improvement Program	2,550,000	13,250,000
Overhead Rating Restoration Program	4,343,000	39,206,000
Overhead Line Corrosion Protection Program	4,785,000	24,815,000
Overhead Lines Seismic Withstand Program	1,250,000	6,250,000
Overhead Lines Wind and Ice Withstand Program	1,250,000	20,000,000
Deficient Rights Study and Acquisition Program	6,000,000	17,000,000
Miscellaneous Rights Acquisition Program	2,000,000	8,000,000
Access and ROW Improvements	2,230,000	10,230,000
New Overhead Lines and Rights of Way Projects Subtotal	52,939,000	291,850,000

Commission Findings

The Commission Panel notes a large increase in the Overhead Life Extension Program, especially beyond F2006/F2007, compared to expenditures in the past five years (BCUC IR 1.59.4). The previous two years' expenditures of $6,600,000 in F2004 and $10,500,000 in F2005 include costs of $12,400,000 for COB related projects, which would have left approximately $2,350,000 per year for other Overhead Life Extension activities. The justification of ramping up this expenditure to an average of $7,575,000 per year in F2006/F2007 and over $12,500,000 after that has not been supplied, and lower expenditures may be prudent until investment increases can be justified by decreasing trends in either overall asset base health or reliability indices. There are several new programs, such as the Overhead Line Seismic Withstand Program and the Overhead Lines Wind and Ice Withstand Program that, although not large compared to the overall budget, contribute to the overall large increase of the Sustaining Capital Portfolio over previous years. The negative consequences associated with low-probability natural physical events may be better absorbed within the inherent N-1 design capability of the system, rather than intensively upgrading all components to present-day standards.

The Commission Panel also notes a sizeable increase in right-of-way-related expenditures and a significant cost and low priority associated with the Deficient Rights Study and Acquisition Program (Exhibit B-1, p. 137). Again, with the upward pressure on the overall Sustaining Capital Portfolio from higher-priority programs, the overall schedule of this program should be reviewed to help level out long-term effects.

The remainder of the proposed F2006 and F2007 expenditures in the overhead lines and rights of way asset classes amounts to $17,706,000. The COB Clamp-top Insulator Replacements and COB Suspension Insulator Replacements Programs account for $11,000,000 of this remainder. The Commission Panel notes that the completion estimate for these Programs will be $9,000,000, or almost 60 percent over their initially approved budgets (BCUC IR 2.113.1). There is a balance to be struck between risk and cost that should be reviewed for these programs.

Based on the foregoing discussion, the Commission Panel directs BCTC to implement reductions in F2006 and F2007 of $3,500,000 and $4,500,000, respectively, in the Overhead Lines and Rights of Way Sustaining Capital Programs.

5.2.8 Summary

The Commission Panel remains concerned about the overall rate increases associated with this Application. An increase in the Sustaining Capital Portfolio is contributing to the overall rate increase. The Sustaining Capital Portfolio is underpinned by the application of the five key driver criteria to the issues confronting the transmission asset base. It is not known whether the increase in the Sustaining Capital Portfolio is attributable to changes within the key driver criteria themselves, or whether the key driver criteria are unchanged, but are being applied with greater rigour. Whichever is true, the resulting Sustaining Capital Portfolio increase is seemingly not being driven by BCTC's primary reliability indicator, which is SAIDI (BCUC IR 1.28.1). The SAIDI reliability index appears to trending slightly downwards (BCUC IR 2.115.2), and the five-year average of 2.08 hours is below the F2006 target of 2.1 hours (BCUC IR 1.28.1). The evidence is not compelling for an increase in the Sustaining Capital Portfolio at this time.

Based upon the discussion above addressing each category of the Sustaining Capital Portfolio, the Commission Panel directs BCTC to implement the following reductions:

- **For the Protection and Control Sustaining Capital Programs, reductions in F2006 and F2007 of $2,000,000 and $3,500,000 respectively,**
- **For the Stations Sustaining Capital Programs, reductions in F2006 and F2007 of $2,500,000 and $4,500,000 respectively,**
- **For the Telecommunications Sustaining Capital Programs, reductions in F2006 and F2007 of $1,000,000 and $2,500,000 respectively,**
- **For the Overhead Lines and Rights of Way Sustaining Capital Programs, reductions in F2006 and F2007 of $3,500,000 and $4,500,000 respectively.**

The Commission Panel suggests that BCTC re-evaluate the key driver criteria in order to yield an on-going lower level of sustaining capital expenditures. The Commission Panel anticipates that the reductions of approximately 10 percent in the F2006 and 15 percent in the F2007 Sustaining Capital Portfolios directed above are sustainable through re-evaluation, re-prioritization and re-distribution of programs. Therefore, the 15 percent reduction should apply to future years' forecasts until changes in the trends of the reliability indices or asset health assessments suggest the need for changes from the status quo in the size of the Sustaining Capital Portfolio.

5.3 BCTC

BCTC stated that the major drivers for capital investments in its own assets are: (a) operational and efficiency issues related to the five control centres; (b) ageing system operations and business systems technology; (c) ageing computer hardware; (d) the requirement to meet NERC/WECC planning standards; (e) a higher number of independent power producers; (f) the new Open Access Transmission Tariff; and (g) the separation of BCTC from BC Hydro. BCTC noted that some of the drivers will be addressed by the System Control Modernization Project (Exhibit B-1, p. 143).

The BCTC Capital Portfolio is planned and managed within four asset groups, the first of which is Business Support Systems. The capital expenditures in this area are primarily associated with providing the business systems that are necessary to support BCTC's business activities. Proposed business systems expenditures include those related to:

- sustaining the Asset Management Information System ($750,000 for each of F2006 and F2007, with a total of $7,250,000 over 10 years);
- replacing the existing OASIS, including the Transmission Scheduling System ("TSS") interface (two projects totalling $1,700,000 in F2006), and making future OASIS upgrades ($500,000 in each year starting in F2007);
- supporting and maintaining the Control Room Operating Window ("CROW") application and infrastructure ($200,000 in each year of the Capital Plan); and
- making miscellaneous changes to the TSS to accommodate tariff changes and future business requirements ($850,000 in F2006 and $500,000 in each subsequent year).

Various small projects bring the total requested funding for business systems projects to $4,825,000 for F2006 and $2,125,000 for F2007 (Exhibit B-1, p. 141). BCTC expected that expenditures on in-progress projects would be $4,552,000 for F2006. It also noted that funding might be required in future years for integration costs related to GridWest, though the timing and amount of the expenditure is uncertain and dependent on industry developments.

The second BCTC Capital Portfolio asset group contains control centre technologies, which are the tools necessary to operate the power system. The largest expenditure for which approval is sought in the F2006 Capital Plan related to this asset group is Control Centre Minor Capital of $500,000 for F2006 and each year thereafter. Total for-approval expenditures in F2006 and F2007 are $795,000 and $625,000, respectively. In-progress projects, including the System Control Modernization Project, bring the total control centre technologies expenditure to \$37.8 million for F2006 and \$76.4 million for F2007 (Exhibit B-1, p. 142).

Facilities management is the third asset group in the BCTC Capital Portfolio. The only project for approval consists of minor upgrades and modifications to BCTC facilities including furniture and other miscellaneous office capital costs, and is estimated at \$200,000 in each of F2006 and F2007 (Exhibit B-1, p. 142).

The final asset group in the BCTC Capital Portfolio is information technology. The largest expenditures in this asset group are for desktop computer software upgrades (\$400,000 in F2006), customer-driven website improvements (\$200,000 in F2006), Microsoft licence renewals (\$160,000 per year), and computer hardware upgrades (\$187,000 in F2006 and \$395,000 in F2007).

BCTC is seeking approval for total information technology expenditures of \$1.5 million in F2006 and \$845,000 in F2007. Including in-progress projects, these values become \$1.8 million and \$895,000, respectively. The total BCTC Capital Portfolio expenditures in F2006 and F2007, including projects already in progress, are expected to be \$49.2 million and \$79.6 million, respectively (Exhibit B-1, p. 142).

In its final comments, the CEC states that it is generally in support of the BCTC Capital projects (Exhibit C9-2, p. 6). However, the CEC is concerned about the dramatic increases in expenditures and the capability of BCTC to properly absorb the aggregate collection of projects and expenditures. The CEC also believes that the planning process appears to have proceeded without adequate levels of prioritization and scheduling. The CEC recommends that the Commission Panel grant BCTC's requested approvals subject to an allowance of \$10 million for the F2006 and F2007 period and a spreading of additional expenditure commitments into future periods.

In response to the CEC's submissions, BCTC states that the capital planning and expenditure process should be driven by need, not by arbitrary levels of expenditures or rate impacts (Exhibit B-11, p. 9). BCTC also states the need and timing for the proposed expenditures are often beyond BCTC's control, and that they are also influenced by BCTC's relatively recent formation and the need to have certain systems and processes in place in the short-term. BCTC therefore submits that the CEC's recommendation should not be accepted.

Commission Findings

The Commission Panel shares the CEC's concern over the size of the proposed capital expenditures and the attendant rate increases. The Commission Panel is also concerned with the lack of detail provided as justification for many of the BCTC Capital projects, the difficulty in understanding the relationship between the individual projects and the overall BCTC technology strategy, and the lack of a project prioritization system (though the Commission Panel acknowledges that BCTC is working on one for F2007 [BCUC IR 2.84.1, p. 4]). These concerns are similar to those expressed above and in the F2005 Reasons for Decision.

The Commission Panel notes that, excluding expenditures on the System Control Modernization Project ("SCMP"), BCTC proposes to spend $14,940,000 in F2006 and $6,045,000 in F2007 on BCTC Capital projects. Given its concerns with the overall level of capital expenditures, and consistent with the directed reductions in Sustaining Capital expenditures, **the Commission Panel directs BCTC to reduce aggregate F2006 and F2007 expenditures by $2,400,000**. This amount, which is 10 percent of the F2006 amount plus 15 percent of the F2007 amount (excluding SCMP expenditures), may be allocated among projects as BCTC sees fit. The Commission Panel expects that project priorities will be provided in future capital plans, which will allow more selective expense reductions should the Commission Panel deem such reductions to be in the public interest. The Commission Panel also notes that more thorough project justifications and priority assessments may increase the Commission Panel's confidence in the need for the projects and reduce the need for expense reductions.

In addition to the general concerns just noted, the Commission Panel has particular concerns about the OASIS-related projects in the F2006 TSCP. BCTC proposes several such projects (F2006 TSCP, p. 146-148; BCUC IR 2.81.5):

- an OASIS replacement project to build a new interface between the Transmission Scheduling System ("TSS") and a new OASIS provider ($700,000 in F2006);
- a project that has been identified for some years and is contingent on FERC and industry reviews of existing OASIS functionality and current industry scheduling systems and practices ($1,000,000 in F2006);
- OASIS future upgrades that are not mandated by FERC but that may be required to address customer or market needs ($500,000 in F2007 and each subsequent year).

Given that BCTC proposes to contract its OASIS out to a service provider, which would presumably make the investments in OASIS to adapt it to FERC and industry requirements and then recover its costs through service charges, it is not clear to the Commission Panel why BCTC requires capital funding for possible enhancements (other than for the interfaces between BCTC systems and the service provider's systems). Adding the uncertainty in project timing, the Commission Panel expects that a reduction in the aggregate OASIS-related amount may be a logical source of the some of the funds the Commission Panel has directed be eliminated from the BCTC Capital program.

The Commission Panel notes that a number of BCTC Capital projects (e.g., Asset Management Information System, TSS Tariff Changes, and Control Centre Minor Capital [F2006 TSCP, pp. 141-142]) are ongoing. For such projects, the Commission Panel finds it helpful to have an understanding of the associated activities and costs. **The Commission Panel therefore directs BCTC to provide, in future capital plan applications, a summary of the previous three years' activities and expenses for each ongoing project whose annual costs exceed $250,000.**

6.0 SUMMARY OF APPROVALS AND DIRECTIVES

This Summary is provided for the convenience of readers. In the event of any difference between the Approvals and Directions in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

Approvals and Directives	Decision Page No.
1. The Commission Panel directs BCTC to provide a clear statement of where, in the overall identification, design, and construction process, it expects the Commission's approval of the need for a Growth Capital project. BCTC is at liberty to propose different processes for different types of projects, but if it does so, it must identify which process is being followed by each project in the capital plan. In particular, the Commission Panel notes that there may be differences between CPCN and non-CPCN projects, and between large and small projects, in this regard.	6
2. The Commission Panel directs BCTC to refine the Growth Capital ranking system to better discriminate between growth capital projects. The ranking system should consider the factors that BCTC has set out in Section 2 of the F2006 TSCP, but should also consider factors such as lead-time, forecast uncertainty, and probabilistic measures such as EENS (see Section 3.2).	7
3. The Commission Panel directs BCTC to include path utilization forecasts in its capital plans whenever transmission capacity upgrades are proposed. The Commission Panel expects that, in providing such forecasts, BCTC will comply with the directions given on page 12 of the F2005 Reasons for Decision.	8
4. The Commission Panel notes that 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. The Commission Panel directs BCTC to report on the status and outcome of those discussions in its next capital plan application.	8
5. The Commission Panel directs BCTC to report the reliability indices applicable to it from Order No. G-103-04 and their associated trends for at least the past five years in the next	9

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capital plan. The reporting of these indices should also state the targets for the specific years against which each indicator was measured.

6. The Commission Panel directs BCTC to comply with the directive given on page 17 of the F2005 Reasons for Decision in its next capital plan. The Commission Panel also directs BCTC to submit the investment policy that it is developing in conjunction with TPAC for Commission review before such policy is implemented. The Commission Panel expects that, at the time the investment policy is submitted, BCTC will be prepared to discuss its "no congestion for firm transmission" policy and DSM options, both of which may affect the policy. 11

7. The Commission Panel therefore directs BCTC to provide, in each future capital plan, a section describing its response to Commission directives from previous capital plans. The status of compliance with each directive is to be reported in each capital plan until such time as BCTC has complied with the directive. 11

8. The Commission Panel directs BCTC to consider economics in its assessment of whether transmission upgrades should proceed. The Commission Panel does not consider that the simple existence of a NERC/WECC Planning Standards violation is sufficient justification for transmission upgrades in every case. 16

9. The Commission Panel directs BCTC to review Attachment J to determine whether any changes are warranted, given the Commission Panel's directives herein on system planning and the interpretation of reliability standards. 17

10. The Commission Panel directs BCTC, if it has not already done so, to initiate discussions with customers (including BC Hydro) on potential customer-provided solutions to transmission constraints, and to report to the Commission on the outcome of those discussions in its next Capital Plan. Without limiting the scope of the discussions, the Commission Panel expects BCTC will examine the following in conjunction with BC Hydro: 19

- options for general (i.e., system- or area-wide) demand reductions, to the extent they are not already covered by existing DSM initiatives such as PowerSmart;
- options for location- or area-specific demand reductions, either planned or in response to system events (e.g., by arming customer-specific remedial action

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schemes);

- demand reduction timing requirements (e.g., all hours, peak months or hours, or only when armed);
- mechanisms for compensating customers, such as reduced rates, direct payments through commercial contracts, or investment deferral credits;
- options for customer-supplied transmission services, such as reactive power or reliability must-run generation.

The Commission Panel further notes that, as the entity responsible for developing solutions to transmission constraints, BCTC is in the best position to identify the extent to which customer- or third-party-provided solutions could defer or eliminate the need for Growth Capital investments. Without pre-judging whether BCTC or BC Hydro (or both) should ultimately contract for non-wires solutions, the Commission Panel expects that BCTC will identify potential non-wires solutions in future studies and capital plan applications.

11. The Commission Panel finds that the three-year interval between asset condition audits is appropriate. However, increasing amounts of asset data should be available at each interval. BCTC's data monitoring, collation and analysis activity should be sufficient to ensure that an adequate data-based condition assessment is available for at least 90 percent of the assets within each class meeting the 70 Percent Rule by the third audit. 26

12. The Commission Panel encourages the preparation and use of a rigorous financial comparison of continued maintenance versus equipment replacement as a key driver in asset management planning. Where possible and practical, this analysis should be done for individual pieces of equipment, with maintenance costs for that piece of equipment based on its actual condition and its required reliability in its specific application. The Commission Panel expects that such financial evaluations will include a comparison against options that were considered but not selected, rather than only an evaluation of the selected option. 26

13. The Commission Panel recommends that the "fatal flaw" factor only be used on individual assets that meet the 70 Percent Rule, and not be applied to entire populations for which valid data may not exist. 26

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Approvals and Directives	Decision Page No.
14. The Commission Panel therefore recommends that, during the design and development of its asset management information systems, BCTC consider the data collection and analysis processes necessary to establish the correlations among asset classes' health index values, failure rates, expected remaining lifetimes, and impacts on reliability indicators such as SAIDI.	27
15. The Commission Panel directs BCTC to file, with each future capital plan, a table showing the changes from one capital plan to the next. The table may be in a form to be determined by BCTC, but must note any projects that have been accelerated, deferred, or cancelled, and must show any changes in expenditure patterns.	30
16. The Commission Panel therefore directs BCTC to report, in the next capital plan, the overall capitalized overhead expenses from F2005 forward and the allocation of the capital overhead expenses to individual projects.	30
17. The Commission Panel therefore approves the Meridian land purchase.	36
18. The Nicola reconfiguration project (definition phase) is approved.	36
19. The Commission Panel rejects BCTC's application for definition-phase funding for the Ingledow SVC project. BCTC is at liberty to re-file its request whenever it chooses, but if it does so, BCTC must provide either: (a) a justification for the project that addresses the issues raised by the Commission Panel; or (b) a plan to develop the justification and a statement as to why the associated costs should be capitalized.	37
20. The Commission Panel therefore approves BCTC's request for definition-phase funding for VITR.	38
21. The Commission Panel denies BCTC's application for approval of the Growth Capital projects on the South Interior bulk transmission system. Instead, the Commission Panel directs BCTC to submit, at the time of its next capital plan, or sooner should it so wish, a comprehensive System Development Plan ("SDP") for the South Interior bulk transmission system.	41

Approvals and Directives

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22. In the Commission Panel's view, the advisability of the multiple-contingency RAS is clear; the project is therefore approved. The Commission Panel also accepts BCTC's view that RAS may be the appropriate solution to certain system problems, and therefore approves the Unidentified RAS Additions project for F2006 and F2007. The Commission Panel expects that actual expenditures on this project will be reported in BCTC's next capital plan application.	42
23. Given the projected cost, geographic extent, environmental issues, and range of customers affected, the Commission Panel directs that BCTC submit a CPCN application for the East Kootenay 230 kV project should BCTC decide to proceed.	44
24. The Commission Panel accepts BCTC's recommendation that the Goward project be approved under the assumption that the proposed 230/138 kV transformer is the best option, and expects that BCTC will make a new application to the Commission if an alternate solution is selected.	45
25. The Commission Panel grants approval for the Area Planning Definition Work for F2006 only. For F2007 and beyond, area planning activities should be treated in accordance with the process(es) that BCTC proposes (and that the Commission ultimately approves) in response to the directives given in Section 2.2.	45
26. The Commission Panel approves the definition-phase expenditures for the Horne Payne transformer replacement. The Commission Panel directs BCTC to consider and report on the appropriate treatment of this project when complying with the directives in Section 2.2.	47
27. The Commission Panel approves the other substation expansion and modification projects as submitted.	47
28. Where the information in a future revenue requirements application is different than the forecasts supplied in the preceding capital plan application, the Commission Panel expects BCTC to provide commentary as to the source of the differences. To further enhance comparisons and the identification of trends in spending, the Commission Panel directs BCTC to report future Sustaining Capital Portfolios in the same format and with the same	49

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classifications as have been adopted in the current Application.

29. The Commission Panel expects BCTC to collect sufficient data to allow the identification of the worst performing asset classes by quantification of the effect of equipment failures on the reliability indices, and to present this data in support of future sustaining capital plans and programs. The Commission Panel reaffirms the following direction from Order No. G-103-04: The Commission therefore directs BCTC to provide, in future Capital Plans, a classification of transmission failures by equipment type and age, as well as an indication of the impact of transmission failures on reliability indices. Statistics should be included for as many years in the past as are reasonably available in order that trends may be observed. Should the requested statistics not exist, BCTC is to file a plan for collecting the necessary data in the future. 51

30. With the objective of reducing the rate increase associated with the rapid rise in the overall Sustaining Capital Portfolio, the Commission Panel encourages the use of the flexibility available in the interpretation and application of NERC/WECC reliability standards to defer or eliminate the need for projects driven by a conservative application of the standards. 52

31. The Commission Panel directs BCTC to implement reductions in F2006 and F2007 of $2,000,000 and $3,500,000, respectively, in the Protection and Control Sustaining Capital program. 53

32. The Commission Panel directs BCTC to implement reductions in F2006 and F2007 of $2,500,000 and $4,500,000 respectively, in the Stations Sustaining Capital Programs. 55

33. The Commission Panel directs BCTC to implement reductions in F2006 and F2007 of $1,000,000 and $2,500,000, respectively, in the Telecommunications Sustaining Capital programs. 56

34. The Commission Panel directs BCTC to implement reductions in F2006 and F2007 of $3,500,000 and $4,500,000, respectively, in the Overhead Lines and Rights of Way Sustaining Capital Programs. 58

35. The Commission Panel anticipates that the reductions in Sustaining Capital expenditures of 58

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approximately 10 percent in F2006 and 15 percent in F2007 are sustainable through re-evaluation, re-prioritization and re-distribution of programs. Therefore, the 15 percent reduction should apply to future years' forecasts until changes in the trends of the reliability indices or asset health assessments suggest the need for further changes in the size of the Sustaining Capital Portfolio.

36. The Commission Panel directs that BCTC reduce aggregate F2006 and F2007 BCTC Capital expenditures by $2,400,000. 62

37. The Commission Panel therefore directs BCTC to provide, in future capital plan applications, a summary of the previous three years' activities and expenses for each ongoing project whose annual costs exceed $250,000. 63

DATED at the City of Vancouver, in the Province of British Columbia, this 23 day of September 2005.

Robert H. Hobbs
Chair

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-91-05

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by The British Columbia Transmission Corporation
for Approval of
the Transmission System Capital Plan F2006 to F2015

BEFORE: R.H. Hobbs, Chair September 23, 2005

O R D E R

WHEREAS:

A. The British Columbia Transmission Corporation ("BCTC") filed its Transmission System Capital Plan F2006 to F2015 ("the Application") pursuant to section 45 (6) and 45(6.1) of the Utilities Commission Act ("the Act"); and

B. BCTC in the Application is seeking an order which states that this plan meets the requirements of Sections 45(6) and 45(6.1) of the Act, approves the 2005 Capital Plan under subsection 45(6.2) (a) and pursuant to Section 45(6.2) (b) approves all projects starting in F2006 and F2007 as listed in Section 7 of the Application; and

C. The Commission by Order No. G-33-05 set down a written hearing process and regulatory agenda for the review of the Application; and

D. The Commission Panel has considered the Application, evidence, and views of intervenors and the Applicant.

NOW THEREFORE the Commission orders as follows:

1. The Application meets the requirements of Section 45(6) and 45 (6.1) of the Act.

2. BCTC is directed to comply with all determinations and instructions set out in the Decision that is issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 23 day of September 2005.

BY ORDER

Robert H. Hobbs
Chair

GLOSSARY AND ABBREVIATIONS

Acronym	Term
ABS	Asset Baseline Study
Acres	Acres International Ltd.
AMMA	Asset Management and Maintenance Agreement
BBC	Brown Boveri Corp (currently Asea-Brown Boveri)
BC Hydro	British Columbia Hydro and Power Authority
BCTC	British Columbia Transmission Corporation
CEA	Canadian Electrical Association
CEC	Commercial Energy Consumers
CPCN	Certificate of Public Convenience and Necessity
COB	Canadian Ohio Brass
CROW	Control Room Operating Window
DSM	Demand Side Management
EENS	Expected Energy Not Served
F2005 Reasons for Decision	Reasons for Decision attached to BCUC Order No. G-103-04
F2006 TSCP	BCTC's F2006 to F2015 Transmission System Capital Plan Application
GIS	Gas Insulated Switchgear
GMS	GM Shrum Generating Station
HILP	High-impact, low-probability
HVDC	High Voltage Direct Current
ICBS	Introduction and Context for the Baseline Study
IEP	Integrated Electricity Plan
ILM	Interior to Lower Mainland
IPP	Independent Power Producer
IRs	Information Requests
IRAHVOL	Island Residents Against High Voltage Overhead Lines
LM-VI	Lower Mainland to Vancouver Island
MORC	Minimum Operating Reliability Criteria
MW	Mega Watt
N-1	Ability of the system to withstand the loss of a single element without loss of load

GLOSSARY AND ABBREVIATIONS

NERC	North American Electric Reliability Council
NITS	Network Integration Transmission Service
NPV	Net Present Value
OATT	Open Access Transmission Tariff
OEM	Original equipment manufacturer
OMA	Operations, Maintenance and Administration
PLC	Power Line Carrier
PTP	Point-to-Point
RAS	Remedial Action Schemes
RCM	Reliability Centred Maintenance
RMR	Reliability must-run
RMS Agreement	Reliability Management System Agreement
SDA	Substation Distribution Asset
SDP	System Development Plan
STSR	State of the Transmission System Report
SVC	Static VAr compensator
TBSR	Transmission Baseline Study Report
TPAC	Transmission Planning Advisory Committee
Transfer Paths	System-to-system interconnection points
TSCP	Transmission System Capital Plan
TSS	Transmission Scheduling System
VITR	Vancouver Island Transmission Reinforcement
WECC	Western Electricity Coordinating Council
WTS	Wholesale Transmission Service

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated April 7, 2005 and Order No. G-33-05 issuing the Notice of Written Hearing and Regulatory Agenda
A-2	Letter and Information Request No. 1 dated April 28, 2005 to British Columbia Transmission Corporation
A-3	Letter and Information Request No. 2 dated June 3, 2005 to British Columbia Transmission Corporation
A-4	Letter No. L-39-05 dated June 15, 2005 amending the filing deadlines established in Order No. G-33-05
A-5	Letter dated July 20, 2005 responding to BC Transmission Corporation letter of July 13, 2005 (Exhibit B-10)
APPLICANT DOCUMENTS	
B-1	**BRITISH COLUMBIA TRANSMISSION CORPORATION** application dated March 23, 2005 for the Transmission System Capital Plan F2006 to F2015
B-2	Letter dated May 5, 2005 filing an update to the Como Lake Feeder Section and 60L20 Slide Protection Project of the Transmission System Capital Plan F2006 to F2015 application
B-3A	State of the Transmission System Report and Asset Baseline Study filed May 6, 2005
B-3B	Asset Baseline Study filed May 6, 2005
B-4	Letter and Responses dated May 20, 2005 to Commission Information Request No. 1 and to Island Residents Against High Voltage Overhead Lines Information Request No. 1
B-5	**CONFIDENTIAL** – Response to Commission Information Request No. 26.1 dated May 20, 2005
B-6	Letter dated May 26, 2005 and responses to Commission Information Requests No. 29.1, 59.3 and 75
B-7	Letter dated June 14, 2005 requesting an extension to the filing dates for responses to the second round of Information Requests, written comments/submissions

Exhibit No.	Description
B-8	Letter dated June 24, 2005 filing responses to Commission Information Request No. 2, Sea Breeze Pacific Regional Transmission System, Inc.'s Information Request and the Island Residents Against High Voltage Overhead Lines (IRAHVOL) Information Request No. 2
B-9	Letter dated June 30, 2005 filing a response to Commission Information Request No. 2 113.1 along with the missing attachment to Commission Information Request 100.3 (Final Draft Report Review - incorrectly referred to in the BC Transmission Corporation June 24, 2005 filing as part of 110.3 - see Exhibit B-8)
B-10	Letter dated July 13, 2005 regarding the Information Request sent by Mr. Mike Guthrie on behalf of the Iskut First Nation
B-11	Letter dated July 20, 2005 and final response to Intervenor Submissions

INTERVENOR DOCUMENTS

C1-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY** – Notice of Intervention dated April 13, 2005
C2-1	**ISLAND RESIDENTS AGAINST HIGH VOLTAGE OVERHEAD LINES** – Notice of Intervention dated April 15, 2005 from Daria Zovi
C2-2	E-mail and Information Request No. 1 dated April 29, 2005
C2-3	E-mail and Information Request No. 2 dated June 3, 2005
C2-4	Final Submission dated July 6, 2005
C3-1	**GALLEGO, JAIRO, EE, MSC** – Notice of Intervention dated April 21, 2005
C4-1	**TRANSCANADA ENERGY** – Notice of Intervention dated April 22, 2005 from Alan Ross
C5-1	**TERASEN GAS INC.** – Notice of Intervention dated April 21, 2005 from Scott Thomson
C6-1	**JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE** – Notice of Intervention dated April 24, 2005 from Brian Wallace

Exhibit No.	Description
C7-1	**CITY OF NEW WESTMINSTER** – Notice of Intervention dated April 22, 2005 from Penny Cochrane
C8-1	**COLUMBIA POWER CORPORATION** – Notice of Intervention dated April 22, 2005 from Bruce Duncan
C9-1	**COMMERCIAL ENERGY CONSUMERS OF BC** – Notice of Intervention dated April 22, 2005 from David Craig
C9-2	Submission and comments dated July 6, 2005 regarding the BC Transmission Corporation responses to Information Requests
C10-1	**ASHCROFT, STAN** – Notice of Intervention dated April 22, 2005
C11-1	**KARSTEN HOLMSEN** – Notice of Intervention dated May 15, 2005
C11-2	Withdrawal notice dated May 18, 2005
C12-1	**SEA BREEZE PACIFIC REGIONAL TRANSMISSION SYSTEM, INC.**– Notice of Intervention dated May 17, 2005 from Tony Duggleby
C12-2	Information Request No. 1 dated May 16, 2005
C13-1	**ISKUT FIRST NATION**– Notice of Intervention dated June 8, 2005 from Mike Guthrie
C13-2	Email dated June 8, 2005 Withdrawing the Cassiar Watch Society as an Intervenor and substituting the Iskut First Nation
C13-3	E-mail and Information Request No. 1 dated July 6, 2005
C14-1	**SALT SPRING ISLAND CAPITAL REGIONAL DISTRICT**– Notice of Intervention dated May 18, 2005 from Gary Holman

Exhibit No.	Description
D-1	Telephone registration dated April 14, 2005 from Wilf Feurst requesting Interested Party Status
D-2	Letter dated April 15, 2005 from N. Moysa requesting Interest Party Status

LETTERS OF COMMENT