Marcel Reghelini
Director, Regulatory Affairs
Phone: 604 699-7331
Fax: 604 699-7537
E-mail: marcel.reghelini@bctc.com

December 20, 2006

Mr. Robert J. Pellatt
Commission Secretary
British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Box 250
Vancouver, BC V6Z 2N3

Dear Mr. Pellatt:

Re: British Columbia Transmission Corporation (BCTC)
Open Access Transmission Tariff (OATT) Compliance Filing – Rate Design Report

Enclosed is BCTC's compliance filing made pursuant to the following orders and letters issued by the British Columbia Utilities Commission (Commission):

1. Order No. G-58-05 concerning BCTC's 2004 Open Access Transmission Tariff (OATT). The Rate Design Report ("Report") is in response to the Commission's directives 1, 8, 10, 14, 15, 17 and 31 of the June 19, 2005, OATT Decision.

2. Order No. G-12-06 issued as a result of BCTC's Application for Permanent Approval of the Interim Dynamic Scheduling Tariff on Exports of Energy and Ancillary Services from BCTC's Control Area. The Report addresses the applicability of BCTC's discount policy to Dynamic Scheduling Service.

3. Letter No. L-15-06 issued regarding BCTC's correspondence dated March 31, 2006, to Cascade Pacific Power Corporation stating that the Report would include a reassessment of the impact of the $55 Minimum Fee for Short Term Point to Point Transmission Service.

4. Letter No. L-16-06 accepting BCTC's proposal dated March 31, 2006 to evaluate in this Report customer-supplied solutions as a response to the 2005 Capital Plan Decision (Order No. G-91-05, directive # 10).

A summary of BCTC's key findings and recommendations is found at Section 1.3 of the Report. BCTC's recommendations with respect to process, including the timing of customer consultation is summarized in Section 1.4 of the Report.

Sincerely,

Original signed by:

Brian Gabel on behalf of
Marcel Reghelini
Director, Regulatory Affairs

Enclosure

REVIEW OF RATE DESIGN ALTERNATIVES

FOR BRITISH COLUMBIA TRANSMISSION CORPORATION'S OPEN ACCESS TRANSMISSION TARIFF:

REPORT TO COMPLY WITH THE BRITISH COLUMBIA UTILITIES COMMISSION'S ORDER NO. G-58-05 AND DECISION AND OTHER REPORTING REQUIREMENTS

British Columbia Transmission Corporation

12/08/2006

Table of Contents

List of Figures

List of Tables

1. Introduction and Summary

1.1 BCTC

British Columbia Transmission Corporation ("BCTC") is a provincial Crown Corporation. BCTC was formed in May 2003, and began operations on August 1, 2003. Under the Transmission Corporation Act,[1] and the Master Agreement with the British Columbia Hydro and Power Authority (BC Hydro),[2] BCTC is responsible for operating, planning, and maintaining BC Hydro's transmission system and certain other related assets, including transmission facilities connecting generation and distribution substation equipment.

BCTC provides transmission services under its Open Access Transmission Tariff (the "OATT").[3] BCTC's OATT generally follows the Federal Energy Regulatory Commission's ("FERC") Order No. 888 *pro forma* tariff. Rates under the OATT are set using an embedded cost approach, in essentially the same way they have been since BC Hydro's Wholesale Transmission Services ("WTS") tariff was first approved by the British Columbia Utilities Commission (the "Commission") in 1997.

The transmission system under BCTC's control is primarily used by one customer, BC Hydro, to serve its domestic load.[4] BC Hydro takes transmission service from BCTC pursuant to a network integrated transmission service (NITS) contract under part 3 of BCTC's OATT. BC Hydro is BCTC's sole NITS customer. BC Hydro also uses BCTC's short-term and long-term point to point ("ST-PTP" and "LT-PTP", respectively) services under part 2 of BCTC's OATT. Other generators and marketers also use PTP services, most commonly to wheel power to and from the United States and into and out of Alberta.

Table 1.1 and Table 1.2 below contain summary statistics of BCTC's transmission revenues and volumes by service type during the period April 1, 2006 to September 30, 2006.

---

[1] S.B.C. 2003. Chap. 44.

[2] One of the Designated Agreements, pursuant to Order in Council No. 1083, Approved and Ordered November 20, 2003.

[3] BCTC's new OATT went into effect on March 1, 2006.

During this six-month period, NITS service to BC Hydro contributed 89% of BCTC's transmission service revenues, LT-PTP service contributed 5.1%, and ST-PTP service contributed the remaining 5.9%. BC Hydro's transmission volumes accounted for 73.8% of the LT-PTP volume, 99.7% of the ST Firm PTP volume, and 92.1% of the ST Non-Firm PTP volume.

Table 1.1 Transmission revenue by customer and service for the six-month period from April 1, 2006 to September 30, 2006

Service type	BC Hydro	Other Customers	Sub-Totals	Percent of Total Revenue
NITS	$236,975,100 100%	$0 0%	$236,975,100	89.0%
LT-PTP	$10,077,801 73.8%	$3,579,448 26.2%	$13,657,249	5.1%
ST Firm PTP	$11,508,945 99.3%	$77,415 0.7%	$11,586,360	4.4%
ST Non-Firm PTP	$3,549,211 90.2%	$386,750 9.8%	$3,935,961	1.5%
Sub-Totals **Percent of Total Revenue**	$262,111,057 98.5%	$4,043,613 1.5%	$266,154,670	

Table 1.2 Transmission volume (MWh) by customer and service for the period from April 1, 2006 to September 30, 2006

Service Type	BC Hydro	Other Customers	Sub-Totals	Percent of Total Volumes
LT-PTP	1,823,878 73.8%	647,600 26.2%	2,471,478	24.4%
ST Firm PTP	5,659,093 99.7%	16,786 0.3%	5,675,879	56.0%
ST Non-Firm PTP	1,832,395 92.1%	158,005 7.9%	1,990,400	19.6%
Total **Percent of Total Volumes**	9,315,366 91.9%	822,391 8.1%	10,137,757	

[4] The terms "domestic load" and "native load" are used interchangeably in this report. In the BCTC context, they mean service taken by BC Hydro under NITS.

1.2 Objective

This report has been prepared to comply with the regulatory directives in the OATT Decision issued by the Commission on June 20, 2005 (the Decision). The Decision was attached to Commission Order No. G-58-05, and was issued in connection with BCTC's August 3, 2004 OATT Application. The Decision requires BCTC to explore alternative cost-based transmission rate designs that promote efficient use of, and competitive access to, BC Hydro's transmission system. The Decision also required BCTC to evaluate its Shaped Service, to review the appropriateness of a Load Ratio Share allocation for NITS billing, and to evaluate the directional aspect of short term service price discounting.

This report also contains BCTC's compliance with other reporting requirements, including those arising from Commission Letter No. L-16-06. In that letter, the Commission accepted BCTC's proposal to address "non-wires solutions" such as re-dispatch of generation and curtailment of load as part of this report. Other issues arising from Commission directives or BCTC commitments that is, the $55 minimum scheduling fee and rate discounting for Dynamic Scheduling Service, are also considered in this report.

BCTC has prepared this report as a compliance filing. As such, it does not propose changes to the tariff and is not, therefore, an application to the Commission seeking any relief. Still, pursuant to the Commission's directives, BCTC does draw conclusions and recommendations in a few areas. In most cases, however, BCTC simply highlights trade-offs and relationships, but has not reached a conclusion on the best approach to follow.

1.3 Key findings and recommendations

The key findings and recommendations in this report are as follows:

1.3.1 General rate design conclusions

1. The application of traditional cost-based ratemaking methods (e.g., cost allocation schemes based on use at the time of a system peak) would result in increases to both the long- and the maximum short-term point-to-point rates, and is unlikely to improve the utilization of, or competitive access to, the transmission system.

2. The existing rate design produces a combination of relatively low LT-PTP rates and discounted short-term rates. This design effectively balances the competing goals of ensuring: (1) a contribution to fixed costs from all system users; (2) high capacity utilization; and (3) competitive transmission access.

1.3.2 LT-PTP Service

1. The most important difference between BCTC's existing design and those of other transmission providers is that BC Hydro, as the only customer that uses the NITS service to meet its domestic load service obligations, is required to underwrite or "backstop" the transmission revenue requirement (TRR). This includes paying for any variations between forecast and actual in PTP revenues. If the Commission were to consider a new cost-based design that closely links transmission rights to costs and rates, then it should also consider at the same time the implications of removing BC Hydro's backstopping obligation and creating a separate revenue requirement for PTP, which is the more common approach.

2. If the backstop is removed in an effort to strengthen the relationship between costs and rates, then there is a strong argument to adopt a ratemaking process that shares the revenues from ST-PTP services among all long-term service users. Since the ST-PTP revenues currently flow only to NITS customers, this change by itself would lower the LT-PTP rates by approximately 8%. When combined with a new cost allocation scheme (such as the 12 coincident peak allocation discussed in Section 4), the LT-PTP rate decrease resulting from the sharing of short term service revenue is eliminated and the new LT-PTP rate would increase by almost 20%.

3. Two new cost-based services may lead to small increases in system utilization. The new services are:

- A LT-PTP service for non-dispatchable resources[5]. The rate for this new class of users would be based on its expected (collective) coincident peak transmission use, rather than the sum of the individual users' maximum reservations.

- A Term PTP service that requires a committed reservation duration of longer than one year (the current limit for short-term reservations), but shorter than the maximum 10-year planning horizon for NITS. Term PTP fills a gap in services between the existing short- and long-term PTP services. BCTC believes that the product might meet the needs of some PTP users, without decreasing the flexibility or service quality of other long-term services. This new service would have no rollover rights. Under one potential design for this service, a Term PTP customer could convert to regular LT-PTP service and obtain rollover rights by executing a facilities agreement prior to the end of the Term PTP Service Agreement.

1.3.3 ST-PTP Service

1. BCTC's short-term pricing formula is a relatively poor predictor of arbitrage opportunity and the value of transmission, but remains relatively good at balancing the twin goals of minimizing "trade blocking" and ensuring a reasonable contribution to fixed costs from every trade.

2. Replacing the current OATT's minimum scheduling fee provision with a minimum per megawatt-hour (MWh) charge, and eliminating discounting for multi-day reservations, can maintain transmission utilization, while providing a minimum level of fixed-cost recovery from all users.

---

[5] Examples of non-dispatchable generation technologies include wind energy and run-of-river hydro. A non-dispatchable generation unit often has an intermittent output profile, largely because the operator has little or no control over input level (e.g., wind speed or stream flow).

3. Eliminating the minimum scheduling fee would help reduce the transmission bill of very small transmission users, and would be justified with a floor price in the form of a per MWh charge.

4. Eliminating discounting for multi-day reservations would improve the performance of the ST-PTP pricing formula because the formula becomes an increasingly poor predictor of transmission value when extended beyond a one-day discounting period.

5. The short-term pricing formula combined with a floor price should be used for billing Dynamic Scheduling Service and other capacity products, because such rates would provide a minimum level of fixed-cost recovery. Moreover, BCTC does not generally distinguish its pricing based on the ways in which its customers can use its services.

1.3.4 NITS Service

1. Two alternative definitions of NITS billing determinants could be used to allocate costs within the class in the event that there was more than one NITS customer. Both alternatives are aimed at stabilizing the bills of potential NITS customers. The first alternative is to lengthen, beyond the current month, the period over which the Load Ratio Share is calculated. This approach makes the most sense under the current design (where the revenue backstop is maintained) and does not require a change to the OATT terms and conditions. The second alternative develops an explicit $/kilowatt-month rate based on a cost allocation driven by the loads of multiple NITS customers. This approach fits most naturally with a scenario in which NITS customers do not have the TRR backstop obligation.

1.3.5 Non-Wires solutions

1. The OATT's existing capital deferral credit should be expanded for both transmission service and interconnection service customers to include both existing generators and loads, so as to promote the use of non-wires solutions for

offsetting or deferring transmission investments. The payment mechanism should also be changed from an offset of transmission service charges to a cash payment so that existing generators and those selling to BC Hydro may participate.

2. BCTC should work with BC Hydro to explore, for the Commission's consideration, a program to facilitate voluntary participation in non-wires solutions by loads, generators, and energy traders.

3. BCTC should work with BC Hydro to ensure that information related to possible non-wires opportunities, including targeted demand-side management and energy procurement, is effectively communicated between the utilities and to other potential service providers.

1.4 Process recommendations

This report identifies a number of potential tariff modifications related to long-term, short-term and interconnection services. These modifications involve various degrees of tariff changes, including:

- Rate changes that simply affect pricing but that do not alter the underlying rate making approach or the existing OATT terms and conditions for transmission service. This would include, for example, changes to the short-term pricing formula.

- Rate changes that use an alternative cost allocation scheme to derive new LT-PTP and ST-PTP rates. While the PTP rate changes can be significant and their implications important, these changes also leave the existing OATT terms and conditions unchanged.

- Rate changes that alter both the rates and the terms and conditions of service. This would include, for example, the separate LT-PTP rates for non-dispatchable generation resources and a new Term PTP Service.

- Proposed changes to the transmission deferral credits, effected through BCTC's interconnection services.

BCTC believes that it is conceptually easier to change prices than terms and conditions. This is true, in part, because there are generally fewer considerations to take account of, such as comparability requirements. However, as a practical matter, changing prices and pricing methodologies can have at least as great an impact on customers as revising the non-price terms of service.

As such, regardless of the nature of the changes that might receive consideration as a result of this report, BCTC will need to undertake customer consultations. Before those consultations take place, BCTC cannot conclude whether any of the design changes described in this report would produce net benefits for its customers, and whether they would allocate those net benefits fairly.

Even if a review of this report suggests that alternative designs appear to have merit, implementation of some of the designs may require a major tariff overhaul, which may not be feasible in the near term. Certainly, any *immediate* tariff modifications must be modest changes that can be implemented within the existing OATT and Open Access Same-Time Information System (OASIS) structures. More fundamental modifications would require additional evaluation, and should only be considered after broadly-based consultation with customers and other stakeholders.

BCTC believes that the short-term rate proposals in this report are fairly discrete; and if acceptable to interveners and the Commission, could be implemented within a reasonably short period of time. BCTC proposes to consult with its customers in February and March of 2007, and to bring any resulting application for tariff changes to the Commission after April 2007.

The long-term rate analysis contained in this report involves more fundamental tradeoffs and tariff modifications. Moreover, FERC is currently undertaking a rulemaking process with respect to its Order No. 888 *pro forma* tariff.[6] While the issues under consideration in that proceeding are not directly applicable to the issues addressed in this report, BCTC expects that it will be consulting with its customers with respect to the implications of FERC's Final Rule following the conclusion of that process. BCTC anticipates that it will consult with its customers on the implications of the long-term rate issues in this report, including Shaped Service, at the same time.

With respect to non-wires issues, BCTC expects that consultations with respect to any immediate tariff changes will be conducted in a time frame similar to that for short-term tariff changes. Other non-wires considerations raised in this report will be reviewed and addressed over a longer time frame.

A summary of the recommendations and proposed process arising from this report is in Table 1.3.

---

[6] The FERC rulemaking process will culminate in a Final Rule. The September 2006 FERC Strategic Plan for Fiscal Years 2006-2011 indicates, at p.22, that the process is targeted to conclude by June 30, 2007.

Table 1.3 Summary of recommendations and proposed process

Subject	BCTC Recommendation	Process and Timeline
ST-PTP Service	1. Modifications to current formula • Reinstate minimum MWh charge (Section 6.4.1) • Eliminate discounting for multi-day reservations (Section 6.4.1) • Eliminate minimum scheduling fee (Section 6.3.5) 2. Apply short-term discounting formula, with above modifications, to Dynamic Scheduling Service and other capacity products (Section 6.3.4)	Conduct customer consultations in February, and March 2007 with an application to be filed, if necessary, after April 2007.
LT-PTP Service	1. No immediate change in LT-PTP Rate Design (Section 4.4.1; Section 4.6) 2. Consult on rate design alternatives (Section 4.4.2; Section 4.5.4) 3. Consult with respect to LT-PTP Term Service and unresolved issues (Section 5.2) 4. Consult with respect to LT-PTP Non-Dispatchable Service and unresolved issues (Section 5.1) 5. Consult with respect to Shaped Service terms and conditions (Appendix E; Section 5.2.4)	Begin customer consultations in Q3 2007 (July – September) following the release of the FERC Final Rule, with an application to be filed, if necessary, in Q1, 2008 (January – March).
Non-Wires	1. Expand deferral credit to include existing generators and loads (Appendix B, Section B.3.1) 2. Change payment mechanism for the deferral credit from an offset of transmission service charges to a cash payment (Appendix B; Section B.3.1)	Conduct customer consultations in February, March 2007 with an application to be filed, if necessary, after April 2007.

1.5 Report organization

The remainder of this report is organized as follows.

- Section 2 defines the scope of the report by outlining BCTC’s response to each directive in the Decision and other reporting requirements.

- Section 3 provides context by discussing competing goals and interests in transmission ratemaking.

- Section 4 reviews cost-based ratemaking and describes a range of cost-based designs for the OATT similar to those used in other jurisdictions.

- Section 5 introduces new service proposals for a LT-PTP rate design for non-dispatchable generation and a new Term PTP Service.

- Section 6 discusses alternative pricing formulae for ST-PTP Service and their effect on electricity trading and revenue.

- Section 7 concludes by discussing some implications arising from the key findings of this report.

This report also has five appendices, each of which addresses a stand-alone topic. Appendix A introduces two options that would stabilize billing determinants for NITS customers other than BC Hydro. Appendix B discusses non-wires alternatives to transmission investments. Appendix C discusses BCTC's approach to developing the cost-basis for rate making alternatives considered in the report. Appendix D describes transmission rate designs used by other Canadian and regional transmission providers. Appendix E describes BCTC's progress in developing its Shaped Service business practices.

2. Scope

The scope of this report is shaped by: (a) the directives in the Decision and Commission Letter No. L-116-06; and (b) BCTC's other reporting requirements, including Commission Order No. G-12-06 (addressing Dynamic Scheduling Service) and (c) BCTC's commitment to address the impact of the $55 minimum scheduling fee.

2.1 The Decision

The regulatory directives in the Decision define much of the scope of this report. They reflect the Commission's view of BCTC's OATT Application:

> "The Commission Panel accepts that within the policy framework created by the FERC Order No. 888 Pro Forma tariff, the Energy Plan and the Master Agreement BCTC has sought to strike an appropriate balance among the interests of its customers. However, while BCTC's intentions are commendable, BCTC by its own admission approached the Application as a mere "tune-up" of the 1998 WTS Tariff. Therefore, the Commission Panel finds that BCTC has not become enough of an agent of change from the longer term perspective. With a rapidly changing electricity industry, a period of some ten years seems too long to go without a fundamental review of rate design. To promote a more efficient use of and competitive access to the transmission system, BCTC must continue to innovate with renewed consideration of options for restructuring the entire tariff from a cost causation perspective." (the Decision, p.13)

Based on the directives in the Decision, which are discussed below, the scope of this report includes a review and recommendation on alternative cost-based designs (including a discussion of the cost of service basis upon which those alternatives are based), PTP service options for non-dispatchable resources, NITS billing determinants, a review of the ST-PTP rates, redispatch and non-wires solutions, and a review of Shaped Service.

2.1.1 Review and recommendation on alternative cost-based OATT designs

The Decision directs a review and recommendation with respect to alternative cost-based OATT designs. Specifically, "[t]he report should address the timing of and manner in which

BCTC may incorporate the results of … a [cost of service] study to effect alternative forms of PTP rates that could further enhance utilization of the transmission system while still reflecting a degree of cost causality. BCTC should include in its report a preliminary recommendation with supporting reasons either for revisions to the OATT rate structures or for maintaining the status quo." (the Decision, p.114)

In compliance with the directives, this report explores a variety of cost-based ratemaking approaches. The findings and some specific recommendations, where warranted by the findings, are presented in subsequent sections of this report. It should be noted, however, that some of the options presented may require new tariff language and/or fundamental modifications in BCTC's business practices. Some of the issues associated with implementing each option are highlighted. This list of issues should, however, be considered preliminary, since further consultation with customers would need to precede any action to implement the findings of this report.

The recommendations and supporting findings contained in this report should be viewed in the context of the Commission's past WTS Decisions. Besides shaping the OATT that is in place today, these decisions reflect the fact that the Commission has generally favoured cost-based designs, even though its decisions have resulted in a tariff that balances a number of competing objectives.

June 25, 1996 Decision

In this decision, the Commission adopted BC Hydro's 1993/94 fully allocated cost of service study ("FACOS") as the basis to set the transmission revenue requirement for BC Hydro's WTS tariff. The approved WTS tariff was, therefore, cost-based, developed using the FACOS which separated the transmission plant in service into the following categories: Generation Related Transmission Assets (GRTAs), 500 kV, 230 kV, 138 kV, and 69 kV lines; transmission substations; and relevant portions of general plant and equipment.[7]

[7] In the Matter of British Columbia Hydro and Power Authority Wholesale Transmission Services Application (June 25, 1996), p. 12 (June 25, 1996 Decision)

The 1993/94 FACOS was primarily developed for retail ratemaking purposes. The study functionalized costs into generation, transmission, and distribution. These costs were then classified as demand, energy, or customer related, and allocated to each retail customer class and rate schedule. Transmission costs were further delineated by voltage level and whether or not they were GRTAs.

The GRTAs were defined to include transmission lines linking remote generation in the North and South Interior regions, the portion of generation substation assets required to step-up the voltage for transmitting power and energy to load, and some other assets[8]. In its October 17, 2003 Report and Recommendations concerning BC Hydro's Heritage Contract, the Commission further determined that a fixed amount of $43.3 million was appropriate as a GRTA value and that asset functionalization of GRTAs otherwise continue to be within the jurisdiction of the Commission. BCTC has retained this fixed-fee approach to functionalization.[9]

The GRTA's costs were equally allocated between demand and energy. Other transmission costs were allocated 100% to demand. Peak demand was defined as the loads of each class during each of the 12 monthly coincident peaks in the test year.

The Commission decided that GRTAs were not part of the TRR[10]. Thus, the TRR only encompassed 500 kV, 230 kV, 138 kV, and 69 kV lines; transmission substations; and relevant portions of general plant and equipment. The Commission did not, however, set service-specific revenue requirements for point-to-point and network services.

The Commission also adopted a competitive market-based approach as the principle for pricing short-term service, resulting in a formula whose concept remains in use today. Finally,

---

8 June 25, 1996 Decision, p.12.

9 One of the terms of the BCTC F2007 Revenue Requirement Negotiated Settlement (November 9, 2006, Commission Order No. G-139-06), paragraph 12, requires BCTC to provide a report in its next revenue requirement application that discusses the merits of the fixed-cost approach to GRTAs relative to an approach that uses actual or forecast costs on a year-by-year basis.

10 "Therefore, the Commission must exercise its judgment, based on the evidence before it, as to whether the majority of the benefits are likely to accrue to the generation or the transmission function. Based on the current evidence, the Commission determines that generation-related transmission facilities should remain functionalized to generation as was done in the 1993/94 FACOS study." (June 25, 1996 Decision, p.15)

the Commission directed BC Hydro to file a WTS tariff that would reflect long-run marginal costs (LRMC) by transmission path.

April 23, 1998 Decision

In 1998, after considering the arguments on the alternative treatments of GRTAs,[11] the Commission affirmed its prior ruling on the TRR determination. Specifically, "[t]his Decision, therefore, directs a treatment of the GRTAs similar to that found in the 1993/94 FACOS study" (April 23, 1998 Decision, p.18).

The Commission also considered: (a) BC Hydro's February 1997 Application that responded to the LRIC-based tariff design directive in the June 25, 1996 decision; and (b) BC Hydro's June 1997 Application that proposed a WTS tariff that conformed with the FERC Order No. 888-A *pro forma* (postage stamp) tariff.

Due to its concern over preserving Powerex's ability to sell electricity into the United States at market-based rates, the Commission accepted BC Hydro's Network Service proposal in its June 1997 Application[12]. For the same reason, the Commission approved BC Hydro's proposal in the June 1997 Application for LT-PTP service, while directing BC Hydro to seek FERC's approval of a LRIC-based tariff[13]. In October 1997, BC Hydro offered a matrix of LRIC-based LT-PTP rates for six point-of-receipt (POR) regions for power injection and six point-of-delivery (POD) regions for power withdrawal. The six regions were Northern Interior,

---

[11] In the Matter of British Columbia Hydro and Power Authority Wholesale Transmission Services Application (April 23, 1998), pp. 5-17 (April 23, 1998 Decision).

[12] "The Commission accepts the Network Service proposed by B.C. Hydro. While the Commission would prefer to see rates for network customers which more directly incorporate appropriate pricing signals, the Commission accepts that the implementation of such rates would require substantial alterations to the non-rate terms and conditions of the FERC pro forma tariff. Given that there is only one network customer at this time, and that this customer pays the residual transmission tariff, the Commission accepts that there is a built-in incentive to minimize transmission costs. As a result, the potential loss of efficiency from approving rates which do not more explicitly reflect long-run incremental costs falls within acceptable boundaries." (April 23, 1998 Decision, p.32)

[13] "Therefore, the Commission approves the one-part rate put forward by B.C. Hydro subject to any adjustments which must be made as a result of determinations made elsewhere in this Decision. In addition, the Commission directs B.C. Hydro to file a Petition for Declaratory Order with FERC, within 90 days of this Decision, asking that it formally rule on the acceptability of the two-part rate as set out in the Reversionary Rate Proposal. If it becomes clear, either through the Petition for Declaratory Order or through other means, that the implementation of locationally efficient rates would not lead to the loss of the PMA, the Commission intends to move expeditiously to see that rates which reflect locationally efficient prices are implemented." (April 23, 1998 Decision, p.38)

Southern Interior, Lower Mainland, Vancouver Island, Alberta and the Bonneville Power Administration (BPA). Finally, the Commission accepted BC Hydro's value-based pricing for ST-PTP service (April 23, 1998 Decision, p.40).

The rate design ultimately adopted in the April 23, 1998 WTS Decision achieved a mix of objectives. Rates were designed to collect the TRR from network, point-to-point, and ancillary services. BC Hydro's decision to take service under the WTS, and its implementation and use of OASIS, was designed to ensure comparable transmission access to third-party suppliers. Economic efficiency was promoted through the locational LT-PTP rates and a market-based ST-PTP rate discounting mechanism. Since the tariff and rates were based on the FERC *pro forma* tariff, the WTS design was simple and well understood, following the industry standard for jurisdictions that do not have a power pool for implementing a competitive generation market[14]. Finally, the rates were determined to be fair, even though they did not fully match each service's rate with its embedded costs, as is commonly found in retail ratemaking proceedings. Given the relatively high costs of transmission in BC, rate fairness was based on the selection of a design that among other things, produced a relatively low LT-PTP rate[15].

2.1.2 Cost basis for rate alternatives

The Decision requires BCTC to consider design changes supported by a cost of service study. In particular, "[t]he Commission Panel therefore directs BCTC to review the options for more fundamental rate design changes, and to report to the Commission by December 31, 2006. In support of this, the Commission Panel directs BCTC to undertake a study that investigates the relationship between particular characteristics of use or users (e.g. capacity factor, size, energy source, time of use, etc.)" (p.114).

---

[14] Lusztig, C., P. Feldberg, R. Orans, and A. Olson (2006) "A survey of transmission tariffs in North America," *Energy* 31: 1017-1039.

[15] The maximum output of installed generation was chosen as the denominator in setting the PTP rates. Since the maximum output of all generators was the largest reasonable figure, it produced the lowest possible LT-PTP rate. The computation is summarized in the Commission's April 23, 1998 Decision that adopted the LT-PTP rate in BC Hydro's WTS tariff. "Customers wishing to take Long-Term Firm Point-to-Point Services must identify specific Points of Receipt and Delivery at which they reserve capacity and are billed based on their maximum use at either the Point of Receipt or Point of Delivery. The maximum rate is equal to B.C. Hydro's total Transmission Revenue Requirement less Short-Term Point-to-Point Revenues, revenues from grandfathered contracts and certain other adjustments divided by the annualized maximum system noncoincident peak" (Exhibit 2, BCUC IR 1, Question 36). (April 23, 1998 Decision, p.36)

BCTC understands that the cost of service study requirement is motivated by the Commission's view that "[t]o promote a more efficient use of and competitive access to the transmission system, BCTC must continue to innovate with renewed consideration of options for restructuring the entire tariff from a cost causation perspective" (the Decision, p.13). In compliance with this requirement, this report considers a wide range of cost-based design options for LT-PTP service. These options are described in Section 4. BCTC's approach to developing the cost basis for these designs is found in Appendix C.

2.1.3 Cost-based design options

The Decision is clear on cost-based design options. "The Commission Panel directs BCTC to undertake a study and review the options for more fundamental changes to its rate design for the December 2006 report discussed in Section 14. In particular, the report should discuss alternative forms of PTP rates that could further enhance utilization of the transmission system while still reflecting a degree of cost causality" (the Decision, p.110).

As a result of the Commission's directive, this report explores a wide spectrum of cost-based rate designs. However, BCTC notes up-front that the principal implication of using a more traditional form of cost-based ratemaking to design PTP rates is that it *may raise the LT-PTP rate*. This result arises from BCTC's current use of installed generation as the allocation factor for all OATT long-term rates[16]. More standard rate designs use allocation factors such as load at the time of the annual system peak (1-CP) or at the twelve monthly system peaks (12-CP). These allocation factors produce a higher share of transmission costs for LT-PTP service than the rate design process used today. A fundamental redesign of the OATT along cost-of-service principles that resulted in a LT-PTP rate increase would run counter to the Commission's stated goals of improving transmission utilization.

In spite of this general result, this report describes some cost-based approaches that BCTC believes have the potential to increase transmission utilization. Section 4 further explains cost-based ratemaking and describes the development and implications of these cost-based design options.

[16] April 23, 1998 Decision, p. 36.

2.1.4 PTP service options for non-dispatchable resources

In its previous OATT Application, BCTC proposed a rate designed to facilitate the development of "BC Clean" resources. BC Clean refers to "electricity generated from resources and facilities built in British Columbia that have a lesser environmental impact relative to conventional generation sources and technology,"[17] and can include biogas, waste heat recovery, geothermal, wind, tidal, and a variety of other generating technologies. The Commission denied BCTC's BC Clean Rate proposal, concluding that "to offer a reduced rate to a class of customers defined by a size and type restriction, such as the BC Clean rate does, is unduly discriminatory. This is not necessarily to say there cannot be differing rates for different users of LT-PTP service, but rather that the basis for any distinction needs to be more robust than the rationale underlying the BC Clean eligibility provisions proposed by BCTC." (the Decision, pp. 51-52)

The Commission also directed BCTC to "undertake a study and review the options for more fundamental changes to its rate design for the December 2006 report discussed in Section 14. In particular, the report should discuss alternative forms of PTP rates that could further enhance utilization of the transmission system while still reflecting a degree of cost causality" (the Decision, p.111).

In light of the Decision, this report considers a number of cost-based options to increase utilization, including FERC's proposed conditional firm service, a voluntary redispatch service similar to the one described by Columbia Grid,[18] and a LT-PTP rate for non-dispatchable generation. This last option recognizes that the contribution of non-dispatchable generators to peak system demand is typically much less than their maximum nameplate capacity. This design, which is described in Section 5, recognizes the differences in BCTC's costs to serve resources that have an output pattern that is non-dispatchable, relative to a generator whose output can be controlled.

---

17 BC Ministry of Energy, Mines and Petroleum Resources, http://www.em.gov.bc.ca/AlternativeEnergy/bc_clean_electric_guidelines.htm.

18 Columbia Grid has described the concept of developing an hour ahead congestion management system that makes use of voluntary generator bids for redispatch. BPA is set to begin testing the initial phase of this concept in the summer of 2007. See the following link for a more complete description. http://www.columbiagrid.org/wpcontent/uploads/2006/09/9%2011%2006%20Reliability%20Redispatch.pdf

2.1.5 NITS billing determinants

The Decision accepted BCTC's Load Ratio Share approach for sharing costs between NITS customers[19]. However, it also directed BCTC to review the appropriateness of this approach.

In response to the Commission's directive, this report has considered alternative billing determinants for NITS and their effect on monthly bills for any customer that might wish to take NITS. The findings are presented in Appendix A of this report.

2.1.6 ST-PTP rate

While the Decision accepts BCTC's ST-PTP rate design, it expresses interest in the effect of alternative pricing formulae on electricity trading and revenue[20]. In particular: "the Commission Panel directs BCTC to include in the December 2006 report, discussed in Section 14, an evaluation of the directional aspect of short-term service price discounting," (the Decision, p.111).

In compliance with this directive, this report contains an evaluation to: (a) quantify the amount of short-term energy trade that flows in the opposite direction of the market prices used in the formula; (b) assess the incremental impact of BCTC's directional discounting practice, and a variety of other ST-PTP discounting formulae, on revenues and the percentage of blocked hours; and (c) assess the accuracy of BCTC's discounting formula in predicting transmission

[19] "The Commission Panel notes the advantages to Network Customers that would result from the JIESC's recommended NITS rate, expressed in $/kW of contract demand, but also observes that reliance on forecast billing demands in setting the rate could potentially result in over or under collections of the Network TRR. The Commission Panel is therefore of the view that BCTC's use of Load Ratio Share for the NITS rate is appropriate for the time being. Given there is currently only one NITS customer, BCTC's proposed approach will more predictably collect the forecast Network TRR." (the Decision, pp.15-16)

[20] "The Commission Panel accepts the proposal that the short-term pricing discounting formula should be directional with the price of transmission equal to zero in the opposite direction of gains from trade, as based on the difference between Alberta and Mid-C market prices. However, the Commission Panel notes the uncertainty about the impacts of the directional proposal. For example, the Commission Panel observes that BCTC was unable to model this aspect of its proposal in its evaluation of the percentage of blocked hours and revenue impacts under different short-term pricing formulas (Exhibit B1-6, AESO IR 2.19.3). Also, in response to cross-examination by Commission counsel, the BCTC panel did not know whether it could be profitable for Powerex to trade into the US when the Alberta price was higher than the Mid-C price (T8: 899)." (the Decision, p.60)

value over multiple days. The findings of this evaluation are described in Section 6 of this report.

2.1.7 Re-dispatch

The Decision directed BCTC "to file a re-dispatch tariff as soon as practicable, and report to the Commission at fiscal year end, if the re-dispatch tariff has not been filed by that time." (the Decision, p.110). On September 23, 2005, the Commission issued its decision regarding BCTC's F2006-F2015 Transmission System Capital Plan Application[21]. This decision directs BCTC to consider options for customer-supplied transmission services as solutions to transmission constraints. Commission Letter No. L-16-06 accepts BCTC's proposal to include the response to the non-wires related directives from both decisions in this report. These responses are provided in Appendix B of this report.

A specific observation is appropriate regarding BCTC's non-wires analysis and recommendations. The non-wires content of this report has been fundamentally shaped by the existing electricity market structure in the province. Two factors are particularly relevant in this context: (a) BCTC is responsible for operating, planning, and maintaining BC Hydro's transmission system pursuant to the Designated Agreements; and (2) BCTC does not own generation or serve retail loads. These parameters shape BCTC's non-wires "tool kit" and, in particular, prevent BCTC from compelling any party, including BC Hydro, to provide generation dispatch or load response for economic (as distinct from reliability) reasons. Consequently, the solutions BCTC identifies in this report are limited to the voluntary participation of BC generators or loads in programs that BCTC believes have an opportunity to increase transmission capacity and utilization.

---

[21] In the Matter of British Columbia Transmission Corporation Transmission System Capital Plan F2006 to F2015 Application (September 23, 2005), (Capital Plan Decision).

2.1.8 Shaped Service

The Decision approved BCTC's proposal for Shaped Service[22] and directed BCTC to "include in the December 2006 report … a summary of the use of Shaped Service, commenting on any evident implications of its use relative to present concerns about available capacity or service degradation" (the Decision, p.47). Since BCTC does not yet have any customers taking its new Shaped Service, it is premature at this time to comment on its impact on other transmission customers. However, some of the issues discussed in this report with respect to the Term PTP Service[23] also apply to Shaped Service, including pricing, rollover rights, and the right of first refusal for new capacity. BCTC proposes to include its Shaped Service in its customer consultations on Term PTP and other long-term service options.

2.2 Other reporting requirements

2.2.1 Commission Order No. G-12-06

In Order G-12-06, the Commission stated, at page 2: "BCTC plans to address the applicability of its discount policy to Dynamic Scheduling Service as part of the comprehensive rate design proposal it will file by December 31, 2006, in accordance with the OATT Decision.[24] … The Commission does not oppose BCTC proposing changes to the applicability of its discount policy to DS Service as part of the rate design application[25] it expects to file by December 31, 2006". BCTC's view on the applicability of a ST-PTP discount for Dynamic Scheduling Service, and other capacity products is described in Section 6 of this report.

2.2.2 Impact of the $55 minimum scheduling fee

In BCTC's March 31, 2006 letter to Mr. Bryenton of Cascade Pacific Power Corporation, BCTC wrote: "The issue regarding the impact of the [$55] minimum fee on small users had been raised and debated in the oral proceeding. … However, BCTC understands your concerns and particularly appreciates your proposals on alternative methods for cost recovery. BCTC will

[22] "The Commission Panel approves the LTF Shaped Service inclusive of BCTC's revisions to the rollover provisions in the OATT Terms and Conditions." (June 20, 2005 Decision, p.47)

[23] A new Term PTP Service is more fully described in Section 5 of this report.

[24] The directive in the Decision was to file this report. Please see the Decision, page 114, directive 31.

[25] Please see footnote 24 *supra*.

evaluate your proposals and other methods of cost recovery with the objective of maintaining fair contribution to cost recovery and lessening the impact on your business and other businesses like yours. BCTC will include the findings and recommendations of this evaluation in the Rate Design Report to be submitted to the Commission by December 31, 2006." In its August 16, 2006 letter to Mr. Bryenton, the Commission concurred that the $55 minimum scheduling fee evaluation should be part of this report. This evaluation is also provided in Section 6.

3. Rate Design Drivers

This report's compliance with the Decision requires a consideration of a wide range of cost-based design options, some of which may be at odds with the Master Agreement, BCTC's rate design goals, or BC's Energy Plan (Energy for our Future: A Plan for BC). Thus, BCTC does not suggest that each of the design options considered here strikes an appropriate balance between the interests of its customers and among the competing rate design objectives that are "within the policy framework created by the FERC Order No. 888 *pro forma* tariff, the Energy Plan and the Master Agreement" (the Decision, p.13).

Indeed, it has been necessary in preparing this report to start from first principles and to consider rate design options that are beyond what BCTC has considered in the past. This broader perspective derives from the Commission's finding that "BCTC has not become enough of an agent of change from the longer term perspective." These new rate designs are considered in the spirit of the Commission's directive to "continue to innovate with renewed consideration of options for restructuring the entire tariff from a cost causation perspective" (the Decision, p.13).

To provide context, this section describes the drivers and the sometimes-competing goals and interests that may come into play in the context of each cost-based design option.

3.1 On-going FERC reviews

The cost-based design options in this report should be viewed along with the on-going efforts by FERC in addressing concerns related to an OATT. This consideration is important and relevant because a significant change to BCTC's existing OATT could affect transmission use and electricity trading by BCTC customers. From the perspective of a trader or independent power producer (IPP) in BC, the US market is a profitable outlet for power export in the heavy-load-hours, especially in the summer when electricity demands are high in the US. From the perspective of a load-serving entity in BC, the US market is a low-cost source for power import in the light-load hours, especially in the spring when there is abundant hydro runoff. Should a rate design option result in an OATT that is not compatible with the FERC Order No. 888 *pro forma* tariff, its implementation could impede cross-border trading.

FERC's May 18, 2006 Notice of Proposed Rulemaking (NOPR)[26] aims to address perceived shortcomings of the Order No. 888 *pro forma* tariff. The NOPR makes it clear that the proposals are not intended to redesign approved, fully-functional regional transmission organization or independent system operator markets. The core elements of the *pro forma* tariff are retained[27].

One of the core elements is the protection of native load, which in BCTC's context is the retail loads served by BC Hydro. For instance, FERC Order No. 888 does not require transmission providers to un-bundle transmission service to their retail native loads, nor does it require that the un-bundled transmission service be taken by retail loads. Moreover, FERC allows a transmission provider to reserve, in its calculation of available transmission capacity (ATC), transmission capacity necessary to accommodate native load growth reasonably forecasted in its planning horizon. Additionally, rollover rights can be restricted under Order No. 888 where the capacity is reasonably forecast to be needed to serve native load customers, as long as that restriction is specified in the customer's service contract. These important aspects of the NOPR allow transmission providers to continue to meet the needs of load serving entities with domestic service obligations, while continuing to offer a FERC-compliant OATT that is consistent with the *pro forma* tariff.

The NOPR proposes five major changes:

1. Improve transparency and consistency in several critical areas (including the calculation of ATC);

---

[26] *Preventing Undue Discrimination and Preference in Transmission Service*, 115 FERC ¶61,211 (Notice of Proposed Rulemaking).

[27] "Although we are proposing many important reforms to Order No. 888 and the pro forma OATT, we also wish to emphasize that we propose to retain many of the core elements of Order No. 888. We note that many of these core elements enjoy broad support across many sectors of the industry." (FERC NOPR, *supra* p.47).

2. Require more stringent transmission planning requirements, including open and transparent planning processes at both the local and regional levels;

3. Amend certain portions of the Order No. 888 *pro forma* tariff to prevent discrimination against new merchant generation;

4. Allow transmission customers better access to information to make their resource procurement and investment decisions; and

5. Amend and clarify rollover rights, “redirects”, and generation re-dispatch.

These proposals represent modifications to discrete terms and conditions of the tariff, with no major changes to the *pro forma* tariff framework.

The drivers for the proposals in the NOPR are, to a large extent, unrelated to BCTC’s response to the Commission’s directive on cost-based rate designs. The drivers of the proposals in the NOPR include[28]: (a) undue discrimination in transmission access due to the transmission monopolist’s economic interest in offering better access to itself as a generation owner or load serving entity; (b) the lack of transparency in the evaluation of available transmission capacity, transmission planning, and the processing of transmission requests; and (c) the lack of incentive to resolve congestion by the transmission owner that is also an integrated utility.

Even if the FERC identified drivers are defined very broadly, they only partially apply to BCTC, an independent transmission provider that does not own generation or serve retail loads. For this reason, BCTC has not sought to respond to, or take a position on, all of the five proposals in the NOPR for modifications to the *pro forma* tariff. BCTC will revisit those proposals in the NOPR, and develop a position on them, if and when they have been approved by FERC.

[28] Preventing Undue Discrimination and Preference in Transmission Service, 115 FERC ¶61,211 (2006) (Notice of Proposal Rulemaking), at para. 21 to 41.

That said, the re-dispatch component of the fifth proposal is related to BCTC's response to Commission Letter No. L-16-06, approving BCTC's proposal to address re-dispatch and customer supplied solutions as part of this report. Details of this are presented in Appendix B.

3.2 Master Agreement

In the Commission proceedings considering BCTC's Application for an Open Access Transmission Tariff and BC Hydro's Interconnected Operations Services to BCTC (the OATT Proceeding), BCTC stated in its final submission that "[t]he Master Agreement, between BC Hydro and BCTC, dated November 12, 2003 (the "Master Agreement"), one of the Designated Agreements, sets out a number of principles that have also been taken into account in designing the OATT. These principles include safety, reliability, availability, efficiency, cost-effectiveness, and service quality. The Master Agreement also contemplates the operation of the transmission system in a manner that maximizes use of the system, through appropriate pricing and discounting policies, subject to Commission approval".[29]

These provisions of the Master Agreement mean that, subject to Commission approval, BCTC must design its OATT to address certain issues (e.g., market access, inter-regional jurisdictions, and optimization of through-put) that may be absent in a traditional cost-based rate design exercise. A cost-based design that raises rates relative to the existing OATT would tend to be inconsistent with the intent of these provisions.

3.3 BCTC rate design goals

The Decision summarizes BCTC's rate design goals as: "reliability, low rates (as low as possible), non-discriminatory access to all eligible customers, transparent and efficient interconnection policy and a fair, efficient, easy-to-use tariff." (the Decision, p.8) BCTC's OATT Application recognized that "these goals may conflict with one another from time to time. For example, enhancing transmission access opportunities may create upward pressure on rates.

[29] OATT Proceeding, Submissions of British Columbia Transmission Corporation, March 22, 2005, p. 4. The relevant sections of the Master Agreement are sections 4.5(b) and 4.6(e)

At the same time, making a tariff easy-to-use can sometimes involve simplifications that compromise economic efficiency. These trade-offs are an inherent part of rate design."[30]

The same tradeoffs continue to exist in cost-based design options. For example, a cost-based allocation of the transmission revenue requirement between NITS and PTP customers might make the LT-PTP rate more volatile and difficult to forecast and use, thereby limiting transmission access for IPPs. In addition, the revision might raise transmission rates, thus reducing transmission utilization. Finally, if the revision were to remove the TRR backstopping by NITS customers, it could create some degree of revenue uncertainty for the utility.

3.4 Energy Plan

In its August 3, 2004 OATT Application, BCTC expressed its reliance on the Energy Plan in developing its OATT proposal[31]. The Energy Plan's four cornerstones are: (1) low electricity rates and public ownership of BC Hydro; (2) secure, reliable supply; (3) more private sector opportunities; and (4) environmental responsibility and no nuclear power sources.

To achieve these objectives, Government described a set of Policy Actions. The relevant Policy Actions cited by BCTC were[32]:

- Policy Action 2: BC Hydro ratepayers will continue to benefit from electricity trade.

- Policy Action 7: High reliability and energy security will be maintained through well functioning natural gas markets and coordinated electricity planning.

- Policy Action 9: Electricity distributors will acquire new supply on a least-cost basis, with regulatory oversight by the Commission.

[30] OATT Proceeding, Ex. B1-1, BCTC Application for an Open Access Transmission Tariff, p.18. (OATT Application)

[31] BCTC OATT Application, page 13.

[32] Please see the Decision at page 7.

- Policy Action 13: The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.

- Policy Action 14: Under new rates, large electricity consumers will be able to choose a supplier other than the local distributor.

- Policy Action 15: BCTC will improve access to the transmission system and enable IPP participation in US wholesale markets.

- Policy Action 20: Electricity distributors will pursue a voluntary goal to acquire 50% of new supply from BC Clean electricity over the next 10 years.

The Decision acknowledged BCTC's effort in promoting the goals described in the Energy Plan but concluded that the Energy Plan would not be used as the sole rationale for such rate design initiatives:

> "The Commission Panel, however, finds itself constrained by its regulatory mandate as set out in the UCA. BCUC must comply with section 59, which provides, in part, that a public utility must not make, demand or receive an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia. The Energy Plan can inspire innovative rate design but cannot be used as sole rationale for such rate design initiatives. The Energy Plan provides ***checkpoints*** for BCTC to ensure that its proposed rate design does not impede implementation of Energy Plan actions by other parties."[33] (***emphasis*** added)

3.5 Conclusion

Taken together, the preceding discussion leads to the following drivers, goals and interests, in addition to the principles of cost causality:

[33] Please see the Decision, page 10.

- Securing continued access for BC market participants to sell electricity at market-based rates in the United States (Master Agreement (4.5b)).

- Maximizing throughput of the BCTC grid (Master Agreement (4.6e)).

- Preserving BCTC's rate design goals of "reliability, low rates (as low as possible), non-discriminatory access to all eligible customers, transparent and efficient interconnection policy and a fair, efficient, easy-to-use tariff." (the Decision, p.8)

- Providing no impedance of Energy Plan implementation by other parties (the Decision, p.10).

The analysis in this report shows that neither the existing OATT, nor any of the alternative cost-based designs described here, can completely satisfy these goals and interests. Tradeoffs remain inevitable, even though the nature of the tradeoffs may evolve along with the recent development in the Pacific Northwest with regard to regional transmission.

BCTC's last OATT Application was filed at a time when Grid West was contemplating fundamental changes in the way transmission was operated and sold in the region. With the demise of Grid West, BCTC is no longer expecting a large-scale institutional solution to transmission issues in the West.

In the immediate term, BCTC only expects moderate changes to emerge from the current FERC review of the *pro forma* 888 tariff. Meanwhile, BCTC and other utilities are pursuing stand-alone or bilateral initiatives to advance the integration and operations of the regional transmission system. These include:

- BCTC and the Alberta Electric System Operator (AESO) are actively studying opportunities to reinforce the interties between the provinces, and to improve capacity sales between them.

- BPA, alone and with regional partners through Columbia Grid, will be piloting a bid-based re-dispatch program in the summer of 2007.

- BPA and the Northwest Power and Conservation Council are drafting a detailed wind integration plan, which is expected to be ready by January 2007.

The inevitable tradeoffs and the on-going development in regional transmission mean that it is essential for BCTC to engage in customer consultation and monitor what is occurring elsewhere before applying for specific tariff changes that may arise from this report. What this report does do is provide information to the Commission and interested parties about the potential implications of alternative cost-based approaches for revising the OATT.

4. Long-term Rate Design Options

4.1 Introduction

This section presents seven long-term rate design options. The options are presented on a continuum; Option 1 is the *status quo* (i.e., BCTC's existing OATT), while Option 7 involves the most fundamental tariff changes considered in this report.

Any of the options presented here could be implemented without significantly changing BC's existing electricity market structure or creating new seams between BC and its neighbouring markets. In particular, ***none*** of the seven options would:

1. Involve developing a load-based "pool" design where the fixed costs of transmission service are primarily collected from loads. This reflects BCTC's belief that such a tariff needs to emerge from provincial public policy, and be adopted as part of a regional solution that eliminates rate pancaking for energy trading over multiple transmission providers in the Pacific Northwest[34]. Unilateral elimination of transmission charges by BCTC for suppliers not connected directly to its BCTC grid would benefit those suppliers, while disadvantaging BC generators that sell into the neighbouring jurisdictions[35].

2. Bill a LT-PTP transmission user on the basis of MWh transmitted (e.g., a tariff with long-term PTP rates expressed in dollars per MWh). Instead, all of the options presented here continue to bill according to a customer's capacity reservation (dollars per MW reserved). This reflects BCTC's belief that peak demands are the primary driver of BC transmission costs.

3. Have rates that are not cost-based. In compliance with the Commission's cost-based design directive, BCTC has only considered cost-based designs with rates

[34] Examples of regional solutions are CAISO, NYISO, ISO-NE, PJM and ERCOT, see Lusztig, et al., op cit.

[35] Pool designs typically charge a load-based access fee, so out-of-province generators would have no-cost access to the BC grid under a pool design. If BC were to adopt this form of pricing prior to other jurisdictions, this benefit would not be reciprocal.

reflective of a transmission user's contribution to the peak demands of the transmission system.

4. Create different cost allocation factors for the bulk, local and intertie portions of the transmission system. BCTC believes that the use of different cost allocation factors would substantially complicate the analysis and would be unlikely to materially change the key results described below. In other words, as long as some measure of peak demands are used to allocate each portion of these costs, the results of the analysis in this report would continue to be consistent with a more detailed cost-based ratemaking process.

4.2 Review of cost-based ratemaking

The seven options reflect how BCTC might redesign its rates to preserve and improve efficiency, while still preserving an underlying cost basis. To provide an appropriate context for the consideration of these options, it is useful to summarize and provide an example of the cost-based ratemaking process. The relevant elements of this review include the differences between typical retail ratemaking, industry-standard transmission ratemaking, and the ratemaking approach that has been employed in BC since the introduction of BC Hydro's WTS tariff in 1997.

4.2.1 Retail ratemaking

A regulated load-serving entity (LSE) like BC Hydro is required to reliably meet its customers' electricity needs. In return, the LSE is permitted to charge its customers rates that allow it to recover its total cost of service (or revenue requirement). Rates must also be set to recover from each class of customer (residential, for example) an appropriate share of the utility's revenue requirement, based on the costs the utility faces to serve that class. This is broadly achieved when a utility's revenue-to-cost ratio for each class approaches unity.

The first step in developing cost-based rates is separating costs into generation, transmission, and distribution functions. Within each function, costs are classified into energy, demand, and customer related costs. Next, costs are allocated to customer classes of service in a manner that preserves the cost causation principle. For example, if an increase in demand of a particular class results in higher costs when that increase coincides with the system peak (or peaks), then demand related costs are allocated based on the demand of each class at the time of the system peak(s).

Therefore, it is common to assess the reasonableness of a rate by assessing the cost-of-service for a customer class, and comparing that, on a unit basis, to the rates actually charged by the utility. This relationship is known as the revenue-to-cost ratio. Typically, regulators consider a rate to be cost-based when the revenue-to-cost ratio approaches 1.0, based on a fully allocated cost of service study. This is notwithstanding that strictly cost-based rates are at times modified, so as to avoid imposing an undue rate burden on any specific retail customer class, or to accommodate other ratemaking goals.

4.2.2 Transmission ratemaking

The industry-standard process used to establish transmission rates mirrors the retail ratemaking process described above. Transmission costs are classified mostly as demand-related and allocated to the long-term services. Typically, the long-term services include both NITS and PTP service. In addition, native load service is often provided outside of these services, either explicitly with a domestic service contract described in the OATT (as in Quebec) or, more commonly, through a contract defined outside of the OATT.

Since transmission is almost entirely comprised of demand related costs, an often-contentious issue in transmission ratemaking is the choice of the basis for allocating costs (usually the coincident peak (CP) cost allocation method). The majority of transmission providers in North America use the 12-CP method. This approach allocates costs to each customer class based on that class's contribution to each of the system's monthly peak demands. However, FERC has also accepted 1-, 3-, and 4-CP methods, in cases where a transmission provider can show that its chosen method is the most reflective of its investment planning[36].

---

[36] Small, M.E. (1994) A Guide to FERC Regulation and Ratemaking of Electric Utilities and Other Power Companies, Edison Electric Institute.

The rate design process used by New Brunswick Power (NB Power) is a good example of the industry-standard[37] for approach to cost-based transmission ratemaking[38], that is used by transmission providers with a FERC Order No. 888 *pro forma* based tariff. NB Power uses the following ratemaking steps:

- *Cost functionalization*. NB Power functionalizes costs into Province Bulk Network, Bulk Network Interconnections, Generator Related Transmission Assets, Generator Step-up Transformers, Local Service, and costs related to its Energy Control Center. The Energy Control Center costs are allocated to Scheduling, System Control and Dispatch ancillary services. All GRTA costs are allocated as direct assignment charges to generators.

- *Determination of long-term Transmission Revenue Requirement (TRR)*. The TRR to be collected under the OATT includes Interconnections, In-Province Bulk Network, and Local Service costs. The long-term TRR is found by netting out revenues derived from short-term firm and non-firm sales, and a wheeling contract that pre-dated the OATT and remains in force.

- *Cost allocation*. NB Power uses a 12-CP method[39] resulting in an allocation of 25.5% of the long-term TRR to the PTP class and the remaining 74.5% to the Network Service class.

- *Long-term rate determination*. Each class' per kilowatt-year rate is the class' allocated revenue divided by the class' billing determinant.

---

[37] "Industry standard" in this context refers to the method of allocating costs to derive rates. The terms and conditions of BCTC's tariff would otherwise be considered to be industry standard. Please see, *infra*, section 4.1.

[38] See NB Power Transmission Tariff Design filing, June 2002.

[39] Peak usage is defined for the PTP class as the existing Long Term Firm Reservations. Peak usage for the Network class is defined by a forecast of average network loads at the time of the 12 monthly system peaks in the fiscal year 2003/2004.

- *Short-term rate determination*. NB Power does not offer a rate discount for ST-PTP services. It sets each short-term rate as a fraction of the yearly rate, following what FERC calls the Appalachian pricing formula. The monthly rate is the yearly rate divided by 12 months per year. The weekly rate is the yearly rate divided by 52 weeks per year. The on-peak daily rate is the weekly rate divided by five weekdays per week. The on-peak hourly rate is the on-peak daily rate divided by 16 on-peak hours per day. The off-peak daily rate is the yearly rate divided by 365 days per year. The off peak hourly rate is the yearly rate divided by 8760 hours per year.

4.2.3 Transmission ratemaking in BCTC's tariff

BCTC's ratemaking mechanism is different from the industry standard approach to cost allocation among customer classes[40]. While BCTC's wholesale rates are cost-based in the sense that, in aggregate, they recover the utility's cost of service, there is no attempt to allocate costs based on each class' use coincident with the system peak, or to set rates that achieve a near-1.0 revenue-cost ratio for each class.

BCTC functionalizes costs to categories of stations, lines, control centres, communications, general administration, and customer. All other costs are treated as demand related because the cost of transmission does not vary with fluctuations in volume.

BCTC's revenue requirement for long-term services is its Net TRR (i.e., net of revenues from engineering and ancillary services). The LT-PTP rate is the Net TRR divided by the rated maximum output of all generators connected to the transmission system. The NITS revenue requirement is the Net TRR less the projected ST-PTP and LT-PTP revenues. A NITS customer's monthly bill is its Load Ratio Share of the NITS revenue requirement divided by 12 months per year.

[40] Although the industry-standard approach is most commonly used, it is by no means used by all transmission providers. For example, Avista derives a LT PTP rate without a cost allocation and collects the residual transmission costs from its NITS customers. Please see Appendix D for a description of the rate design processes used by other Canadian and regional transmission providers.

This ratemaking process means that BC Hydro's native load is "backstopping" BCTC's Net TRR, because a dollar decrease in PTP revenue would exactly translate into a dollar increase in the NITS revenue requirement. Reallocation occurs only on the basis of forecast PTP revenue. It is unrelated to changes in the costs to serve each class.

BCTC's ST-PTP rates are based on a market price index that attempts to estimate the value of transmission as a fraction of the electricity price difference between Alberta and the Mid-Columbia electricity market (Mid-C). The rate is capped at the yearly LT-PTP rate.

There are important differences between the rate design of BCTC's current OATT and the industry-standard approach (e.g., NB Power's ratemaking mechanism described above). These differences include: (a) BC Hydro's native load backstopping of BCTC's Net TRR; (b) crediting of all ST-PTP revenues to NITS; (c) the relatively low LT-PTP rates produced by using the maximum capacity of all interconnected generators as the billing determinant (instead of contribution to peak demand); and (d) ST-PTP rate discounting based on a price index formula to promote transmission utilization and electricity trading.

However, given the dominant use of the system by a single customer (as shown in Table 1.1), and the volatile and unpredictable use of PTP service based on ever-changing market conditions, BCTC's current rate design approach and short-term discounting policy have two clear benefits. First, the backstopping portion of the design ensures full cost recovery by BCTC and provides stable LT-PTP rates for customers. Second, the short-term discounting approach promotes open access to and efficient use of the transmission system. This is notwithstanding that BCTC's current OATT rates do not have a clear link with the utility's cost of service on a class-by-class basis.

4.3 Summary of design options

With the cost-based ratemaking review as the backdrop, this section summarizes the seven long-term rate options described along a continuum of change. The options considered by BCTC are:

- Option 1 is the *status quo*.

- Option 2 is the *status quo* combined with a new Term PTP Service, which will be further detailed in Section 5.

- Option 3 modifies the *status quo* by proportionally sharing the ST-PTP revenues between long-term service classes.

- Options 4 and 5 show how two cost-based allocation methodologies could be used to modify the existing ratemaking process.

- Option 6 is the most commonly used design, following the approach used by NB Power's OATT, as described above.

- Option 7 is the same as Option 6, with the addition of a new LT-PTP service for non-dispatchable generators. The non-dispatchable service is also more fully described in Section 5.

Options 4 through 7 explicitly allocate transmission costs between NITS and PTP services. As such, they remove at least a portion of the current revenue requirement backstopping by the NITS customer class. Options 2 and 7 introduce new services that are more fully described in Section 5.

4.3.1 Implications of cost-based designs on TRR backstop

Removal of the backstop would be a fundamental change from the *status quo* design, where BC Hydro ratepayers pay for the entire transmission system, with their cost responsibility offset by contributions from others. In contrast, allocation of a targeted revenue requirement for each long-term service class would require that each class only pay for the portion of the system that they use at the time of the system peak. Each class' transmission rights [41] would then be associated with the specific payment by that class. This could prompt a fundamental shift in thinking about tariff obligations and the associated transmission rights. Specifically, without a

TRR backstop in place, it might be asked to what extent the native load of BC Hydro should be entitled to reserve uncommitted system capacity for load growth.

There are two different perspectives in connection to the TRR backstop. The first perspective argues that since the system was built for domestic service objectives (including the utility's trading activities to serve domestic load and export surplus generation), it is for domestic load to use and pay for. Selling what it does not need helps reduce domestic load's cost obligation. In short, PTP or other NITS customers compete and pay for the residual system capability after native load service requirements have been completely met.

The second perspective argues that transmission capacity that is not currently committed to native load service should be made available (on a common carrier model) to independent generators, marketers, and other users of the transmission system on the same basis as it is for native load service. While it may be true that the current system was designed to meet the current needs of native load customers, it does not follow that native load should have preferential access to new service[42]. Under this approach, costs are allocated to PTP users on the basis of peak demand contributions by current users.

Both perspectives are valid, but each can lead to different conclusions about system rights. The first perspective leads to retaining the TRR backstopping that accompanies the protection of the native load's continued transmission rights. The second perspective leads to eliminating native load's backstopping obligation and, in turn, to a possible revision in the way that growth in native load's transmission service requirements is accommodated. Thus, adopting

---

[41] For example, if the system has an 8000 MW coincident peak and the LT-PTP class' share is 1000 MW based on its reserved capacity, the LT-PTP class revenue requirement is one-eighth (1000 MW ÷ 8000 MW) of the total long-term revenue requirement.

[42] The view goes beyond FERC's Order No. 681, 116 FERC 61,077 (2006), regarding Long-Term Firm Transmission Rights in Organized Electricity Markets. In that order, FERC's proposed additions to the Federal Power Act state:

> "(4) Long-term firm transmission rights must be made available with term lengths (and/or rights to renewal) that are sufficient to meet the needs of load serving entities to hedge long-term power supply arrangements made or planned to satisfy a service obligation. The length of term of renewals may be different from the original term. Transmission organizations may propose rules specifying the length of terms and use of renewal rights to provide long-term coverage, but must be able to offer firm coverage for at least a 10 year period. (5) Load serving entities must have priority over non-load serving entities in the allocation of long-term firm transmission rights that are supported by existing capacity. The transmission organization may propose reasonable limits on the amount of existing capacity used to support long-term firm transmission rights."

a strictly cost-based design can have significant implications on cost responsibility and right assignment of system access rights to each transmission customer class.

As alternative cost-based designs are evaluated, consideration must also be paid to the rate and revenue implications of class-based revenue requirement responsibility. For example, if BCTC were to use a 12-CP methodology to allocate a revenue obligation to LT-PTP customers, it must design rates to collect those revenues from LT-PTP customers over a defined time period. And in doing so, it must determine how to manage variances between each class' forecast and actual revenues. The key to making a "no-backstop" rate design workable is to develop a ratemaking process that produces relatively predictable LT-PTP rates with stable revenue collection and equitable fixed cost contribution.

Designing predictable LT-PTP rates can be challenging. Under the current TRR backstopping arrangement, BCTC is assured of collecting the TRR. Through the general rate-setting mechanism (described below), forecast changes in PTP revenues are reflected dollar-for-dollar in the NITS revenue obligations. All variances between actual and forecast PTP revenues flow back to the NITS customers through a deferral accounting mechanism.

Adopting a more common cost-based design would require, at a minimum, revising the single deferral account mechanism to allow account variances to be shared among all long-term service users. However, if this sharing mechanism were to allocate account variances using the Load Ratio Share of each class of service, it would still have the net effect of NITS customers being responsible for a large portion of the PTP revenue variations. Alternatively, separate deferral accounts could be developed for each class with any class-specific deviations between forecast and actual revenues maintained within the same class. This option, however, might require that BCTC carry substantial balances in its PTP deferral account in an effort to stabilize the PTP rates. For example, a 50% reduction in LT-PTP revenues in year one would lead to a 100% increase in the LT-PTP rate in year two, if the entire revenue shortfall were to be collected over the following year.

4.3.2 Rate summary

Table 4.1 below summarizes rate outcomes that could be expected under each of the seven options[43]. The table shows that BCTC's current design yields the second lowest LT-PTP rate of $3.818/kilowatt-month (kW-month). The lowest LT-PTP rate of $3.525/kW-month is achieved under Option 3, which assigns a portion of the ST-PTP revenue to the LT-PTP class, in contrast to the *status quo* which assigns the ST-PTP revenue to the NITS customer. Options 4 through 7 modify the *status quo* by adopting alternative cost allocators (i.e., 1-CP or 12-CP), and these options result in higher LT-PTP rates. The 12-CP method under Options 5 through 7, though commonly used, leads to the highest LT-PTP rate. Additional steps such as netting the ST-PTP revenue from the TRR before allocation, as is done under Options 6 and 7, can be used to lower the LT-PTP rate, but this does not fully offset the effects of changing from the *status quo* to a coincident-peak allocator[44].

Table 4.1 also shows illustrative rates for a design that has both LT-PTP dispatchable and non-dispatchable services, Option 7. The jurisdictional examples are taken from Appendix D. These rates are indicative only, because they depend on a number of variables that have not yet been specified (e.g., load factor, and location and diversity of participants). A full description of this option is provided in Section 5.

---

[43] The rate calculations use the F2007 revenue requirements for BCTC, Asset Management and Maintenance Revenue Requirement, and B.C. Hydro Owners Revenue Requirement that resulted from the negotiated settlements for each company pursuant to Commission Order No. G-139-06 relating to BCTC and Order No. G-143-06 relating to B.C. Hydro.

[44] And for reasons explained above, it would be hard to justify changing the short-term revenue allocation without changing to some form of allocation between rate-classes, and eliminating the revenue backstop.

Table 4.1 Summary of seven rate design alternatives

Alternative	Jurisdictional examples	LT-PTP Rate ($/kW-mo.)
1. *Status quo* - Existing OATT	BC is the only jurisdiction where connected capacity is used to design an LT-PTP rate	$3.818
2. *Status-quo* plus new Term Service	None	$3.818
3. Net the ST-PTP revenue from the TRR before setting the LT- PTP rate	The ST-PTP revenue netting is commonly used	$3.525
4. Modify the *status quo* via the 1-CP method	Hydro Quebec and SaskPower use the 1-CP method for cost allocation. BPA attempted to use 1-CP but bill impacts led to negotiated settlement.	$4.235
5. Modify the *status quo* via the 12-CP method	Most jurisdictions use 12-CP method for cost allocation	$4.941
6. After netting the ST-PTP revenue, use the 12-CP method to allocate the new TRR between NITS and LT-PTP customers	Most commonly used approach (e.g., NB Power)	$4.561
7. Same as Option 6 but add a separate LT-PTP Non-Dispatchable Service	None	$4.535 dispatchable, $2.267 non-dispatchable (illustrative)

4.4 Details of cost-based rate designs

4.4.1 Option 1: Status quo

Figure 4.1 illustrates the process used to design the existing OATT rates for NITS, LT-PTP and ST-PTP services. The ratemaking process begins with the calculation of the Net TRR. This Net TRR does not include revenue from scheduling and dispatch, engineering, and other ancillary services (AS).

The LT-PTP rate of $3.818/kW-month is derived from the Net TRR, which is $508,600,000 per year, divided by the product of 11,100 MW of generation capacity connected to the BCTC grid and 12 months.

The LT-PTP rate is also used to set the rate cap for ST-PTP firm service. The hourly firm rate cap is the daily rate (monthly rate * 12 months / 365 days) divided by 24 hours, or $5.25/MWh. Weekly rates are set using a combination of the hourly rate formula and the firm rate cap. Section 6 of this report describes the ST-PTP pricing formula in more detail.

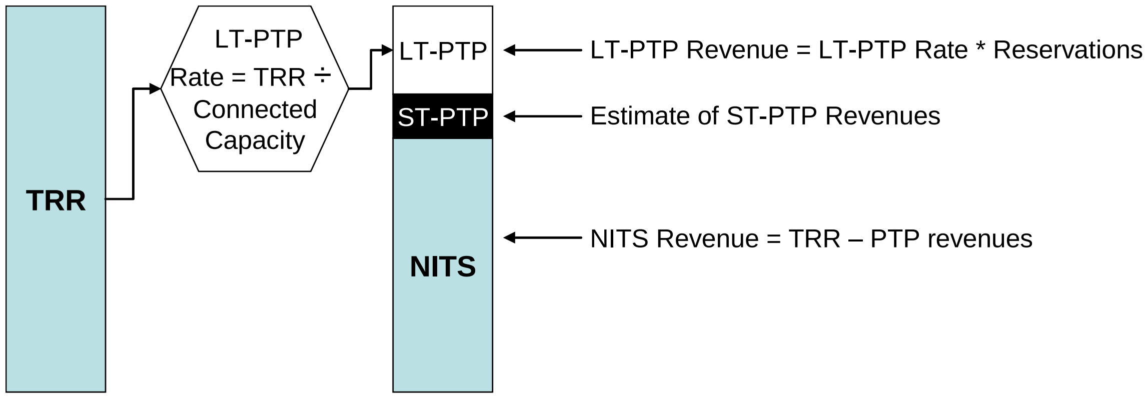

Figure 4.1 Design of existing OATT rates

The right side of Figure 4.1 shows that the NITS revenue requirement is the Net TRR less revenues from BCTC's sale of LT-PTP and ST-PTP services. NITS customers are responsible for paying this Residual TRR. A dollar decrease (increase) in the PTP revenue translates into a dollar increase (decrease) in the Residual TRR; hence, NITS customers are responsible for backstopping the Net TRR and they receive the benefits from increased PTP sales.

Viewed step-by-step, the process for designing the long-term rates in the existing OATT is as follows:

Step 1: Determine the overall revenue requirement per year for all OATT-recoverable BCTC services.

Step 2: Determine the annual Net TRR for long-term rates by subtracting the expected revenues derived from Ancillary Services and engineering services. This is the TRR referenced in Figure 4.1.

Step 3: Set the billing determinant for the LT-PTP rate in $/kW-month at the total kW capacity of all the generators on BC Hydro's system multiplied by 12 months. The total capacity is 11,100 MW, which converts to 133,200,000 kW-months.

Step 4: Derive the LT-PTP rate as the Net TRR divided by the LT-PTP billing determinant.

Step 5: Estimate the annual revenues from LT- and ST-PTP services. These are the white and black boxes shown in Figure 4.1.

Step 6: Set the Residual TRR to be paid by all NITS customers equal to the Net TRR less the LT-PTP and ST-PTP revenues. The monthly charge is the Residual TRR estimated over a future 12 month period divided by 12 months. If there are multiple NITS customers, each NITS customer's monthly charge is based on its Load Ratio Share at the time of the monthly system peak. The NITS monthly bill is adjusted each time there is an authorized adjustment in the TRR.

Applying this process to the updated cost-of-service data yields the numerical results in Table 4.2.

Table 4.2 *Status quo* rate calculation

					Source and Notes
Transmission Revenue Requirement					
1	Transmission Revenue Requirement	$	518,200,000	Step1	Table C.2
2	less Scheduling and Dispatch	$	(3,300,000)		BCTC RFRD, Table 11-3
3	less Engineering	$	(300,000)		BCTC RFRD, Table 11-3
4	less Ancillary Services Other Revenues	$	(6,000,000)		BCTC RFRD, Table 11-3
5	Net TRR for RD	$	508,600,000	Step 2	Line 1 plus Lines 2 through 4
Long Term PTP					
6	Connected Load of BC Gen (MW)		11,100.00		BCUC Design
7	Annual Billing Determininants (KW-mo)		133,200,000	Step 3	Line 6 * 12 * 1000
8	LT PTP Rate ($/kW-mo)	**$**	**3.818**	Step 4	Line 5 / Line 7
9	LT PTP Reservations (kW-mo)		8,292,000		691MW * 1000kW/MW *12 Months
10	LT PTP Revenue ($)	$	31,700,000	Step 5	Line 8 * Line 9
11	LT PTP Conversions ($)	$	(6,000,000)		
Short Term PTP					
12	ST Firm PTP Cap ($/MWH)	$	5.25		Round(Line 8 * 12/365, 3)/24 * 1000
13	Short Term PTP Revenue**	$	45,100,000	Step 5	BCTC RFRD, Table 11-1.
NITS					
14	Residual TRR	$	437,800,000		Line 5 – Line 10 – Line 11 – Line 13
15	Monthly Charge	$	36,483,333	Step 6	Line 14/12

*BCTC RFRD = BCTC Revenue Forecast and Rate Determination (BCTC F2007 Revenue Requirement Application)
**The Short Term PTP revenue would be updated based on the pricing formula selected and the change in the firm cap.

Note that line 11 shows a reduction in LT-PTP revenues of $6 million to reflect the forecasted conversion of customers from LT-PTP to ST-PTP service. Rather than forecasting conversion levels for each rate alternative presented herein, the remainder of this report presents rates using the same conversion assumption. Accordingly, the ST-PTP revenues are reduced by $6 million in the subsequent tables.

BCTC's *status quo* tariff offers the same services under the same terms and conditions offered by most other transmission providers. As such, from a terms and conditions perspective, it is an industry-standard tariff, reflective of the *pro forma* open access tariff for a jurisdiction such as BC that does not have a power pool but still seeks to promote a competitive generation market through bilateral trading[45]. However, BCTC's *rate design* differs from the most commonly used *pro forma* design such as NB Power's in three important ways:

1. The design does not have an explicit allocated revenue requirement for PTP service. Instead, rate comparability between PTP and Network service is assured by dividing the Net TRR by the nameplate capacity of all the generators on the BC Hydro's system (as if all transactions were made on a LT-PTP tariff). Since the nameplate capacity is higher than any measure of peak demand, the LT-PTP rate is substantially lower than it would be under a more standard design with an explicit allocated revenue.

2. All revenues generated from ST-PTP service are credited back to NITS service, which in BCTC's case is solely used by BC Hydro to meet its load service obligations. This aspect of the design results in a higher LT-PTP rate than if ST-PTP revenues were credited back to all long-term service customers.

3. When the actual LT-PTP revenues deviate from the projected levels, the deviations are tracked through a deferral account, with its balance allocated back to the NITS class.

The *status quo* design balances a number of competing objectives. First, the design produces stable and comparatively low rates for LT-PTP service. The rate calculation is unconnected to variations in either PTP or NITS sales and only depends on the TRR and the capacity of generators connected to the BCTC grid. This makes the LT-PTP rate very predictable and consistent. This stability is a necessary feature of any design that aims to facilitate project development.

Second, backstopping the Net TRR by NITS customers ensures a stable and predictable source of revenues and full recovery of the Net TRR by BCTC.

[45] Lusztig, et al.

Third, the tariff complies with the Master Agreement, by producing a LT-PTP rate that is as low as possible – to encourage throughput – but producing a tariff that meets comparability tests and that is acceptable to BC stakeholders. This was confirmed in the Decision.

Finally, the approved OATT has been determined to effectively balance BCTC's rate design goals that incorporate the transmission-related Policy Action from the Energy Plan.

4.4.2 Option 2: *Status quo* plus new Term PTP Service

This design option is the *status quo*, with the addition of a new PTP service, Term PTP, that has a limited term of longer than one year (the current maximum for short-term service) and shorter than BCTC's 10-year transmission planning horizon. The service would not have rollover rights. Section 5 of this report describes two different forms of Term-PTP service. In its simplest form, the service could be discounted to reflect the fact that it is inferior to LT-PTP service. Alternatively, Term PTP service could be provided with (a) a right of first refusal to any capacity that becomes available at the time of renewal, and (b) an opportunity to upgrade to LT-PTP service prior to the end of the term. In this case, Term-PTP service would not be discounted.

The rate calculation for this option mirrors the rate calculation for the status quo with the exception that Term PTP revenue would be treated in the same way that short-term service is treated today. Figure 4.2 below shows the proposed ratemaking process.

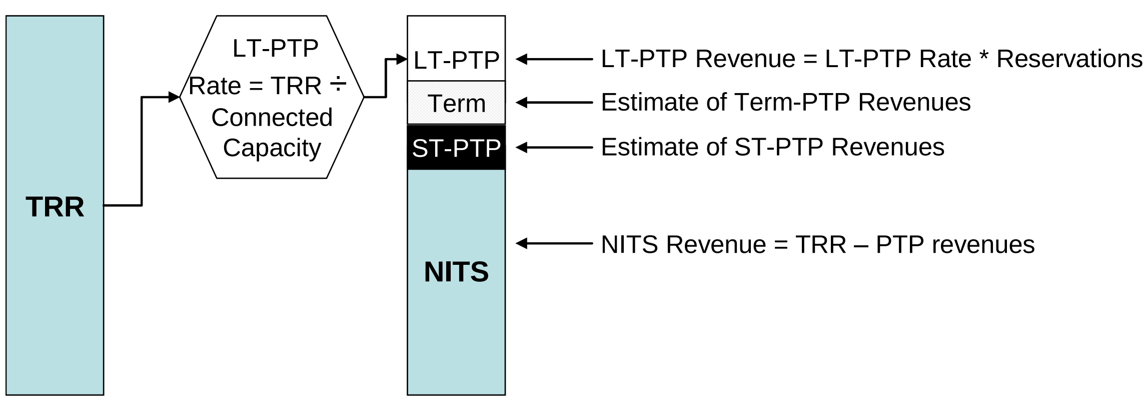

Figure 4.2 *Status Quo* plus Term PTP Service

The right side of Figure 4.2 shows that the NITS revenue requirement is the TRR less the revenues from BCTC's sale of LT-PTP, ST-PTP and Term PTP services. Thus, the NITS revenue continues to be a residual obligation that moves in opposite direction of the LT-PTP, ST-PTP, and Term PTP revenues. As NITS customers are still responsible for this residual revenue, they continue to backstop the TRR.

For clarity, the process for designing the long-term rates in the existing OATT is given below:

Step 1: Determine the overall revenue requirement per year for all OATT-recoverable BCTC services.

Step 2: Determine the Net TRR for long-term rates by subtracting the expected revenues derived from Ancillary Services and Engineering services. This is the TRR referenced in 4.2.

Step 3: Set the billing determinant for the LT-PTP rate in $/kW-month at the total kW capacity of all the generators on BC Hydro's system multiplied by 12 months. The total capacity is 11,100 MW, which converts to 133,200,000 kW-months.

Step 4: Derive the LT-PTP rate as the Net TRR divided by the LT-PTP billing determinant.

Step 5: Estimate the annual revenues from LT-PTP, ST-PTP, and Term PTP services. These are the white, black and cross-hatched boxes shown in 4.2.

Step 6: Set the Residual TRR to be paid by all NITS customers equal to the Net TRR less the LT-PTP, ST-PTP and Term PTP revenues. The monthly charge is the Residual TRR estimated over a future 12 month period divided by 12 months. If there are multiple NITS customers, each NITS customer's monthly charge is based on its Load Ratio Share at the time of the monthly system peak. The NITS monthly bill is adjusted each time there is an authorized adjustment in the TRR.

For the purpose of calculating illustrative rates for this option, BCTC has assumed approximately $20 million per year of additional Term-PTP sales at the estimated rate of $3/kW-month (a figure that lies between the LT-PTP rate and the ST-PTP index price). Under this design, the new Term PTP service would have no rate impact on the LT-PTP service or rate, but probably would reduce the capacity available for ST-PTP sales. BCTC has assumed that ST-PTP service revenues drop by $10 million per year, leaving NITS customers with a net reduction in their transmission service bills of $10 million per year. Section 5 of this report describes Term PTP service in more detail and the pricing/service options BCTC is contemplating.

Table 4.3 *Status quo* with New Term-PTP Service rate calculation

					Source and Notes
Transmission Revenue Requirement					
1	Transmission Revenue Requirement	$	518,200,000	Step 1	Table C.2
2	less Scheduling and Dispatch	$	3,300,000)		BCTC RFRD, Table 11-3
3	less Engineering	$	(300,000)		BCTC RFRD, Table 11-3
4	less Ancilliary Services Other Revenues	$	(6,000,000)		BCTC RFRD, Table 11-3
5	Net TRR for RD	$	508,600,000	Step 2	Line 1 plus Lines 2 through 4
Long Term PTP					
6	Connected Load of BC Gen (MW)		11,100.00		BCUC Decision
7	Annual Billing Determinants (KW-mo)		133,200,000	Step 3	Line 6 * 12 * 1000
8	LT PTP Rate ($kW-mo)	**$**	**3.818**	Step 4	Line 5 / Line 7
9	LT PT Reservations (kW-mo)		8,292,000		691MW * 1000kW/MW * 12 Months
10	LT PTP Revenue ($)	$	31,700,000	Step 5	Line 8 * Line 9
11	LT PTP Conversions ($)	$	(6,000,000)		
Term PTP					
12	Term PTP Revenue	$	20,000,000	Step 5	Illustrative
Short Term PTP					
13	ST Firm PTP Cap ($/MWH)	$	5.25		Round(Line 8 * 12 / 365, 3) / 24 * 1000
14	Short Term PTP Revenue**	$	35,100,000	Step 5	Assumes some sales move to Term PTP
NITS					
15	Residual TRR	$	427,800,000		Line 5 – Line 10 – Line 11 – Line 12 - Line 14
16	Monthly Charge	$	35,650,000	Step 6	Line 15 / 12

*BCTC RFRD = BCTC Revenue Forecast and Rate Determination (BCTC F2007 Revenue Requirement Application)
** The short Term PTP revenue would be updated based on the pricing formula selected and the change in the firm cap.

4.4.3 Option 3 – Apply proportional sharing of the ST-PTP revenue

Option 3, shown in Figure 4.3 below, is a design with a single change from the *status quo*: netting out the ST-PTP revenue estimate from the TRR prior to computing the LT-PTP rate[46]. When compared to the *status quo*, this results in a LT-PTP rate reduction. The lower LT-PTP rate can be justified by an argument that all long-term customers should share the benefit of

[46] The ST-PTP revenue could be based on the most recent year's value.

ST-PTP revenue because all long-term service customers effectively release capacity into the short-term service market when they submit reservations or energy schedules that are lower than their maximum reserved capacity.

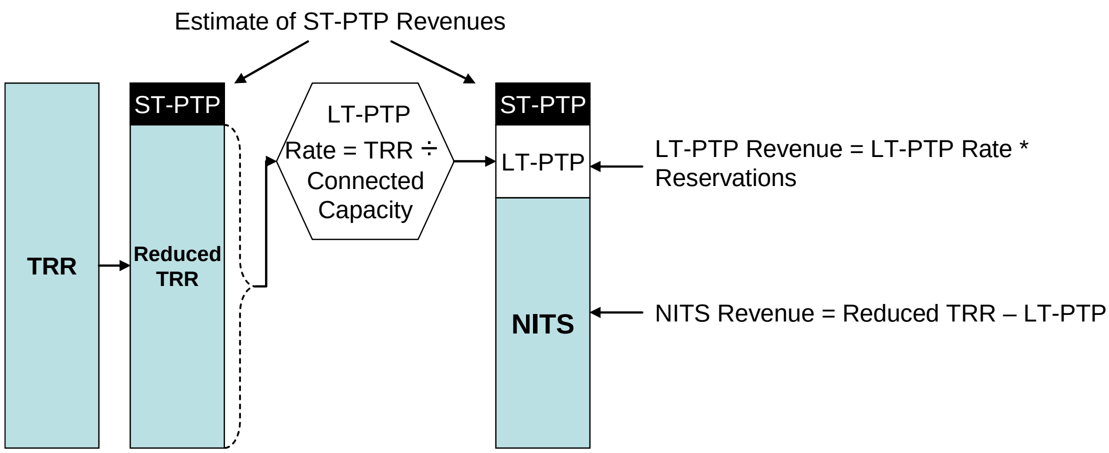

Figure 4.3 Option 3 – Apply proportional sharing of PTP revenues

The process for designing the transmission rates under Option 3 is given below. For easy comparison, deviations from the *status quo* process are again highlighted in **bold**.

Step 1: Determine the overall revenue requirement for all OATT-recoverable BCTC services.

Step 2: Determine the Net TRR for long-term rates by subtracting the expected revenues derived from Ancillary Services and Engineering services. This is the TRR referenced in Figure 4.1.

Step 3: Estimate the annual revenue from ST-PTP services.

Step 4: Compute the Reduced TRR (equal to the Net TRR from Step 2 less ST-PTP revenue from Step 3) to be paid by NITS and LT-PTP customers.

Step 5: Set the billing determinant for the LT-PTP rate at the total kW capacity of all the generators on BC Hydro's system multiplied by 12 months. The total capacity is 11,100 MW, which converts to 133,200,000 kW-months.

Step 6: Derive the LT-PTP rate (in $/kW-month) as the Reduced TRR from Step 4 divided by the LT-PTP billing determinant from Step 5.

Step 7: Find the NITS revenue requirement, which is the Residual TRR (Reduced TRR – LT-PTP), to be paid annually by all NITS customers. The monthly charge is the NITS revenue requirement divided by 12 months. If there are multiple NITS customers, each NITS customer's monthly charge is based on its Load Ratio Share at the time of the monthly system peak.

Applying this process to the updated cost-of-service data yields the numerical results in Table 4.4.

Table 4.4: Apply proportional sharing of ST-PTP revenues

Transmission Revenue Requirement					Source and Notes
1	Transmission Revenue Requirement	$	518,200,000	Step 1	Table C.2
2	less Scheduling and Dispatch	$	(3,300,000)		BCTC RFRD, Table 11-3
3	less Engineering	$	(300,000)		BCTC RFRD, Table 11-3
4	less Ancilliary Services Other Revenues	$	(6,000,000)		BCTC RFRD, Table 11-3
5	Net TRR for RD	$	508,600,000	Step 2	Line 1 plus Lines 2 through 4
6	Short Term PTP Revenue (no conversions)**	$	39,100,000	Step 3	BCTC RFRD, Table 11-1, less $6 M
7	Reduced TRR for NITS and LT PTP	$	469,500,000	Step 4	Line 5 – Line 6
Long Term PTP					
8	Connected Load of BC Gen (MW)		11,100.00		BCUC Decision
9	Annual Billing Determinants (KW-mo)		133,200,000	Step 5	Line 8 * 12 * 1000
10	LT PTP Rate ($/kW-mo)		**$3.525**	Step 6	Line 7 / Line 9
11	LT PTP Reservations (kW-mo)		8,292,000		691MW * 1000kW/MW * 12 Months
12	LT PTP Revenue ($)	$	29,227,432		Line 10 * Line 11
NITS					
13	Residual TRR	$	440,272,568		Line 17 – Line 12
14	Monthly Charge		$ 36,689,381	Step 7	Line 13 / 12

*BCTC RFRD = BCTC Revenue Forecast and Rate Determination (BCTC F2007 Revenue Requirement Application)
** The Short Term PTP revenue would be updated based on the pricing formula selected and the change in the firm cap.

This alternative design is a minor variant of the *status quo* and has similar attributes. Sharing PTP revenues this way acts to reduce the LT-PTP rate by 8%, from $3.818/kW-month to $3.525/kW-month. As a result, it also lowers the rate cap for ST-PTP rates. Both changes are relatively small and would not be expected to change usage significantly. As these rate changes may raise the Residual TRR, NITS customers may see a very small increase in their costs of transmission service. Assuming no changes in usage, the Residual TRR to be paid by NITS customers would increase by about 0.6%, from $438 million under the *status quo* to $440 million.

4.5 Allocation-based options

Options 4 through 7 are designs based on explicit cost allocations that divide BCTC's long-term revenue requirement between the NITS and LT-PTP service classes. BCTC assumes that these design options would, at least partially, remove the TRR backstop obligation of NITS customers. If the removal is complete, adopting any one of these designs means that NITS customers are responsible for paying only their allocated share of the TRR. This ensures that a cost-based NITS rate would yield a cost-based revenue recovery, not an amount that varies simply due to changes in changes in PTP revenues (either forecast or actual).

4.5.1 Option 4 – Modify the *status quo* via the 1-CP method

Figure 4.4 illustrates a single change from the *status quo*: allocating a share of the TRR to the LT-PTP service using the 1-CP method. For ease of comparison with Figure 4.1 above, this figure retains the existing short-term ratemaking components. The option assumes that NITS customers do not backstop the TRR and are responsible for paying their allocated share of the TRR.

Under the 1-CP method, the LT-PTP share of the Net TRR is equal to: (a) LT-PTP load at the time of system annual peak, divided by (b) the sum of NITS and LT-PTP loads at the time of system annual peak. This LT-PTP revenue requirement is shown as the white box in Figure 4.4.

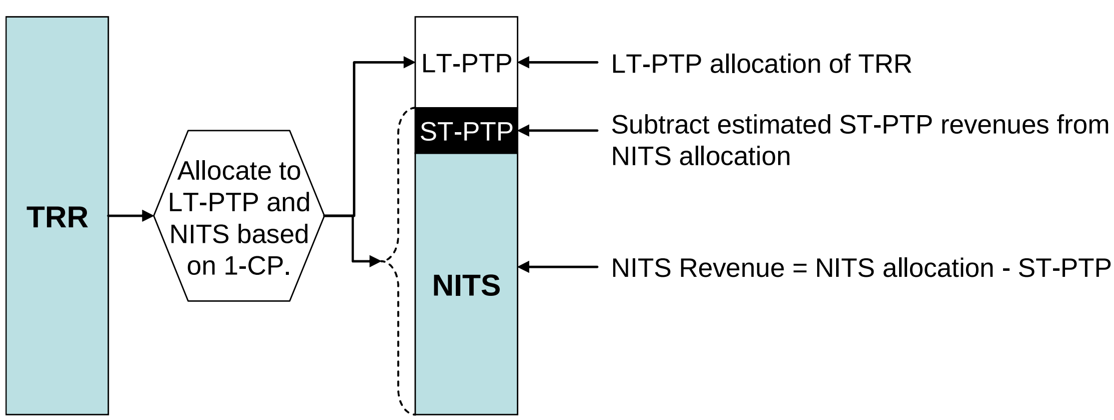

Figure 4.4 Option 4 – Modify the *status quo* via the 1-CP method

The process for designing the long-term rates under Option 4 is given below[47]. The deviations from the *status quo* process are highlighted in **bold**.

Step 1: Determine the overall revenue requirement for all OATT-recoverable BCTC services.

Step 2: Determine the Net TRR for long-term rates by subtracting the expected revenues derived from Ancillary Services and Engineering services. This is the TRR referenced in Figure 4.1.

Step 3: Estimate the NITS and LT-PTP loads at the time of system peak. LT-PTP load at the time of system peak is the sum of LT-PTP annual load reservations.

Step 4: Allocate the Net TRR based on the relative load contributions of the NITS and LT-PTP customers at the time of system peak. Specifically, LT-PTP Allocated TRR = Net TRR * [LT-PTP load / (NITS load + LT-PTP load)].

Step 5: The LT-PTP $/kW-month rate is the LT-PTP Allocated TRR divided by the LT-PTP billing determinants. The LT-PTP billing determinants equal the sum of the LT-PTP annual load reservations multiplied by 12 months.

Step 6: Estimate the annual revenues from ST-PTP services.

Step 7: NITS revenue requirement, which is the Residual TRR (Net TRR – LT-PTP Allocated TRR – ST-PTP revenue). The monthly charge is the NITS revenue requirement divided by 12 months. If there are multiple NITS customers, each NITS customer's monthly charge is based on it Load Ratio Share at the time of the monthly system peak.

Applying this process to the updated cost-of-service data yields the numerical results in Table 4.5 below. The option produces allocated revenue requirements and defined rates for LT-

[47] To avoid redundancy and confusion, the derivation of the short-term rate caps is not repeated here or in the subsequent long-term rate design discussions. For details on the short-term rate caps, please see Section 4.1 above.

PTP service, and an allocated revenue requirement for NITS service. The process increases the LT-PTP rate by 11%, from $3.818/kW-month to $4.235/kW-month. The rate cap for ST-PTP service would increase from $5.25 to $5.79/MWh. Assuming no change in sales, expected LT-PTP revenues would increase from $31,700,000 to $35,116,167 per year compared with Option 1. This increase benefits BC Hydro's domestic consumers by reducing the NITS revenue obligation by $3,416,167 per year.

BCTC found only two utilities in its survey, Trans-Energie and SaskPower, which use a 1-CP method to allocate costs among long-term services for domestic loads, other network loads, and PTP service. Although BPA has stated that its preferred method of transmission cost allocation is 1-CP, its 2006 rates were set through negotiated settlement to mitigate billing impacts. In contrast, the 12-CP allocation is recommended by FERC, and is the most commonly found approach among both FERC jurisdictional and Canadian transmission providers.

Table 4.5 Modify the *status quo* via the 1-CP method

Transmission Revenue Requirement						Source and Notes
1	Transmission Revenue Requirement	$ 518,200,000			Step 1	Table C.2
2	less Scheduling and Dispatch	$ (3,300,000)				BCTC RFRD, Table 11-3
3	less Engineering	$ (300,000)				BCTC RFRD, Table 11-3
4	less Ancilliary Services Other Revenues	$ (6,000,000)				BCTC RFRD, Table 11-3
5	Net TRR for RD	$ 508,600,000			Step 2	Line 1 plus Lines 2 through 4
Long Term PTP (1-CP Allocation)		Non LT-PTP	LT-PTP	Total		
6	1-CP Demands (MW)	9,317	691	10,008	Step 3	Table C.3
7	Allocation shares	93.1%	6.9%	100.0%		Line 6/Line 6 Total
8	1-CP Allocated Revenues	$ 473,483,833	$35,116,167	$508,600,000	Step 4	Line 6 * Line 5
9	LT PTP Reservations (MW)		691			
10	LT PTP Reservations (kW-mo)		8292000			Line 9 * 12 * 1000
11	LT PTP Rate ($kW-mo)		**4.235**		Step 5	Line 8 / Line 10
Short Term PTP						
12	ST Firm PTP Cap ($/MWH)	$ 5.79				Round(Line 11 * 12 / 365, 3) / 24 * 1000
13	Short Term PTP Revenue (no conversions)**	$ 39,100,000			Step 6	BCTC RFRD, Table 11-1, less $6 M
NITS						
14	Residual TRR for NITS	$ 434,383,833				Line 5 – Line 8 (PTP) – Line 13
15	Monthly Charge for NITS	$ 37,198,653			Step 7	Line 14 / 12

*BCTC RFRD = BCTC Revenue Forecast and Rate Determination (BCTC F2007 Revenue Requirement Application)
** The Short Term PTP revenue would be updated based on the pricing formula selected and the change in the firm cap.

4.5.2 Option 5 – Modify the *status quo* via the 12-CP method

In response to filed evidence in BCTC's last OATT Application supporting the use of the 1-CP method, BCTC's filed rebuttal evidence indicating that BCTC's annual load profile is similar to other FERC jurisdictional utilities that use a 12-CP allocation method[48]. BCTC argued that the 12-CP method yields a more appropriate cost allocation than the 1-CP method. However, BCTC also observed that adopting the 12-CP method would substantially raise PTP rates, which is inconsistent with the Commission's view of encouraging utilization as stated in the Decision[49].

Option 5 assumes that NITS customers do not backstop the TRR and are responsible for paying their allocated share of the TRR. It is conceptually identical to Option 4, but instead of the 1-CP method, this option uses the 12-CP method to allocate a share of the TRR to the LT-PTP service.

Under the 12-CP method, the LT-PTP share of the Net TRR is equal to: (a) the sum of monthly LT-PTP loads at the time of system monthly peaks, divided by (b) the sum of system monthly peaks. The monthly LT-PTP loads at the time of system peak are the sum of the annual load reservations. Again, the alternative eliminates the NITS backstop.

Table 4.6 below shows the numerical results of using a 12-CP method to link rates and costs.

---

[48] OATT Proceeding, Ex. B1-18, Rebuttal Evidence of Ren Orans, February 9, 2005, P. 14, Table 2

[49] "The Commission Panel finds that the main objective of the LT-PTP rate should be to provide an appropriate price signal to encourage utilization, while requiring PTP users to make a fair contribution to system costs such that all users of the system benefit." (the Decision, p.36)

Table 4.6: Modify the *status quo* via the 12-CP method

	Transmission Revenue Requirement					*Source and Notes*
1	Transmission Revenue Requirement	$ 518,200,000			*Step 1*	*Table C.2*
2	less Scheduling and Dispatch	$ (3,300,000)				*BCTC RFRD, Table 11-3*
3	less Engineering	$ (300,000)				*BCTC RFRD, Table 11-3*
4	less Ancillary Services Other Revenues	$ (6,000,000)				*BCTC RFRD, Table 11-3*
5	Net TRR for RD	$ 508,600,000			*Step 2*	*Line 1 plus Lines 2 through 4*
	Long Term PTP (12-CP Allocation)	Network	PTP	Total		
6	Average 12-CP Demand (MW)	7,887	691	8,578	*Step 3*	*Table C.3*
7	Allocation shares	91.9%	8.1%	100.0%		*Line 6 / Line 6 Total*
8	12-CP Allocated Revenues	$ 467,629,774	$ 40,970,226	$ 508,600,000	*Step 4*	*Line 6 * Line 5*
9	LT PTP Reservations (MW)		691			
10	LT PTP Reservations (kW-mo)		8292000			*Line 9 * 12 * 1000*
11	LT PTP Rate ($kW-mo)		**4.941**		*Step 5*	
	Short Term PTP					
12	ST Firm PTP Cap ($/MWH)	$ 6.75				*Round(Line 11 * 12 / 365, 3) / 24 * 1000*
13	Short Term PTP Revenue	$ 39,100,000			*Step 6*	*BCTC RFRD, Table 11-1, less $6 M*
	NITS					
14	Residual TRR	$ 428,529,774				*Line 5 – Line 8 (PTP) – Line 13*
15	Monthly Charge	$ 35,710,814			*Step 7*	*Line 14 / 12*

*BCTC RFRD = BCTC Revenue Forecast and Rate Determination (BCTC F2007 Revenue Requirement Application)
** The Short Term PTP revenue would be updated based on the pricing formula selected and the change in the firm cap.

As with the previous alternative, this rate design is more in line with the practice that is commonly used by most utilities that have adopted the FERC Order No. 888 *pro forma* design than is BCTC's current design. However, this alternative increases the LT-PTP rate by about 30%, from $3.818/kW-month to $4.94/kW-month. Assuming no change in sales, expected LT-PTP revenues would increase from $31,700,000 to $40,970,226 per year and BC Hydro's domestic consumers could expect to reduce their transmission payments by $9,270,226 per year when compared with Option 1.

The rate cap for short-term service would increase from $5.25/MWh to $6.83/MWh. A rate change of this magnitude has the potential to restrict economic long- and short-term point-to-point transmission usage. Some fraction of the expected sales lost could be recaptured through effective discounting.

4.5.3 Option 6 –Proportional sharing of Short-term revenues and 12-CP method

This design combines Options 3 and 5. It assumes that NITS customers do not backstop the TRR and are responsible for paying its allocated share of the TRR. It provides rates that are strongly related to costs by its use of a 12-CP cost allocation. And, it allocates ST-PTP revenues proportionally back to customers based on their relative shares of peak transmission usage. The net effect of these modifications (i.e., sharing ST-PTP revenues with all long-term services customers and using the 12-CP method) raises the LT-PTP rate by 20%, from $3.818/kW-month to $4.56/kW-month. Although this rate design might have the strongest relationship to BCTC's costs, it would not improve transmission utilization or encourage development of intermittent generation.

The rate calculation for this alternative is shown below in Table 4.7.

Table 4.7: Proportional sharing plus 12-CP

	Transmission Revenue Requirement								*Source and Notes*
1	Transmission Revenue Requirement	$	518,200,000					*Step 1*	*Table C.2*
2	less Scheduling and Dispatch	$	(3,300,000)						*BCTC RFRD, Table 11-3*
3	less Engineering	$	(300,000)						*BCTC RFRD, Table 11-3*
4	less Ancillary Services Other Revenues	$	(6,000,000)						*BCTC RFRD, Table 11-3*
5	Net TRR for RD	$	508,600,000					*Step 2*	*Line 1 plus Lines 2 through 4*
6	Short Term PTP Revenue	$	39,100,000					*Step 3*	*BCTC RFRD, Table 11-1, less $6M*
7	LT TRR for NITS and LT PTP	$	469,500,000					*Step 4*	*Line 5 - Line 6*
	Long Term PTP (12-CP Allocation)		Non - LT-PTP		LT-PTP		Total		
8	Average 12-CP Demand (MW)		7.887		691		8,578	*Step 5*	*Table C.3*
9	Allocation shares		91.9%		8.1%		100.0%		*Line 8 / Line 8 Total*
10	12-CP Allocated Revenues	$	431,679,471	$	37,820,529	$	469,500,000	*Step 6*	*Line 7 * Line 9*
11	LT PTP Reservations (MW)				691				
12	LT PTP Reservations (kW-mo)				8292000				*Line 11 * 12 * 1000*
13	LT PTP Rate ($kW-mo)				**4.561**			*Step 7*	*Line 10 / Line 12*
	NITS								
14	Residual TRR	$	431,679,471						*Line 10 (Network)*
15	Monthly Charge	$	35,973,289					*Step 8*	*Line 14 / 12*

*BCTC RFRD = BCTC Revenue Forecast and Rate Determination (BCTC F2007 Revenue Requirement Application)
** The Short Term PTP revenue would be updated based on the pricing formula selected and the change in the firm cap.

4.5.4 Option 7 – Option 6 plus LT-PTP service for non-dispatchable generation

This design modifies Option 6 by adding a new class of service alongside NITS and PTP for non-dispatchable generation that may have an intermittent output profile. It continues to assume that NITS customers do not backstop the Net TRR and are responsible for paying their allocated share of the Net TRR. It has the same cost-related attributes as Option 6. Costs are allocated among the three classes of service based on the 12-CP method. As is discussed in Section 5 below, the new LT-PTP service recognizes that non-dispatchable generation imposes lower costs on the BC grid relative to their nameplate capacity than dispatchable generation.

In the illustrative case shown in Table 4.8, introduction of a new dispatchable LT-PTP service lowers the rates of both LT-PTP and NITS customers because we have assumed that the service produces 100 MW of new reservations and only imposes a 50 MW increase in peak demand. The incremental revenues reduce the rates for both dispatchable LT-PTP and NITS service. Our example produces a reduction in both the NITS and the dispatchable LT-PTP rate of 0.6% relative to the rate under the 12-CP method in Option 6. The new reservations are induced by a rate that is 50% lower for non-dispatchable generators, compared to the standard LT-PTP rate from Option 6. On a per-MWh basis, a 30% capacity-factor non-dispatchable user would pay an average of $10.345/MWh, compared to $20.86/MWh under the standard, 12-CP method. A dispatchable, 100% capacity-factor, user would pay an average of $6.21/MWh for LT-PTP service.

Table 4.8. LT-PTP rate based on 12-CP method with a separate non-dispatchable LT-PTP Service

		Network	PTP-Dispatch	PTP-Non-Dispatch	Total		Source and Notes
	Transmission Revenue Requirement						
1	Transmission Revenue Requirement	$ 518,200,000				*Step 1*	*Table C.2*
2	less Scheduling and Dispatch	$ (3,300,000)					*BCTC RFRD, Table 11-3*
3	less Engineering	$ (300,000)					*BCTC RFRD, Table 11-3*
4	less Ancillary Services Other Rev	$ (6,000,000)					*BCTC RFRD, Table 11-3*
5	Net TRR for RD	$ 508,600,000				*Step 2*	*Line 1 plus Lines 2 through 4*
6	Short Term PTP Revenue**	$ 39,100,000				*Step 3*	*BCTC RFRD, Table 11-1, less $*
7	Reduced TRR for RD	$ 469,500,000				*Step 4*	*Line 5 - Line 6*
	Long Term PTP (12-CP Allocation)						
8	12-CP Demands (MW)	7,887	691	50	8,628	*Step 5*	*Illustrative*
9	Allocation shares	91.4%	8.0%	0.6%	100.0%		*Line 8 / Line 8 Total*
10	12-CP Allocated Revenues	$ 429,177,851	$ 37,601,356	$ 2,720,793	$ 469,500,000	*Step 6*	*Line 7 * Line 9*
11	LT PTP Reservations (MW)		691	100			
12	LT PTP Reservations (kW-mo)		8292000	1200000			*Line 11 * 14 * 1000*
13	LT PTP Rate ($kW-mo)		**4.535**	**2.267**		*Step 7*	*Line 10 / Line 12*
	Short Term PTP						
14	ST Firm PTP Cap ($/MWH)		$ 6.21				*Round(Line 13 * 12 / 365, 3) / 24 * 1000*
	NITS						
14	Allocated TRR	$ 429,177,851					*Line 10*
15	Monthly Charge	$ 35,764,821				*Step 8*	*Line 15 / 12*

*BCTC RFRD = BCTC Revenue Forecast and Rate Determination (BCTC F2007 Revenue Requirement Application)
** The Short Term PTP revenue would be updated based on the pricing formula selected and the change in the firm cap.

4.6 Conclusions

Having considered the seven options in detail, BCTC offers the following broad conclusions.

First, the application of a traditional cost-based allocation method (e.g., 12-CP) to BCTC's rate-setting would result in increased LT-PTP rates, and is unlikely to improve the capacity utilization of, or competitive access to, the transmission system.

Second, the existing rate design produces relatively low LT-PTP rates which helps balance the sometimes-competing goals of cost contribution by all system users, high capacity utilization, and competitive transmission access.

Third, netting out the short-term revenues from the long-term revenue requirement before computing the LT-PTP rate can further reduce that rate.

Fourth, two new cost-based services may lead to small increases in asset utilization. These services are:

- *Term PTP service*. Section 5 below contains analysis regarding the range of pricing and service-condition alternatives for a service of this kind.

- *LT-PTP service for non-dispatchable resources*. This service's lower rate reflects that expected aggregate coincident peak transmission use, rather than the sum of the individual users' reservations.

Finally, if the Commission were to consider a cost-based design that uses a peak allocation approach to link transmission costs and rates, it should also consider at the same time the implications of removing BC Hydro's backstopping obligation. Eliminating the backstop would invite an argument for a ratemaking process that shares the revenues from short-term PTP services among all long-term service users. BCTC proposes to consult with customers on the implications of the above described options at the same time that it conducts consultations on the changes to the FERC Order No. 888 *pro forma* tariff.

5. Service for Non-Dispatchable Generators and Term PTP Service

This section discusses two new services designed to improve the utilization of the transmission system:

a) LT-PTP service for non-dispatchable generators; and

b) Term PTP service.

Both of these services were introduced in Section 4. The LT-PTP service was shown as Option 7, while Term PTP service was shown as an addition to the *status quo* as Option 2.

5.1 LT-PTP Service for non-dispatchable generators

When the Commission rejected BCTC's proposal for a separate service for BC Clean resources, it left the door open for the development of a new design featuring "differing rates for different users of LTF PTP service" under eligibility provisions that are "more robust than the rationale underlying the BC Clean eligibility provisions proposed by BCTC." (the Decision, pp. 51-52)

Following the Commission's directive, this section presents a new cost-based long-term transmission service option for non-dispatchable generators that may have intermittent output patterns, like wind energy and run of the river hydro. Because non-dispatchable resources use transmission very differently than dispatchable resources and other PTP customers, BCTC can reasonably justify having a cost-based rate design reflective of their transmission usage pattern. This would represent a material change from the existing OATT, which charges all users of PTP service based on their reservations, regardless of their actual transmission usage patterns.

5.1.1 Transmission access by non-dispatchable generation

For a non-dispatchable generator selling directly to BC Hydro under a power purchase agreement, transmission service is not an issue of concern because BC Hydro takes the generator's output under its NITS contract[50]. Under the existing rate design, the addition by BC

[50] It should be noted that generators selling to BC Hydro still take interconnection service directly from BCTC.

Hydro of a NITS designated resource will not materially change the LT-PTP rate or the NITS bill (except inasmuch as it affects the installed generation and, therefore, the billing determinant). However, a non-dispatchable generator that sells to non-BC Hydro buyers may see costly transmission service on a dollars per MWh basis.

Under the *pro forma* tariff structure, BCTC's LT-PTP service requires a non-dispatchable generator to make a capacity reservation based on the generator's nameplate capacity, even if the generator seldom fully utilizes the reserved space. This generator's inability to spread the reservation charge ($/MW-month) over many MWh can make the LT-PTP service prohibitively expensive[51]. For example, a wind generator with a relatively low capacity factor of around 30% has an average transmission cost of over $17/MWh[52].

Adoption of a 1-CP or 12-CP cost allocation approach does not alleviate the high per MWh cost problem for non-dispatchable resources if they remain in the same rate class as other generators. However, the per MWh transmission charge for non-dispatchable generators can be reduced, yet remain cost-based, if these generators receive their own explicit cost allocation, as would be the case under Option 7 described in Section 4. If this new service induces new reservations, rates for other LT transmission users will also decrease. If the new service displaces LT PTP reservations, reducing the LT-PTP rate for non-dispatchable resources will raise the LT-PTP rate for dispatchable resources relative to both the status quo and relative to an allocation approach with a single class for all LT-PTP transmission service. As a result, as long as the rate encourages new reservations, it will tend to lower the NITS revenue obligation, since the overall contribution from PTP services will be greater.

5.1.2 Dispatchable versus non-dispatchable generation

The important distinction between non-dispatchable resources and other PTP transmission customers is that other PTP customers have control over the extent and timing of

---

[51] Jurisdictions with a power pool design (e.g., PJM, NEPOOL and ERCOT) do not have the problem of a high per MWh transmission cost. This is because transmission costs are typically recovered through load-based access fees and generators gain access to the transmission system by submitting winning energy bids into a centralized market. Since intermittent resources have very low operating costs, they have little trouble gaining access to the transmission system, although they may be required to pay congestion charges that can be unpredictable.

their utilization of the capacity reserved under the LT-PTP service. Owners of dispatchable resources control their transmission usage through their decisions about when to dispatch the resource. Similarly, traders that transact in the spot and forward electricity markets control their transmission utilization by way of their buying and selling decisions. Furthermore, PTP service is re-assignable; if the original purchaser has no use for the service in a given hour, he/she can resell the service to another party who can then make use of it. To ensure that the option can be supplied, BCTC must plan to provide sufficient capacity to maintain firm service to meet the customer's potential transmission use up to their full reserved capacity even during the periods of peak demand on the transmission system.

In contrast, a non-dispatchable generating resource has an intermittent output profile. These generators use the transmission system whenever they are able to generate, and make no use of the system when the resource is unavailable. Due to their intermittent nature, on average non-dispatchable resources would be expected to make a smaller contribution to peak system usage relative to their nameplate capacity than would a dispatchable resource that is on virtually all the time, or predictably during the heaviest use periods. Moreover, the combined output profile of multiple non-dispatchable resources may make a relatively smaller contribution to peak system usage than a single non-dispatchable resource, due to diversity among the output profiles of the individual resources. In this way, non-dispatchable resources resemble loads, when viewed from a system cost perspective.

Within the group of non-dispatchable generation resources, some technologies have more predictable output than others. For example, a run-of-river hydro plant's output is predictably high during spring run-off months of April to June, but low during other months. In the months of December through February, some run-of-river hydro plants may have very low output, due to the winter freeze. In contrast, wind energy is less predictable than run-of-river hydro; this is notwithstanding that a wind-energy unit on Vancouver Island is expected to have the highest output in the winter months and lower output in the summer months.

---

[52] The average rate is the $5.25/MWh LT-PTP rate divided by the capacity factor. Hence, if a generator's capacity factor is 0.30, its average rate is $17.50/MWh.

Because of their intermittent transmission usage, end-use loads are typically served not under a "capacity reservation" construct like PTP service but under a "pay-as-you-go" construct, where costs are allocated based on contribution to system peak demand (on either an annual, seasonal, or monthly basis). Non-dispatchable generating resources have similar transmission usage characteristics to loads. It is therefore logical to consider a pay-as-you-go rate design for these facilities. This section discusses the issues surrounding transmission service to non-dispatchable generators and presents a pay-as-you-go rate design as one option for a new LT-PTP service that BCTC could offer to these resources.

5.1.3 FERC alternatives

FERC has recognized that the *pro forma* tariff's LT-PTP reservation based on maximum capacity is ill-suited to the physical characteristics of a wind resource. In fact, FERC convened a conference of industry experts to discuss transmission issues facing wind generators in December 2004, and concurrently issued a staff briefing paper[53]. The briefing paper notes that "Under current capacity-based reservation rules, wind generators typically must acquire long-term firm transmission for the maximum output of the facility even though actual use of the reserved capacity is much less. Due to this, wind developers face higher costs relative to other transmission users... The choice between the standard long-term firm point-to-point transmission service in excess of what they need, and non-firm point-to-point transmission service that is less than what they require and with no guarantee of availability, puts wind resources in a difficult competitive position." (pp. 25-26)

The FERC staff briefing paper goes on to discuss variations on the PTP service in the *pro forma* OATT that might be more appropriate to non-dispatchable resources with intermittent output. These include:

1. Hourly firm point-to-point service;

2. Curtailable or "conditional" firm point-to-point transmission service;

[53] Staff Briefing Paper: Assessing the State of Wind Energy in Wholesale Electricity Markets, Docket No. AD04-13-0000 (November 22, 2004) (F.E.R.C.).

3. Recallable, long-term firm point-to-point transmission service;

4. A commodity charge for service to small and/or low load-factor customers, "billed as service is scheduled and used up to a specified reservation level (essentially, simulating an energy-based access fee by substituting the effective capacity of an intermittent generator into the generally applicable capacity-based fee)"; and

5. Reserving firm capacity equivalent to the unit's effective capacity, and using "priority non-firm" transmission where output is greater than the effective capacity.

The breadth of the solutions on the FERC list shows that the issue of how to design open access transmission rates that do not unduly penalize non-dispatchable resources for their low capacity factors was not settled two years ago. It remains unsettled today.

5.1.4 LT-PTP Service for non-dispatchable generation

BCTC's consideration of a separate LT-PTP service for non-dispatchable generation emerges from an evaluation of each of the FERC-suggested alternatives.

First, BCTC already offers hourly firm PTP service that can be used by a non-dispatchable generator for day-ahead or hour-ahead scheduling. However, hourly firm service is of limited value in enabling developers to obtain project financing, as transmission access remains uncertain over the duration of the project. Thus far, no non-dispatchable generator uses this service.

Second, FERC proposes three non-firm PTP services, encompassing the conditional firm, long-term recallable, and priority non-firm services. These services are similarly of limited value to developers of non-dispatchable resources because the lack of firm, long-term transmission rights injects cash flow uncertainty that hampers their ability to obtain project financing.

Finally, BCTC does take a favourable view of the FERC staff briefing paper's option of "substituting the effective capacity of an intermittent generator into the generally applicable capacity-based fee" for service to small and/or low capacity-factor customers[54]. This alternative is suitable for applying a cost-based approach to price transmission used by non-dispatchable generators whose: (a) combined transmission usage seldom approaches their nameplate capacities; and (b) low capacity factor reduces their expected contribution to the system peaks.

BCTC notes, however, that there is currently no cost causation rationale to justify altering the cost responsibility of non-dispatchable resources relative to other LT-PTP customers in cases where new investment is required solely to facilitate a service request from a non-dispatchable resource.

5.1.5 LT-PTP rate design for non-dispatchable generation

BCTC believes that a LT-PTP rate for a non-dispatchable generation class would be consistent with the Commission's directives to explore "alternative forms of PTP rates that could further enhance utilization of the transmission system while still reflecting a degree of cost causality." (the Decision, p.111) Such a rate would enhance utilization of the transmission system by reducing the per-MWh cost of transmission service for non-dispatchable generators, but would not be discriminatory because it is solely driven by transmission usage and cost characteristics of the class, and not by the individual user's identity, environmental characteristics, or other factors unrelated to transmission usage.

Figure 5.1 illustrates a design option based on the 12-CP cost allocation approach plus proportional sharing of ST PTP revenues case (Option 6) in Section 4. It differs from Option 6 in that it creates two LT-PTP services, one for dispatchable generation and one for non-dispatchable generation. It allocates costs and derives rates separately for each LT-PTP service.

---

[54] Staff Briefing Paper, Assessing the State of Wind Energy in the Wholesale Electricity Markets, op cit, p.27.

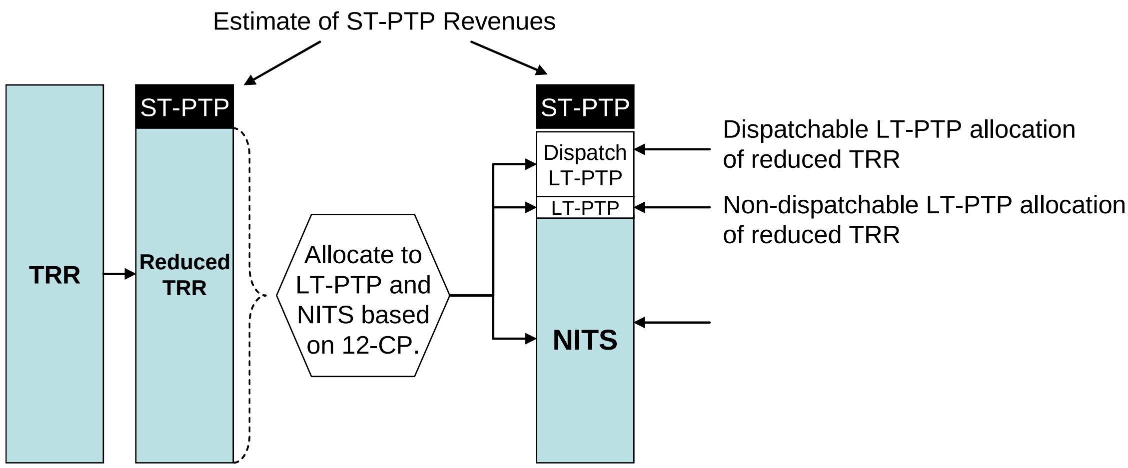

Figure 5.1 Separate non-dispatchable LT-PTP service

The process for designing the LT-PTP rates is given below. For ease of comparison, deviations from the status quo process are highlighted in **bold**.

Step 1: Determine the overall revenue requirement for all OATT-recoverable BCTC services.

Step 2: Determine the Net TRR for long-term rates by subtracting the expected revenues derived from Ancillary Services and Engineering services. This is the TRR referenced in Figure 5.1

Step 3: Estimate the annual revenue from ST-PTP services.

Step 4: Compute the Reduced TRR (equal to the Net TRR from Step 2 less the ST-PTP revenue from Step 3) to be paid by NITS and LT-PTP customers.

Step 5: Estimate the loads of the NITS, dispatchable LT-PTP, and non-dispatchable LT-PTP services at the time of the monthly system peaks. The load at the time of the monthly peaks for dispatchable LT-PTP is the sum of the annual load reservations. Non-dispatchable LT-PTP would be based on expected loads, rather than reservations.

Step 6: Allocate the Reduced TRR based on the relative load contributions of the NITS, dispatchable LT-PTP customers, and non-dispatchable LT-PTP at the time of the monthly system peaks.

Step 7: The dispatchable LT-PTP $/kW-month rate is the dispatchable LT-PTP revenue divided by the dispatchable LT-PTP billing determinants. The dispatchable LT-PTP billing determinants equal the sum of the dispatchable LT-PTP annual load reservations multiplied by 12 months. The non-dispatchable LT-PTP $/kW-month rate is the non-dispatchable LT-PTP revenue divided by the non-dispatchable LT-PTP billing determinants. The non-dispatchable LT-PTP billing determinants equal the sum of the non-dispatchable LT-PTP monthly load reservations.

Step 8: The NITS revenue requirement is the allocated revenue requirement from Step 6. The monthly charge is the NITS revenue requirement divided by 12 months. If there are multiple NITS customers, each NITS customer's monthly charge is based on it Load Ratio Share at the time of the monthly system peak.

Applying this process to the updated cost-of-service data yields the numerical results already shown in Section 4 in Table 4.8.

5.1.6 Unresolved issues

There are unresolved issues in connection with the further development of a non-dispatchable rate. Though not exhaustive, the list of issues includes:

- What should be the criteria to qualify a generation resource as non-dispatchable?

- Should the rate be based on a class of non-dispatchable generators, or should the rate be applied to generators individually? If non-dispatchable generators together form a class of customers, the rate of one non-dispatchable generator would depend on the transmission usage characteristics of another non-dispatchable generator. An alternative would be to allocate costs individually to non-dispatchable generators based on their own coincidence factors.

- What should be the rate design inside the class? If non-dispatchable generators do form a single class, the transmission rate inside the class could be based on the individual generators' contributions to the class peak demand[55].

- Should the rate be differentiated by the degree of non-dispatchability of the resource, so as to strengthen the rate's cost basis, even if that increases implementation complexity?

- Should the non-dispatchable service be limited to resources below a specific size?

- Should the non-dispatchable rate apply only to bulk transmission where usage diversity of non-dispatchable generators can reasonably be expected to occur?

- Should the non-dispatchable rate apply to local transmission where usage diversity of non-dispatchable generators (e.g., several wind generators clustering at a remote location) may not exist (and, as such, the generator's non-coincident peak (NCP) is likely to be the driver of system investment)?

- Should the non-dispatchable service be non-reassignable to ensure that usage attributable to the non-dispatchable class follows their expected usage pattern?

[55] One may consider the alternative of billing non-dispatchable generators using an energy-based rate designed to recover the class revenue requirement. But this alternative would be contrary to BCTC's objection to billing a LT-PTP transmission user on the sole basis of MWh transmitted. Please see Section 4.1.

5.2 Term PTP Service

5.2.1 Introduction

BCTC believes that it may be possible to improve transmission capacity utilization using a Term PTP service. Such a service would have the following general characteristics: (a) available for a term of between one and ten years, which is longer than the ST-PTP service, but less than BCTC's 10-year planning horizon; (b) sold without rollover rights; and (c) offered at a price that exceeds short-term firm.

The Term PTP service does not alter the first two of BCTC's existing pricing and service rules for new LT-PTP service:

1. If there is **sufficient ATC** over and beyond the term of the request, customers are given a firm contract with rollover rights and the price is based on the standard embedded cost based rate.

2. If there is **insufficient ATC** over and beyond the term of the request and system upgrades are required to provide ATC for service, customers are provided an option to be financially responsible for the higher of incremental or embedded costs and receive full service for the duration of their request with rollover rights.

The new service, however, aims to modify or enhance the third rule that governs BCTC's provision of conditional rollover rights.

3. If there is **insufficient ATC**, beyond the term of the request then BCTC offers service with a conditional rollover right and the price is based on embedded costs.

5.2.2 Basis for Term PTP

BCTC's consideration of the Term PTP service is motivated by the following factors:

First, in spite of efforts to promote transmission expansion that is funded from non-utility sources, the majority of new capacity is being built by utilities and funded by rate base. So while it is possible under BCTC's OATT for a customer's LT-PTP request to trigger system expansion, the more likely scenario is that BC Hydro's domestic load growth will drive system upgrades. Therefore, the likely case is that domestic customers underwrite the incremental cost of new facilities by virtue of the NITS backstop.

Second, as domestic loads grow, it is becoming increasingly unlikely that LT-PTP service will be sold with an unconditional rollover right.

Third, once an investment in the system has been made, there is an opportunity to sell any residual capacity until it is needed by the native load. Those sales can increase utilization and lower rates for all long-term service customers. This would follow the same system optimization principles as partial service, where customers are given something as close to their request as possible.

5.2.3 Term PTP designs

The Term PTP service will use all or most of the existing terms and conditions of LT-PTP service. The most challenging element of the Term PTP design is its pricing. It is clear that it should not be based on incremental price, since then it should carry a rollover right like a customer funding new capacity expansion to meet its request for LT-PTP service. It is equally clear it should not be based on the short-term formula, which is only appropriate for very short time horizons, as shown in Section 6.

BCTC contemplates that the new Term PTP service would have one of the following designs:

1. One-year to five-year term at the full LT-PTP rate

Under this design, the customer would: (a) have the right of first refusal to new capacity that becomes available at contract expiration; and (b) be offered the opportunity to upgrade capacity 18 months before contract expiration (or on a longer time-frame as determined by construction requirements). The pricing for this service is based on embedded cost. This design has the advantage that embedded cost pricing is relatively easy and transparent. The rate would, in most cases, be less than what a customer would pay today if it gained capacity by compelling the construction of new facilities[56]. However, pricing at full embedded cost is the same as what is offered today under BCTC's LT-PTP service with conditional rollover rights, despite the fact that Term PTP is an inferior-quality service.

2. One-year to five-year term at a discounted price

This design contemplates a discounted price with a ceiling set at the full LT-PTP rate and a floor at last year's average ST-PTP rate for firm service. Within that range, pricing options would include using the arithmetic average of the full LT-PTP rate and the last year's average ST-PTP rate.

Under this option, the customer would have no right of first refusal to new capacity. At the end of the contract term, the capacity would either: (a) be reclaimed by the party that underwrote it (generally the NITS customer building to serve domestic load); or (b) be reposted for sale as a Term PTP product for the period it is available, or up to five years.

In support of this approach, it could be argued that price discounting is appropriate because the Term PTP service is less valuable than the existing LT-PTP rate that carries rollover provisions. And BCTC's tariff allows for discounting service where the contract term is limited, where no new facilities are being developed, and where the motive is improving utilization in the near term. Discounting is expected to improve utilization, offering some benefit to customers that do not need a rollover right or would not have received one anyway based on existing system constraints.

However, discounting Term PTP service presents some unresolved pricing issues. First, a market-based formula for Term PTP is unlikely to be workable, for reasons of accuracy that are explained in Chapter 6. Second, without a market-based formula, BCTC would be left to choose between: (a) an administrative arrangement (e.g., halfway between short-term and long-term PTP rates) which lacks precision; or (b) an auction-style mechanism that is likely to suffer from

[56] The assumes that in most cases the incremental cost of an upgrade is higher than the embedded cost based rate.

liquidity concerns. BCTC has not fully explored these and other pricing arrangements, including a combined approach of an auction with a price floor.

5.2.4 Unresolved issues

There are also non-price issues that would have to be resolved before a Term PTP rate could be introduced, including:

- Is one to five years the appropriate term limit? The term minimum must be at least one year, the maximum term for ST-PTP service. At the same time, the term maximum should not be so long that it becomes difficult to forecast available capacity.

- Should the revenue from Term PTP sales be credited against the TRR before determination of the LT-PTP rate, or should the revenue be credited against the NITS backstop?

- If Term PTP service is introduced, is it necessary that Shaped Service also be amended to limit its rollover rights? Term PTP service aims to address the situation of **insufficient ATC** and a customer that is unable or unwilling to pay for the upgrade. Similarly, Shaped Service customers are unable to reserve a full block of LT-PTP service. Therefore, service comparability supports the view that the two services should to some degree have similar rights and terms.

- Should there be any limits on reassigning Term PTP service? The LT-PTP service in the existing OATT can be reassigned. But if Term PTP is sold at a discounted rate, it could be argued that the service should not have the same reassignment right.

5.3 Conclusion

BCTC believes that two new cost-based rates could be introduced to provide a small increase in utilization.

A rate for non-dispatchable generators would be based on their expected collective coincident peak use rather than on the sum of the individual users' maximum reservations. This would reduce the average cost (per MWh) of transmission for these customers, and tend to encourage utilization of the transmission system. This rate would still reflect cost causation principles because these generators can be expected to make a smaller contribution to peak system usage relative to their nameplate capacity than would a dispatchable resource that is more predictably generating and has an option to use transmission capacity during the heavier use periods.

A Term PTP service could also be developed to meet the needs of some PTP users, without decreasing the flexibility or service quality of other long-term services. This service would require a committed reservation duration longer than one year (the current limit for short-term reservations), but shorter than the maximum ten-year planning horizon. A number of designs are possible for this rate.

As set out in the section, there are a number of unresolved price and non-price issues associated with each of these services. For that reason, BCTC believes that it should consult with its customers, at the same time that it consults with its customers regarding the other long-term rate options, prior to making any specific recommendation.

6. Short-Term Point-to-Point Pricing Formula

6.1 Introduction

The Decision accepted BCTC's ST-PTP rate design. In granting its approval, however, the Commission noted that the directional aspect of the proposed rate design had not been subject to quantitative analysis[57]. As a result, the Commission Panel directed BCTC to "include in the December 2006 report … an evaluation of the directional aspect of short-term service price discounting." (the Decision, p.111)

In compliance with this directive, this section presents an analysis of three directional aspects of BCTC's current ST-PTP rate formula:

- Zero-price reservations and energy schedules in the opposite direction of market prices[58] since the implementation of the new formula;

- Appropriateness of discounting multiple-day transactions using the current rate formula; and

- The "blocking" effect of various rate formulae, including the incremental impact of the directional formula on the percentage of blocked hours and revenues relative to a non-directional formula.

As part of this analysis, BCTC reviewed whether the formula is acting as intended, that is, by reflecting the direction and magnitude of contemporaneous arbitrage opportunities between US and Alberta markets. BCTC's review finds that the formula often fails to accurately predict the direction of expected trade, likely due to volatility in the Alberta Power Pool market prices.

As a result of these findings, BCTC reviewed whether immediate changes to the design of the ST-PTP rate formula would improve the performance of the rate design. BCTC

[57] The Decision, p.60.

considered such changes as eliminating the directional aspect of the rate, reinstating a price minimum of between $0.50 and $2.00 per MWh, eliminating discounting beyond one day, and using Dow Jones hourly prices instead of daily heavy-load hour (HLH) and light-load hour (LLH) prices. BCTC's review finds that despite its inaccuracy, the current formula is effective in collecting a reasonable contribution to fixed costs, while blocking relatively few economic transactions.

These findings lead to three recommendations for improving the performance of the ST-PTP rate: (1) reinstating a price floor to ensure that all transactions make a minimum contribution to fixed costs; (2) eliminating discounting for multi-day reservations; and (3) eliminating the minimum scheduling fee of $55. These recommendations can be implemented through a rate application that does not entail changes to the terms and conditions of the OATT.

6.2 Current design of BCTC's ST-PTP rate

ST-PTP service is available on both a firm and non-firm basis for reservation periods up to one year. The non-discounted rates are displayed in Table 6.1 below.

Table 6.1: Current non-discounted PTP rates

1)	Yearly delivery:	One-twelfth of the demand charge of $45.816/kW of Reserved Capacity per year.
2)	Monthly delivery:	$3.818/kW of Reserved Capacity per month.
3)	Weekly delivery:	$0.881/kW of Reserved Capacity per week.
4)	Daily delivery:	$0.126/kW of Reserved Capacity per day.
5)	Hourly delivery:	$0.0053/kW of Reserved Capacity per hour.

Reservations of up to one month may be discounted according to a formula designed to capture a fair portion of the economic gain from electricity trade. The formula sets the hourly rate equal to one-quarter of the value of the gains from trade,[59] approximated by the difference between posted market prices in Alberta and at the Mid-Columbia (Mid-C) trading hub in Washington State, with an adjustment for transmission system losses. The gain approximation

[58] An energy schedule is said to be in opposite direction of market prices if the market price at the point of delivery for power withdrawal is lower than the price at the point of receipt for power injection.

[59] The Commission first approved the value-based pricing concept and its rate formula in its June 25, 1996 Decision. It affirmed the same in its April 23, 1998 Decision.

assumes ***contemporaneous*** arbitrage that entails buying electricity in the low-price market at a given hour and selling the ***same*** electricity in the high-price market at the ***same*** hour.

The formula is applicable to reservations of between one hour and one month, according to Table 6.2 below.

Table 6.2: Discounted ST-PTP rates based on the hourly rate formula and rate caps

for reservations of 1 week or less	**Formula**
Hourly Firm Rate	Minimum (Firm Hourly Formula, Firm Cap Rate)
Hourly Non-Firm Rate	Minimum (Firm Hourly Formula - $1/MWh, Firm Cap Rate)
Daily Firm Rate	Sum of 24 Hourly Firm Formula / 24
Daily Non-Firm Rate	(Sum of 24 Hourly Firm Formula / 24) - $1/MWh
1 Week Firm Rate	Daily Firm Rate + .5 (Firm Cap Rate – Daily Firm Rate)
1 Week Non-Firm Rate	(Daily Firm Rate = .5 (Firm Cap Rate – Daily Firm Rate)) - $1/MWh
For reservations beyond 1 week	
X Week Firm Rate	(1 x Weekly Firm Rate) + ((X – 1) x Firm Cap Rate)) / X
X Week Non-Firm Rate	((1 x Weekly Firm Rate) + ((X – 1) x Firm Cap Rate)) / X – 1 $/MWh
Where X is the number of weeks in the reservation	

BCTC's 2004 OATT Application proposed an update to the discounting formula, replacing the California-Oregon border (COB) price index with the more liquid Mid-C price index, and replacing the Alberta gas-based electricity price estimate with the actual values from the Alberta Power Pool. The Commission also approved BCTC's proposals to: (a) eliminate the $1 price floor for non-firm service; (b) allow the rate to go to zero in the opposite direction of market opportunity as predicted by the formula; and (c) calculate the price for firm service directly, with a $1 discount for non-firm service.

6.3 Analysis of BCTC's current rate formula

6.3.1 Transmission sales and revenue during before and after the new OATT

BCTC's new OATT went into effect on March 1, 2006. The tables below compare transmission sales and revenue during the period from April 1 to September 30, 2006[60] with sales and revenue from the same period in 2005, under the WTS tariff. Table 6.3 indicates that PTP transmission volumes increased by 30% in 2006 over the same period in 2005. The table also shows a change in the reservation patterns, particularly for BC Hydro. In 2005, BC Hydro reserved non-firm over firm service by a 2-to-1 ratio. In 2006, BC Hydro preferred firm service by a 3-to-1 ratio over non-firm.

Table 6.4 shows PTP transmission revenues. While PTP sales increased by 30%, revenues declined by 17%. This outcome is not unexpected, as BCTC's stated goal for its new OATT was to increase PTP sales volumes through more effective discounting. Table 6.5 shows that the effect of BCTC's new discounting formula was to reduce BCTC's average revenue per MWh reserved from $4.54 to $2.88/MWh. Average revenue for all ST-PTP service declined by 50%, from approximately $4/MWh to $2/MWh.

Table 6.3: PTP transmission reservations (MWh x 1000), 4/1/05 – 9/30/05 and 4/1/06 – 9/30/06

	4/1/2005-9/30/2005			**4/1/2006-9/30/2006**			
	BC Hydro	**Other Customer**	***Total***	**BC Hydro**	**Other Customers**	***Total***	***Percent Change***
Long Term Firm PTP	1,892	414	2,306	1,824	648	*2,471*	*7.2%*
Short Term Firm PTP	1,755	92	1,847	5,659	17	*5,676*	*207.3%*
Short Term Non-Firm PTP	3,430	210	3,640	1,832	158	*1,990*	*-45.3%*
Total	7,077	716	7,793	9,315	823	*10,137*	*30.1%*

Table 6.4: PTP transmission revenues ($Million), 4/1/05 – 9/30/05 and 4/1/06 – 9/30/06

	4/1/2005-9/30/2005			**4/1/2006-9/30/2006**			
	BC Hydro	**Other Customer**	***Total***	**BC Hydro**	**Other Customers**	***Total***	***Percent Change***
Long Term Firm PTP	$ 11.1	$ 2.4	$ 13.5	$ 10.1	$ 3.6	*$ 13.7*	*0.92%*
Short Term Firm PTP	$ 10.3	$ 0.5	$ 10.8	$ 11.5	$ 0.1	*$ 11.6*	*7.5%*
Short Term Non-Firm PTP	$ 10.5	$ 0.6	$ 11.1	$ 3.5	$ 0.4	*$ 3.9*	*-64.5%*
Total	$ 31.9	$ 3.5	$ 35.4	$ 25.1	$ 4.1	*$ 29.2*	*-17.5%*

[60] BCTC began operating under its new OATT on March 1, 2006. However, in order to ensure that the analysis is as useful as possible, BCTC excluded the first month of operations from the analysis period to ensure that customers had fully adjusted their own practices.

Table 6.5: Average revenue ($per MWh) of PTP transmission reservations, 4/1/05 – 9/30/05 and 4/1/06 – 9/30/06

	4/1/2005 – 9/30/2005			4/1/2006 – 9/30/2006			
	BC Hydro	Other Customers	*Total*	BC Hydro	Other Customers	*Total*	*Percent Change*
Long Term Firm PTP	$5.89	$5.76	*$5.87*	$5.53	$5.53	*$5.53*	*-5.8%*
Short Term Firm PTP	$5.87	$5.13	*$5.84*	$2.03	$4.61	*$2.04*	*-65.0%*
Short Term Non-Firm PTP	$3.05	$2.98	*$3.04*	$1.94	$2.45	*$1.98*	*-35.0%*
Total	*$4.51*	*$4.86*	*$4.54*	*$2.70*	*$4.92*	*$2.88*	*-36.6%*
All Short-term	$4.00	$3.64	$3.98	$2.01	$2.66	$2.02	*-49.2%*

6.3.2 Reservations and utilization by price point and path

This subsection analyzes BCTC's actual transmission rates and transmission usage during the period from April 1, 2006 to September 30, 2006, and considers the new formula's performance against that of the previous formula. Most of the recent changes to BCTC's short-term rates were designed to increase usage of the BC system, in alignment with the Master Agreement and BCTC's rate design goals.

BCTC evaluated the prevalence of zero-price transmission reservations during the six-month sample period. Table 6.6 and Table 6.7 report, by path, summary statistics for transmission reservations made over this period. The tables show that 29% of all reservations were made at the zero price.

Table 6.6: Reservations by price point and path, 4/1/06 – 9/30/06

ST-PTP Rate	@AESO - BPAT	@BPAT - AESO	AESO - BCTC	BCTC - AESO	BCTC - BPAT	BPAT - BCTC	*Total*
$0.00	251	1,066	2	3,422	9,735	38	*14,514*
$0.01-0.99	53	259	-	312	1,296	-	*1,920*
$1.00-1.99	67	286	-	259	128	-	*740*
$2.00-2.99	48	199	-	252	191	46	*736*
$3.00-3.99	36	222	-	183	101	4	*546*
$4.00-4.99	57	150	-	298	193	-	*698*
$5.00+	3,663	1,119	717	13,413	2,164	9,185	*30,261*

Table 6.7: Share of reservations by price point and path, 4/1/06 – 9/30/06

ST-PTP Rate	@ AESO – BPAT	@BPAT – AESO	AESO – BCTC	BCTC – AESO	BCTC – BPAT	BPAT – BCTC	*Total*
$0.00	6%	32%	0%	19%	71%	0%	29.4%
$0.01-0.99	1%	8%	0%	2%	9%	0%	4%
$1.00-1.99	2%	9%	0%	1%	1%	0%	1.5%
$2.00-2.99	1%	6%	0%	1%	1%	0%	1.5%
$3.00-3.99	1%	7%	0%	1%	1%	0%	1%
$4.00-4.99	1%	5%	0%	2%	1%	0%	1.4%
$5.00+	88%	34%	100%	74%	16%	99%	61.2%

Figure 6.1 compares the distribution of hourly prices during the period from April 1, 2006 to September 30, 2006 with the same period in 2005 (i.e., prior to the implementation of the new formula). The 2005 period shows a relatively broad distribution of prices between $1.00 and $6.00 per MWh. In 2006, by contrast, 90% of reservations were made at either the zero price or the maximum price. Only a small percentage of reservations were made at the formula rate. Replacing the gas-based proxy with a highly volatile Alberta Power Pool price has resulted in a rate that very seldom lands between the price floor and the price ceiling.

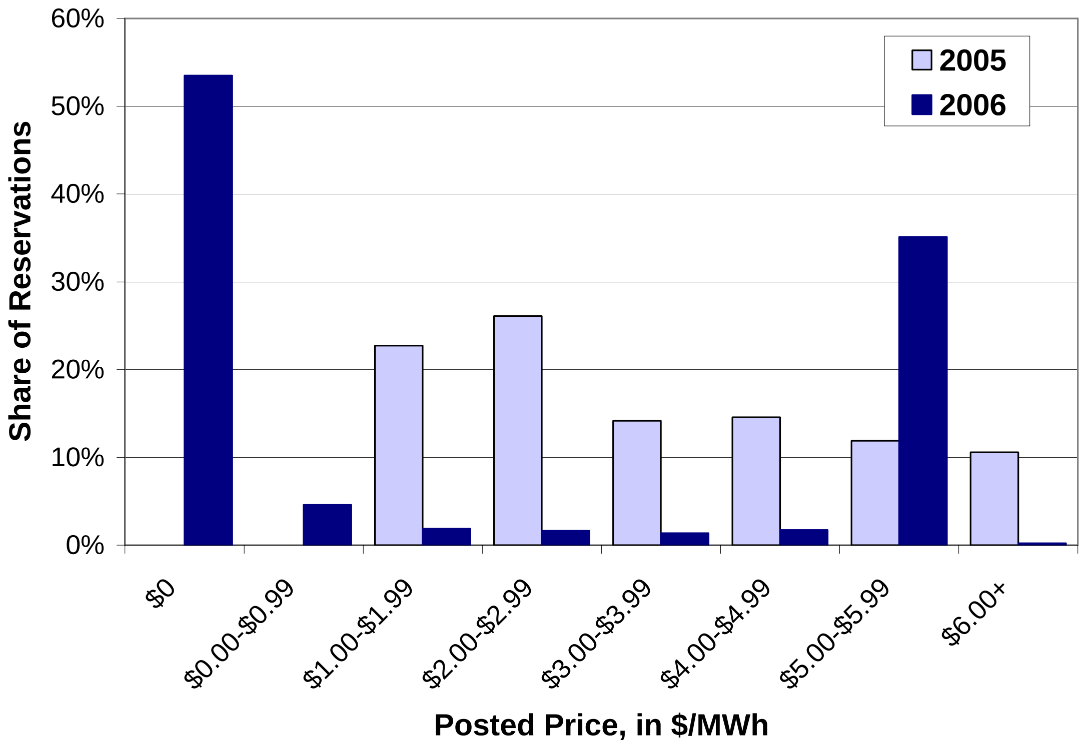

Figure 6.1 Distribution of hourly ST-PTP prices, 4/1/05 – 9/30/05 and 4/1/06 – 9/30/06

As a further test of the value of directionality, BCTC considered energy schedules in four directions: (1) northbound (from the US into BC or from BC into Alberta), (2) southbound (from Alberta into BC or from BC into the US), (3) forward (toward higher market prices), and (4) reverse (toward lower market prices). Table 6.8 shows that energy was scheduled in the northbound direction during 81% of hours and in the southbound direction during 99% of hours, implying that energy was scheduled in both directions in roughly 81% of hours. The same table also shows that energy was scheduled in the forward direction (i.e., with the arbitrage opportunity suggested by the formula) during 93% of hours, and in the reverse direction (i.e., against the direction of arbitrage predicted by the formula) during 87% of hours. This table suggests that actual trading opportunities are different from, and likely more complex than, the contemporaneous arbitrage assumption that underlies the ST-PTP rate formula.

Table 6.8: Energy schedules by direction, 4/1/06 – 9/30/06

	Actual	Percent
Total hours	4,391	100%
Hours with northbound energy schedules	3,572	81%
Hours with southbound energy schedules	4,351	99%
Hours with both northbound and southbound energy schedules	3,561	81%
Hours with neither northbound nor southbound energy schedules	29	1%
Hours with forward energy schedules	4,102	93%
Hours with reverse energy schedules	3,821	87%
Hours with both forward and reverse energy schedules	3,561	81%
Hours with neither forward nor reverse energy schedules	29	1%

6.3.3 Accuracy of the ST-PTP rate formula beyond two days

Two reasons may explain the ST-PTP rate formula's inaccuracy in capturing the direction and size of transmission value:

1. *Stale price data*. The market price used to determine the rate is too far removed in time from when the trades take place. In a volatile market like Alberta, this means that the direction of contemporaneous arbitrage opportunities is often reversed from the direction predicted by two-day old data used by BCTC's current ST-PTP rate formula to set the rate for the hour of actual delivery.

2. *Overly simplified approximation of trading opportunity*. The formula contemplates only contemporaneous inter-market energy arbitrage. In reality, there are more and different trading products and opportunities for which traders will, and do, purchase transmission.

This subsection analyzes the degree to which inaccuracies in the formula worsen as the time horizon increases. This is relevant because the rate formula is used not just to determine the daily transmission rate, but to determine rates for transactions of up to one week, as shown above in Table 6.2.

The analysis is based on hourly Alberta prices and daily Mid-C prices during the period from January 1, 2003 to December 31, 2005. Alberta prices are averaged over heavy- and light-load hours to produce daily HLH and LLH values. To gauge the information content of the price difference on day *t*, Figure 6.2 plots the price difference on day (*t*+2) on the vertical axis against the price difference on day *t* on the horizontal axis. If the price difference on day *t* were a good predictor of the price difference on day (*t*+2), the plot would be tightly linear. This figure indicates a poor relationship between the two price differences, particularly during heavy-load hours. This indicates that the rate may not perform well during periods beyond two days.

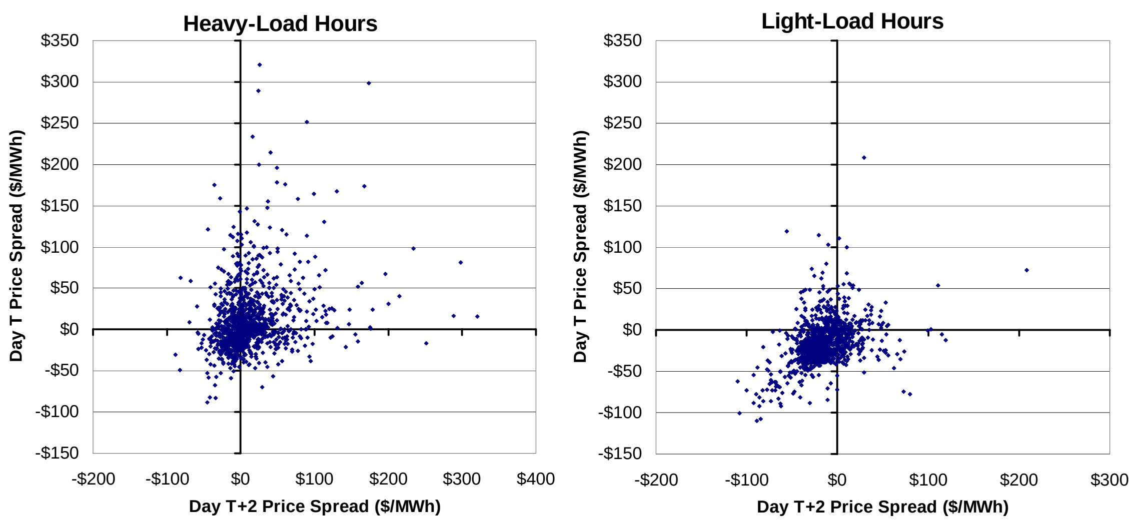

Figure 6.2 Price difference on day *t* versus price difference on day (*t*+2)

Table 6.9 summarizes the performance of the price difference during heavy-load hours with respect to direction. The table shows that the HLH price difference on day *t* has, on average, a 61% chance being a directionally correct forecast of the price difference on day (*t*+2). The forecast performance degrades over multiple days.

Table 6.10 shows that the LLH price difference on day *t* has, on average, a 73% chance as a directionally correct forecast of the price difference on day (*t*+2). The forecast performance remains unchanged over multiple days.

Table 6.9: Performance of the HLH price difference on day *t* as a forecast of the direction of positive transmission value on days (*t*+2), …, (*t*+8)

	Day *t*+2	Day *t*+3	Day *t*+4	Day *t*+5	Day *t*+6	Day *t*+7	Day *t*+8
Number of Days	1,096	1,095	1,094	1,093	1,092	1,091	1,090
Same Direction as Day *t*	668	653	647	611	584	605	617
Opposite Direction from Day *t*	428	442	447	482	508	486	473
Percent of Days with Correct Direction	61%	60%	59%	56%	53%	55%	57%

Table 6.10: Performance of the LLH price difference on day *t* as a forecast of the direction of positive transmission value on days (*t*+2), …, (*t*+8)

	Day *t*+2	Day *t*+3	Day *t*+4	Day *t*+5	Day *t*+6	Day *t*+7	Day *t*+8
Number of Days	1,096	1,095	1,094	1,093	1,092	1,091	1,090
Same Direction as Day *t*	800	773	772	772	785	784	789
Opposite Direction from Day *t*	296	322	322	321	307	307	301
Percent of Days with Correct Direction	73%	71%	71%	71%	72%	72%	72%

This analysis indicates that the current rate formula is a poor predictor of directional value by the time data are two days old, and that this performance degrades slightly in subsequent days. One possible source of this inaccuracy is the price fluctuations that occur depending on the day of the week. For example, weekend prices tend to be lower than weekday prices, particularly during peak hours. The Western Systems Power Pool (WSPP) standard products traded at Mid-C do not include a Sunday HLH package; Sunday is bundled with Monday light-load hours into a single package that is traded on Fridays. However, Table 6.11 shows that excluding Sundays and weekday deliveries for which the Sunday price difference set the ST-PTP rate does not alter the performance of the rate formula.

Table 6.11: Performance of the HLH price difference on day *t* as a forecast of the direction of positive transmission value on days (*t*+2), …, (*t*+8), excluding Sundays

	Day *t*+2	Day *t*+3	Day *t*+4	Day *t*+5	Day *t*+6	Day *t*+7	Day *t*+8
Number of Days	770	769	768	767	766	765	764
Same Direction as Day t	477	470	462	429	414	365	433
Opposite Direction from Day t	293	299	306	338	352	400	331
Percent of Days with Correct Direction	62%	61%	60%	56%	54%	48%	57%

Another possible explanation for the formula's inaccuracy is the price volatility that the Alberta Power Pool exhibited during the three-year period. As an example, Figure 6.3 shows the contemporaneous hourly prices in the Alberta Power Pool and at Mid-C during December 2005. The figure shows that peak-hour prices in Alberta reached a high of over $700/MWh, and frequently topped $200/MWh, while Mid-C prices never topped $170/MWh. Moreover, prices on some days are substantially higher in Alberta than at Mid-C, while the opposite is true on other days.

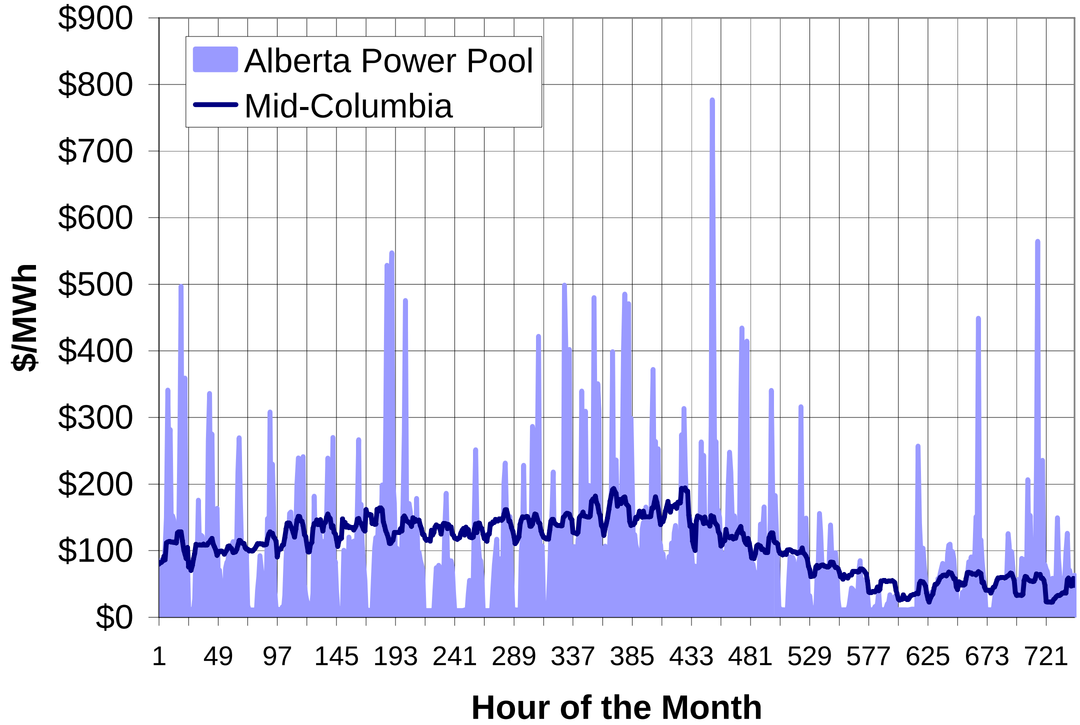

Figure 6.3 Hourly prices in Alberta and at Mid-C during December 2005

The performance of the price formula between Mid-C and Alberta contrasts to that which would exist if the formula were applied between Mid-C and another Western trading hub, Palo Verde (PV) in Arizona. Table 6.12 shows the performance of a hypothetical rate formula based on the HLH price difference between Mid-C and PV. The table shows that the rate formula has the correct sign on every day of the 770-day sample period (again excluding all Sunday deliveries and all weekday deliveries for which the Sunday price difference would set the ST-PTP rate). This occurs because the HLH PV price was higher than the Mid-C price on each of the 933 days for which an HLH price was reported.

Table 6.12: Performance of the HLH price difference between Mid-C and Palo Verde on day *t* as a forecast of the direction of positive transmission value on days (*t*+2), …, (*t*+8), excluding Sundays

	Day *t*+2	Day *t*+3	Day *t*+4	Day *t*+5	Day *t*+6	Day *t*+7	Day *t*+8
Number of Days	770	769	768	767	766	765	764
Same Direction as Day *t*	770	769	768	767	766	765	764
Day *t* and Day *t*-2 Opposite Direction from Day *t*	-	-	-	-	-	-	-
Percent of Days with Correct Direction	100%	100%	100%	100%	100%	100%	100%

6.3.4 Dynamic Scheduling Service

In its February 2, 2006 Order No. G-12-06, the Commission stated: "BCTC plans to address the applicability of its discount policy to [dynamic scheduling] DS Service as part of the comprehensive rate design proposal it will file by December 31, 2006, in accordance with the OATT Decision. … The Commission does not oppose BCTC proposing changes to the applicability of its discount policy to DS Service as part of the rate design application it expects to file by December 31, 2006." (p.2)[61]

Dynamic Scheduling (DS) Service is used by customers to sell spinning reserve, supplemental reserve, or balancing energy to neighbouring control areas. DS Service is a capacity service; the actual energy transfers fluctuate during the hour and may even be zero. The use of transmission for DS Service requires BCTC to maintain sufficient capacity on the path to accommodate energy transfers that may fluctuate during the hour up to the reserved capacity.

BCTC's evaluation finds that during the period from April 1, 2006 to September 30, 2006, BC Hydro was the only BCTC customer that used DS Service (BC Hydro's use of DS Service was to sell reserves and balancing energy to California). In designating transmission service for DS Service, BC Hydro used either existing LT-PTP contracts or purchased additional short-term firm transmission service. BCTC collected $1.64 million in LT-PTP revenue from BC Hydro for 957,813 MWh of DS Service. The average price of ST-PTP transmission purchased by BC Hydro for DS Service was $1.70/MWh.

[61] The directive in the Decision was to file this report. Please see footnote 24, *supra*.

BCTC's treatment of, and operations under DS Service schedules made under a LT-PTP or ST-PTP reservation, is largely the same as under other energy schedules[62]. BCTC sells transmission service and does not distinguish among the various ways its customers can use the service to create value. BCTC does not recommend any change to its current practice as a result of this review. Additionally, attempts to capture additional revenue by varying the discounting approach for DS Service are likely to have limited success, and may reduce economic utilization of the transmission system. Reinstating a small price minimum for ST-PTP service should resolve any concern that DS Service does not make a minimum contribution to fixed costs.

6.3.5 $55 minimum scheduling fee

In a March 31, 2006 letter to Mr. Bryenton of Cascade Pacific Power Corporation, BCTC agreed to provide an evaluation of the $55 minimum scheduling fee[63]. In its August 16, 2006 letter to Mr. Bryenton, the Commission concurred that an evaluation of the $55 minimum scheduling fee should be included as part of this report.

BCTC instituted the minimum scheduling fee as a result of its decision to apply for removal of the minimum price on ST-PTP reservations. BCTC now intends to propose to reinstate a floor on the ST-PTP rate, and will, therefore, also propose to eliminate the minimum scheduling fee. BCTC estimates that the minimum scheduling fee resulted in approximately $100,000 of incremental revenue (above what could have collected in the absence of the charge) between April and September 2006. However, based on the results presented in table 6.14, BCTC expects that a floor of $0.50/MWh on the ST-PTP rate would recover substantially more than $100,000 of incremental revenue, so the elimination of the minimum scheduling fee will have no financial impact on BCTC.

---

[62] There are minor distinctions: BCTC cannot "net" a DS schedule against an energy schedule in the opposite direction in order to create capacity across an internal constraint. Thus, a DS schedule can be thought of as consuming slightly more transmission than an energy schedule. Further, unused DS reservations cannot be released for resale. However, BCTC does not view these distinctions as material in the current context.

[63] Specifically, BCTC wrote: "[t]he issue regarding the impact of the [$55] minimum fee on small users had been raised and debated in the oral proceeding. … However, BCTC understands your concerns and particularly appreciates your proposals on alternative methods for cost recovery. BCTC will evaluate your proposals and other methods of cost recovery with the objective of maintaining fair contribution to cost recovery and lessening the impact on your business and other businesses like yours. BCTC will include the findings and recommendations of this evaluation in the Rate Design Report to be submitted to the Commission by December 31, 2006."

6.4 Improvements to the current formula

6.4.1 Near-term improvements

BCTC's proposal to make the transmission rate directional rested upon the notion that the value of transmission on the BC system could be approximated by the difference between energy market prices in Alberta and the US. However, the findings from the above analysis calls into question this assumption. First, the analysis indicates that the current rate formula is directionally incorrect, resulting in an erroneous zero-price, during approximately 40% of the heavy-load hours and 30% of the light-load hours. This pricing error increases for reservations of longer than one day. Second, nearly one third of the reservations during the period from April 1, 2006 to September 30, 2006 were zero-price reservations, a greater number than would be expected if transmission were mostly used to schedule contemporaneous energy from a low-priced market to a high-priced market. Finally, energy was scheduled in both the northbound and southbound directions in 81% of the hours during the same period, further indicating that the BCTC system is not predominantly used to schedule contemporaneous energy from a low-priced market to a high-priced market.

As a result of this analysis, BCTC concludes that the directional aspect of the current rate formula does not perform as well as it was intended at the time of its last rate application, and that allowing the price of transmission to go to zero in the opposite direction of two-day old market prices fails to meet the balanced objectives of increasing throughput and ensuring a fair contribution from all system users. Therefore, BCTC recommends that a minimum price be reinstated in order to ensure that all transmission reservations make a reasonable contribution to the fixed costs of the transmission system. Subject to contrary evidence it might learn of during consultations in February and March, 2007, BCTC expects to file an Application to this effect after April 2007.

In addition, the market price difference used to calculate the ST-PTP rate is found to be a poor predictor of market price differences even two days later, much less one month (the current maximum discounting period). Market volatility and trading practices suggest that relatively short trading horizons underpin most actual use of the transmission system. Under such conditions, discounting reservations longer than one day does little to encourage throughput.

Consequently, BCTC may propose eliminating discounting for multi-day reservations in its application after April, once it has had the opportunity to consult with its customers. The results of this blocking analysis are shown in Figure 6.4 and summarized in Table 6.14.

6.4.2 Blocking and revenue effects of alternative rate designs

The previous subsection describes improvements that could be made to BCTC's ST-PTP rate formula in light of the prevalence of zero-price reservations and the formula's inability to accurately capture the direction and size of transmission value. This subsection tests some of those improvements, along with a variety of other alternative rate designs, using a blocking analysis similar to that presented in BCTC's 2004 OATT Application.

The blocking analysis in BCTC's 2004 OATT Application estimated the per MWh value of transmission for a through transaction (e.g., Alberta to US), which is the contemporaneous positive difference between the price at the point of delivery (e.g., US) and the price at the point of receipt (e.g., Alberta). A transaction is considered "blocked" during each hour in which the discounting formula results in a per MWh transmission cost that is greater than the value of the transaction.

For this report, BCTC recalculates its blocking analysis using a range of possible formulae, listed in Table 6.13. To do this, BCTC makes use of an enhanced blocking analysis that accounts for transactions in which a transmission user with hydro storage uses the ST-PTP service to buy energy during light-load-hours and resell it during heavy-load hours. This enhancement allows the analysis of the blocking effect of a given transmission rate on "in" and "out" transactions, in addition to the "through" transactions that were modeled in BCTC's 2004 OATT Application.

Table 6.13: ST-PTP discounting formulae tested for this report

Name	Description	Directional	Price Cap
1. Current formula	[Mid-C – AESO] ÷ 4	Yes, $0 in opposite direction	$5.30
2. Current formula, non-directional	[Mid-C – AESO] ÷ 4, both directions	No	$5.30
3. Current formula w/ Appalachian cap	[Mid-C – AESO] ÷ 4	Yes, $0 in opposite direction	HLH cap = Annual/4160, LLH cap = Annual/8760
4. Current formula w/ 50¢ min	[Mid-C – AESO] ÷ 4, minimum value of $0.50/MWh	Yes, $0.50 in opposite direction	$5.30
5. Current formula w/ $1.00 min	[Mid-C – AESO] ÷ 4, minimum value of $1.00/MWh	Yes, $1.00 in opposite direction	$5.30
6. Full, non-discounted rate	$5.30 fixed rate	No	$5.30
7. Non-discounted rate, Appalachian method	$11.16 during HLH, $5.30 during LLH	No	HLH cap = Annual/4160,LLH cap = Annual/8760
8. Fixed-price, high version	Fwd: $4.00 HLH, $2.00 LLHRev: $2.00 HLH, $1.00 LLH	Yes	$4.00
9. Fixed-price, low version	Fwd: $2.00 HLH, $1.00 LLHRev: $1.00 HLH, $0.50 LLH	Yes	$2.00
10. Fixed-price, medium version	Fwd: $3.00 HLH, $1.50 LLHRev: $1.50 HLH, $0.50 LLH	Yes	$3.00
11. $1 min HLH, 50¢ min LLH	[Mid-C – AESO] ÷ 4, minimum value of $1.00/MWh during HLH and $0.50/MWh during LLH	Yes, $1.00 or $0.50 in opposite direction	$5.30

Four conclusions emerge from this blocking analysis. First, the analysis supports the view that BCTC's current formula blocks fewer transactions than nearly all other formulae, while still maintaining a reasonable contribution to fixed costs. There is no other rate formula that blocks fewer transactions without reducing the average revenue per transaction, or that increases revenue collection without blocking more transactions. Similar results from the prior blocking analysis led BCTC to support its current rate formula, and the result of this analysis affirms BCTC's position.

Second, the analysis indicates that eliminating the directional aspect of the current formula would result in a substantial increase in blocked transactions (from 11% to 18% of all transactions). Again, despite the shortcomings of the current formula, it is relatively successful at achieving BCTC's goals.

Third, the analysis validates BCTC's policy of discounting ST-PTP reservations. Most transmission providers seek to maximize revenue rather than throughput and do not discount ST-PTP reservations. Indeed, the most common ST-PTP rate design uses the Appalachian formula, which results in a substantially higher hourly rate during peak hours. However, eliminating the discounting policy altogether would increase blocking from 11% to over 30% of all transactions under a fixed hourly rate, and to 42% of transactions if the Appalachian formula (AEP method in Figure 6.4) were used.

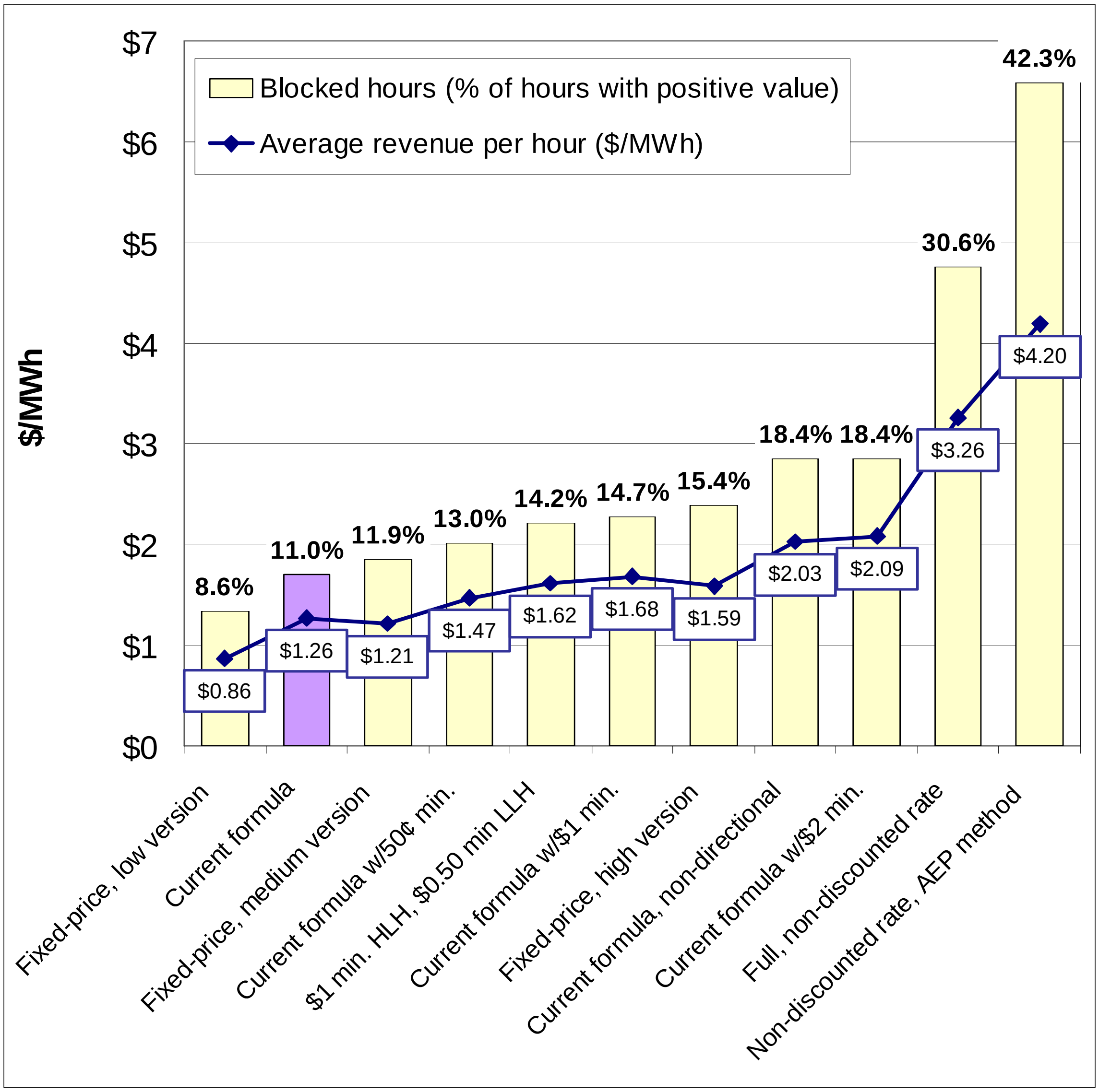

Figure 6.4: Analysis of the blocking effect of different ST-PTP rate formulae

Finally, the analysis shows that reinstating a modest price floor does not substantially affect blocked transactions and assures that each transaction makes a reasonable contribution to fixed costs. Setting a price floor at $0.50/MWh increases blocked transactions from 11% to 13% of transactions, while a $1 price floor blocks 14.7% of hours.

Taken collectively, this analysis and that in preceding sections of this report indicate that while BCTC's existing formula may not accurately capture the value of transmission at any point in time, it does do a reasonable job of cost recovery, while blocking relatively few trades. As a result, BCTC believes that the formula should be retained as the basis for single-day discounting, with the addition of a reasonable price floor that would apply in both directions.

Table 6.14: Summary results of blocking analysis

#	Formula	Blocked hours (% of hours with positive value)	Average revenue per transaction ($/MWh)	Average revenue per hour ($/MWh)	Total revenue (assuming current formula yields $50M)
1	Current formula	11.0%	$2.642	$1.265	$50.0
2	Current formula, non-directional	18.4%	$4.426	$2.031	$80.3
3	Current formula w/50¢ min.	13.0%	$3.155	$1.473	$58.2
4	Current formula w/$1 min.	14.7%	$3.680	$1.684	$66.6
5	Current formula w/$2 min.	18.4%	$4.778	$2.091	$82.7
6	Full, non-discounted rate	30.6%	$8.833	$3.258	$128.8
7	Non-discounted rate, AEP method	42.3%	$13.960	$4.197	$165.9
8	Fixed-price, high version	15.4%	$3.503	$1.591	$62.9
9	Fixed-price, low version	8.6%	$1.782	$0.864	$34.2
10	Fixed-price, medium version	11.9%	$2.558	$1.212	$47.9
11	$1 min. HLH, $0.50 min LLH	14.2%	$3.514	$1.618	$64.0

6.4.3 Use of Dow Jones Mid-Columbia hourly index

BCTC's current rate formula is calculated using daily Mid-C prices by time-of-day (HLH and LLH) period, and the blocking and revenue effects presented thus far presume the continuation of this practice. However, Dow Jones publishes an index of hourly Mid-C prices calculated from voluntary reports of bilateral trades. Prices for delivery on day *t* are currently posted after the pre-schedule period on day (*t*+1),[64] and therefore do not represent a timing improvement over the two-day-old data that is currently used to derive the ST-PTP rate. However, the hourly price index has a more granular intra-day profile that may better reflect persistent hourly arbitrage opportunities between Alberta and the US.

Table 6.15 shows that an hourly transmission rate formula is not appreciably better at predicting the direction of trade than the existing formula. An hourly formula based on two-day old data (the best that is available to BCTC under Dow Jones' current publishing practices) has the correct direction during 66% of hours, compared with 62% of hours during HLH periods and 73% of hours during LLH periods under the current formula. An hourly formula based on the same-hour prices from the previous day would have the correct direction 69% of hours. Because of these results, BCTC does not recommend moving to an hourly price index at this time.

64 http://djindexes.com/mdsidx/index.cfm?event=energyUSDaily

Table 6.15: Performance of the one-day and two-day lagged hourly price differences between Mid-C and Alberta

	Hour - 24	Hour - 48
Number of Hours	26,280	26,256
Formula Same Direction as Hourly Price	18,225	17,274
Formula Opposite Direction of Hourly Price	8,055	8,982
Percent of Hours with Correct Direction	69%	66%

6.4.4 Eliminating price discounting for daily reservations

BCTC currently discounts transmission reservations up to one month in length, with a lesser discount for weekly service beyond one week. BCTC's policy of discounting ST-PTP service is aimed at increasing utilization of the transmission system by decreasing the number of hours during which its transmission rate is greater than the margin available to its customers from selling in regional energy markets. However, nearly half of ST-PTP transmission reservations (49% of reserved megawatts) are for hourly service. Moreover, BCTC's practice of discounting daily reservations requires the use of two-day lagged price data for determining the ST-PTP rate, as discussed above.

BCTC is already recommending elimination of price discounting for reservations longer than one day. BCTC would also consider eliminating price discounting for daily service. This would enable BCTC to reduce the lag on the price data used to determine an hourly transmission rate from two days to one day, an idea that is worth exploring in future customer consultations.

In support of BCTC's consideration of eliminating price discount for daily service, Table 6.15 shows that reducing the lag to a single day would improve the directional accuracy of an hourly ST-PTP rate formula from 66% to 69%. Table 6.16 indicates an improvement in the daily prices:[65] from 61% to 68% for HLH and from 73% to 81% for LLH.

[65] Daily prices are calculated using the average of hourly prices during HLH and LLH periods in the same manner as is currently done with hourly Alberta Power Pool prices.

Table 6.16: Performance of the one-day and two-day lagged daily time of use price differences between Mid-C and Alberta

	HLH		LLH	
	Day *t*+1	Day *t*+2	Day *t*+1	Day *t*+2
Number of Days	1,097	1,096	1,097	1,096
Same Direction as Day t	746	668	890	800
Day T and Day T-2 Opposite Direction from Day *t*	351	428	207	296
Percent of Days with Correct Direction	68%	61%	81%	73%

6.4.5 Allocating remaining available transmission capacity via auction

BCTC's current approach to ST-PTP rate discounting is made necessary by imperfect information about the market value of transmission. If BCTC knew the market value of the transmission it was selling it could, in theory, use that information to price ST-PTP reservations to minimize blocking, while making a reasonable cost recovery. Absent such information, BCTC uses a discounting formula that aims to estimate the transmission value and allocate a share of that value to BCTC's domestic transmission users. The analysis presented so far in this section and the one used in BCTC's 2004 OATT Application show that the formula yields a reasonable outcome, albeit through an imperfect means.

In the longer term, it may become possible to use an auction process to uncover a more accurate value of transmission. During BCTC's OATT proceeding, BC Hydro proposed that BCTC replace its discounting formula with duration and price displacement to establish a floor for the ST-PTP transmission rate. BC Hydro called its proposal as "a form of auction process (i.e., they allow a customer the opportunity to obtain transmission service by placing a "higher" value on the service, thereby potentially displacing another customer who placed a lower value on the service). … In BC Hydro's opinion, BCTC's proposed formula is merely a mechanism to establish a market approximation for a price floor for the transmission service discounting. BCTC's proposal does not eliminate the displacement procedures."[66]

[66] OATT Proceeding, Ex. B2-8, Direct Testimony of Michael McDougall, December 17, 2004, p. 3.

In theory, an auction of short-term transmission capacity could reveal the market value of transmission in a given day or hour, ensuring that all available transmission capacity was assigned to market participants who value the capacity most.

However, there are two possible risks related to a transmission capacity auction. The most fundamental concern is a lack of competition in the market. In particular, the presence of a dominant user responsible for 95% of the transmission makes it unlikely that an auction mechanism could reveal the true market value of transmission[67]. In fact, since many transactions on the BCTC system are uniquely available to BC Hydro/Powerex, there should be an expectation that an auction would not reveal the value of transmission. That is because a trade could have high value to one user, but the singular nature of that opportunity means that no other party has any interest in bidding. Therefore, the capacity would be expected to sell at zero or a minimum price – but there would be no expectation it would sell for its "value" (i.e., the margin available in the trade opportunity). This does not preclude using an auction *per se*, but it does mean that in a market with a dominant player, an auction may tilt the balance toward utilization and away from ensuring a "fair" contribution on all transactions.

A secondary concern is that an ST-PTP capacity auction would result in "seams" between BC and neighbouring jurisdictions, particularly since none of BCTC's neighbours allocate ST transmission in such a manner.

Perhaps the combination of an auction with a minimum contribution to fixed costs might be able to achieve maximizing use and efficient allocation, while ensuring that all transmission users make a fair contribution to fixed costs. In markets with power pools, for example, an auction process is typically used to sell financial transmission rights (FTR). These rights hedge the holder against congestion costs between two locations within the control area. An additional fee, designed to ensure that all users make a contribution to fixed costs, is paid for exports out of the control area.

---

[67] Klemperer, P. (2002) "What really matters in auction design," Journal of Economic Perspectives 16(1): 169-189.

BCTC will continue to monitor the performance of its formula approach, and consider whether some form of auction might eventually be appropriate. BCTC is not, however, proposing an auction approach at this time.

Summary

BCTC's short-term pricing formula is a relatively poor predictor of arbitrage opportunity and value, but remains relatively good at balancing the twin goals of minimizing "trade blocking" and ensuring a reasonable contribution to fixed costs by every trade.

Replacing the current OATT's minimum scheduling fee provision with a minimum per megawatt-hour (MWh) charge, and eliminating discounting for multi-day reservations, can maintain transmission utilization, while providing a minimum level of fixed cost recovery from all users.

Eliminating the minimum scheduling fee would help reduce the transmission bill of very small transmission users, and would be justified with a per MWh charge.

Eliminating discounting for multi-day reservations would improve the performance of the ST-PTP pricing formula because the formula becomes an increasingly poor predictor of transmission value when extended beyond a one-day discounting period.

The short-term pricing formula combined with a minimum per MWh charge should be used for billing Dynamic Scheduling Services and other capacity products, because such rates would provide a minimum level of fixed cost recovery. Moreover, BCTC does not generally distinguish between the ways in which its customers can use its services to provide value and does not, at this time, see a need to distinguish among energy and capacity uses for the purposes of the discounting policy.

7. Conclusion

7.1 Beyond industry-standard, cost-based rate designs

This report has presented a number of options for modifying BCTC's LT-PTP rate design along cost-of-service lines to make the rate more responsive to the needs of BCTC's customers. However, in describing these options, BCTC has been mindful of the fundamental tension that exists between the two competing goals of having rates that are based on industry-standard, cost-of-service designs and increasing utilization of the BCTC system. This tension exists because BCTC's current rates were designed with the explicit goal of keeping the LT-PTP rate as low and stable as possible.

BCTC's current design has two features that contribute to this goal. The first feature is the use of the sum of nameplate generating capacity connected to the BCTC grid as the allocation factor for establishing the LT-PTP rate, resulting in a rate that is substantially lower than designs based on more common allocation factors such as 1-CP or 12-CP, as discussed in some detail in Section 4. The second feature is the "backstopping" of the transmission revenue requirement by the NITS customer that allows BCTC to avoid the need to defer over- or under-collections of the PTP revenue requirement, resulting in a stable LT-PTP rate that does not require frequent adjustments to resolve over- or under-collections. The combination of these two features results in a LT-PTP rate that, relative to other rate designs, favours increasing utilization, while maintaining an acceptable contribution to fixed costs from PTP users.

Thus, the most important conclusion that emerges from this review of cost-based design alternatives to BCTC's OATT is that moving from its current design to more commonly used, cost-of-service design is likely to decrease, not increase, utilization because of the higher LT-PTP rates that such a design would inevitably entail. Indeed, moving to the most common method of allocating costs among NITS and PTP, the 12-CP method, would result in a 30% increase in the LT-PTP rate. BCTC emphasizes this conclusion throughout Section 4 of this report.

While this report has focused primarily on rate designs that reflect industry-standard, cost-of-service methodologies for cost allocation, it also describes some modifications to BCTC's current design that would help to improve utilization without undertaking a fundamental rate design change. The new Term PTP product described in Section 5.2 represents an option for transmission service that PTP customers do not currently have. Similarly, in Section 4, BCTC shows that subtracting ST-PTP revenue from the TRR before calculating the LT-PTP rate would result in a slight decrease in the LT-PTP rate. These options may help to increase utilization.

Less easily addressed outside the context of more commonly used, cost-of-service based rate design is the issue of PTP transmission service for non-dispatchable resources that may have intermittent output profiles. The rate design option that BCTC presents in Section 5.1 establishes non-dispatchable resources as a third class of long-term service alongside NITS and LT-PTP, and allocates the TRR among the three classes based on a 12-CP method. This design option, therefore, presumes the existence of a cost allocation among NITS and PTP customers, in contrast to BCTC's current rate design in which no such cost allocation occurs. Under this option, access to the transmission system by non-dispatchable resources would be improved but cost allocation requires the initial step of moving to a 12-CP cost allocation methodology, which results in a higher LT-PTP rate that may result in a reduction in utilization by other LT-PTP customers. Establishing a third class within the context of BCTC's current design would not resolve the issue, because the use of nameplate generating capacity as the allocation factor would result in identical rates for dispatchable and non-dispatchable classes. Thus, improving access by non-dispatchable resources would appear to require the paradoxical step of increasing the rate paid by all other PTP customers, not because of the existence of the non-dispatchable class of service itself, but because of the necessary prerequisite of moving to a 12-CP cost allocation methodology for all PTP customers.

In order to avoid this outcome, it may be necessary or desirable to depart to some degree from the strict cost-of-service paradigm that underlies the industry standard rate design. BCTC's current design is not based strictly on industry-standard cost-of-service principles, yet in BCTC's view it does meet the Commission's goals of "reflecting a degree of cost causality", while promoting utilization of the BCTC system through low LT-PTP rates. Further modification of BCTC's existing design could result in an outcome that is similar to that reflected in Option 7 (in

Section 4), while avoiding the paradoxical outcome of increasing the LT-PTP rate. As an example, an adjustment factor can be applied to the current LT-PTP rate for non-dispatchable resources that would result in a non-dispatchable rate identical to the rate under Option 7 (ie. an adjustment factor of 40.6% would produce a rate of $2.27/kW-monthly). This rate clearly reflects a “degree of cost causality”, because it is identical to the rate derived for Option 7 using a more standard cost allocation methodology.

A variety of methods could be used to derive the appropriate adjustment to the LT-PTP rate. The adjustment factor could be as low as the expected or actual capacity factor of the non-dispatchable resource during the year. Alternatively, it could be based on the contribution of non-dispatchable resources to system peak demands, either monthly or annually. Other options could include the development of both an energy charge and a demand charge, in order to land somewhere in between the rate at 30% capacity factor and the rate assuming a 100% capacity factor. The key distinction between these options and Option 7 is that the adjustment factor would be applied to the PTP rate derived using the current allocation factor of total nameplate generating capacity, rather than deriving directly from the cost allocation methodology. These designs are thus one-step removed from a strict, cost-of-service construction, even if their outcomes are similar to those that would obtain under more standard methods.

7.2 Short-term pricing

The inaccuracy of the ST pricing index as a measure of transmission value is a clear reminder that it is very difficult to forecast hourly electricity market prices, even for a period as short as two days. In spite of the forecasting issues, the resulting ST-PTP prices have been sufficiently low to remove transmission as a barrier to efficient levels of electricity trade. Although the index has increased utilization as intended, many of these transactions took place at very low or zero transmission prices resulting in a 17% drop in ST-PTP revenues (please see Table 6.4).

BCTC’s evidence in Section 6 shows that the elimination of discounting beyond one day (more than a two-day forecast) and the replacement of the minimum scheduling fee with a floor price of $0.50-1.00 per MWh will increase average rates and recover a portion of the lost revenues without substantially increasing barriers to efficient trade.

7.3 BCTC Recommendations on Process

This report has recommended a number of changes to BCTC's short-term rate design. In BCTC's view, these proposals are reasonably discrete and, if acceptable to interveners and the Commission, could be implemented within a reasonably short period. BCTC proposes to consult with its customers in February and March 2007, and to bring any applications for tariff changes that result from those consultations to the Commission after April 2007.

The LT-PTP analyses presented in this report reflect more fundamental tradeoffs and modifications. As indicated in Section 3, FERC is currently undertaking a rulemaking process with respect to the Order No. 888 *pro forma* tariff. While the issues that are under consideration in that proceeding are not directly applicable to the issues addressed in this report, BCTC contemplates that it will be consulting with its customers at the conclusion of that process[68] with respect to the implications of FERC Final Rule. Thus, BCTC will consult with its customers with respect to the FERC rulemaking and the LT-PTP alternatives raised in this report at the same time. BCTC also proposes to consult with its customers in that same time frame regarding the potential Term PTP Service, NITS billing, and any modifications that may need to be made for Shaped Service. BCTC will finalize its consultation schedule once the FERC Final Rule has been determined.

With respect to non-wires alternatives, BCTC's proposals regarding further process are presented in Appendix B of this report.

BCTC's recommendations on process are summarized in Section 1 in Table 1.3.

[68] BCTC currently contemplates that these consultations will commence in the third quarter of 2007.

Appendix A Appropriateness of Load Ratio Share for NITS billing

A.1 Introduction

The Decision accepts BCTC's Load Ratio Share approach for dividing the NITS revenue obligation in the event that there are multiple NITS customers. "The Commission Panel notes the advantages to Network Customers that would result from the JIESC's recommended NITS rate, expressed in $/kW of contract demand, but also observes that reliance on forecast billing demands in setting the rate could potentially result in over or under collections of the Network TRR. The Commission Panel is therefore of the view that BCTC's use of Load Ratio Share for the NITS rate is appropriate for the time being. Given there is currently only one NITS customer, BCTC's proposed approach will more predictably collect the forecast Network TRR." (the Decision, pp.15-16)

However, the same decision directs BCTC to address "the appropriateness of a change to the Load Ratio Share approach for NITS billing of Network Customers, particularly if more Network Customers materialize prior to December 2006. Reasons for either changing or not changing the approach should be supported by a discussion of the volatility of Network Customers' bills using the Load Ratio Share as well as the stability of the resulting revenue (Section 3.1)." (the Decision, p.107)

In compliance with this directive, this appendix considers alternative billing determinants for NITS, and their effect on monthly bills for other potential NITS customers, including industrial customers that might wish to take that service. In doing so, the appendix first describes, in Section A.2, the existing NITS billing, thus providing the context in which the alternative billing determinants can be viewed.

Section A.3 proposes to lengthen the period over which the Load Ratio Share is calculated. In this case, the revised Load Ratio Share for a given NITS customer is: (a) the 12-month rolling average of the NITS customer's monthly peaks, divided by (b) the 12-month rolling average of ***all*** NITS customers' monthly peaks. The resulting customer-specific load ratio is stable, even though the monthly peaks of a dominant NITS customer such as BC Hydro may exhibit large seasonal fluctuations.

Section A.4 develops an explicit $/kW-month rate that is applicable to a NITS customer's monthly peak demands, for the purpose billing the customer's transmission use. As the rate applies to a customer's individual peak demands, the customer's bill is independent of other customers' peak demands. Hence, a NITS customer with stable monthly peaks will also have stable monthly bills.

A.2 NITS billing under the existing OATT

Under the existing OATT, the monthly bill for a NITS customer (e.g., BC Hydro) is calculated for a given month using the following steps:

Step 1: Compute the monthly revenue requirement for the NITS class. As shown in Section 4 of this report, each month's NITS class revenue requirement is the annual residual TRR (i.e., TRR less PTP revenue) divided by 12 months. Hence, the monthly NITS class revenue requirement does not vary monthly.

Step 2: Compute the monthly Load Ratio Share of a NITS customer. Suppose the billing month is January. This NITS customer's January Load Ratio Share is: (a) the customer's January load at the time of the January system peak, divided by (b) the sum of all NITS customers' January loads at the time of the January system peak.

Step 3: Set the monthly charge to a NITS customer as: (a) the monthly NITS class revenue requirement from Step 1, multiplied by (b) the monthly load ratio from Step 2.

The above steps mean that if there is only one NITS customer, as is the case today with BC Hydro, the ratio is always equal to 1, and BC Hydro's monthly NITS bill does not fluctuate. However, when there are multiple NITS customers, the monthly bill of a relatively small customer with stable monthly loads (e.g., an industrial customer with multiple load and generation sites) moves with the monthly peaks of BC Hydro. In particular, the small customer's bill is at its lowest level in the coldest month (e.g., December or January) when BC Hydro's load peaks. In a mild weather month (e.g., June), the small customer's bill is at its highest level when the BC Hydro's load troughs.

The Load Ratio Share billing can be seen as inconsistent with the cost-based ratemaking principle for two reasons. First, the small customer's monthly bill is inversely related to the monthly system peak.   Second, the small customer's bill variation is caused by the large customer's monthly load fluctuation, even though the small customer's load varies little from one month to another.

A.3 Lengthen the period over which the Load Ratio Share is calculated

Under the current rate calculation, a NITS customer's monthly bill is its relative share of the monthly coincident peak demand times the monthly NITS revenue obligation. If this customer (e.g., an industrial customer) is small relative to the dominant NITS customer (e.g., BC Hydro), the former's monthly Load Ratio Share can be significantly affected by the latter's load fluctuations. One way to stabilize the small customer's NITS bill is to use a rolling average of the current and prior 11 month period to make the monthly Load Ratio Share calculation. The resulting monthly Load Ratio Share is: (a) the rolling average of the small customer's most recent 12 coincident peaks, divided by (b) the rolling average of the system's most recent 12 monthly coincident peaks. For new small customers with fewer then 11 months of historical coincident peak demands, the rolling average would ignore those months without historical data (i.e., the months would not be set to zero for purposes of calculating the average).

Once the customer's monthly load ratio is found, its monthly bill is the ratio times the NITS revenue obligation, divided by 12.

Table A.1 shows BC Hydro's monthly system peaks in 2005, which exhibit a strong seasonal pattern, and a hypothetical customer (ABC Corp), which has constant monthly coincident peaks of 100 MW throughout the year. The table shows that the small customer's monthly Load Ratio Shares and bills under the existing NITS rate design fluctuate between a low of $414,000 and a high of $573,000, due entirely to BC Hydro's load variations. There is no cost basis to this shift in billing.

Table A.1: NITS customer bills under the *status quo* rate design

	Coincident Peaks (MW)		Load Ratio Shares		Monthly Residual TRR ($000)	Customer Bills ($000)		
	BC Hydro	ABC Corp	BC Hydro	ABC Corp		BC Hydro	ABC Corp	Total
Apr	7,156	100	99%	1%	36,742	36,235	506	36,742
May	6,588	100	99%	1%	36,742	36,192	549	36,742
Jun	6,314	100	98%	2%	36,742	36,169	573	36,742
Jul	6,517	100	98%	2%	36,742	36,186	555	36,742
Aug	6,426	100	98%	2%	36,742	36,179	563	36,742
Sep	6,678	100	99%	1%	36,742	36,200	542	36,742
Oct	7,244	100	99%	1%	36,742	36,241	500	36,742
Nov	8,585	100	99%	1%	36,742	36,319	423	36,742
Dec	8,775	100	99%	1%	36,742	36,328	414	36,742
Jan	8,732	100	99%	1%	36,742	36,326	416	36,742
Feb	8,322	100	99%	1%	36,742	36,305	436	36,742
Mar	7,983	100	99%	1%	36,742	36,287	455	36,742
Total					440,900	434,967	5,933	440,900

In contrast, the bills under the 12 month rolling average design of the customer's 12 monthly peak loads will have substantially less variation. Table A.2 shows the bill calculations for BC Hydro and the hypothetical small customer. In this case, the customer's bills vary only a small amount, between $487,000 and $497,000.

Table A.2: NITS customer bills based on Load Ratio Shares computed using 12-month rolling average of loads

	Coincident Peaks (MW)		12-mo. rolling avg		Load Ratio Shares		Monthly Residual TRR ($000)	Monthly Bills ($000)		
	BC Hydro	ABC Corp	BC Hydro	ABC Corp	BC Hydro	ABC Corp		BC Hydro	ABC Corp	Total
Apr	6733	100								
May	6318	100								
Jun	6386	100								
Jul	6523	100								
Aug	6496	100								
Sep	6478	100								
Oct	7277	100								
Nov	8232	100								
Dec	8410	100								
Jan	8904	100								
Feb	7967	100								
Mar	7377	100								
Apr	7156	100	7,293.7	100.0	99%	1%	36,742	36,245	497	36,742
May	6588	100	7,316.2	100.0	99%	1%	36,742	36,246	495	36,742
Jun	6314	100	7,310.2	100.0	99%	1%	36,742	36,246	496	36,742
Jul	6517	100	7,309.7	100.0	99%	1%	36,742	36,246	496	36,742
Aug	6426	100	7,303.8	100.0	99%	1%	36,742	36,245	496	36,742
Sep	6678	100	7,320.5	100.0	99%	1%	36,742	36,247	495	36,742
Oct	7244	100	7,317.8	100.0	99%	1%	36,742	36,246	495	36,742
Nov	8585	100	7,347.2	100.0	99%	1%	36,742	36,248	493	36,742
Dec	8775	100	7,377.6	100.0	99%	1%	36,742	36,250	491	36,742
Jan	8732	100	7,363.3	100.0	99%	1%	36,742	36,249	492	36,742
Feb	8322	100	7,392.8	100.0	99%	1%	36,742	36,251	490	36,742
Mar	7983	100	7,443.3	100.0	99%	1%	36,742	36,255	487	36,742
Total							440,900	434,975	5,925	440,900

A.4 Calculate an explicit NITS rate

The calculation of an explicit rate over a future test period can yield stable bills for NITS customers with stable peak demands. To illustrate the rate calculation under the 1-CP method explained in Section 4 of this report, the NITS rate ($/kW-month) is found using the following steps:

Step 1: Estimate each NITS customer's load at the time of the annual system peak. Thus, a NITS customer's monthly billing determinant is the customer's load at the time of the annual system peak[69].

Step 2: Compute the NITS class total kW-months as 12 months times the sum of all NITS customers' loads from Step 1.

Step 3: Set the monthly rate ($/kW-month) as (a) the NITS class revenue requirement, divided by (b) the NITS class total kW-months from Step 2.

Under the 1-CP method, the monthly bill for each NITS customer reflects the customer's contribution to the annual system peak. A NITS customer's bill, once set, does not vary monthly over the test period. Instead, in the case of the small customer, it matches the stable monthly loads. Although the 1-CP method would continue to provide BCTC with a stable and predictable source of revenues, the revenue collected from each customer would be based on their estimated usage, and would not reflect their actual usage at the time of the coincident peak for the year. Deferral accounts would be required for NITS customers, as would a process for adjusting rates to amortize deferral account balances.

Table A.3 shows an example of a $3.31/kW-month NITS rate calculated using the 1-CP method. The same explicit rate calculation can be made using the 12-CP method, as shown in Table A.4. The resulting rate is $4.99/kW-month.

---

[69] If the new NITS customer is an existing BC Hydro load customer, its NITS load can be based on: (a) its contract demands; or (b) its measured demand.

Table A.3: NITS rate design using 1-CP method

	BC Hydro	ABC Corp	Total	
1 Estimated Coincident Peak (MW)	11,000	100	11,100	
2 CP * 12 months (MW-mo)			133,200	*Line 1 * 12*
3 Residual TRR ($000)			440,900	
4 Monthly Rate ($/kW-mo)			3.31	*Line 3 / Line 2*
5 Monthly Charge ($000/month)	36,411	331	36,742	*Line 1 * Line 4*

Table A.4: NITS rate design using 12-CP method

	BC Hydro	ABC Corp	Total	
1 Sum of 12-CP (MW-mo)	87,101	1,200	88,301	*see Table 6.2*
2 Residual TRR ($000)			440,900	
3 Monthly Rate ($/MW-mo)			4.99	*Line 2 / Line 1*

A.5 Conclusion

In the Decision, the Commission directed BCTC to address "the appropriateness of a change to the Load Ratio Share approach for NITS billing of Network Customers, particularly if more Network Customers materialize prior to December 2006." (the Decision, p.107) Based on the analysis in this Appendix, the Load Ratio Share computation in the existing OATT can be changed to reduce the bill volatility that may arise in the case of multiple NITS customers.

BCTC has considered two alternatives: (a) use a rolling average of peak demands to compute Load Ratio Shares; and (b) compute an explicit $/kW-month rate using the 1-CP or 12-CP method. If the existing NITS billing were to be modified, BCTC believes (a) is preferable to (b) for two reasons, provided here to comply with the Commission's reporting requirement[70]:

2) A change in the Load Ratio Share computation does not require any change in the tariff language, thus facilitating its implementation.

3) Retaining the Load Ratio Share approach, though not the existing computation, ensures the full recovery of the total NITS revenue requirement. This avoids the possible under- or over-collection that can occur under an explicit NITS rate, as a result of the actual NITS loads deviating from the estimated loads used to compute the $/kW-month rate.

Notwithstanding the above reasons, BCTC does not recommend modifying the NITS billing because currently there is only one Network Customer. When the need arises, BCTC will consult with its customers before making any modification to the Load Ratio Share calculation.

[70] "Reasons for either changing or not changing the approach should be supported by a discussion of the volatility of Network Customers' bills using the Load Ratio Share as well as the stability of the resulting revenue (Section 3.1)." (the Decision, p.107)

Appendix B Re-dispatch and Customer Supplied Solutions as Non-Wires Alternatives to Transmission Investment

B.1 Introduction

The Decision directed BCTC "to file a re-dispatch tariff as soon as practicable, and report to the Commission at fiscal year end, if the re-dispatch tariff has not been filed by that time" (p.110). On September 23, 2005, the Commission issued its Capital Plan Decision (CPD) regarding BCTC's F2006-F2015 Transmission System Capital Plan Application. The CPD directed BCTC to consider options for customer-supplied transmission services as solutions to transmission constraints, stating:

> "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:
>
> - 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." (pp.65-66)

Although the Commission did not specify re-dispatch service as a customer-supplied solution in the CPD, BCTC considers re-dispatch service as one of the customer-supplied options for transmission services, similar to reactive power and reliability must run (RMR) generation.

In a letter to the Commission dated March 31, 2006, BCTC indicated that subsequent to the OATT Decision and CPD, it had studied the development of a re-dispatch tariff using the following steps: (1) identify alternative service options; (2) consult with customers and the Transmission Planning Advisory Committee (TPAC); (3) choose the option with best potential to be a customer-provided solution to transmission constraints;[71] (4) identify market potential for the chosen option; and (5) identify implementation requirements for the chosen option.

BCTC indicated that it would continue to evaluate re-dispatch service within the context of the Commission's broader instruction in the CPD, by considering customer-supplied solutions for relieving transmission constraints. BCTC also proposed to include the results of that evaluation in this report. By Letter No. L-16-06, the Commission accepted BCTC's proposal. This appendix presents the evaluation referred to in BCTC's March 31, 2006 letter and accepted by the Commission in Letter No. L-16-06.

To view this appendix in proper context, one must be mindful that BCTC does not own or control generation facilities. Nor does BCTC serve any retail end-use loads. This lack of generation ownership and load serving responsibility has important implications. First, some of the re-dispatch provisions in FERC's OATT Notice of Proposed Rulemaking[72] are of limited

[71] BCTC consulted TPAC on March 2, 2006 and June 22. 2006. In addition, BCTC consulted with customers on January 17 and 19, 2006.

[72] Preventing Undue Discrimination and Preference in Transmission Service, Docket Nos. RM05-25-000 and RM05-17-000 (May 18, 2006)(Notice of Proposed Rulemaking). This NOPR contemplates amending the pro-forma OATT to include more comprehensive re-dispatch obligations than are included in the current FERC Order No. 888 tariff. Because BCTC has no generation resources available to it for economic dispatch (i.e., for purposes other than short-term reliability), it requested from the Commission in its previous OATT application, and received, approval to modify section 30.5 of its tariff, removing the pro-forma tariff's re-dispatch obligations (and replacing that obligation with a commercially reasonable effort). The same rationale that under-pinned that change (i.e., that BCTC has no generation to re-dispatch) defines the context of this report.

relevance to BCTC. Put plainly, BCTC cannot offer re-dispatch service as other providers do under a FERC *pro forma* tariff, including the Bonneville Power Administration. Second, BCTC cannot compel loads or resources in BC to provide non-wires solutions for the benefit of third parties. All opportunities considered here must rely on the voluntary supply of generation or load services. Finally, non-wires potential in BC resides largely within BC Hydro and its customers, and any viable solution will involve cooperation between BC Hydro and BCTC.

This appendix does not propose pilot programs of the kind proposed by BPA for the summer of 2007[73]. Similarly, it does not propose any solutions that require a transparent price for altering BC Hydro's generation schedules (e.g., mandating BC Hydro to post a re-dispatch offer price). Such opportunity-cost-based approaches have been proposed without success, most recently in BCTC Network Economy Application, largely because of implementation concerns from BC Hydro.

What the appendix does is to describe the perspectives and solutions that BCTC believes to be pragmatic in the current environment. BCTC has not focused on the theoretical engineering potential of non-wires opportunities, but rather on those initiatives with practical economic potential.

B.2 Non-wires perspectives

BCTC consulted with its TPAC in developing its non-wires perspectives. This advice was critical to helping BCTC frame the practical economic potential of various non-wires "tools". Nevertheless, BCTC's conclusions may, in places, be more conservative than the view preferred by some TPAC members.

There are two non-wires perspectives. The first perspective is to use non-wires alternatives to defer or replace transmission investment. The second perspective is to use non-

[73] The BPA pilot program is for within-the-hour reliability re-dispatch. It is a reactive program, where within-the-hour re-dispatch is used to reduce flows on four pilot cutplanes that are congested. Price is to be determined by the generation owner, and BPA will decide if the cost and availability of re-dispatch will meet the within-hour criteria. BPA will enter into re-dispatch contracts with participating generators.

wires alternative to resolve congestion and create now available capacity, without building transmission infrastructure. Each perspective is detailed below.

B.2.1 Transmission capital deferral or replacement

In considering the appropriate application of non-wires alternatives to transmission, BCTC's first principle is to not compromise system reliability. BCTC believes that non-wires alternatives are only viable where they provide some clear advantages (e.g., cost, timing, market opportunity, or community acceptance), without compromising reliability. This emphasis on reliability can complicate a cost-benefit review of non-wires alternatives because these solutions often provide a different level of reliability than a traditional transmission-only solution. Hence, the expected reliability level of all options must be measured or screened prior to any economic evaluation of alternatives. Moreover, the reliability impact of non-wires solutions must be measured as a cumulative portfolio over a relatively long time horizon. While one non-wires project may be acceptable if it has substantial cost savings and raises no overall reliability concerns, several such projects taken together could weaken the system over time if care is not taken.

For example, an individual generator is often seen to provide less reliability than a new transmission line because of fuel constraints, delivery issues applicable to a generator, and maintenance needs. Moreover, a generator is typically built to deliver energy and power, not solely for serving transmission needs. To be sure, a generator's transmission function can be supplied by contract (e.g., RMR) with the transmission company. Nonetheless, the contracted generator offers a lower standard of direct control to the transmission operator than do transmission facilities.

That said, there is clearly a point where a diversified volume of generators or flexible loads can reliably replace a transmission line. Part of the long-run and cumulative perspective on non-wires planning is to assess whether such a portfolio of distributed generation, for example, is likely to emerge in the required time frame.

Bulk transmission

Viewed practically in the BC context, BCTC does not expect that customer-supplied solutions create a material opportunity for permanent capital replacement on the integrated bulk system, simply because there are relatively few of such projects in BCTC's current capital plan and because of the nature and timing of those projects. To ensure that potential projects are not ruled out, however, BCTC suggests a high-level screening approach for the Commission's consideration. Successfully used in some jurisdictions like New York and California,[74] the approach aims to achieve the goal of integrated transmission planning, but without unwarranted regulatory delay and analysis.

Notwithstanding its reservations about long-term customer-supplied opportunities on the bulk system, BCTC does see valuable potential in customer-supplied alternatives as a form of short-term, or "bridging", solution. That is, in cases where construction time lines or other considerations mean that a transmission-based solution cannot be in service at the time additional capacity is required, it may be useful to employ a temporary customer-supplied solution to cover an intervening period. For example, BCTC and BC Hydro have engaged in discussions with Norske Canada (now Catalyst Paper Corporation) to address transitional supply concerns to Vancouver Island.

Local transmission

BCTC believes that there may be more of a significant and permanent role for customer-supplied solutions on the local or radial system. This is based, in part, on the fact that the additive weakness described for the bulk system is less of a concern there, because the impact of

---

[74] For example, the New York Public Service Commission requires, as part of the market restructuring in the state, that utilities perform local integrated resource planning studies for transmission or distribution projects that exceeded a threshold capital cost (e.g.: $2 million for Orange and Rockland and $10 million for Consolidated Edison). The smaller projects are not subject to this requirement (NYPSC Order No, 97-16, p. 17). California utilities complete extensive integrated planning studies for large bulk system projects. Smaller projects are screened with a simple economic test (PG&E Distributed Generation Guideline - DCS Guideline D-G0058) or based on situations that are particularly conducive to distributed generation (Compliance Filing of San Diego Gas and Electric Company Pursuant to D.03-02-068). BPA uses both an economic screening and collaborative approach to development of cost effective non-wires solutions for only their larger transmission projects with budgets above $10 million in 2004, and dropping to $2 million in 2005 (Non-wires solutions round table, goals for 2005).

a particular non-wires solution on a radial section of the system is easier to recognize and plan for.

In contrast to the integrated bulk system, the conceptual evaluation of customer-supplied solutions on the local or radial system is relatively straight-forward: where expansion is needed (either as a tariff-driven upgrade or advanced under BCTC's expansion policy), non-wires or customer-supplied solutions will be considered to be viable alternatives if they are cost effective relative to the transmission alternative. This evaluation must take account of the reliability implications of the solutions being compared, as well as all other ancillary cost and benefits, such as system support and community acceptance.

Sometimes, local or radial system transmission reinforcements may be prohibitively expensive, leaving non-wires solutions as the only practical alternative for a needed system upgrade. In such cases (reinforcing service to a remote industrial facility, community, or recreational resort, for example) the alternative to a local or radial non-wires solution may simply be the *status quo*, not a transmission project.

In cases where a wires-based solution is not in BCTC's capital plan, the issue becomes somewhat more complex. Consider, for example, a long radial feed (either bulk or local). Reinforcement costs to loop this circuit may be prohibitive. However, it may be identified that an available non-wires solution is much less costly. The challenging question here is whether the incremental reliability benefits are justified against normal planning criteria and competing funding priorities.

This kind of "single-solution" non-wires project is clearly worthy of evaluation, on a case-by-case basis without an overly prescriptive policy framework. However, the evaluation should reflect BCTC's general belief that incremental reliability or other attributes can only be considered "benefits" of a project if they contribute to BCTC's compliance with existing planning criteria or norms. Reliability improvements beyond prevailing standards may not be worth investing in.

B.2.2 Creating transmission capacity through re-dispatch

Besides deferring or replacing capital investment, non-wires or customer-supplied solutions may create additional transmission capacity for the following purposes:

4) Create ATC for a LT-PTP contract;

5) Create a buy-through alternative for constrained periods in a Shaped Service contract; or

6) Create additional ST-PTP and Term PTP opportunities.

These ATC-creating non-wires approaches are generally known as re-dispatch agreements, and can be supplied by either generators or loads. BCTC supports, conceptually, at least, the use of re-dispatch as a non-construction means of creating ATC and, thereby, facilitating cost effective opportunities for using the existing transmission system.

BCTC's role in re-dispatch

In considering re-dispatch arrangements, BCTC has concluded that they must be entirely voluntary. That is, BCTC cannot impose an obligation on BC Hydro or any other generator or load to make a re-dispatch offer in favour of a third-party transmission customer. This is consistent with BCTC's tariff, its Key Agreements with BC Hydro, and its contractual relationships with other parties to whom it provides service.

Given that constraint, BCTC believes that its proper role in re-dispatch might be to create mechanisms that inform potential re-dispatch suppliers about the prevailing value of additional ATC that is useful to other transmission customers. BCTC also believes that it could properly have a role in facilitating the relationship between a potential supplier of generation or load management services, and a potential beneficiary (i.e., the potential transmission customer seeking ATC, or load-serving utility seeking to lower the overall cost of serving its customers, by trading off generation and transmission alternatives). Finally, BCTC believes that it may, on occasion, directly purchase dispatch rights from a generator or curtailment rights from a load, where doing so can effectively delay or eliminate the need for transmission construction.

BCTC believes that at the lower end, its proper role could be as little as simply hosting a "bulletin board" style foundation for bilateral transactions[75]. At the upper end, BCTC could take a very active role by creating a reconfiguration or related style of transmission market, in an attempt to bring liquidity and flexibility to transmission re-sale and load- or generation-based re-dispatch offers. In the middle, BCTC could play a contract facilitation role. This might involve re-dispatch-created ATC or paying generators to locate and perform in a manner that defers or replaces transmission investment. At the same time, BCTC could act as a re-seller of these generation or load services to benefiting parties, including BC Hydro. This could be on a matched (pre-determined pairs of buyer and seller) or an unmatched (inventory) type basis.

BC Hydro's role in load management

Peak load reduction is a customer-supplied solution for reducing or deferring the need for new construction, and creating room on the existing system. BC Hydro has an extensive program under its Power Smart brand. BCTC believes that it would be duplicative and counter-productive for it to engage in load management in any way that caused it to replicate or encroach on BC Hydro's Power Smart programs. Moreover, BCTC believes that, in the vast majority of cases, its role should be to identify transmission-related DSM opportunities for BC Hydro rather than attempt to implement resultant programs itself.

For example, if BCTC's access to transmission knowledge leads to it recognizing potential to defer transmission investment by localized peak-shaving, that information should be properly communicated to BC Hydro. BCTC believes that the channels for this sort of communication should be refined and formalized, to ensure the maximum possible use of these load-management opportunities.

---

[75] The bulletin board referenced here is designed to actively match buyers and sellers. It should not be confused with information-posting initiatives that BCTC may use in other contexts.

There may remain, however, a set of cases where BCTC can engage directly in load management. This may include targeted "bridging" solutions, such as the arrangements that BCTC and BC Hydro have discussed with Norske Canada (Catalyst Paper Corporation), or as may exist for service to a community such as Golden. That is, where load management opportunities are not generalized – but, rather can be focused on an identifiable customer or small set of customers – BCTC believes that it may have a role in contracting directly for load-management services with these loads.

BCTC understands that BCTC and BC Hydro potentially buying load-management service from the same customer base risks creating pricing outcomes that are not in the best interest of ratepayers. BCTC believes, however, that this circumstance can be avoided by the utilities and the Commission (for example, the Commission could insist that utilities not enter into contracts that are priced to allow rent-extraction by the supplying load). At the same time, BCTC believes that it would be extremely difficult to draw a bright line between the respective roles of BC Hydro and BCTC in respect of all load management. Attempting to do so, in fact, is likely to cause more harm than good, in the form of foregone opportunity.

B.3 Implementation

BCTC has considered three avenues to implement non-wires alternatives: (1) expansion of its existing deferral credit; (2) market for re-dispatch; and (3) improved communication on load management. Each avenue is described below.

B.3.1 Expansion of the deferral credit

The first avenue is to expand the deferral credit that the Commission approved with modification, following BCTC's application for a transmission deferral credit in the last OATT proceeding. This deferral credit grants eligible generators 75% of the value of any transmission capital deferral made possible by their agreeing, and living up, to specified performance commitments. The expansion aims to improve the credit in two ways: (1) to adjust the payment mechanism from a transmission credit to cash, so that it can be available to customers (like loads or generators selling to BC Hydro) that are connected to the transmission system but that do not directly purchase transmission service from BCTC; and (2) to expand customer eligibility from new generators to existing generators and loads.

Payment mechanism

At present, payments are to be made against future PTP transmission service. This approach was chosen as a mechanism to protect ratepayers from making up-front payments and the risk of subsequent non-performance. The collective effect of the performance commitment and the payment approach is that the credit is only available to dispatchable generation units selling to parties other than BC Hydro. Generators selling to BC Hydro are part of BC Hydro's NITS resources and, as a result, they do not take PTP service and have no transmission bills. These generators currently cannot benefit from the deferral credit because there is no means for them to receive the credit payments.

BCTC recognizes the limitations of its existing payment mechanism. In its future tariff application, BCTC expects to propose that performance commitments be paid in cash on an annual basis, amortized over a reasonable period of time. For cash flow reasons, BCTC expects that it will seek recovery of these payments within its rates each year.

BCTC believes that this payment change will make the deferral credit of potential interest to generators holding energy supply contracts with BC Hydro. However, the degree of flexibility those generators have to meet BCTC's performance obligations will depend on the nature of the agreements that the generators have with BC Hydro. For example, if BC Hydro's energy supply contracts were designed to allow generators that could provide transmission benefits the operating flexibility to offer BCTC such services, then there is a potential for increased aggregate value.

Customer eligibility

The deferral credit was designed to replace area-specific pricing that had existed in BC Hydro's Wholesale Transmission Services tariff. As such, the deferral credit was seen principally as a locational price signal, providing an incentive for generators to site in places where they could benefit the transmission system. Because of this perspective, the deferral credit was limited to new generators taking LT-PTP service, since only new facilities could respond to a locational incentive for plant siting.

This “locational pricing” perspective ignores the possibility that existing generators and loads could also help the transmission system to defer capital, if they agree to operate in specific ways. So while a price signal telling an existing facility where to locate is pointless, a price signal telling them the value of acting a certain way is not.

Therefore, BCTC proposes to extend the deferral credit to existing generators and loads, using the terms and conditions that exist today to determine the value of the transmission capital deferred. BCTC proposes to consult with its customers with respect to the performance commitments that will be required to be eligible for the deferral credit and with respect to the criteria for evaluating such commitments.

Moreover, if BCTC identifies through its regular planning activities that particular locations and performance-contract combinations are of particularly high value, it will either seek to have BC Hydro tailor generator-dispatch or load management calls in those locations (either permanently or on a bridging basis) or undertake such calls itself. BCTC expects to further explore these opportunities with BC Hydro and other potential suppliers in the coming months.

Finally, for new loads, BCTC will propose that BC Hydro’s prevailing extension policy continue to apply to loads at the time of interconnection. However, once interconnected, BCTC would perceive the load to be “existing”, and would treat it like other loads for the purposes of the credit eligibility and payment determination. In addition, and as described in Section B.3.3 of this Appendix, BCTC will identify those areas of its system where capital programs could be deferred by the location of new loads and communicate such information to interested parties.

B.3.2 Market for re-dispatch

The value of non-wires and customer supplied solutions partly derives from the opportunity to use the contracted behaviour of either generators or loads to create additional

ATC at particular times. To access that value, BCTC could undertake anything on a spectrum from creating a simple bulletin board to implementing a full reconfiguration auction[76].

In consultation with stakeholders, it was determined that there was relatively little expectation of success from the more conservative end of the spectrum (i.e., a simple bulletin-board type approach). BCTC agrees with this perspective. There is simply no evidence that the lack of re-dispatch activity currently available in BC for third-party benefit is a function of a communication problem between potential buyers and sellers.

However, BCTC also heard from stakeholders that they would be reluctant to see large amounts of money spent on developing the infrastructure for a reconfiguration (or similar) approach, unless there was a clear business case for this. And most stakeholders seem to doubt that such a case could be made because of the lack of liquidity in the current energy market in BC. BCTC has similar reservations.

To make re-dispatch work in BC, BCTC believes that BC Hydro would need to support the initiative. After all, BC Hydro owns or controls the overwhelming majority of generators that could participate in such a regime. Loads and those holding non-BC Hydro transmission agreements could be important players in a re-dispatch market, but they alone could not justify or sustain one.

BCTC's current tariff contemplates that BCTC take commercially reasonable steps to investigate re-dispatch options to create ATC for LT-PTP service requests. To date, BC Hydro has not offered to provide such services. BCTC has no reason to expect that the institutionalization of re-dispatch would, itself, change BC Hydro's perspective on the value of this opportunity.

[76] A reconfiguration auction allows generators or loads to offer to change their behaviour in a particular period for a particular price. Those with transmission rights can also offer a price at which they would re-assign that transmission in a certain period. These offers are then the basis for a system "reconfiguration". This typically involves using a linear programming model designed to optimize system value against a range of bids from those seeking transmission capacity.

One may postulate that if a re-dispatch mechanism were in place, it would generate a price signal for BC Hydro (and others) to evaluate the potential of offering to re-dispatch.

BCTC believes, however, that the price-signal argument is likely inadequate to justify creating a re-dispatch market (i.e., to actively pursue Option 3 as set out in BCTC's March 31, 2006 letter to the Commission). This is true for two reasons. First, there is unlikely to be enough liquidity in the market to create any meaningful price signal. Second, there is no reason to believe that BC Hydro's past practice to not actively engaging in re-dispatch would be changed or usefully informed by a better price signal (particularly one generated from an illiquid market). To believe otherwise would imply that BC Hydro is currently under-utilizing the potential of its system. BCTC has no reason to believe that to be true.

Nevertheless, BCTC will continue exploring with BC Hydro to determine if it is viable to create an active and transparent re-dispatch market or service in the future.

B.3.3 Improved communication on load management

BCTC heard from TPAC that one of the best opportunities for customer-supplied solutions lies in targeted DSM programs. In particular, TPAC emphasized the potential for initiatives that might be identified by BCTC using its unique transmission information, and implemented by BC Hydro through its well-developed Power Smart brand.

BCTC agrees with the perspective. Hence, BCTC will, as part of its regular planning process, be identifying those areas of its system where capital programs could be deferred or operations improved by the use of targeted or general demand-response initiatives. BCTC will make these assessments as specific as possible, and define as precisely as possible the load-based solution that might be taken to achieve the benefit.

At the same time, BCTC will work with BC Hydro to ensure that the benefits of the load-management solutions are communicated to the relevant parties within BC Hydro on a time frame that allows for action in accord with transmission-planning. In addition, BCTC believes that other market participants will also be interested in this information. BCTC will develop a process for posting such information on BCTC’s website after consulting customers on the format and content of such postings.

Appendix C Cost Basis for Rates

The cost basis of the long-term rate designs described in Sections 4 and 5 of this report is consistent with the approach used for BCTC's Fiscal 2007 (F2007) revenue requirements settlement. The functionalization approach used for BCTC's F2007 revenue requirements and for this report is based on BC Hydro's 1993/94 FACOS, which has underpinned BC Hydro's and BCTC's transmission tariffs since 1997. The approach has, however, been updated to reflect a number of changes related to the identification of transmission as a separate line of business within BC Hydro and the separation of BCTC into a distinct entity with defined roles and responsibilities.

Table C.1: F2007 TRR

	$ millions	BCHORR	AMMRR	BCTCRR	Total TRR
		(a)	(b)	(c)	(d)
1	Allowed Return	103.2		2.9	106.1
2	Finance Charges	119.5		0.2	119.7
3	OM&A	17.0	87.3	74.9	179.2
4	Depreciation & Amortization	102.4		14.6	117.0
5	Grants & Taxes	87.8		0.3	88.1
6	Cost of Market			6.8	6.8
7	**Subtotal - Gross TRR**	**429.9**	**87.3**	**99.7**	**616.9**
8	Less Non-Tariffed Revenue	(66.6)		(32.1)	(98.7)
9	**Total - Net TRR**	**363.3**	**87.3**	**67.6**	**518.2**

Table C-2 Functional Allocation of the Gross TRR

	Functional Use ($ millions)	Revenue Requirement Share Gross TRR	Non-Tariffed Revenues	Net TRR
		(a)	(b)	(c)
1	Generation - Control	1.0	(1.0)	-
2	Transmission - Lines	279.9	(31.9)	248.0
3	Transmission - Stations	184.3	(15.0)	169.3
4	Transmission - Control & Operation	75.9	(6.6)	69.3
5	Transmission - General	22.3	-	22.3
6	Transmission - Customer	9.3	-	9.3
	Subtotal Transmission	**571.7**	**(53.5)**	**518.2**
7	Distribution - Stations	36.8	(36.8)	-
8	Distribution - Operations	7.4	(7.4)	-
9	**Total Gross TRR**	**616.9**	**(98.7)**	**518.2**

As shown in Table C.1, BCTC's TRR has three components: the BCH Owner's Revenue Requirement (BCHORR), BCTC's Revenue Requirement (BCTCRR), and the Asset Management and Maintenance Revenue Requirement (AMMRR). The AMMRR recovers costs incurred by BCTC for the management and maintenance of BC Hydro's Transmission System. As indicated at line 8 of Table C.1, adjustments are made to the BCHORR and the BCTCRR to account for generation and distribution costs that are the responsibility of BCTC to manage, but which are not properly a part of the transmission function from a rate making perspective. Much of this adjustment reflects capital and maintenance related to the GRTAs and distribution stations. There are also costs related to generation and distribution operations services.

Table C.2 also shows this division of BCTC's areas of responsibility between generation, transmission, and distribution, and provides a different view on how this broad responsibility is narrowed into OATT-recoverable costs (the Net TRR) for ratemaking purposes. Table C.2 provides a further delineation within the transmission function, into lines, stations, control & operations, general, and customer. Table C.4 provides the detailed cost elements that support the functional classification of the TRR.

C.1 Cost allocation analysis

Once costs are set out in the manner shown above, the Net TRR can be allocated to various OATT services. In this study, the focus of the cost-based rate alternatives has been to separate costs between NITS and LT-PTP. In particular, the study was developed to identify the cost impact of various illustrative rate options. For the purpose of analysing the cost impact of the illustrative long term rate options, the Net TRR ($518.2 million) has been used, as this is the portion of the Gross TRR properly recoverable from OATT services.

C.2 Determination of system usage

The existing OATT design is cost-based in aggregate – that is, the rates recover the utility's cost of service. However, because rates are currently set so that NITS customers pay all system costs adjusted for PTP revenues (i.e., NITS customers backstop the system), there has been no previous need to allocate the net TRR between various OATT services.

However, in this report, BCTC is presenting rate designs that require an allocation of the revenue requirement between NITS and PTP services. BCTC makes use of two traditional methods for allocating costs to various classes of service. These approaches allocate costs on the basis of a class' use of the system at the time of its single (1-CP) or monthly (12-CP) peak(s).

The development of cost-based rate options uses the fiscal 2006 year (F2006) as the basis for its analysis. In measuring the contribution to the system peak(s) for LT-PTP service, BCTC has used reserved capacity rather than actual use. This practice recognizes that capacity for these customers is reserved on a long-term basis and that the transmission system is designed to accommodate the full use of the reserved capacity at any time, including the time of monthly system peaks. Table C.3 illustrates the resulting 1-CP and 12-CP cost allocation factors as between NITS and LT-PTP Service. These factors form the basis for the cost allocations shown in the relevant options in Section 4.

Table C.3: F2006 1CP and 12CP

	F2006	1CP	12CP
		(a)	(b)
1	**(MW)**		
2	Network	9,317	7,887
3	Long Term PTP	691	691
4	**(%)**		
5	Network	93.1%	91.9%
6	Long Term PTP	6.9%	8.1%

Table C.4: Functionalization and classification detail

Functionalization & Classification (Demand)
$ millions

			Generation	Transmission					Distribution	
		Total	Control	Stations	Lines	Control & Operation	Communication & General	Customer	Stations	Operations
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	***Asset Base***									
2	**BC Hydro**									
3	Active Assets	4,815.3	-	1,694.8	2,739.1	-	186.2	-	195.2	-
4	Accumulated Depreciation	(2,370.1)	-	(831.9)	(1,342.8)	-	(101.3)	-	(94.1)	-
5	Unamortized Contribution in aid	(90.0)	-	(30.7)	(55.8)	-	(3.5)	-	-	-
6	Unfinished Construction (WIP)	115.9	-	51.6	49.6	-	14.7	-	-	-
7	Demand Side Management	29.1	-	-	-	-	-	29.1	-	-
8										
9	**BC Hydro Asset Base**	2,500.2	-	883.8	1,390.1	-	96.1	29.1	101.1	-
10	**BCTC**									
11	Active Assets	85.3	-	-	-	85.3	-	-	-	-
12	Accumulated Depreciation	(39.9)	-	-	-	(39.9)	-	-	-	-
13	Unamortized Contribution in aid	-	-	-	-	-	-	-	-	-
14	Unfinished Construction (WIP)	76.2	-	-	-	76.2	-	-	-	-
15	Land & Building Capital Lease	6.7	-	-	-	6.7	-	-	-	-
16										
17	**BCTC Asset Base**	128.3	-	-	-	128.3	-	-	-	-
18										
19	**Total Transmission Asset Base**	**2,628.5**	**-**	**883.8**	**1,390.1**	**128.3**	**96.1**	**29.1**	**101.1**	**-**
20	***Expense***									
21	**BC Hydro**									
22	Allowed Net Income	103.2	-	36.0	58.1	-	3.5	1.2	4.4	-
23	Finance Charges	119.5	-	41.7	67.3	-	4.1	1.4	5.0	-
24	OMA	5.8	-	-	1.0	-	4.8	-	-	-
25	Cost of Market	-	-	-	-	-	-	-	-	-
26	Corporate Business Sustaining Costs	11.2	-	3.8	5.9	-	-	-	1.5	-
27	Depreciation & Amortization	99.0	-	45.1	41.2	-	7.2	-	5.5	-
28	DSM	3.4	-	-	-	-	-	3.4	-	-
29	Grants & Taxes	87.8	-	24.9	51.5	-	2.7	-	8.7	-
30										
31	BC Hydro Total Cost	429.9	-	151.5	225.0	-	22.3	6.0	25.1	-
32	Less: Non-Tariff Revenue	(66.6)	-	(13.3)	(28.2)	-	-	-	(25.1)	-
33										
34	**Total BC Hydro Transmission Expense**	363.3	-	138.2	196.8	-	22.3	6.0	-	-
35										
36	**BCTC**									
37	Deemed Allowed Return	2.9	-	-	-	2.9	-	-	-	-
38	Deemed Interest Expense	0.2	-	-	-	0.2	-	-	-	-
39	OMA	162.2	1.0	32.8	54.9	51.1	-	3.3	11.7	7.4
40	Cost of Market	6.8	-	-	-	6.8	-	-	-	-
41	Depreciation & Amortization	14.6	-	-	-	14.6	-	-	-	-
42	Grants & Taxes	0.3	-	-	-	0.3	-	-	-	-
43										
44	BCTC Total Cost	187.0	1.0	32.8	54.9	75.9	-	3.3	11.7	7.4
45	Less: Non-Tariff Revenue	(32.1)	(1.0)	(1.7)	(3.7)	(6.6)	-	-	(11.7)	(7.4)
46										
47	**Total BCTC Transmission Expense**	154.9	-	31.1	51.2	69.3	-	3.3	-	-
48										
49	Total Transmission Expense	616.9	1.0	184.3	279.9	75.9	22.3	9.3	36.8	7.4
50	Less; Non-Tariff Revenue	(98.7)	(1.0)	(15.0)	(31.9)	(6.6)	-	-	(36.8)	(7.4)
51										
52	**Total Transmission Expense**	518.2	-	169.3	248.0	69.3	22.3	9.3	-	-

Appendix D Survey of Canadian and Regional Tariff Rate Designs

Table D.1: Survey of transmission rate designs in North America

Utility/ Territory	L-T Service Design	How are costs allocated among rate classes?	Billing Determinants
Canada Open Access Designs			
BCTC	Standard 888 Design	BCTC's rates are based on a back stop model with no explicit cost allocation process. The $/kW-month LT PTP rate is set by dividing the TRR by the product of the connected load of all BC generators times 12 months. NITS customers pay for the total transmission revenue requirement net of all revenues produced from PTP service. Since Native load customers are the only existing NITS customer, they underwrite or backstop the TRR.	**NITS-** Monthly network charge is based on the transmission customer's Load Ratio Share multiplied by 1/12 of the TRR net of point to point revenues, scheduling and dispatch revenues, and engineering services revenues. The Load Ratio Share has the standard FERC definition (FERC Order 888 pp. 296-297), and is calculated on a rolling 12-month basis. A customer's bill under this method is equal to the Monthly Network TRR times the fraction defined by a customer's 12 months of coincident peak loads divided by the sum of all network customers' 12 month coincident peak loads (12-CP). **LT PTP-** The Point-to-Point bill is based on reserved capacity multiplied by a point-to-point charge.
Hydro-Québec TransÉnergie	Standard 888 Design.	HQT has PTP Customers but no network customers. Native load is a separate service. There are 4 costs types to allocate between native load and PTP: Power Station Connections are allocated based on 1-CP Network costs and Interconnection costs for Churchill Falls is also allocated using 1-CP All other Interconnection costs are allocated between PTP and native load using TTC (Total Transmission Capacity), in which native load is allocated costs	**Monthly network charge (for native load)-** Based on the transmission customer's Load Ratio Share multiplied by 1/12 of the allocated TRR. The allocated TRR is calculated using a forecast of PTP revenues. Variations in PTP revenues are not recovered through deferral accounts. The Load Ratio Share is based on the customer's weather normalized annual coincident peak over the calendar year (1-CP). **LT PTP-** The Point-to-Point bill is based on reserved capacity multiplied by a point-to-point charge.

Utility/ Territory	L-T Service Design	How are costs allocated among rate classes?	Billing Determinants
		associated with the import capacity share and PTP is allocated costs based on the export capacity share. Existing Customer Connection costs are allocated 100% to native load.	
SaskPower	Standard 888 Design.	12-CP is used from previous year to allocate costs between PTP and NITS customers.	**NITS-** Monthly network charge based on 1/12th of Load Ratio Share of allocated TRR. Load Ratio Share is based NITS customer's load at time of coincident peak (1-CP). **LT PTP-** The Point-to-Point bill is based on reserved capacity multiplied by a point-to-point charge.
Manitoba Hydro	Standard 888 Design.	All transmission costs are considered demand-related and allocated using a 2-CP method calculating average summer and winter peaks (based on top 50 hours). Subtransmission is allocated based on NCP.	**NITS-** Monthly network service demand charge based on Load Ratio Share multiplied by 1/12th of the allocated TRR. The Network Customer's monthly Network Load is its hourly load coincident with the Transmission Provider's Monthly Transmission System Peak. **LT PTP-** The Point-to-Point bill is based on reserved capacity multiplied by a point-to-point charge.
New Brunswick Power	Standard 888 Design.	Allocation based on 12-CP, with each CP being the sum of network rate class load and the LT PTP reservation.	**NITS-** Monthly network service demand charge based on Load Ratio Share multiplied by 1/12th of the allocated TRR. The Network Customer's monthly Network Load is its hourly load coincident with the Transmission Provider's Monthly Transmission System Peak. **LT PTP-** The Point-to-Point bill is based on reserved capacity multiplied by a point-to-point charge.
Nova Scotia Power	Standard 888 Design.	12-NCP method "for the purpose of setting Native Service Provider's wholesale transmission tariff"	**NITS-** Monthly network service demand charge based on Load Ratio Share of allocated revenues multiplied by 1/12th of the residual TRR. Load Ratio Share is based NITS customer's net non-coincident monthly peak load. **LT PTP-** Reserved capacity times the demand charge rate.

Utility/ Territory	L-T Service Design	How are costs allocated among rate classes?	Billing Determinants
Canadian Pool Designs			
Alberta	Pool design with access fees.	Beginning January 1, 2006, load customers directly pay all costs of the transmission system except for losses.	**Demand Transmission Services-** Based on both monthly coincident and non-coincident peak ($/MW-month), plus small energy charge. **Supply Transmission Service-** Losses Charge ($/MWh of energy supplied times location specific loss factor). **Import Opportunity Service-** Based on Losses Charge (same as supply transmission service.) **Export Opportunity Service-** usage charge ($/MWh), incremental loss charge as a percentage of pool price, plus incremental cost of system support services required by the transaction.

Utility/ Territory	L-T Service Design	How are costs allocated among rate classes?	Billing Determinants
Ontario (Pool Design) – Hydro One	Pool design where all loads pay network service fees in $/kW form. There is a separate export and through fee. Currently, there are no congestion charges for transmission usage within the province. Congestion costs are collected from all users through pro-rata uplift charges and the transmission usage fees.	There are three pools of transmission costs. Based on the 2007-2008 cost of service study submitted to the OEB, "Network charges are allocated based on the higher of CP or 85% NPC (7am-7pm), Line Connection and transformation connection costs are allocated based on NCP, Transmission meter costs are allocated based on the number of meter points." [NERA 2006]	Customer demand is the sum of (a) loss-adjusted demand supplied by the transmission system and (b) demand supplied by embedded generation for which approvals were obtained after October 30, 1998. Provincial transmission service (applicable to transmission customers who own facilities directly connected to the transmission system and withdraw power from the system): network billing demand is the higher of (a) customer's monthly coincident peak demand (MW), and (b) 85% of the customer's peak demand during the peak period (7 am – 7 pm), business days. Billing demand is multiplied by $/kW monthly rate. Monthly billing determinant for line and transformation connection service rate is the non-coincident peak demand (MW) in any hour in the month. Billing demand is multiplied by $/kW monthly rates. Retail transmission for Hydro One's core retail customers: (a) energy-only customers billed for metered or estimated consumption (cents/kWh) adjusted by total loss factor; (b) demand customers ($/kW/month) billed for customer's peak demand in billing period. Retail transmission for LDCs and direct-connect industrials (monthly demand > 5MW) to low-voltage system: billing determinant for network service is peak demand from 7 am to 7 pm, business days. Billing determinant for line and transformation connection service is non-coincident peak by delivery point. Core and acquired retail customers and low-voltage system customers who do not participate in the IMO markets are billed a wholesale market service rate in cents/kWh for metered energy adjusted by the total loss factor. Local distribution companies (LDCs) and direct access customers also pay a monthly low-voltage facility charge in $/kW, based on customer's average 1999 peak monthly demand between 7 am and 11 pm, business days. Exports and wheel throughs billed at $1/MWh of energy exported.

Utility/ Territory	L-T Service Design	How are costs allocated among rate classes?	Billing Determinants
U.S. Open Access Designs			
Bonneville Power Administration (BPA)	Mostly standard 888 design with network and point-to-point rates covering most of the TRR. Additional rates ("Formula Power Transmission Rate" and "Integration of Resources Rate") for transmission of non-Federal power within the Federal system. Separate, pancaked rates for the Southern Intertie and Montana	BPA network costs are currently allocated based on a negotiated settlement, with results similar to a 1-CP allocation. For the period of 1996 through 2001, the allocation between LT Service Classes was based on a negotiated settlement more closely resembling 1-NCD (non-coincident demand).	**Network Service (NT)-** Network load coincident with the monthly system peak load (12-CP). Customers that use non-Federal transmission facilities to serve a portion of their firm load receive a reduction in their BPA charge. The bill is calculated as network load multiplied by the sum of the base TRR charge ($/kW) and the load shaping charge ($/kW). **LT PTP-** Reserved capacity times the demand charge. Non-firm hourly PTP is billed for scheduled kWh. **Formula Power-** Monthly charge based on billing demand multiplied by 1/12 of the sum of the main grid charge and secondary system charge. Billing demand is the higher of (a) the transmission demand; (b) highest hourly scheduled demand for the month; (c) ratchet demand over the past 11 months. **Integration of Resources-** Monthly charge based on $/kW multiplied by billing demand, which is the higher of (a) annual transmission demand, (b) highest hourly scheduled demand for the month, (c) ratchet demand Southern Intertie Rate and Montana Intertie Rate billed as reserved capacity times the demand charge.
Puget Sound Energy	Standard 888 design plus additional charge for use of "wholesale distribution" facilities.	Costs are not explicitly allocated among classes. The PTP rate was set in the test year, and the Network customers are each charged based on monthly system load share. Variations between forecasted and actual load are paid for by the transmission owner rather than NITS customers.	**NITS-** Monthly network service charge based on 1/12 of TRR times each customer's Load Ratio Share. Load Ratio Share is based on 12-CP. **LT PTP-** Reserved capacity times the demand charge rate.
Idaho Power	Standard 888 Design.	12-CP weighted by transmission marginal monthly demand cost. Because there are only transmission deficits and in the 3 summer months (June, July, and August), transmission marginal costs are allocated base only the cost-weighted CPs in these three months.	**Network Service-** Monthly network service charge based on 1/12 of allocated TRR times each customer's Load Ratio Share. Load Ratio Share is based on 12 CP. **LT PTP-** Reserved capacity times the demand charge.

Utility/ Territory	L-T Service Design	How are costs allocated among rate classes?	Billing Determinants
Avista	Standard 888 Design.	Costs are not explicitly allocated among classes. The PTP rate was set in the test year (1995), and the Native load rates are determined though a separate retail process. Variations between forecasted and actual load are paid for by the transmission owner rather than NITS customers.	**NITS-** Monthly network service charge based on 1/12 of TRR times each customer's Load Ratio Share. Load Ratio Share is based on monthly rolling average 12-CP. **LT PTP-** rate was created as the test year (1995) TRR divided by the transmission load same as what was determined as the PTP share of 12-CP in the test year which was 1995. **Native load**- Rates are determined separately as "bundled retail service" and overseen by state regulators. Revenue from PTP customers is determined based on a predetermined price of TRR divided by transmission peak load in the test year.
U.S. Pool Designs			
CAISO (California)	Pool design with load-based access fees to recover TRR and separate fee for exports and wheel throughs. Zonal congestion management system with usage charges for zone-to-zone transactions. Financial Transmission Rights (FTRs) to hedge inter-zonal congestion are allocated to load serving entities (LSEs) based on historical use; remaining capacity made available in annual FTR auctions. Net cost of intra-zonal congestion charged to all scheduling coordinators through a grid operations charge.	CAISO "classifies transmission costs as energy and allocates these costs to transmission users on the basis of energy taken off the grid." [NERA 2006] The transmission access charge (TAC) is allocated on a gross load basis. Gross load is defined as the energy (adjusted for losses) delivered to end-use customer loads directly connected to the system and located in a participating transmission owner's (PTO) service territory. It excludes load subject to wheeling access charges…Currently TAC-area rates are based on the transmission revenue requirement of the PTO. An increasing percentage of the total revenue requirement for all participants is divided by the ISO-wide load, while the remaining share is PTO-specific." [NERA 2006]	Access charge billed monthly as sum of the user's share of the MWh delivered by the distribution company or scheduling coordinator times TRR/12. Wheeling service is billed monthly as the wheeling access charge (TRR of the applicable control area) multiplied by the amount of energy wheeled, measured in MWh. Access charge is calculated net of behind-the-meter qualifying facilities. Usage charges for inter-zonal congestion management in cents/kWh for scheduled flows.
PJM	Pool design with load-based access fees to recover TRR and separate export fees. Nodal	Zonal NITS charges are calculated for each customer based on the "zone in which the load of the customer is located. A transmission customer's daily NITS	**Network access charge-** Based on the load coincident with the annual peak of the zone times (TRR/365). For exports, network access charge is based on daily load at the border of PJM coincident with the annual peak of that area times (TRR/365).

Utility/ Territory	L-T Service Design	How are costs allocated among rate classes?	Billing Determinants
	congestion management system with Firm Transmission Rights. Firm transmission customers are allocated rights that entitle them to a share of the FTR auction revenues. Customers may "self-schedule" these auction revenue rights as FTRs in annual auction, or they can retain them and receive their allocated load-ratio share of FTR auction revenues.	requirement is based on the load in the hour of the PJM peak load (1-CP) for the twelve consecutive months ending October 31 of the year prior to the calendar year." [NERA 2006]	Time lag before a Network Customer's reduced peak load will result in a reduced tariff because daily coincident peak calculated using the "twelve month period ending October 31 of the calendar year preceding the calendar year in which the billing month occurs." **PTP-** The Point-to-Point access charge is billed based on the maximum reserved capacity, multiplied by a zonal charge based on the zone containing the point of delivery (or border price for exports and wheel throughs). Usage charge in $/MWh.

Source Documents:

Bonneville Power Administration, "Transmission Rate Case Workshop Draft", August 2006. http://www.transmission.bpa.gov/business/rates_and_tariff/ratesdocs/Network_Cost_Allocation.pdf

Hydro-Québec TransÉnergie, "Allocation of the Cost of Service Projected Pilot Year 2005, Request R-3549-2004 – Phase 2, HQT-3, Document 6", June 2005. (English Translation)

ISO/RTO Planning Committee, "ISO/ RTO Electric System Planning: Current Practices, Expansion Plans and Planning Issues," February 2006. http://www.caiso.com/179c/179c9e0086c0.pdf

NERA Economic Consulting, Assessment of AESO Transmission Cost of Service Analysis, Prepared for Alberta Electric System Operator (AESO), October 2006. http://www.aeso.ca/files/2006-10-31_NERA_Assessment_of_AESO_Cost_of_Service_Analysis.pdf

New Brunswick Power, NB Power Transmission Tariff Design, June 2002. http://www.regie-energie.qc.ca/audiences/3493-02/PreuveInterv3493/Preuve_EnergieNB-TariffDesignANG-13sept02.pdf

Parmesano, Hethie, Amparo Nieto and Veronica Irastorza, NERA Economic Consulting, Survey of Electric Utility Embedded Cost Methods for Generation and Transmission in North America, Prepared for Manitoba Hydro, May 2004. http://www.nera.com/publication.asp?p_ID=2093

Appendix E Evaluation of Long-Term Firm PTP Shaped Service

E.1 Introduction

The Decision accepted BCTC's proposal to provide Shaped Service. As part of that determination, the Commission acknowledged that BCTC had taken steps to ensure that its Shaped Service proposal did not pose a material risk to the availability of capacity for NITS load growth and did not degrade the existing rights of NITS and LT-PTP customers. The Commission also directed BCTC to include in the report a summary of the use of Shaped Service, commenting on any implications of its use relative to present concerns about available capacity or service degradation.

As of November 30, 2006, BCTC has not awarded Shaped Service. Therefore, this appendix only describes BCTC's

a) assessment of the potential for, and impact of, Shaped Service; and

b) development of new business practices to ensure proper implementation of Shaped Service, including rollover rights for Shaped Service.

E.2 General assessment of the impact of Shaped Service

In response to LT-PTP service requests, BCTC determines the long-term firm ATC based on prior commitments during the most congested month of the requested time period, using forecast NITS loads and forecast transmission system conditions. Where a LT-PTP service request cannot be met from long-term firm ATC, BCTC assesses the applicability of Shaped Service to the transmission path required for the service requested. As explained below, Shaped Service applies to wheel-though service between the US and Alberta and exports to the US from generation resources in the BC Interior.

1. Shaped Service potential and impact on the interties and existing customers

The shape of firm ATC on the BCTC system is created by the variation in service requirements for NITS service over the year, primarily due to the variation in the shape of the forecast NITS load and forecast system requirements. Firm ATC at the interties does not vary with NITS load. As a result, firm ATC at an intertie is expressed as a flat block and does not have a shape. Therefore, Shaped Service does not apply to service requests for exports to the US from generation resources located in the Lower Mainland and imports to BCTC Network.

2. Shaped Service potential and impact on BCTC internal paths

Firm ATC on BCTC internal paths changes with the Network Customer's forecast loads and forecast system conditions. Therefore, Shaped Service applies to service requests that require the use of BCTC's internal paths. This includes LT-PTP requests for wheel-through services between Alberta and US (in both directions), and export services from the BC Interior to the US.

E.3 New business practices for responding to LT-PTP service requests and determining the availability of Shaped Service

BCTC has developed a new business practice for determining the availability of Partial Service or Shaped Service. This business practice specifies a process by which BCTC uses existing ATC information to determine if partial service or Shaped Service is available and to offer partial service or Shaped Service pending the results of a system impact study. The business practice includes:

a) a description of partial service and Shaped Service, which is a form of partial service where the monthly capacity reserved can vary over the term of the request;

b) how service agreements for these services will be offered in conjunction with system impact study agreements and the required customer response; and

c) the process for granting rollover rights.

BCTC's business practices on LT-PTP requests and Shaped Service are found in Section 15 and 16 of BCTC's Business Practices located at

http://www.bctc.com/NR/rdonlyres/4EEFF805-EDA2-4975-89C5-FFEAA750BDB7/2046/2006Nov6Section15updated.pdf and http://www.bctc.com/NR/rdonlyres/BD0B7A16-C9D5-4001-A0E9-985D808548B8/0/2006Sep28Section16RolloverforLTFSvc.pdf, respectively.

E.4 Implementation

During the OATT proceedings, the intent of the Shaped Service was described as follows. The shape of the service offered is defined by the shape of capacity available in the first year of the initial service request. This shape is replicated over time in 12 month increments to obtain a service with 12 months of non-zero capacity.

The application of this principle in practice may be demonstrated by an example:

First, assume that in response to a LT-PTP service request for one year, BCTC determined that the capacity in January is zero. BCTC would offer the customer a two year service agreement with zero capacity in the month of January in both years.

Second, assume further that in the course of conducting the system impact study, BCTC discovered that, in the situation described above, there may be sufficient ATC for the month of January in the second year. In this case, BCTC believes that the customer should be provided the additional month of service and BCTC would offer a two year service agreement with zero capacity in the month of January in the first year only. BCTC believes that the tariff may need to be clarified to ensure this result.

BCTC proposes to consult with customers as part of the customer consultation on the design of LT-PTP service as described in Section 1.4 of this report.