IN THE MATTER OF

BRITISH COLUMBIA TRANSMISSION CORPORATION

AND

APPLICATION TO INCUR CAPITAL EXPENDITURES
TO CONSTRUCT THE
5L51 AND 5L52 THERMAL UPGRADE PROJECT

DECISION

April 22, 2008

Before:

R.H. Hobbs, Chair
L.A. O'Hara, Commissioner
A.A. Rhodes, Commissioner

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1.0 BACKGROUND AND REGULATORY PROCESS

1.1 Background and Overview

On December 12, 2007, British Columbia Transmission Corporation ("BCTC") applied to the British Columbia Utilities Commission ("the Commission") pursuant to section 45(6.2)(b) of the Utilities Commission Act, RSBC 1996 c.473 ("the Act"), and as directed by the Commission in its F2008 Capital Plan Decision, for public interest approval of proposed capital expenditures to upgrade the thermal rating of transmission circuits 5L51 and 5L52 ("the Thermal Upgrade Project" or "TUP") to increase firm transmission capacity on the US-BC intertie in a south-to-north direction ("the Application").

The Thermal Upgrade Project is the first project to be proposed under BCTC's Transmission Expansion Policy ("TEP"). The TEP was developed with stakeholder input in 2005 in partial response to Special Direction No. 9 to the Commission, B.C. Reg. 157/2005 ("SD-9"), authorizing it to consider, *inter alia*, *anticipated* demand for electricity in exercising its discretion under the Act. The TEP represents a departure from BCTC's conventional planning process, which is based upon customer commitments under BCTC's Open Access Transmission Tariff ("OATT"), and contemplates expansion of the transmission system in advance of confirmed need.

Following development of the TEP, BCTC, with additional stakeholder input, developed its "TEP implementation plan" to identify and prioritize projects to be advanced under the TEP. This process is more fully described in Exhibit B-1, Appendix C.

Although the TUP is being presented as a TEP project, BCTC has stated that it is not seeking approval of either the TEP itself or BCTC's TEP implementation plan in the Application, and that the TUP is to be evaluated on its individual merits (Exhibit B-1 p. 5; BCTC Argument, para. 4, 47).

1.2 Regulatory Process

BCTC filed the Application on December 12, 2007. On December 24, 2007, by Order No. G-163-07, the Commission directed that a Written Public Hearing be held to decide the matters brought forward in the Application, established a Regulatory Timetable for the proceeding, and also directed BCTC to provide adequate notice of the Application and Written Public Hearing in local news publications to the public in the vicinity of the TUP. Following one round of Information Requests ("IRs") and Responses, BCTC filed its Argument on February 29, 2008. On March 7, 2008 arguments were received on behalf of British Columbia Hydro and Power Authority ("BC Hydro"), BC Old Age Pensioners' Organization et al. ("BCOAPO"), Independent Power Producers Association of British Columbia ("IPPBC") and the Joint Industry Electricity Steering Committee ("JIESC"). BCTC filed its Reply on March 14, 2008, completing the written proceeding.

Following a Commission determination in this proceeding, BCTC will seek approval of the TUP from the National Energy Board ("NEB") as the circuits in issue involve international transmission lines. BCTC expects to address any additional project consultation, First Nations consultation and environmental concerns prior to its submission to the NEB.

BCTC also requires approval from the Western Electricity Coordination Council ("WECC") for a path re-rating to increase the Accepted Rating of the path to 2800 MW in order to make use of the additional capacity created by the TUP.

No other approvals or consultations, including with U.S. authorities, are contemplated.

2.0 REGULATORY CONTEXT

2.1 Special Direction No. 9 and the Transmission Expansion Policy

BCTC's evidence is that the TUP, although technically being advanced pursuant to the TEP, is also being advanced on an accelerated basis outside the broader TEP project identification and assessment process (Exhibit B-1, p. 49).

BCTC also notes that "[t]he transmission planning method contemplated in SD-9 represented a departure from the way in which BCTC has traditionally planned the transmission system, which involved planning based on existing contracts for transmission services" (Exhibit B-1, p. 10).

BCTC also states:

> "…SD-9… was issued in 2004 …authorizing the Commission to consider, as part of the justification for new transmission facilities, the anticipated future demand for electricity and electricity services, including transmission services. SD-9 also authorizes the Commission to allow the recovery of costs from current rates, which are justified based on future probabilistic benefits from proposed equipment or facilities. Specifically, section 4 of SD-9 provides:
>
> 4 In the exercise of its jurisdiction under section 45 (1) and (6.2) of the Act as that jurisdiction relates to applications brought, or capital plans filed, by the transmission corporation, including any applications or capital plans for which the transmission corporation is responsible for obtaining commission approval under paragraph 4.12 (a) of the Master Agreement, the commission may
>
> (a) consider and take into account
>
> (i) the anticipated demand for electricity and electricity service, including transmission service, over a period considered by the commission to be reasonable, including the increase in demand that may be created by, or attributable to, the construction and operation of proposed transmission equipment or a proposed transmission facility, and

(ii) the benefits, including the benefits related to enhanced access to, and expansion of, electricity markets, that the commission considers are reasonably likely to result from any proposed expenditures for any one or more of

(A) studies in respect of,
(B) design of,
(C) planning the acquisition or construction of,
(D) construction of, and
(E) operation of

the proposed transmission equipment or facilities, and

(b) determine that expenditures referred to in paragraph (a) (ii) that are justified on the basis of the future benefits to be derived from the proposed equipment or facilities may be recovered in current rates" (Exhibit B-1, pp. 3-4).

BCTC's further evidence is that, in response to a directive from the Commission made in its June 2005 Decision on BCTC's OATT application, BCTC prepared and filed a paper entitled "Evaluation Methodology for Considering Transmission System Expansion Without Committed Contract", also known as the "Transmission Expansion Policy (TEP) Paper" in December of 2005. According to BCTC the paper "…contemplated BCTC making investments that range from advancement or expansion of customer driven capacity to new capacity investments that are underwritten by ratepayers" (Exhibit B-1, p. 10, Appendix A).

On January 30, 2006, the Commission acknowledged the TEP and indicated, *inter alia*, that it "properly complies with the directive…" (Exhibit B-1, Appendix B).

BCTC's evidence is that "…since that time [January 30, 2006], BCTC has consulted with stakeholders in respect of the TEP" (Exhibit B-1, p. 11).

BCTC states that in November 2006 it initiated internal consultation to investigate ways of incorporating TEP into planning processes and to identify any additional issues associated with TEP implementation. This process resulted in the development of a draft TEP implementation plan, the principle elements of which included further clarity on the drivers of TEP benefits such as lower cost energy supply, trade/wheeling opportunities, new load opportunities and long-run transmission system optimization. BCTC identified specific financial and non-financial attributes to be used in evaluating TEP opportunities. Additional external stakeholder consultation on TEP was also undertaken in May, 2007 (Exhibit B-1, Appendix C, p. 3).

2.2 Project Selection, Commission Directives 21 and 22

BCTC states that in response to Directives 21 and 22 made by the Commission in the F2008 Capital Plan Decision in June 2007, and in response to stakeholder input from the TEP consultation process, it undertook an accelerated project identification exercise in 2007 using a subset of projects identified in its 2006 State of the Transmission System Report and others which it had also identified as candidates. The TUP was identified in accordance with the directives "…as a TEP project and an intertie expansion project that could be reasonably assessed and potentially advanced within a short period of time, subject to the outcome of further technical and business analyses." It was also identified as "…a promising candidate to advance for full evaluation on an immediate basis due to its relatively modest complexity, the availability of information for evaluation purposes and straightforward rate-payer benefits" (Exhibit B-1, pp. 11-12, 43-44).

The TUP itself was not the subject of extensive public consultation. As noted above, BCTC anticipates addressing any project consultation, First Nations consultation and environmental issues prior to submitting the TUP to the NEB. Public consultation steps that BCTC has undertaken specific to the TUP project are:

17 October 2007	Announcement on BCTC website of its intention to advance the TUP as the first project under the TEP.
18 October 2007	BCTC informed attendees at its TEP Workshop #1 of its intention to propose the TUP for advancement under the TEP.

12 December 2007	The Application is filed with the Commission and distributed to all BCTC F2008 Capital Plan Registered Interveners as well as all parties involved in the TEP consultation process.

(Exhibit B-2, BCUC 1.3.2)

BCTC notes in the Application that public interest approval of expenditures for projects of similar complexity and cost, and approval to construct the project itself, would ordinarily be sought as part of its Transmission System Capital Plan, but, as this is the first project to be advanced under the TEP, approval has been sought separately. BCTC notes that the benefits used to establish that the TUP is in the public interest are based on forecast, but non-committed, future demand for transmission services, as contemplated by SD-9 and the TEP (Exhibit B-1, pp. 3- 5).

The business case for the TUP is based on the identification and quantification of benefits that would be derived from the sale of incremental Available Transmission Capacity ("ATC") enabled by the thermal upgrade, primarily on a Long Term ("LT") Firm Point-to-Point ("PTP") basis for south-to-north transfers (BCTC Argument, p. 5). BCTC's evidence is that "…[t]here is also the potential for increased Short-Term ("ST") Firm or Non-Firm transmission use on the BC-US intertie, on both south-to-north and north-to-south directions…[but] …these benefits have not been included as they are not necessary to justify the Thermal Upgrade Project" (Exhibit B-1, p. 34).

2.3 Public Interest

BC Hydro "supports a BCUC determination that the TUP is in the interests of persons within British Columbia who receive, or may receive, service from BCTC" (BC Hydro Argument, p. 1).

The BCOAPO argues that the Application "…raises the broader issue of the definition of the 'public interest' for the purposes of the… Act" and opposes the BCTC interpretation as expressed in its response to BCUC 1.1.2 "…that 'persons within BC' refers to ratepayers (current and future) of BCTC regardless of whether the ratepayer is physically located in BC." BCOAPO is "…strongly opposed to the assertion that our utilities should be regulated with a view to providing benefit to extra-provincial interests" (BCOAPO Argument, para. 23-30).

In response to the BCOAPO's argument that the "public interest" does not/ought not to include extra-provincial interests, BCTC argues that the Commission must take into consideration the interests of all users of the transmission system in B.C. BCTC argues that "…[t]here is a general principle of utility regulation precluding undue discrimination in rates…" and that "…BCTC's OATT…is premised on the notion of equal access to transmission in BC…regardless of the identity of the customer or where the customer's head office and operations are situated" (BCTC Reply, para. 20).

Commission Determination

The Commission agrees with BCTC that the TUP is an appropriate project to advance on an accelerated basis pursuant to the TEP and Commission Directives 21 and 22 from the F2008 Capital Plan Decision.

The Commission further agrees that the TUP falls squarely within SD-9 and the TEP, being put forward in the absence of committed contracts and on the basis of anticipated ratepayer benefits.

The Commission accepts the appropriateness of the analysis based on expected ratepayer benefits and confirms BCTC's broader proposition that BCTC's OATT is premised on the notion of equal access to transmission in B.C. and that B.C. enjoys similar treatment in terms of the benefits derived from non-discriminatory open access transmission tariffs in other jurisdictions.

The Commission Panel will not comment further on the broader TEP implementation issues raised by Intervenors, but expects these will be addressed in ongoing refinement of the TEP and future TEP applications.

3.0 PROJECT DESCRIPTION, PROJECT ALTERNATIVES AND CAPITAL COSTS

The TUP involves upgrading the 500 kV 5L51 and 5L52 transmission circuits that comprise the Ingledow-Custer transmission tie, also referred to as the western tie of the BC-US intertie. The circuits connect the Ingledow substation in the BCTC Control Area to the Custer substation in the Bonneville Power Administration ("BPA") Control Area. By increasing the circuit ratings of 5L51 and 5L52 from 2,520 and 2,000 Amperes respectively to 3,000 Amperes, the upgrade will result in an additional 870 Megawatts ("MW") of south-to-north firm transmission capacity on the BC-US intertie (Exhibit B-1, p. 3).

Upgrading the circuits will increase the Total Transfer Capability ("TTC") of the BC-US intertie in a south-to-north direction and the Firm Total Transfer Capability ("FTTC") of the BC-US intertie in both power flow directions, thus creating Firm ATC in both directions (Exhibit B-1, p. 15). BCTC defines TTC as the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post-contingency system conditions. For the BC-US intertie, the FTTC is defined as that part of the BC-US Intertie TTC, which BCTC determines it can continue to serve immediately after the permanent forced outage of a single system element (Exhibit B-1, p. 17).

BCTC explains the directional differences in the TTC and FTTC impacts of the project as follows:

> "For south-to-north transfers, the proposed increase in FTTC (from present 1,930 MW to the proposed 2,800 MW) takes the FTTC above the existing 2,000 MW TTC for the path. For this reason, it is necessary for BCTC to seek an increase to the TTC to match or exceed 2,800 MW through the WECC path rating process.
>
> In the case of north-to-south transfers, the FTTC of the intertie will be increasing, but will not reach the existing TTC limit of 3,150 MW and therefore will not drive a need to increase the TTC. Furthermore, the TUP does not add any ability of the BC system to respond to the TTC limiting contingency of the loss of both 5L51 and 5L52 when exporting 3,150 MW from BC to the USA. Therefore, the TTC will not be increasing as a result of the TUP" (Exhibit B-2, IPPBC 1.1.1).

The proposed scope of work for the project involves the raising of ten existing towers, installation of one new tower and re-tensioning of the conductors on three spans. No ground contour work or substation work is required, nor will there be any plant retirements or removal of assets (Exhibit B-1, p. 15).

Alternative transmission solutions to the TUP would involve construction of a new transmission line or the addition of a phase shifting transformer on the Teck-Cominco 230 kV line from Waneta to Nelway to Boundary in the BPA Control Area. Because the cost of both alternatives is significantly higher than the TUP alternative, BCTC decided to focus its assessment on reviewing various options for the TUP (Exhibit B-1, pp. 29-30). The four 5L51 and 5L52 upgrade options that were considered by BCTC from the cost and capacity benefit perspective are summarized in Table 4-3 of the Application as shown below. The estimated cost for the TUP is $ 3.1 million including overhead, inflation and interest during construction ("IDC") based on the preferred Upgrade Option 2 and the expected in-service date of March 31, 2010. The cost estimate has a range of accuracy of +20%/-10% (Exhibit B-1, pp. 15, 30).

Table 4-3. 5L51 and 5L52 Upgrade Options

Upgrade Option	Reinforcement Description	Revised Cost Estimate (Accuracy Range)	Capacity Benefit
1	Upgrade capacity of 5L52 to match that of 5L51	$2.4M (-10% + 20%)	Increase BC-US path FTTC by 450 MW to 2380 MW
2	Upgrade both 5L51 and 5L52 to a thermal rating of 3000 Amp	$3.1M (-10% +20%)	Increase BC-US path FTTC by 870 MW to 2800 MW
3	Upgrade both 5L51 and 5L52 to a thermal rating of 3400 Amp.; Upgrade station equipment at Ingledow substation	$5.0M (-50% + 100%)	Increase BC-US path FTTC by 1215 MW to 3145 MW
4	Upgrade both 5L51 and 5L52 to a thermal rating of 4000 Amp; Upgrade other network and station equipments	Not Determined but Expected to be Significantly Higher	Increase BC-US path FTTC by 1735 MW to 3665 MW

Source: Exhibit B-1, p. 30
Note (1): BCTC subsequently noted that the directional path reference in Table 4-3 is incorrect. The correct path direction should be US-BC (Exhibit B-2, BCOAPO 1.10(a)).

The four upgrade options were screened against the forecast market demand as shown in Table 4-4 of the Application below.

Table 4-4. Screening of Upgrade Options

Upgrade Option	**Incremental Firm TTC/ATC**	**Forecasted Market Demand** (note 1)
1	450 MW	450 MW (note 2)
2	870 MW	550 MW
3	1215 MW	550 MW
4	1735 MW	550 MW

Source: Exhibit B-1, p. 30
Note 1: Forecast Market Demand in this table reflects the Expected Forecast of 550 MW.
Note 2: Forecast Market Demand for Upgrade Option 1 is capped by the 450 MW incremental TTC associated with Upgrade Option 1.

The selection process leading to the Upgrade Option 2 becoming the preferred option is addressed in further detail in section 4 of this Decision.

4.0 MARKET BARRIERS, IDENTIFICATION OF OPPORTUNITY, AND PROJECT SELECTION

Introduction

The current tariff mechanisms have not triggered an investment in 5L51 and 5L52 for reasons identified by BCTC and noted in this section of the Decision. This section considers the evidence and arguments regarding the forecasts of US-BC and US-AB transmission service with the increase in the FTTC from TUP. BCTC's preferred project option is then discussed based on the expected forecast of the US-BC and US-AB transmission service. The cost-effectiveness analysis of the preferred project option is considered in section 5.

4.1 Market Barriers

As noted in section 2 of this Decision, BCTC considers the TUP to be a TEP project. The TEP Paper identifies three categories of projects:

a) A planned system upgrade for a Network Customer that can be beneficially advanced in time;

b) A planned system upgrade required for either a Network, Point-to-Point, or Interconnection customer that can be beneficially be made larger than the immediate requirement; and

c) A project (or advance study work on a project) that BCTC identifies as having future benefits, but which has not been triggered by a customer request.

TUP is considered by BCTC to be a Category C Project (Exhibit B-2, BCUC 1.2.1), and BCTC proposes to advance the project before a customer request.

According to BCTC, current tariff mechanisms, namely, the OATT, have not successfully triggered an investment in 5L51 and 5L52, despite queue requests dating to April 2002 (Exhibit B-2, BCUC 1.39.1). BCTC submits that upgrades will not proceed under OATT because users are not willing to make the necessary commitments to increase the FTTC because of two market barriers: 1) the length of time required to provide transmission service capacity when the required facilities are not in place; and 2) the requirement for market participants to financially backstop, through a letter of credit, any investments required to achieve additional transfer capability (Exhibit B-1, p. 18).

BCTC further submits that funding upgrades that may then benefit competitors may prevent a participant from increasing the incremental transfer capability (Exhibit B-2, BCUC 1.29.5). For example, Option 2 provides more than four times the amount of firm capacity required by the largest service request (Exhibit B-2, BCUC 1.41.1). The risk tolerance of the users may be reflected in the fact that 13 out of 17 of the queue requests as of July 31, 2007 are requesting service with a start time that is earlier than the TUP in-service date. BCTC suggests customers may not be prepared to fund an upgrade with attractive long-term benefits, particularly in cases where the future benefits do not accrue to them, but to potential competitors (Exhibit B-2, BCUC 1.41.1).

4.2 Identification of Opportunity

The justification (“business case”) of the TUP turns on an assessment of additional revenues from transmission service (“market up-take”) for US-BC and US-AB transfers resulting from an increase to the FTTC made available by the TUP. BCTC believes that historical, pending customer requests in the OATT queue for LTF PTP service indicate market interest in additional capacity. In addition, BCTC believes that the TUP will capture additional demand that is not currently reflected in the queue (Exhibit B-1, p. 21).

BCTC relies on three indicators as evidence for a likely demand for additional firm south-to-north transmission that the TUP will provide:

a) BCTC OATT queue activity for US-BC and US-AB transfers;

b) The outlook for power market price differentials between the U.S. and Alberta; and

c) Historical south-to-north power flows and transmission schedules on the BC-US intertie (Exhibit B-1, p. 19).

The market up-take estimates are based on consideration of queued customer requests, knowledge of customers, and historic attrition rates (Exhibit B-1, p. 25). The Application, Table 4-2, page 26 provides a minimum forecast, conservative forecast, and expected forecast up-take estimate. The estimate of ATC up-take is provided with a probability of meeting or exceeding the estimate in the near-term and long-term. Table 4-2 of the Application is reproduced below.

Table 4-2. Estimate of Market Up-take for US-BC and US-AB Transfers

	Path	Total Queued Customer Requests	Estimate of ATC Up-Take (on a LT Firm Basis)	Probability of Meeting or Exceeding the Estimate in the Near-Term	Probability of Meeting or Exceeding the Estimate in the Long-Term (>5 years)
	Minimum Forecast				
1	US-BC	400 MW	0 MW or 0%	High	High
2	US-AB	950 MW	75 MW or 8%	High	High
3	Total	1350 MW	75 MW or 6%	High	High
	Conservative Forecast				
4	US-BC	400 MW	200 MW or 50%	Medium	High
5	US-AB	950 MW	75 MW or 8%	High	High
6	Total	1350 MW	275 MW or 20%	Medium	High
	Expected Forecast				
7	US-BC	400 MW	200 MW or 50%	Medium	High
8	US-AB	950 MW	350 MW or 37%	Medium	High
9	Total	1350 MW	550 MW or 41%	Medium	High

(Source: Exhibit B-1, p. 26)

BCTC estimates there is a 95 percent and 75 percent probability that the TUP will exceed the minimum and conservative forecast amounts, respectively (Exhibit B-2, BCUC 1.28.1).

BCTC arrived at the 550 MW forecast demand by discounting the 1350 MW of OASIS queue requests as of July 31, 2007 for US-BC and US-AB LTF transmission service based on an analysis of queue attrition levels back to 2002. As of February 6, 2008, total demand in queue for south-to-north LTF transmission service has increased from 1350 MW to 2150 MW, although the up-take continues to be discounted from 1,350 MW (Exhibit B-2, BCUC 1.9.1) and there is no firm ATC on the US-AB path (Exhibit B-2, IPPBC 1.1.3).

The WECC approved Path Rating for south-to-north transfers is 2,000 MW. TUP will increase FTTC by 870 MW or 45 percent over the present limit, conservative and expected forecasts of incremental revenue are 24 percent and 52 percent increases on F2008 LTF PTP revenues (Exhibit B-2, BCUC 1.30.1). In addition, the analysis shows that a three-year deferral of the TUP would reduce the expected NPV by $60.3 million (Exhibit B-2, BCUC 1.29.2).

BCOAPO submits Network Integration Transmission Service ("NITS") accounts for more than one-half of the current south-to-north transfer capacity of 2,000 MW (FTTC), and that the self-sufficiency policy is likely to make the long-term need for this service questionable (BCOAPO Argument, para. 8; Exhibit B-2, BCOAPO 1.6.a). BCOAPO submits that the US-BC transmission service to support NITS will likely decline as self-sufficiency is attained. BCOAPO further suggests that the 2007 Open Season process, which has not yet been completed, may trigger an expansion and should be completed before TUP is approved (BCOAPO Argument, p. 3). BCTC submits that the approach consistent with SD-9 and the TEP is to proceed with TUP at the earliest possible in-service date. Furthermore, BCTC submits that the Open Season process does not eliminate the two market barriers and a request resulting from the Open Season would trigger Upgrade Option 1 (BCTC Reply, para. 18).

BCTC submits that there is no evidence that imports will level off with self-sufficiency (BCTC Reply, para. 8). BCTC submits that the use of the intertie will depend on market prices in the U.S. and BC, and that BC Hydro's hydroelectric generation is well positioned so that market activity will continue after self-sufficiency is achieved. As BCTC submits, the Energy Plan expressly recognizes that this market activity will continue after self-sufficiency is achieved (BCTC Reply, para. 8). BCTC is of the view that self-sufficiency requirements may increase the demand for transmission service out of BC, but that transmission service into BC may not change; BCTC provided an illustration of the net effect of the self-sufficiency policy on generation (Exhibit B-2, BCUC 1.42.4). However, BCOAPO submits that BCTC acknowledges that self-sufficiency will change the flows and use of transmission service (BCAOPO Argument, para. 10).

BCOAPO submits that the business case should not look at 20 years but rather "something in the order of 5 years", which is approximately the length of time from the in-service date to the self-sufficiency date (BCOAPO Argument, para. 12). BCTC submits that transmission assets have a useful life much longer than five years and the cost-effectiveness analysis should reflect the useful life of the assets. BCTC notes that the business case for TUP is still positive using five years (BCTC Reply, para. 11).

As well as the queue requests, BCTC relies on historical power flows as evidence to support its up-take analysis. The evidence of US-BC power flows is provided in the form of a scatter diagram with a large number of hourly points bumping up against the 2,000 MW import limit, which BCTC suggests is indicative of the 2,000 MW import limit being a constraining factor (Exhibit B-1, Figure 4-3, p. 25).

BCTC is also of the view that the long-term forecast of Alberta and Mid-C spot market prices supports a favourable outlook for long-term US-AB transmission services. The spot market prices adjusted for wheeling charges and losses are provided; however, BCTC notes that the amount of trade activity will depend on seasonal and hourly price variations. BCTC notes that the business case for TUP does not rely on market price forecasts for energy in the Alberta or Mid-C markets (Exhibit B-2, BCUC 1.7.1).

BCTC is of the view that it is not necessary to discount expected up-take from TUP to account for competition from other planned projects (Exhibit B-1, p. 27), in part because BCTC does not believe that there are any projects currently under development that would directly compete with the opportunity afforded by TUP (Exhibit B-2, BCUC 1.6.4).

4.3 Project Selection

In section 3 of this Decision, the Upgrade Options are identified with the reproduction of Table 4-3 from the Application (Exhibit B-1, p. 30).

The selection of Option 2 as the preferred option is based on the up-take analysis provided in the previous section. The up-take estimate of 550 MW is insufficient to justify Option 3 and Option 4. That is, Option 2 is preferred to Option 3 and Option 4 because of the lower cost, and Option 2 is preferred to Option 1 because Option 1 does not provide sufficient capacity given the up-take analysis.

Commission Determination

The Commission Panel accepts that queue activity and the historical power flows are all indicative of an opportunity to increase the use of the US-BC and US-AB paths. The Commission Panel also accepts that the market barriers identified by BCTC are a reasonable explanation as to why current tariff mechanisms have not triggered what would seem to be a modest investment for significant, forecast benefits. However, the Commission Panel does not agree with BCTC that the Open Season would necessarily result in Upgrade Option 1, since Option 2 could reasonably be pursued as a Category B TEP project.

The three up-take forecasts noted in the table above provide an up-take range of 75 MW to 550 MW. It is also important to note that the cost range of the three options for which cost estimates are provided is narrow, $2.4 million to $5 million. Moreover, the difference between the least cost Option 1 with a cost estimate of $2.4 million and the recommended Option 2 with a cost estimate of $3.1 million is even narrower. Therefore, for the purposes of selecting among the four options identified in the Application, the Commission Panel accepts the use of the expected forecast of 550 MW.

The Commission Panel agrees with BCTC that market activity will continue after self-sufficiency is achieved. The Commission Panel also accepts that the use of the US-BC and US-AB paths may change with self-sufficiency as suggested by BCOAPO. The Commission Panel does not agree with BCTC that the cost-effectiveness analysis should reflect the useful life of the assets but rather the likely term of the benefits to be provided by the project, which may in fact be shorter. However, given the use of the expected forecast to select amongst project options and the positive NPV with a five-year investment horizon, the Commission Panel concludes that risk of insufficient transmission use to cover the costs of the project is an acceptable risk. In this regard, the opportunity cost risk of delay of approximately $60 million also needs to be considered.

The Commission Panel accepts the BCTC suggestion that SD-9 and the TEP support proceeding with TUP at the earliest possible in-service date. Further, the Commission Panel accepts that the Open Season process does not eliminate the two market barriers. Therefore, the Commission Panel concludes that BCTC should not wait for the completion of the 2007 Open Season before proceeding with TUP.

5.0 COST-EFFECTIVENESS ANALYSIS FOR THE TUP PROJECT

BCTC indicates the TUP is evaluated on an economic basis and from the perspective of BC's electric utility ratepayers (Exhibit B-1, p. 17). BCTC also states it has considered non-financial factors associated with the project. As noted in section 3 of this Decision, BCTC assumes a cost of $3.1 million for Upgrade Option 2, its preferred alternative. This cost estimate includes overhead, inflation and IDC and has an estimated accuracy of -10 percent to +20 percent. BCTC indicates there are no significant increases in operating or maintenance costs associated with the TUP (Exhibit B-1, p. 29).

BCTC submits there is a sound business case for the TUP based solely on benefits that would be derived from the sale of incremental ATC enabled by the upgrade, primarily on a LT Firm PTP basis for south-to-north transfers (BCTC Argument, para. 3). As noted in section 4 of this Decision, BCTC's assessment of market up-take for LT Firm PTP south-to-north transfers considers attrition of existing queued requests, longer-term market forecasts, and potential competition from other transmission projects, among other factors.

BCTC estimates net benefits for Upgrade Option 2 on a present value basis over 20 years of approximately $256 million ($2007). This is based on its expected forecast for incremental south-to-north LT Firm PTP sales of 514 MW per year after full subscription of the remaining 36 MW of ATC on the intertie as of 2009 (Exhibit B-1, Table 4-7, p. 33). As part of Table 4-7, BCTC also provides estimates of net benefits under minimum, conservative and maximum benefits scenarios for incremental south-to-north LT Firm PTP sales. BCTC‘s minimum scenario assumes sales of only 39 MW per year, which produces net benefits of $17.1 million. BCTC's conservative scenario assumes incremental sales of 239 MW per year with net benefits of approximately $118 million. BCTC's Estimated Theoretical Maximum Benefits Scenario assumes incremental sales of 870 MW with net benefits of approximately $435 million. BCTC also conducted 20-year and one-year break-even analyses in order to provide some indication of ratepayer risk. These analyses depict the amount of contracted capacity required for net benefits to equal zero. The 20-year break-even analysis requires incremental LT Firm PTP sales of 5 MW per year for 20 years. The one-year break-even analysis requires a one-year sale of 62 MW to break even (Exhibit B-1, p. 33).

In response to Commission and Intervenor IRs, BCTC also conducted NPV and break-even analyses on the basis of different blends of ST Firm and Non-Firm usage (e.g., Exhibit B-2, BCUC 1.23.1, 1.24.1, 1.24.2). Net benefits were lower under these scenarios, but still positive, ranging from approximately $0.6 million under the Minimum Scenario to approximately $286 million under the Theoretical Maximum Benefits Scenario, based on south-to-north PTP Sales assuming Short-Term Firm ("STF") Rates. Net benefits are somewhat higher under Short-term Non-Firm Rates, although still lower than under Long-Term Firm Rates. Break-even points were higher under various alternative rate scenarios. BCTC also prepared a version of Table 4-7 assuming a five-year delay in project up-take (Exhibit B-2, BCOAPO 1.11c). Under this scenario, the 20-year and one-year break-even points increased to 8 and 76 MW, respectively, and the minimum and maximum theoretical net benefits decreased to $10 million and $275 million, respectively. BCTC argues the TUP provides a favourable business case under all of the scenarios it examined (BCTC Argument, para. 22).

BCTC notes that the TUP would result in an increase in the north-to-south FTTC of the BC-US intertie, but TUP business case does not rely on these benefits, as there are other constraints (e.g., Interior to Lower Mainland transmission capacity), which currently limit the overall potential for increased firm exports to the US. BCTC also notes there is the potential for increased Short-Term (ST) Firm or Non-Firm transmission use on the BC-US intertie, on both south-to-north and north-to-south directions, which have not been included in the business analysis because they are not necessary to justify the TUP (Exhibit B-1, p. 34). BCTC also suggests that First Nations, stakeholder and environmental considerations are not anticipated to adversely impact the economic viability of the TUP (Exhibit B-1, p. 29). Given the strength of the business case based solely on incremental revenues from transmission sales, BCTC indicates it did not conduct a trade benefit analysis for the TUP. However, BCTC notes that the project could generate additional margin for Powerex from incremental trade activities that would provide BC Hydro ratepayer benefits, assuming the current $200 million cap on trade benefits accruing to ratepayers has not been exceeded (BCTC Argument, para. 34).

The forecast Transmission Revenue Requirement ("TRR") impact of the TUP is summarized in Table 5-2 of the Application (Exhibit B-1, p. 36). The TRR impact is estimated at $0.3 million for F2011, which represents about 0.06 percent of the approved F2008 TRR, or 0.01 percent of the approved total F2008 BC Hydro Revenue Requirement (Exhibit B-1, p. 36).

BCTC notes that the TRR is recovered through OATT services, namely NITS, PTP and Ancillary Services. Net benefits from the sale of additional PTP transmission services will reduce the NITS charge. BCTC notes that as BC Hydro is currently the only NITS customer on the transmission system, any reduction to the NITS charge will ultimately be realized by BC Hydro ratepayers (BCTC Argument, para. 33). In Table 5-3 of its Application, BCTC provides three scenarios showing a reduction in the NITS charge of 0.1, 0.4, and 0.8 percent on a 20-year present value basis under the Minimum, Conservative and Expected up-take scenarios, respectively (Exhibit B-1, p. 37).

BCTC notes that the TUP will increase PTP rates by 0.05 percent or $0.002 per kW per month (BCTC Argument, para. 34, footnote 57). However, BCTC notes the Project also provides PTP customers with an opportunity to earn incremental trade revenues on import, export and wheel-through transactions.

BCOAPO argues the rate impact of the project is "marginal at best" (BCOAPO Argument, para. 7). As noted in section 4 of this Decision, BCOAPO takes issue with the projected up-take of the project, arguing that the Province's self-sufficiency policy and constraints facing deliveries to Alberta will result in lower levels or shorter durations of up-take. In light of the self-sufficiency policy, BCOAPO argues the upgrade must be viewed primarily as serving north-to-south deliveries and the primary beneficiary of incremental trade in electricity from B.C. into the U.S. will be the Provincial Treasury and not ratepayers due to the $200 million cap on trade income benefits accruing to ratepayers (BCOAPO Argument, para. 13-15). Specifically, BCOAPO argues: "…the real beneficiary of this Project will be the Provincial Treasury. It is inequitable that the cost should be borne by ratepayers" (BCOAPO Argument, para. 30).

BC Hydro argues the TUP will provide benefits to the users of the transmission system relative to the costs of the upgrade (BC Hydro Argument, p. 1). The JIESC considers the TUP project costs to be minor in relation to potential benefits. The JIESC also does not consider the $200 million cap in net revenues from Powerex that accrue to the benefit of ratepayers as a reason not to approve the TUP because current trade revenues are well below the $200 million cap (JIESC Argument, p. 1). The IPPBC supports the TUP but raises the concern that the cost allocation of transmission was not considered. The IPPBC suggests that the approach used by BCTC to justify the TUP would disadvantage transmission projects advanced under the TEP to serve a number of separately owned, potential IPP projects in a geographic area ("Cluster Projects"). In particular, the IPPBC appears to be concerned about the lack of consideration of trade benefits accruing to Powerex in BCTC's business case analysis (IPPBC Argument, p. 4-5).

BCTC argues there is no evidence to support BCOAPO's assertions that Government's commitment to self-sufficiency will result in BC Hydro releasing its transmission capacity currently used for imports. BCTC argues the use of the intertie for trading in any given period is a function of a number of factors including regional hydrological and climatic conditions, loads, and market prices. BCTC argues there will continue to be benefits to short term trading activity and these benefits are expressly recognized in the Energy Plan (BCTC Reply, para. 8). BCTC also notes that the BCOAPO failed to account for the return of the Down Stream Benefits under the Columbia River Treaty (BCTC Reply, para. 9), and that a significant portion of the queued requests are to facilitate wheel-through transactions, not imports to serve domestic load (BCTC Reply, para. 10). BCTC also argues that a five-year financial assessment horizon, as proposed by BCOAPO, risks significantly underestimating the benefits associated with the project because the revenues to be received will not reflect those recoverable over the life of the assets. BCTC also notes that the business case for the TUP is still positive based on LT Firm PTP rates and a five-year NPV (BCTC Reply, para. 11).

With respect to the magnitude of ratepayer benefits and the primary beneficiaries of the TUP, BCTC notes the forecast ratepayer benefits are significant in absolute terms and that it would be inappropriate to reject a project with low costs and low risk, solely because the net benefit in percentage terms is small (BCTC Reply, para. 12). BCTC also notes that its business case does not rely on trading benefits but rather on incremental revenues from the sale of PTP service and their impact on NITS charges, which is not affected by the $200 million cap on Powerex net income accruing to BC Hydro ratepayers (BCTC Reply, para. 14).

With respect to the IPPBC's concerns about the precedent of the TUP analysis for other TEP projects, BCTC agrees that future TEP proposals might not match the extent of the TUP's favourable business case, and agrees the TUP should not be interpreted as the threshold for project advancement under the TEP. However, BCTC rejects the idea of re-labeling projects such as the TUP as non-TEP projects (BCTC Reply, para. 23). With respect to its evaluation methodology, BCTC submits that a TEP project should produce a net benefit or neutral impact to the NITS customer (whether through a lower NITS charge or from a combination of a lower NITS charge and trade benefits) since the NITS customer backstops the TRR (BCTC Reply, para. 25). BCTC also submits that, in this Application, it was appropriate to forego an assessment of trade benefits because of the modest capital cost and that it would be inappropriate to establish a firm rule requiring a trade benefits analysis for all TEP projects (BCTC Reply, para. 26).

Commission Determination

The Commission Panel finds the TUP has a favourable business case when taking into account solely expected incremental north-to-south LT Firm PTP sales as a result of the project. The Commission Panel also finds the business case remains favourable under all of the scenarios examined by BCTC. The Commission Panel agrees with BCTC that the risk to ratepayers is small given the low capital costs of the project and the low break-even thresholds for contracted capacity under various scenarios.

The Commission Panel agrees with BCTC that the primary beneficiary of the project is the NITS customer through the reduced TRR that will need to be recovered from the NITS customer as a result of incremental LT Firm PTP sales. The Commission Panel notes that PTP customers will see a small increase in PTP rates, but agrees with BCTC that this will be offset by increased trading opportunities for these customers arising from the expansion. The Commission Panel notes that BCTC's business case does not include any allowance for possible benefits arising from additional short-term and non-firm transmission revenues or from incremental trading opportunities for

Powerex. The Commission Panel agrees with BCTC that it is not necessary to quantify these additional potential benefits given the business case is robust without them. The Commission Panel agrees with BCTC that the issue of the $200 million cap on net trade income from Powerex accruing to ratepayers is irrelevant in this circumstance since the business case does not rely on trade revenues to demonstrate net benefits to ratepayers. The Commission Panel agrees with BCTC that the absolute net benefits to ratepayers are significant and worth pursing, even if they are small in percentage terms.

The Commission Panel agrees with BCTC that a TEP project should produce net benefits for the NITS customer through either a lower NITS charge or from a combination of a lower NITS charge and trade benefits, given the NITS customer is the ultimate backstop on the TRR. The Commission Panel agrees with BCTC that trade benefits may be relevant to the justification of other TEP projects, but sees no reason to establish a firm rule requiring an assessment of trade benefits given the costs of such an assessment and the possibility that such an assessment may not be required in every circumstance, as in the case of the TUP.

While not determinative in the context of the TUP Application, the Commission Panel wishes to note the following issues raised by BCTC's justification and evaluation methodology for the TUP that may become important in the context of a larger and riskier TEP Application. First, the Commission Panel notes that there may be interim steps to advancing expansion projects that should be given more consideration by BCTC. In particular, BCTC may want to give more consideration to seeking a determination that design and permitting expenditures are in the public interest, thereby reducing subsequent lead times for strategic projects, but making actual construction of the projects conditional on other factors, such as signed contracts. The Commission Panel also notes that while the TEP is intended to allow advancement of projects in the absence of signed contracts, BCTC may wish to give more consideration to the additional weight that may be given to projects where there are contracts for at least some of the additional capacity, as a further indication of market interest. The Commission Panel also notes the Open Season process is not at odds with proceeding with Option 2 given that there is a provision in the TEP to allow for larger increments than requested by customers. Indeed, an Open Season could be a reasonable first step to justifying an expansion, even if it does not produce sufficient commitments to justify the entire increment. It certainly could provide further support for market interest. However, the Commission Panel did not give any weight to this in the TUP Application given the large net benefits and low risks associated with the TUP.

The Commission Panel is also concerned that BCTC may not be giving adequate consideration to the effects of an expansion on existing uses and revenues. The business case for the TUP is based entirely on incremental demands and there is an implicit assumption current uses will not change or that the expansion will have no effect on current uses. The Commission Panel does not consider this a reasonable assumption, but again no weight was placed on this given the low costs and risks of the TUP.

The Commission Panel agrees with BCTC that an analysis of trade benefits may not always be warranted. However, when one is required, the Commission Panel would expect a more sophisticated analysis than simply looking at price differentials among market hubs. The Commission Panel notes that BCTC's original analysis of the price differential between Mid-C and Alberta failed to take into account wheeling charges between the markets. In addition, the Commission Panel notes the forecasts used by BCTC differ significantly from those put forward by BC Hydro. In an analysis of trade benefits, the Commission Panel would expect a market model such as the one used by BC Hydro in its price forecasting methodology to be run depicting average import and export prices (and revenues) with and without the proposed expansion.

The Commission Panel also cautions BCTC that while congestion may be a good rationale for initiating a study of the opportunities for and impacts of an expansion, congestion statistics in and of themselves are not adequate evidence of need or a benefit.

Finally, the Commission Panel notes that in its analysis of the costs and benefits of a project deferral, BCTC relied solely on a deterministic analysis. The Commission Panel considers that one of the main benefits of deferral is the potential reduction in uncertainties and the flexibility it offers, and that a deferral therefore has some "option value." An analysis of that option value may be warranted when a more significant project is being considered.

6.0 CONCLUSION

The TUP is the first project advanced pursuant to the TEP. In this Decision, the Commission Panel agrees with BCTC that this is an appropriate project to advance on an accelerated basis and that it clearly falls within the scope of a TEP project.

The justification for the project turns on forecasts of ratepayer benefits expected from increased use of the US-BC transmission paths. For the purpose of selecting among project options, the Commission Panel accepts the expected forecast of ratepayer benefits put forward in advance of committed contracts. Moreover, the Commission Panel concludes that BCTC’s cost-effectiveness analysis is appropriate given the expected ratepayer benefits, particularly when considered relative to the cost estimates and risks for the project.

DATED at the City of Vancouver, in the Province of British Columbia, this 22nd day of April 2008.

Original signed by:

ROBERT H. HOBBS
PANEL CHAIR

Original signed by:

LIISA A. O'HARA
COMMISSIONER

Original signed by:

ALISON A. RHODES
COMMISSIONER

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-58-08

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

and

An Application by
British Columbia Transmission Corporation
for Approval to Incur Capital Expenditures to Construct the
5L51 and 5L52 Thermal Upgrade Project

BEFORE: R.H. Hobbs, Chair
L.A. O'Hara, Commissioner
A.A. Rhodes, Commissioner

April 22, 2008

O R D E R

WHEREAS:

A. On December 12, 2007 British Columbia Transmission Corporation ("BCTC") applied, pursuant to Section 45(6.2)(b) of the Utilities Commission Act ("the Act") and as directed in the F2008 Capital Plan Decision, for public interest approval of capital expenditures for a thermal upgrade of transmission circuits 5L51 and 5L52 (the "Thermal Upgrade Project"); and

B. The Thermal Upgrade Project involves upgrading the 500 kV 5L51 and 5L52 transmission circuits that comprise the Ingledow-Custer transmission tie, also referred to as the western tie of the B.C.-U.S. intertie. The circuits connect the Ingledow substation in the BCTC Control Area to the Custer substation in the Bonneville Power Administration ("BPA") Control Area. By increasing the circuit ratings of 5L51 and 5L52 from 2,520 and 2,000 Amperes respectively, to 3,000 Amperes, the upgrade will result in an additional 870 Megawatts ("MW") of south-to-north firm transmission capacity on the B.C.-U.S. intertie; and

C. The estimated cost for the Thermal Upgrade Project is $3.1 million based on the preferred Upgrade Option 2 and the expected in-service date is March 31, 2010; and

D. Special Direction No. 9 ("SD-9") authorizes the Commission to consider, as part of the justification for investment in new transmission facilities, the anticipated future demand for electricity and electricity services. SD-9 also authorizes the Commission to allow the recovery of costs from current rates, which are justified based on future benefits from proposed equipment or facilities; and

E. While the Thermal Upgrade Project is the first project to be advanced for approval under BCTC's Transmission Expansion Policy ("TEP"), BCTC is not seeking approval of the TEP or its TEP implementation plan; and

F. National Energy Board ("NEB") public interest approval for the project is required before construction can commence because 5L51 and 5L52 are international power lines; and

G. On December 24, 2007 by Order No. G-163-07, the Commission directed that a Written Public Hearing be conducted for deciding the matters brought forward in the Application, established a Regulatory Timetable for the proceeding and directed BCTC to provide adequate notice in local news publications to the public in the vicinity of the project; and

H. On February 29, 2008, BCTC filed its Argument on the Application; and

I. On March 7, 2008, British Columbia Hydro and Power Authority ("BC Hydro"), British Columbia Old Age Pensioners' Organization *et al.* ("BCOAPO"), Independent Power Producers Association of B.C. ("IPPBC"), and the Joint Industry Electrical Steering Committee ("JIESC") filed their written Arguments on the Application; and

J. On March 14, 2008, BCTC filed its Reply; and

K. The Commission has reviewed the Application, information requests, documents and submissions and the Commission notes that BC Hydro, IPPBC, and JIESC support the Application while BCOAPO states that "This Application should be refused, without prejudice to BCTC's right to re-apply once the 2007 Open Season process has been completed"; and

L. Considering the Application and the estimated cost, size and unique nature of the Thermal Upgrade Project, the Commission has determined that the Application is in the public interest and that approval of the plan and the proposed expenditures be granted to BCTC as set out in the Decision released concurrently with this Order.

NOW THEREFORE pursuant to Section 45(6.2) (b) of the Utilities Commission Act and as directed in the F2008 Capital Plan Decision, the Commission grants approval for BCTC to Incur Capital Expenditures to construct the 5L51 and 5L52 Thermal Upgrade Project, Option 2, as set out in the Application.

DATED at the City of Vancouver, in the Province of British Columbia, this 22nd day of April 2008.

BY ORDER

Original signed by:

Robert H. Hobbs
Chair

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

and

British Columbia Transmission Corporation
Application for Approval to Incur Capital Expenditures to Construct the
5L51 and 5L52 Thermal Upgrade Project

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated December 24, 2007, issuing Order No. G-163-07 establishing the Regulatory Timetable
A-2	Letter dated January 24, 2008, issuing Information Request No. 1 to BC Transmission Corporation
APPLICANT DOCUMENTS	
B-1	Letter dated December 12, 2007 filing the Application for approval to Incur Capital Expenditures to Construct the 5L51 and 5L52 Thermal Upgrade Project
B-1-2	Received December 24, 2007 filing additional description and location of work regarding the application
B-2	Letter dated February 14, 2008 filing Responses to Information Requests No. 1
B-2-1	Letter dated February 19, 2008 filing an addendum for the responses to Information Requests No. 1
INTERVENOR DOCUMENTS	
C1-1	**JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE (JIESC) –** Letter dated January 7, 2008, from R. Brian Wallace, filing request for Registered Intervenor status

Exhibit No.	Description
C2-1	**BC HYDRO POWER & AUTHORITY (BCHYDRO) –** Online web registration dated January 8, 2008, filing request for Registered Intervenor status
C2-2	Letter dated January 31, 2008 filing Information Request No. 1 to BCTC
C3-1	**INDEPENDENT POWER PRODUCERS OF BC (IPBC) –** Letter dated January 10, 2008, from David Austin, Tupper Jonsson & Yeadon, legal counsel, and for Steve Davis, President, filing request for Registered Intervenor status
C3-2	Letter dated January 31, 2008 filing Information Request No. 1 to BCTC
C4-1	**BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION ET AL (BCOAPO)** - Letter dated January 10, 2008 from Jim Quail requesting Registered Intervenor status and status for Bill Harper, Econalysis Consulting Service Inc.
C4-2	Letter dated January 30, 2008, filing Information Request No. 1 to BCTC
C5-1	**MATSQUI FIRST NATIONS LANDS DEPARTMENT** – Letter dated January 17, 2008, from John Rowan filing request for Registered Intervenor status
C6-1	**SEA BREEZE PACIFIC JUAN DE FUCA CABLE LP** – Online web registration received January 23, 2008, from Monique Stevenson filing request for Late Registered Intervenor status and reasons
C6-2	Letter dated January 31, 2008 filing Information Request No. 1 to BCTC

INTERESTED PARTY DOCUMENTS

D-1	**ALTA ENERGY** - Online web registration received January 24, 2008, from Stephen Kukucha filing request for Interested Party status