IN THE MATTER OF

British Columbia Hydro and Power Authority

WHOLESALE TRANSMISSION SERVICES APPLICATION

DECISION

June 25, 1996

BEFORE:

Dr. Mark K. Jaccard, Chairperson
Kenneth L. Hall, P. Eng., Commissioner
Dr. Paul G. Bradley, Commissioner

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EXECUTIVE SUMMARY

On November 10, 1995, British Columbia Hydro and Power Authority ("B.C. Hydro", "the Applicant", "the Utility") filed an Application to provide Wholesale Transmission Services within its service area. The Application consists of three new tariff services to wholesale customers: Network Transmission Service, Point to Point Transmission Service and Ancillary Services.

Network Service consists of the provision of transmission service from multiple points of supply to multiple points of delivery within the Province of British Columbia. It is available on a non-recallable (i.e., non-interruptible) basis only, for periods of one year or more and is meant to be comparable with the service B.C. Hydro provides to itself to serve its captive customers.

Point to Point Service consists of the provision of transmission service from specified points of receipt to specified points of delivery. It is available for the delivery of energy to domestic wholesale customers and must be used for the delivery of electricity exports to the border. The Point to Point tariff provides three options for taking service. These are a long-term (i.e., greater than one year) non-recallable option, a short-term non-recallable option, and a short-term recallable option.

Ancillary Services consist of a bundled load following, operating reserve and reactive power/voltage control service and a separate loss compensation service. Customers taking either Network or Point to Point Service may purchase Ancillary Services from B.C. Hydro or may elect to acquire the services in some other manner.

The potential beneficiaries of these new services are expected to be: (1) West Kootenay Power Ltd. and the municipal utilities it now serves as well the municipal utility of New Westminster; (2) Independent Power Producers who wish to sell to municipal utilities and to the export market; (3) Alberta electricity producers who wish to transmit power through British Columbia; (4) B.C. Hydro's Power Supply Business Unit; and (5) parties wishing to import electricity into British Columbia. All Services contained in the Application were approved by the BCUC on an interim basis, commencing January 31, 1996.

In this Decision, the Commission approves all three Wholesale Transmission Service tariffs. However, the Commission determines that the tariffs must be modified for refiling by September 1, 1996 and requires further analysis and a new Application by January 1, 1997. The Commission is particularly concerned with (1) the methodology used by B.C. Hydro to determine those assets whose costs are to be recovered in the transmission tariff, and (2) the rate design method employed by B.C. Hydro. This Executive Summary provides some detail on the Commission's determination with respect to these two key issues. Further detail on these issues, and on specific items in the tariffs, are found in the Decision.

Based on the evidence and argument presented with respect to this Application, it is the Commission's judgment that B.C. Hydro has not justified the functionalization of generation-related transmission facilities to transmission. Although the Commission acknowledges the technical validity of B.C. Hydro's assertion that remote generation sources may be operated to the benefit of the transmission network, in the Commission's judgment, the Utility has not demonstrated the true extent of the benefit provided by these assets.

The Commission is concerned that no costs be functionalized to transmission unless there is evidence that the major benefit of the asset relates to transmission. Based on the current evidence, the Commission determines that generation-related transmission facilities should remain functionalized to generation as was done by B.C. Hydro in the 1993/94 FACOS study.

With respect to the functionalization of 69 kV and 138 kV lines, the Commission accepts that B.C. Hydro has demonstrated that some of these facilities provide assistance to the transmission function in terms of interconnection with higher voltage lines and back-up routes under fault conditions. Therefore, the Commission determines that for the purpose of setting the immediate transmission tariff, these assets should remain functionalized as in the 1993/94 FACOS study.

In summary, the Commission directs B.C. Hydro to file an adjusted transmission revenue requirement and associated Network and Point to Point Service rates no later than September 1, 1996, which reflect the treatment of generation-related assets similar to that found in the 1993/94 FACOS study. These transmission rates will replace the interim rates and will be effective from January 31, 1996.

Furthermore, the Commission directs B.C. Hydro to file new rates, no later than January 1, 1997, based on a study which more precisely identifies its transmission revenue requirement. In particular, the new transmission revenue requirement should reflect the relative benefits which generation-related transmission assets provide to the generation and transmission functions, the extent to which 138 kV and 69 kV lines provide transmission benefits and the role of DSM with respect to transmission.

In addition, it is the Commission's judgment that there is a need to develop more efficient pricing signals than those which are contained in the proposed B.C. Hydro rates. In particular, the rates charged for wholesale transmission service should reflect the marginal costs of providing service on a regional basis.

In coming to this conclusion, the Commission has considered B.C. Hydro's argument that more efficient price signals are not needed at this time. However, the Commission finds that the Utility has failed to prove its case that it will not face any transmission constraints which might be mitigated through price signals that encourage the siting of generation to particular locations. Moreover, the Commission does not accept B.C. Hydro's argument that locationally efficient price signals are not needed until such time as transmission constraints occur.

As indicated in the body of this Decision, the Commission's responsibility under its Act is to set rates which are fair, just and reasonable. It is the Commission's judgment that this means rates that attempt to signal at least, in part, the costs of incremental changes in the use of various components of the B.C Hydro system.

Accordingly, the Commission directs B.C. Hydro to apply for new rates for wholesale transmission service which reflect long-run marginal costs and locational considerations by January 1, 1997. Based on the evidence and argument in this proceeding, the Commission suggests that an appropriate starting point is the methodology used to estimate the long-run incremental cost estimates by region as developed in the B.C. Hydro CONES Report. The rates must be designed to collect the full transmission revenue requirement. This dual requirement, to recover full embedded cost and to signal the incremental cost of transmission between various locations on the British Columbia grid, could be met by a pricing structure that includes an access charge, by scaling non-recallable tariffs, or by such other method as B.C. Hydro may develop. The Application should also address any other necessary changes to the tariffs as a result of this direction.

In the meantime, the Commission accepts the methodology which gave rise to the rate forms proposed in the current application with respect to Network Service and non-recallable Point to Point Service. However, the actual dollar amount of the rates must be adjusted in line with the determinations set out in Chapter 2 of this Decision and filed with the Commission no later than September 1, 1996. Such rates will be retroactive to January 31, 1996.

With respect to B.C. Hydro's proposal for pricing recallable service, the Commission agrees with the Utility that the price should be related to the value of the service. However, the Commission is concerned that, as acknowledged by B.C. Hydro, the proposed index, which is based on a generic Alberta generator and the California Oregon Border price, is not ideal. Accordingly, the Commission directs B.C. Hydro to examine methods for developing a more satisfactory index (or indices), with the goal of obtaining more precise indicators of the value of transmission over various segments of its transmission grid. The results of this examination are to be filed with the Commission as part of the January 1, 1997 Application.

In the meantime, the Commission accepts B.C. Hydro's recallable pricing proposal as filed for the B.C. Hydro transmission system with the exception of the B.C. Hydro-Alberta intertie. With respect to the intertie, the Commission accepts the proposal put forward by the Grid Company of Alberta for a simultaneous hourly auction when the B.C. Hydro-Alberta intertie is constrained. In the absence of a constraint, the Commission directs that the recallable pricing proposal put forward by B.C. Hydro apply.

Further details with respect to the Commission determinations are contained within the body of the Decision.

1.0 INTRODUCTION

1.1 Background

British Columbia Hydro and Power Authority ("B.C. Hydro", "the Applicant", "the Utility") is a Provincial Crown Corporation whose mandate is to generate, transmit and distribute electricity in British Columbia. B.C. Hydro does so throughout British Columbia except for a few municipal districts served by municipal utilities and in the Kootenay and South Okanagan areas which are served by West Kootenay Power Ltd. ("WKP"). B.C. Hydro operates under the *Hydro and Power Authority Act* and is subject to regulation by the British Columbia Utilities Commission ("the Commission", "the BCUC"). All provisions of the *Utilities Commission Act* ("the Act") apply to the Utility except for sections dealing with utility financing and asset disposition [*B.C. Hydro and Power Authority Act*, Section 52(6)].

On November 10, 1995, B.C. Hydro filed an Application to provide Wholesale Transmission Services ("the Application"), including related ancillary services, within its service area. By way of Commission Order No. G-109-95, the Commission set the Application down for a public hearing to commence March 4, 1996. In addition, the Order approved the use of the tariffs contained within the Application on an interim basis, commencing January 31, 1996.

There were 16 hearing days, during which the Commission heard evidence from four B.C. Hydro witness panels on policy matters, the transmission revenue requirement, rate design and implementation issues. In addition, the Commission heard evidence from a variety of intervenors including the Independent Power Association of British Columbia ("IPABC"), the B.C. Energy Coalition ("BCEC"), WKP, Inland Pacific Energy Services ("IPES") and the City of New Westminster ("New Westminster"). As well, Commission staff sponsored an independent review of B.C. Hydro's transmission revenue requirement by Ms. D. Toulson and Mr. W. Stephenson of the firm of Barakat and Chamberlin, who also gave testimony on their findings at the hearing. The evidentiary portion of the hearing ended on April 2, 1996, with final argument received thereafter.

1.2 Events Leading Up to Application

Prior to this Application, B.C. Hydro had filed two previous applications aimed at opening access to its transmission system. In 1991, B.C. Hydro filed a Rate Design Application which included, among other items, a proposal for open access to its transmission system for both wholesale and large industrial customers and for regional rates. These aspects of the 1991 application did not receive the support of potential customers and the Commission directed B.C. Hydro to work with its customers to develop new services. In January 1995, B.C. Hydro again filed an Industrial Service Options Rate Design Application which contained a proposal for wholesale transmission access. However, this application was withdrawn before it could be considered in a public hearing due, in part, to the lack of support from potential customers and to concerns about potential impacts if the electricity market were restructured.

In 1995, the Provincial Government directed the Commission to hold a review into the British Columbia electricity market. As a result of the Electricity Market Structure Review, the Commission recommended that all utilities owning transmission assets submit wholesale transmission service tariff applications to the BCUC. At the time of this Decision, the Government has not yet responded to the Commission's Report.

Also in 1995, B.C. Hydro and its non-regulated subsidiary, the British Columbia Power Exchange Corporation ("Powerex"), joined two Regional Transmission Groups ("RTGs"): the Western Regional Transmission Association, and the Northwest Regional Transmission Association. RTGs are U.S. based voluntary organizations, composed of both utility and non-utility members, that agree to adhere to rules for wholesale transmission access. Under the terms of the RTGs, each utility member is required to allow other utility members to use its transmission system in a manner that is comparable to its own use. Included in the bylaws of each of these associations is a requirement that each member utility file, with its own regulator, wholesale transmission tariffs within 180 days of the bylaws of the RTG being approved by the Federal Energy Regulatory Commission ("FERC"). Accordingly, B.C. Hydro was required to file this Application with the BCUC by November 13, 1995.

As well as encouraging the formation of the RTGs, FERC issued, on March 29, 1995, a "Notice of Proposed Rule Making" and "Supplementary Notice of Proposed Rule Making" ("the NOPR") (Exhibit 8). The NOPR addressed issues relating to the opening of access to transmission lines, including stranded assets, recommended procedures for developing wholesale transmission rates and specified initial pro forma tariffs for Network Service, Point to Point Service and Ancillary Services. The NOPR has since been confirmed, with modifications, by FERC Order No. 888 - Open Access and Stranded Costs, and Order No. 889 - Information Systems and Standards of Conduct. In addition, FERC has issued a new Notice of Proposed Rule Making, the "CRT" Capacity Reservation Open Access, which proposes that each public utility replace the Open Access Rule pro forma tariff with a capacity reservation tariff by December 31, 1997.

1.3 Description of Current Application

The B.C. Hydro Application consists of three new tariff services to wholesale customers: Network Transmission Service, Point to Point Transmission Service, and Ancillary Services.

Network Service consists of the provision of transmission service from multiple points of supply to multiple points of delivery within B.C. Hydro's control area, that is the Province of British Columbia. It is available on a non-recallable (i.e., non-interruptible) basis only, for periods of one year or more and is meant to be comparable with the service B.C. Hydro provides to itself to serve its captive customers.

Point to Point Service consists of the provision of transmission service from specified points of receipt to specified points of delivery. It is available for the delivery of energy to domestic wholesale customers and must be used for the delivery of electricity exports to the border. The Point to Point tariff provides three options for taking service. These are a long-term (i.e., greater than one year) non-recallable option, a short-term non-recallable option, and a short-term recallable option.

Ancillary Services consist of a bundled load following, operating reserve and reactive power/voltage control service and a separate loss compensation service. Although the FERC pro forma included energy imbalance, scheduling and dispatch within its bundled Ancillary Services offering, B.C. Hydro provides these services as part of the Network and Point to Point Services. Customers taking either Network or Point to Point Service may purchase Ancillary Services from B.C. Hydro or may elect to acquire the services in some other manner.

The rates contained in the Application are based on B.C. Hydro's estimate of its Transmission Revenue Requirement, which was determined with the help of a cost of service study rather than through the formulaic approach used by FERC. The approach to calculating the individual transmission rates is generally consistent with the FERC pro forma tariffs, although differences in the terms and conditions associated with the rates occur.

The stated objectives of B.C. Hydro's proposed tariffs are to enhance the use of the transmission system, improve access to export markets for all B.C. power producers and encourage economic development (Exhibit 1A, p. W-B-1). This was restated in final argument when B.C. Hydro stated that its objectives are to ensure that B.C. Hydro continues to be a player in the integrated western North American system and that the efficient use of its transmission system is encouraged (T: 2572).

1.4 Principles for Determining the Design of Wholesale Transmission Services Rates

Under its Act, the Commission is charged with setting rates for utility service which are just and reasonable and not unduly discriminatory. The relevant sections of the Act are as follows:

64(1) The commission, on its own motion, or on complaint by a public utility or other interested person that the existing rates in effect and collected or any rates charged or attempted to be charged for service by a public utility are unjust, unreasonable, insufficient, unduly discriminatory or in contravention of this Act, regulations or any law, may, after a hearing, determine the just, reasonable and sufficient rates to be observed and in force, and shall, by order fix the rates.

65(3) It is a question of fact, of which the commission is the sole judge, whether a rate is unjust or unreasonable, or whether in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or whether a service is offered or furnished under substantially similarly circumstances and conditions.

65(4) In this section a rate is "unjust" or "unreasonable" if the rate is
- (a) more than a fair and reasonable charge for service of the nature and quality furnished by the utility,
- (b) insufficient to yield a fair and reasonable compensation for the service rendered by the utility or a fair and reasonable return on the appraised value of its property, or
- (c) unjust and unreasonable for any other reason.

66(1) In fixing a rate under this Act or regulations
- (a) the commission shall consider all matters that it considers proper and relevant affecting the rate,
- (b) the commission shall have due regard, among other things, to the fixing of a rate that is not unjust or unreasonable, within the meaning of section 65, and
- (c) where the public utility furnishes more than one class of service, the commission shall segregate the various kinds of service into distinct classes of service; and in fixing a rate to be charged for the particular service rendered, each distinct class of service shall be considered as a self contained unit, and shall fix a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates fixed for any other unit.

In its evidence, B.C. Hydro identified five principles that FERC uses to evaluate wholesale transmission service tariff proposals. The five principles are:

(1) the tariff must be designed to collect the traditional revenue requirement;

(2) the tariff must offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of the system;

(3) the tariff should promote economic efficiency;

(4) the tariffs should be fair. That is, there should be no cross-subsidization between third parties and existing customers; and

(5) the tariff should be practical and easy to administer (Exhibit 1A, pp. W-Q-RO-5-7).

In assessing its Application, B.C. Hydro stated that its proposal meets four of the five FERC principles. The Utility noted that the proposed non-recallable rates do not serve the objective of efficiency as well as they meet the principles of fairness and practicality because the rates contained in the Application are based on embedded rather than incremental costs and are charged on a postage stamp rather than regional basis. However, B.C. Hydro argued that efficiency is unlikely to be served by the piecemeal introduction of either incremental or regional pricing (Exhibit 1A, p. W-Q-RO-8).

2.0 DETERMINATION OF TRANSMISSION REVENUE REQUIREMENT

2.1 Functionalization of Assets

2.1.1 General Approach

As indicated in Chapter 1 of the Decision, B.C. Hydro determined its transmission revenue requirement with the help of a Fully Allocated Cost of Service ("FACOS") study. FACOS studies are used by utilities to help them determine the appropriate amount of revenue to collect from each customer class for providing service to it. Generally, a FACOS study consists of four steps. These are:

- the determination of the utility's total cost of providing service, i.e., the utility's revenue requirement;
- the separation of these costs into categories which reflect the broad functions which the costs are incurred to meet, such as generation, transmission and distribution, (commonly referred to as functionalization);
- the separation of the functionalized costs into classes which reflect why the costs were incurred, e.g., to meet growing demand at a point in time, to meet growing energy requirements over time, or because of increased customers on the system (commonly referred to as classification); and
- the allocation of the functionalized and classified costs amongst rate classes based on the extent to which a rate class causes the cost to be incurred, (commonly referred to as allocation).

The separation of costs into the above categories frequently requires judgment since many utility costs are incurred to achieve more than one objective. For example, transmission capacity is used by all customers, in varying quantities at varying times, so that direct assignment of these costs to particular customer classes cannot be undertaken and some other method of assigning costs must be devised.

To determine its transmission revenue requirement, B.C. Hydro began with its 1993/94 FACOS study and then modified it to reflect the Utility's belief of how to design a fair, just and reasonable rate for providing an unbundled rather than bundled transmission service.

Starting with rate base, B.C. Hydro functionalized all assets as belonging to either a transmission or a collective 'other' category. Expenses were also functionalized as belonging to either the transmission or 'other' category. In some cases, direct assignment of expenses to the transmission or 'other' category was possible. Where expenses were incurred to serve multiple functions, B.C. Hydro divided the costs between the transmission and 'other' category in proportion to the value of transmission rate base relative to the value of total rate base (at original cost) (Exhibit 1A, Tab G-1). Based on this approach, B.C. Hydro estimated its transmission revenue requirement to be $548.2 million for the 1996 fiscal year, later updated to $550.2 million (Exhibit 1A, Tab P).

B.C. Hydro stated that transmission assets include all 69 kV and higher voltage transmission lines plus the transformation facilities necessary to step up generation to these voltages (T: 2515). In particular, transmission plant in service was defined to include: generation-related transmission; 500 kV, 230 kV, 138 kV, and 69 kV lines; transmission substations; and the relevant proportion of general plant and equipment (such as Production, Customer Service, Vehicles, Communications and other miscellaneous equipment) (Exhibit 1A, pp. W-G-1-9 and 10).

More specifically, generation-related transmission facilities were defined to include: (1) those transmission lines which tie remote generation located in the North and South Interior regions of the province to the rest of the system; (2) the portion of generation substation assets related to transformation equipment which steps up voltage from the level at which it is generated to the bulk transmission voltage used to carry power towards the load; and (3) some general assets (Exhibit 1B, BCUC IR1, Q-54-2). In contrast to generation substations, transmission substations act to connect transmission from different generation facilities, segment very long transmission lines, provide locations for static transmission voltage control equipment and contain step-down transformation to supply local loads or reinforce lower voltage lines.

The inclusion of generation-related transmission facilities and most generation substation costs in the transmission function is a departure from the method used in the 1993/94 FACOS study and results in a wholesale transmission tariff with higher rates than would otherwise have occurred. B.C. Hydro defended this approach, arguing that these items are necessary elements of the integrated transmission network as it is currently used (T: 2515).

Many intervenors challenged B.C. Hydro on its reasons for deviating from the functionalization found in the 1993/94 FACOS study. Most intervenors disagreed with the inclusion in the transmission revenue requirement of assets at the generation end of the network (e.g., remote transmission lines, generation substation facilities) and some parties disputed the inclusion of lower voltage facilities (e.g., 138 and 69 kV lines). Some argued that B.C. Hydro's functionalization of its own assets is inconsistent with its treatment of past and proposed connection and upgrade costs charged to independent power producers ("IPPs"). Others indicated that it is inappropriate for B.C. Hydro to require wholesale transmission service users to pay for segments of the transmission that they would never reasonably use. Finally, some argued that including these costs in the transmission revenue requirement will increase rates for all customers, even higher above marginal costs than they would otherwise be, and will discourage more efficient use of the transmission system. In contrast, the inclusion of these costs in generation would not significantly change behavior (Exhibit 29, pp. 20 and 21).

2.1.2 Remote Transmission Lines & Generation Substations

B.C. Hydro justified the functionalization of remote transmission lines and generation substation facilities to transmission on the basis that the system is a single integrated network. B.C. Hydro submitted that remote facilities provide stability and system security benefits as well as ancillary services for the entire integrated network and that the step-up transformation elements of the generation substations increase the efficiency of transmission by reducing transmission losses (T: 2516, Exhibit 1A, p. W-J-YM(P2)-4).

Mr. Mansour, testifying on behalf of B.C. Hydro, presented two cases to demonstrate how generation related facilities act as part of the integrated network (T: 647-658). First, he showed that if there is a system failure, the presence of 'wheeling' transactions between Alberta and the Bonneville Power Authority could create or exacerbate stability problems on the system. In addition, he prepared stability diagrams that show that instantaneously tripping a remote B.C. Hydro hydroelectric generator (either at Mica or GM Shrum) maintains system stability during a fault. From this analysis, Mr. Mansour concluded that remote generation facilities provide a cost effective way of maintaining system stability and, therefore, these facilities should be included when determining the transmission revenue requirement.

In addition, B.C. Hydro argued that its current treatment of remote 500 kV facilities is entirely consistent with FERC's treatment of similar facilities in recent decisions (T: 2523 and 2524). Mr. Stone, a consultant testifying on behalf of B.C. Hydro, presented a number of cases in which FERC allowed a utility to include the cost of remote transmission facilities into the transmission revenue requirement (Exhibit 1A, pp. W-M-HSS-6-8). Although B.C. Hydro accepted that FERC precedent is in no way binding on the Commission, it suggested that the precedent warranted earnest consideration because of FERC's abundant experience in considering wholesale transmission applications (T: 2528).

As indicated above, several intervenors challenged B.C. Hydro's proposed functionalization of generation-related transmission assets to transmission. Mr. Nieboer, a consultant testifying on behalf of WKP, argued that B.C. Hydro's logic is circular. Mr. Nieboer claimed that transmission stability problems are exacerbated by the existence of the long-distance 500 kV lines. Therefore, although the management of remote generation facilities may correct stability problems, the presence of the very long high voltage transmission lines also may be, in part, responsible for the instability situation (T: 2331).

Mr. Nieboer stated that only those transmission facilities clearly used to provide wholesale transmission service should be included in the transmission revenue requirement (Exhibit 42A, Tab C, p. 7), while transmission facilities constructed to connect remote generation plant to the grid should be functionalized to generation. He concluded that some 500 kV lines should be excluded entirely from the transmission function, as could approximately 70% of other lines. He determined the latter proportion by dividing the amount of power the remote transmission lines deliver to regional load, including losses, by the amount of power these lines deliver to distant loads (Exhibit 42A, Tab C, p. 14). Mr. Nieboer concluded that it would be appropriate to exclude $1.59 to $1.95 billion from the calculation of Transmission Plant.

In addition, WKP stated that while FERC's practice during Stage One of the Open Access NOPR appears to favor inclusion of generation-related transmission costs in the transmission revenue requirement, it is probably due to the need for simplicity and uniformity in the Stage One rates. WKP argued that generally accepted rate-setting practice suggests that the costs of generation-related facilities should not be included in wholesale transmission rates (Exhibit 42A, p. B-5).

Mr. Stephenson, a consultant hired by Commission staff to review B.C. Hydro's functionalization of assets, stated that it is inappropriate to functionalize all remote 500 kV lines to transmission. He distinguished between remote facilities and network facilities based on indicators such as distance, isolation, whether the lines are radial (i.e., usually deliver power in one direction from the generator to the main transmission system), and whether a wholesale transmission customer would be likely to use the lines (Exhibit 31B, pp. 2-4). Using these criteria, he evaluated each 500 kV line individually and recommended that B.C. Hydro exclude several of them.

Mr. Stephenson also recommended that the Commission require B.C. Hydro to use a flow-based method for transmission pricing since it would allow the Utility to avoid functionalizing contentious facilities (Exhibit 31B, pp. 6 and 7). A flow-based method relies upon simulations of changes in power flows with and without a transaction to determine the proportion of different facilities used for the transaction. Mr. Stephenson indicated that he used power flow analysis to confirm his belief that remote lines should not be functionalized to transmission (T: 2009).

The Council of Forest Industries, the Mining Association of British Columbia and the Electro-Chemical Producers ("the Industrial Customers") and IPES supported the functionalization of the 500 kV lines to generation as was done in the 1993/94 FACOS study. In defense of their position, they noted the comments regarding the functionalization to generation made by R.J. Rudden & Associates in a report dated May 1995, and attached to the 1993/94 FACOS study.

> "B.C. Hydro has recognized that some transmission plant are generation related (regardless of voltage level). This identification of "remote" transmission is an accepted practice in cost of service studies. Specific remote transmission facilities tie remote generation into the transmission grid .... Remote generation provides for cheaper generation, but carries with it an additional transmission cost. The cost of that remote transmission is viewed as part of the cost of generation, and should not be functionalized to transmission." (Exhibit 1B, BCUC IR1, Q-59, RJ Rudden & Associates, Inc., p. 8).

As indicated earlier, B.C Hydro argued that the functionalization contained in the 1993/94 FACOS study could not be used to determine the transmission revenue requirement because this represents a "use not contemplated when the FACOS was written" (T: 2515). Specifically, Mr. Little, the consultant who authored the May 1995 report, indicated that his assessment had been done assuming a vertically integrated utility providing a bundled service. In such an environment, Mr. Little emphasized that the primary concern is to determine whether current rates recover the cost of serving each class of customer and is not to achieve a precise functionalization of assets where a lack of precision will not affect the calculation of the revenue to cost ratios. With respect to the 1993/94 FACOS study, he indicated that because assets properly functionalized to generation and generation-related transmission assets were classified in the same manner, 50% to demand and 50% to energy, he could assign generation-related transmission assets to the generation function for ease of calculation (T: 726, Exhibit 1A, p. W-I-JWL-6). B.C. Hydro agreed that with the new modifications, generation-related transmission assets are now classified 100% to demand but, where demand is allocated between customers using the 12 CP methodology, B.C. Hydro argued that the ultimate allocation to rate classes is not significantly affected (T: 896 and 897).

Mr. Little was also questioned about another passage in the May 1995 Report, in which he stated:

> "In an unbundled environment, all independent generators would be responsible for unbundled transmission service. In an unbundled environment, all independent generators would be responsible for providing power at the appropriate voltage level. Therefore, RJRA endorses B.C. Hydro's functionalization of generation substations to generation" (Exhibit 1B, BCUC IR1, Q-59, RJ Rudden & Associates, Inc., p. 9).

In supporting the changed B.C. Hydro policy of now functionalizing generation substations to transmission, Mr. Little admitted that, at the time he wrote the May 1995 Report, he had assumed that in an unbundled environment B.C. Hydro would require independent power producers to provide their own step-up facilities (T: 663), implying that consistency required B.C. Hydro to functionalize its own generation substations to generation. However, Mr. Little stated that Mr. Mansour's testimony indicated that B.C. Hydro is willing to share the cost of step-up transformers of independent generators if they provide transmission system benefits so that functionalization of these assets to transmission is appropriate. This position was expressed in B.C. Hydro's final argument when the Utility committed to treat step-up transformation which "... renders the transmission function more efficient as a transmission expense regardless of who owns the generation." (T: 2526). Indeed, B.C. Hydro appeared to indicate that all costs would be functionalized to transmission (T: 2526).

As alluded to above, there was significant discussion during the course of the hearing and in final argument as to whether B.C. Hydro's proposed functionalization of its own 500 kV and step-up transformation assets is consistent with the assignment of costs B.C. Hydro plans to impose on IPP customers requiring new network connections or upgrades to access B.C. Hydro's transmission system. In its Application, B.C. Hydro stated that the cost of Direct Assignment facilities, constructed for the sole use or benefit of facilitating a request for service under the tariff, would be borne by the customer requesting the service (Exhibit 1A, p. W-C-1-7), while the costs of network upgrades that benefit both the transmission customer requesting the service that caused the upgrade and the system generally could be shared between the customer and B.C. Hydro (Exhibit 1A, p. W-C-1-10).

In his written evidence, Mr. Fussell, a witness for the Utility, stated that the proposed method for allocating the responsibility for Network Upgrade costs is similar to that used for allocating system reinforcement costs incurred to serve Rate Schedule 1821 customers. Specifically, B.C. Hydro would define a maximum amount of cost to be included in the determination of rate charges and any costs in excess of the maximum amount would be collected from the customer requesting the network upgrade (Exhibit 1A, p. W-N-CFF-2). However, during the hearing, Mr. Fussell agreed that B.C. Hydro will likely modify this condition to be consistent with the Commission decision on system extensions (T: 1059 and 1060).

Further elaboration was provided when the Industrial Customers questioned how B.C. Hydro will treat future 500 kV lines necessary to connect IPP generation to the grid. As with step-up transformation, Mr. Mansour stated that if the IPP facilities provide no benefits to the system, they will not be included as part of the transmission revenue requirement. If these facilities do provide system benefits, then Mr. Mansour stated that they could be functionalized to transmission, with B.C. Hydro and the IPP sharing the costs of the remote 500 kV line on the basis of the relative benefit the system receives versus the benefit the generator receives (T: 712-716).

The Industrial Customers asked whether a similar split between the generation and transmission function could be undertaken for B.C. Hydro's own 500 kV lines (T: 716 and 719). Although Mr. Mansour agreed that generation-related facilities provide a benefit to generators (T: 718 and 719), Mr. Little stated that he is unaware of any methodology that splits an asset between two functions because the asset provides a benefit to both functions. Instead, Mr. Little argued that on a case-by-case basis it is possible to determine whether an asset is a benefit to the transmission system or to the generation system, resulting in an either/or allocation (T: 721).

In addition to the concerns identified with respect to the similarity of treatment between B.C. Hydro assets and IPP assets, IPES expressed concern that the proposed treatment of IPP step-up transformation is not consistent with B.C. Hydro's past practice with respect to IPPs (T: 2694). In the past, IPPs have been required to pay all of the costs of step-up transformation. However, Mr. Mansour indicated that past IPP generation had been "built to deliver flat blocks of energy sales without being part of system dispatch, load following, system protection, etc." (Exhibit 1A, p. W-J-YM(P2)-8) and so had not provided system benefits. Accordingly, he asserted that it would not have been appropriate to include the costs of IPP step-up transformation in B.C. Hydro's transmission revenue requirement.

2.1.3 138 kV and 69 kV Lines

In determining the transmission revenue requirement, B.C. Hydro included all the 138 kV and 69 kV lines. B.C. Hydro referred to the historical development of the transmission system and concluded that:

> "[t]he 69 and 138 kV components provided the main transmission service to many parts of the province at that time and complemented the integrated network operation of the system ... As the integrated system evolved and grew to higher capacity and higher voltage classes, the 69 kV and the 138 kV systems continued to perform a primary function of direct interconnection to higher voltages, providing back-up routes under contingencies involving higher voltage transmission ..." (T: 2516 and 2517).

Mr. Mansour presented testimony in support of B.C. Hydro's approach by reviewing the function of the 69 kV lines in the Lower Mainland under certain circumstances and indicating that these lines provide back-up services (Exhibit 21). These lines represent over half of B.C. Hydro's 69 kV facilities. No formal analysis of the function of the remaining 50% of the 69 kV facilities was available although Mr. Mansour indicated that he expected similar findings (T: 936 and 937).

With respect to the 138 kV lines, B.C. Hydro asserted that the bulk of the 138 kV lines on Vancouver Island are fully integrated with higher and lower voltage classes; the lines around Shrum are looped and integrated with the 230 kV and 500 kV lines to provide main transmission to municipalities and connection with an IPP; and the lines in the South Interior (East) provide alternate transmission routes to back-up higher voltage transmission in normal and emergency circumstances (Exhibits 9 and 21, T: 2522 and 2523). B.C. Hydro also noted that all existing IPPs are connected to the integrated network at either the 69 kV or the 230 kV level. The inclusion of the 69 kV and 138 kV lines in the transmission revenue requirement was supported by Mr. Nieboer (Exhibit 42A, Tab C, p. 7).

Ms. Toulson and Mr. Stephenson challenged the inclusion of the 69 kV and 138 kV lines in the transmission revenue requirement. They recommended that about half of the 138 kV system and virtually all the 69 kV system be excluded from the transmission rate base, arguing that these facilities are not required for transmission service and do not enhance the reliability of the service (Exhibit 31A, p. 9). These conclusions resulted from Mr. Stephenson's definition of subtransmission, which he categorized as lower voltage facilities whose primary function is to deliver power to distribution substations and to connect relatively small generators. Ms. Toulson supported these conclusions further, with reference to a Minnesota Power and Light case in which subtransmission facilities were excluded from the definition of transmission (Exhibit 31A, p. 9). IPABC also supported a review of the 69 kV system to determine under what circumstances and to what extent it should be considered to be transmission (T: 2609).

According to B.C. Hydro, the facilities referred to in the Minnesota Power and Light case were normally operated with the switches open. B.C. Hydro testified that the majority of the 138 kV and 69 kV circuits in the Lower Mainland are normally operated with the switches closed (T: 925), thereby providing back-up power flow paths when higher voltage lines are out of service. Furthermore, B.C. Hydro argued that Mr. Stephenson drew his conclusions without a full understanding of B.C. Hydro's system (T: 2866).

2.1.4 Step-down Transformation

As discussed above, B.C. Hydro functionalized all of its own step-up transformation facilities to transmission, but did not functionalize step-down transformation facilities, at the distribution end of its system, to transmission (T: 2517). Mr. Stone noted that, although it could be argued that these facilities provide the dual functions of transmission and distribution, B.C. Hydro did not have sufficient information to conclude that these should not remain functionalized to distribution at the time of the application (T: 812). This treatment is consistent with the functionalization contained in the 1993/94 FACOS study (Exhibit 1A, BCUC IR1, Q-59, RJ Rudden & Associates, Inc., p. 9).

No intervenors argued that step-down transformation should be included in the definition of transmission, although B.C. Hydro noted that the Grid Company of Alberta ("Gridco") includes step-down transformation in its transmission rates (T: 2517).

2.1.5 Treatment of Demand-Side Management ("DSM")

The transmission revenue requirement, as put forward in this Application, does not include any DSM costs. Mr. Mansour stated that DSM has only a very limited impact on either new transmission investment or the freeing up of existing transmission capacity (T: 366) and that most of the benefits relate to generation. In response, the BCEC argued that DSM measures provide numerous benefits to all consumers and directly benefit wheeling customers by providing transmission system stability through peak reduction and contributing to rational system planning (T: 2676 and 2677). Accordingly, the BCEC suggested that the proposed rates be amended to include a portion of DSM costs (T: 2679).

2.2 IPABC Revenue Requirement Evidence

As indicated in earlier sections, there was significant debate during the course of the hearing as to which physical assets should be considered as transmission assets when establishing the transmission rate base and transmission revenue requirement. In addition to these questions, there was also debate concerning how total rate base should be defined. This is important since the ratio of transmission rate base to total rate base is used by B.C. Hydro to determine the transmission revenue requirement.

Based on the 1993/94 FACOS study, rate base consists of plant in service, plus work in progress, plus deferred demand side management, less accumulated depreciation and unamortized contributions in aid of construction. The rate base also excludes unamortized contributions regarding the Columbia River Treaty. However, under Special Direction #8 to the BCUC, the equity portion of B.C. Hydro's capital structure is defined to include both unamortized contributions in aid of construction and unamortized contributions regarding the Columbia River Treaty. Accordingly, B.C. Hydro's net operating income reflects a return on both of these items.

The IPABC presented testimony and argument that allocating net operating income between transmission and other functions, on the basis of rate base defined as net of contributions in aid of construction and contributions related to the Columbia River treaty, is inconsistent with the basis on which net income is generated. Further, the IPABC maintained that this exclusion leads to an overallocation of net operating income to the transmission function since only a small proportion of contributions in aid of construction are related to the transmission function.

The IPABC was also critical of the allocation of interest expense based on rate base because rate base contains work in progress, (i.e., projects under construction), but the interest expense is net of work in progress. Similarly, interest expense reflects investment in working capital but working capital is not included in rate base. Accordingly, the IPABC suggested that interest expense be allocated on the basis of rate base, with work in progress removed and investment in working capital added. If this were done, the IPABC maintained that the charges allocated to transmission would be reduced since the proportion of work in progress in the transmission category is greater than in the distribution and generation categories, while investment in working capital is more heavily concentrated in customer service and distribution.

Finally, the IPABC was critical of the treatment of operating and maintenance charges which are allocated by B.C. Hydro primarily on the basis of plant in service. The IPABC noted that this leads to an allocation of operating and maintenance costs to the transmission function which is inconsistent with that reported by the Canadian Electrical Association. In addition, they noted that there is no separate account for thermal generation operation and maintenance costs.

In response to the above, B.C. Hydro noted that it had used a traditional methodology to develop the transmission revenue requirement (T: 2529). Further, B.C. Hydro stated that acceptance of the IPABC suggestions would lead to "incongruous results" (T: 2532). For example, B.C. Hydro objected to the inclusion of working capital in rate base, indicating that current assets are typically funded by current liabilities. B.C. Hydro also stated that the IPABC suggestion would result in the full amount of the accounts receivable being functionalized to customer services even though the accounts receivable reflect the bundled product which customers buy (T: 2534 and 2535).

2.3 Commission Determination

Based on the evidence and argument presented with respect to this Application, it is the Commission's judgment that B.C. Hydro has not justified the functionalization of generation-related transmission facilities to transmission. Although the Commission acknowledges the technical validity of B.C. Hydro's assertion that remote generation sources may be operated to the benefit of the transmission network in the event of an emergency and may be called upon to provide ancillary services, in the Commission's judgment, the Utility has not demonstrated the true extent of the benefit provided by these assets. Accordingly, the Commission does not accept that the transmission system benefits justify functionalizing 100% of the cost of generation-related transmission facilities to transmission. Further, the Commission notes that extending B.C. Hydro's rationale for functionalizing these assets to transmission could suggest that even certain generation units could be functionalized to transmission. This is because the generation units connected to these remote lines also play a role in stabilizing the transmission network.

In coming to this determination, the Commission acknowledges the position put forward by Mr. Nieboer, on behalf of WKP, that with large generation facilities located at great distances from the load centres, during periods of system disturbance, stability problems could be considerably amplified by the existence of these long transmission lines.

In addition, the Commission notes certain internal inconsistencies in the proposed treatment of potential IPP-owned generation-related facilities and in the current treatment of these facilities when compared with the treatment of similar B.C. Hydro-owned facilities. Although B.C. Hydro has committed to treat IPP-owned step-up transformation that renders the transmission function more efficient as a transmission expense, it suggested that other IPP generation-related facilities would only be functionalized to transmission on the basis of the relative benefit the system received versus the benefit the generator received (T: 712-716). With respect to its own generation-related facilities, no splitting of the assets between functions is proposed (T: 721), despite B.C. Hydro's agreement that generation-related facilities, such as generation substations, do provide benefits to generation as well as transmission (T: 718 and 719).

Given Mr. Little's statement that he is not aware of any methodology which splits the costs of a specific asset between two functions (T: 721), the Commission is concerned that no costs, whether initially incurred by B.C. Hydro or an IPP, be functionalized to transmission unless there is evidence that the major benefit of the asset relates to transmission. 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.

With respect to the functionalization of 69 kV and 138 kV lines, the Commission accepts that B.C. Hydro has demonstrated that some of these facilities provide assistance to the transmission function in terms of interconnection with higher voltage lines and back-up routes under fault conditions. Although B.C. Hydro has not provided evidence as to how frequently these lines are called upon to provide these services, and the Commission understands that these lines also provide sub-transmission functions in terms of supplying power to the distribution system, the balance of the evidence suggests that these facilities are likely to provide a significant benefit to the transmission function. Therefore, the Commission determines that for the purpose of setting the immediate transmission tariff, these assets should remain functionalized as in the 1993/94 FACOS study.

With respect to DSM, the Commission accepts that DSM is an alternative to transmission and that this should be reflected in the transmission revenue requirement. Therefore, the Commission directs B.C. Hydro to undertake a study to determine what portion of its DSM costs can be attributed to transmission. This study should be filed with the Commission no later than January 1, 1997.

With respect to the arguments put forward by the IPABC regarding the calculation of the revenue requirement, the Commission is not persuaded that the suggested adjustments are necessary. In addition, the Commission's judgment is that at least some of the recommendations, particularly those which relate to the functionalization of accounts receivable to customer services, are inappropriate since they do not reflect the fact that the services for which customers pay reflect all utility functions.

In summary, the Commission directs B.C. Hydro to file an adjusted transmission revenue requirement and associated Network and Point to Point Services rates no later than September 1, 1996, which reflect the treatment of generation-related assets similar to that found in the 1993/94 FACOS study. These transmission rates will replace the interim rates and will be effective from January 31, 1996.

As argued by B.C. Hydro, the Commission accepts that the precision required of a FACOS study which is assessing bundled services is less than that required of a study which is assessing unbundled services. **Therefore, the Commission directs B.C. Hydro to file new rates, no later than January 1, 1997, based on a study which more precisely identifies its transmission revenue requirement. In particular, the new transmission revenue requirement should reflect the relative benefits which generation-related transmission assets provide to the generation and transmission functions, the extent to which 138 kV and 69 kV lines provide transmission benefits, and the role of DSM with respect to transmission.**

3.0 DESIGN OF NETWORK AND POINT TO POINT TRANSMISSION RATES

3.1 Basic Principles

3.1.1 Embedded Versus Marginal Costs

It is generally accepted that fair, just and reasonable rates are those that yield the total revenue requirement of the utility, including a fair return on capital, and reflect the present and future costs incurred by the utility in providing the service. It is also generally accepted that rates based on the embedded cost of service are more effective in achieving the first objective, while rates based on marginal cost, and therefore requiring some form of rate design to equate average cost to average revenue, are more effective in achieving the second. In either case, rates may be 'postage stamp', that is the same rate is charged each customer of a particular rate class everywhere within the utility's service area or the rates may be regionally differentiated.

As indicated in section 1.3, B.C. Hydro has proposed three basic transmission rates: Network Service, non-recallable Point to Point Service and recallable Point to Point Service. In addition, as discussed in Chapter 4, B.C. Hydro is offering two Ancillary Services schedules: a bundled service including load following, reactive power support and system protection, and a loss compensation service. In determining the appropriate rates for Network and Point to Point Services, B.C. Hydro began with its estimated 1996 transmission revenue requirement, which, as discussed in Chapter 2, was based on the Utility's historical embedded costs. The form of these rates, as well as the associated Terms and Conditions, reflect the FERC pro forma tariffs.

The Network Service rate was determined by dividing the transmission revenue requirement by the 1996 forecast of B.C. Hydro's average 12 monthly hourly peak consumption levels to achieve an average flat embedded cost rate, for the billing month. The minimum contract term is 12 months.

The long-term, non-recallable Point to Point Service rate, which is comparable to the Network Service rate in terms of duration and quality of service, was determined by dividing the transmission revenue requirement by the forecast of B.C. Hydro's annual hourly peak consumption level. B.C. Hydro indicated that the difference in the two approaches, (i.e., the average 12 monthly hourly peak consumption levels versus the annual hourly peak consumption), reflects the fact that Point to Point Service gives the customer the right to deliver power into the system and extract power from the system at specific points and to assume that power flows along a specified path between the two points (i.e., the contract path), up to the reserved capacity at all times (Exhibit 1B, BCUC IR1, Q-8).

The monthly short-term, non-recallable Point to Point Service rate for the November to February period (i.e., the four months of the year in which consumption is greatest) was determined by dividing the annual long-term non-recallable rate by four. For parties wishing to take the rate on a daily rather than monthly basis during this period, the annual rate was divided by the number of week days in the four month period, i.e., 80 days. To establish a weekly rate, the daily rate was multiplied by five, the number of weekdays in a week.

For the non-peak periods (i.e., March through October), B.C. Hydro proposed an hourly rate for short-term non-recallable Point to Point Service. The rate was determined by dividing the annual long-term non-recallable rate by the number of hours in the year.

In addition to non-recallable Point to Point Service, the B.C. Hydro Application also contained a proposal for short-term recallable Point to Point Service. For this service, rates are established on a day ahead basis and are equal to one-quarter of the difference between the California Oregon Border ("COB") price for peak electricity and the cost of producing peak electricity in Alberta, i.e., the price of gas at the Alberta Energy Company ("AECO") Hub converted to electricity at an assumed heat rate plus 20% losses. The Application stated that the maximum hourly charge for short-term recallable Point to Point Service is the short-term non-recallable rate divided by the number of hours in a typical year, while the minimum hourly charge is the administration costs allocated to the transmission function divided by total sales, rounded to .1 cent (Exhibit 1A, pp. W-F-6 and 7).

The charge for the bundled Ancillary Service is .13 cents per kWh and was determined by converting the FERC pro forma ancillary service charge of .1 cent per kWh into Canadian funds. B.C. Hydro proposed that the loss compensation charge be posted from time to time and be determined after consideration of its costs and the current market value (Exhibit 1A, p. W-F-8). More specifically, B.C. Hydro indicated that the loss compensation charge would be the higher of: (1) the marginal running cost of B.C. Hydro's generating plants, including opportunity costs as determined from the ability of the system to store energy for a later, more beneficial use; (2) the cost of importing from other systems; and (3) the price others are willing to pay for incremental generation (Exhibit 1B, BCUC IR1, Q-38, p. 2).

In its Application, B.C. Hydro defended its primary reliance on embedded costs to establish rates, stating that its Network and Point to Point Service rates achieve a fair sharing of the transmission revenue requirement and comparable treatment for B.C. Hydro's captive retail customers and wholesale transmission customers (Exhibit 1A, p. W-F-1). Although Dr. Orans, a witness for B.C. Hydro, appeared to recognize that rates based solely on embedded costs, as the proposed non-recallable rates are, may not give customers the most efficient pricing signals, he indicated that the loss in efficiency in the generation supply market would not be significant. Dr. Orans indicated that this is because B.C. Hydro does not anticipate constraints on its main transmission grid over the next four to five years and foresees no new generation being built to serve market demand, due to an excess of supply in the western region of North America (T: 1569).

In addition, B.C. Hydro indicated that it has incorporated marginal cost considerations into certain aspects of its proposal. B.C. Hydro stated that its recallable rates are not based on embedded cost pricing but rather reflect the short-run market value of transmission (T: 2582). As well, B.C. Hydro stated that its proposal with respect to charging for system losses reflects marginal as opposed to embedded cost pricing principles, since for the first four years of any non-recallable longer term contract a new customer would be charged based on the incremental losses that the customer's transmission imposes on the system, as opposed to system average losses.

Furthermore, B.C. Hydro argued that its system has been developed in the context of an embedded cost pricing methodology and that any move away from this has the potential to be unfair to those who have made substantial investment based on this approach. B.C. Hydro stated that it rejects the suggestion that there is anything so distinctive about wholesale transmission access that a new approach has to be developed to the pricing of the service (T: 2472).

In addition, Dr. Orans indicated that a piecemeal movement towards marginal cost based rates has the potential to cause end-use decisions which are not based on least cost to society. Particularly if retail access to IPPs is allowed, but B.C. Hydro continues to offer its services in their current form, Dr. Orans suggested that pricing wholesale transmission based on marginal costs will lead to a situation in which end-use customers compare the incremental cost of new IPP generation plus the marginal cost of transmission to the bundled postage stamp average retail rate when choosing between non B.C. Hydro and B.C. Hydro supply. This could lead them to choose IPP generation even if B.C. Hydro's marginal generation costs were lower (T: 1668). Finally, B.C. Hydro stated that embedded costs rates serve the objectives of fairness and simplicity and these objectives of rate design also need to be met.

In contrast, several intervenors indicated that further effort should be made to incorporate marginal cost prices into the wholesale transmission rates charged by B.C. Hydro. IPES categorized B.C. Hydro as unnecessarily taking an either/or approach to the issue of the extent to which rates should be based on embedded or marginal costs. IPES stated that, while the total revenue requirement and the average level of rates could and should be based on embedded costs, the structure of rates should be designed to reflect, as best as possible, marginal costs (T: 2696).

In addition, IPES questioned B.C. Hydro's assertions that there will be no loss of efficiency from rates based solely on embedded costs. IPES pointed out that decisions are being made to develop new resources and that these resource decisions will be distorted by inefficient transmission rates, particularly if B.C. Hydro's Power Supply Division, or an IPP, intends to take the proposed rates fully into account in choosing amongst resources (T: 2698). In response to this assertion, B.C. Hydro distinguished between new generation built by third parties to serve market demands, which the Utility suggested will only respond to the pricing signal provided by transmission, and generation by B.C. Hydro which will be acquired based on the Resource Acquisition Policy developed by B.C. Hydro in accordance with directives from the government (T: 2859 and 2860). Accordingly, B.C. Hydro argued that the efficiency of locational decisions for new resources developed by B.C. Hydro will not be affected by the design of transmission rates over the next five years. With respect to third party generation, B.C. Hydro argued that no new sources of supply would be constructed because of existing excess capacity in the market (T: 2859).

IPES also challenged B.C. Hydro's assertion that the transmission system is not facing constraints and, in this regard, referenced the situation with respect to Vancouver Island and the Lower Mainland (T: 2698).

The Consumers Association of Canada (B.C. Branch) et al. ("CAC (B.C.) et al.") also suggested that B.C. Hydro's statements are misleading when one considers that the planning, design, environmental assessments, approvals, engineering and construction of major new transmission lines to Vancouver Island could take four to five years (T: 2625). In response, B.C. Hydro argued that, because transmission constraints to Vancouver Island are due to deterioration of existing lines, these will occur regardless of the location of new generation. With respect to constraints to the Lower Mainland, B.C. Hydro argued that these could be removed through relatively inexpensive transmission enhancement measures as opposed to constructing new transmission lines (T: 303-305, and 1143).

The IPABC also questioned B.C. Hydro's reliance on embedded costs to design rates. Dr. Ruff, a witness appearing for the IPABC, stated that one of the principal objectives of a modern electricity transmission system is "to come up with prices for transmission service that give the right incentives and the right price signals in a competitive market for efficient and fair competition in the future" (T: 1749).

In order to provide efficient price signals, Dr. Ruff suggested that spot transmission prices reflecting short-run marginal costs should be developed (Exhibit 29, p. 19). Although he recognized that, in the current environment, prices based on short-run marginal costs will not result in the Utility recovering its revenue requirement, he suggested that any revenue shortfall could be recovered through grid access charges. To minimize inefficiencies and inequities that arise from the grid access charges, he suggested that they be designed to recover the most money from those who receive the most benefit from the transmission service, as measured by their willingness to pay (Exhibit 29, p. 20).

Although supportive of grid access charges in principle, IPES suggested that the particular circumstances of B.C. Hydro; namely preferential access of B.C. Hydro's Power Supply Division to transmission due to the integrated nature of the company, means that no embedded cost-based access fee should be imposed, so that third party users face the same incremental costs of transmission use faced by B.C. Hydro (T: 2712).

Dr. Ruff indicated that the lack of transmission constraints on the B.C. Hydro system does not suggest that marginal cost price signals are unnecessary. He noted that B.C. Hydro testified to the high reliability standards incorporated into the design of the transmission system (T: 1733-35) and suggested that this means that the system will never face constraints (T: 1895 and 1896). According to the IPABC, if this logic is maintained, B.C. Hydro will never be in a position to design rates which provide appropriate marginal cost signals to generation investors and wholesale purchasers (T: 2700).

3.1.2 Postage Stamp Versus Location Related Tariffs

Related to the discussion of the relative merits of embedded cost and marginal cost pricing was a discussion of the desirability of including some form of locational consideration in the wholesale transmission service rates. The proposed tariffs involve the use of postage stamp rates, i.e., the rate is the same for all parties no matter where they are located on B.C. Hydro's transmission system. Several parties to the hearing (e.g., IPABC, IPES) indicated that economic efficiency could be enhanced if wholesale transmission service rates were not postage stamp but instead reflect some element of locational differences in costs. Three broad options for including locational considerations in the rates were identified during the course of the hearing. These are: (1) regional wholesale rates which result in regional retail rates; (2) regional wholesale rates which do not result in regional retail rates; and (3) locational generation credits which do not result in regional wholesale or retail rates.

With respect to the first option, B.C. Hydro stated that it recognizes that the Commission has jurisdiction to order regional retail rates but urged the Commission not to do so (T: 2478). B.C. Hydro stated:

> " ... there is not a need to determine the regional versus postage stamp issue in the context of a specific rate application such as this and the government has indicated that it considers the fairness implications of a change in approach from postage stamp to regionally based rates as being significant enough to be avoided without specific government direction." (T: 2478).

With respect to the second option, B.C. Hydro recognized that it is technically possible (T: 1032), but indicated that it is unnecessary since, as discussed above, the transmission system is currently unconstrained. In addition, B.C. Hydro argued that it is very difficult to determine where and when future constraints will occur on the transmission system (T: 184 and 185) so that the establishment of locational price signals now could encourage generators to locate in areas which would later prove undesirable. Accordingly, the Utility stated that it is preferable to implement a locationally neutral rate design until such time as it is apparent that the system is becoming constrained (T: 2499). Finally, B.C. Hydro stated that implementing locationally differentiated wholesale rates, while maintaining postage stamp retail rates, would give rise to policy issues regarding balancing mechanisms between regions (T: 2506).

When constraints do occur, B.C. Hydro suggested that a system of flexible "real time" locational generation credits, i.e., the third option, be implemented. WKP also supported the use of locational generation credits (T: 2723) as did the CAC (B.C.) et al. (T: 2627).

While all parties to the hearing appeared to agree that regional retail rates are not an appropriate outcome for this hearing, several intervenors suggested that option 2, the reflection of locational considerations in the wholesale transmission services rates, is desirable. For example, the BCEC recommended that the Commission direct B.C. Hydro to refile a segmented wholesale transmission service rate while retaining postage stamp rates at the retail level (T: 2684). In contrast to B.C. Hydro's position regarding locational generation credits, IPES stated that such credits are inadequate, since they would be *ad hoc*, solely at the discretion of B.C. Hydro and might not be practical for new developers supplying third party loads (T: 2700).

Dr. Ruff, testifying for IPABC, indicated that he viewed postage stamp rates as being neither fair nor efficient since the costs and benefits of the electric system differ by location. He stated that, if prices for use of the system do not reflect these differences, operating and investment decisions will be distorted (Exhibit 29, p. 21). Accordingly, Dr. Ruff suggested that B.C. Hydro should replace the rolled-in postage stamp approach with a market oriented approach (Exhibit 29, p. 2). Specifically, he suggested that transmission rates reflect the difference in the value of energy at different locations with grid access fees charged, as discussed above, to preserve the revenue requirement (Exhibit 29, p. 22).

3.2 Distance Based Pricing

Several possible methods of incorporating locational considerations into wholesale transmission service rates were discussed during the course of the hearing. Generally, these options fell into one of two broad categories: wheeling based methods such as contract path, MW-mile and zonal rates; and market based methods based on locational energy prices which reflect transmission congestion costs, e.g., nodal pricing.

Under the contract path method, a specific path is designated between power receipt and delivery points and the wheeling charges are computed by identifying the costs of facilities that make up the path. Under the MW-mile method, a power flow analysis is performed to identify how the flows on each line of a system will change with a given wheeling transaction. Wheeling charges are calculated by comparing the increase in MW miles on each line to the total MW-miles. Under the zonal rate method, the transmission system is divided into regions with postage stamp rates calculated for each region. The charge for any individual transaction depends on the number of zones affected by the transaction (Exhibit 31A, pp. 11 and 12).

WKP stated that the unique geographic circumstances in B.C. supports distance based transmission rates. Of the several options discussed in the hearing, WKP indicated that it supports zonal rates (T: 2723).

Nodal, or congestion, pricing is based on the concept that differences in the price of electricity at different locations come about due to constraints on the transmission system. Specifically, the difference in the price of electricity at different locations reflects the short-run marginal cost of overcoming the transmission constraint, i.e., the incremental cost of losses and of any redispatch necessary to overcome transmission constraints (Exhibit 29, p. 29). Therefore, proponents of nodal pricing suggest that the appropriate transmission rates should be the difference in the price of electricity at different locations.

Dr. Ruff stated that locational pricing of energy is conceptually the right way to price energy on a grid, since the short-run marginal costs, when projected over time, signal the value of transmission investments which allow energy to be moved from where it is cheap to where it is expensive (Exhibit 29, p. 29).

IPABC recognized that nodal spot pricing is not ready for introduction into B.C. today. Accordingly, Dr. Ruff suggested that, until such locational energy prices are established, transmission prices should be based on the best available estimates of marginal costs. Two possible estimates suggested were an extension of the recallable transmission pricing approach, as proposed by B.C. Hydro, or the estimate of zonal incremental facility costs and losses contained in B.C. Hydro's Cost of New Electricity Supply ("CONES") report (Exhibit 29, pp. 35 and 36). IPES suggested that, although the estimates contained in the CONES report reflect long-run rather than short-run marginal costs, the use of the estimates would give third party users the same transmission price signal that B.C. Hydro uses for its own resource acquisition decisions (T: 2700).

In response, B.C. Hydro argued that the lack of current constraints on the system means that nodal or congestion pricing will not result in different locational price signals (T: 2862). Dr. Orans argued that it is very difficult to provide a long-term value for transmission capacity, given the prevalence of change in the market (T: 1036). Mr. Mansour argued that this could lead to incorrect signals and thus undesirable generation location decisions (T: 184, 185 and 544).

In assessing the desirability of location related transmission rates, IPABC asked the Commission to recognize that most IPP generation would likely be developed near the main load and include some form of cogeneration and a sale to a nearby party. Accordingly, IPABC maintained that it would use but a small portion of B.C. Hydro's transmission facilities (T: 2590).

As indicated earlier, WKP supported zonal rather than nodal pricing. Similarly, CAC (B.C.) et al. stated that while it found congestion pricing appealing in principle, it is not convinced that they are workable in a "... system very heavily dominated by one generation supplier facing large, 'lumpy' transmission investments." (T: 2627). Consequently, the CAC (B.C.) et al. did not support transmission congestion pricing but, as indicated earlier, called for locational generation credits (T: 2627).

3.3 Specific Concerns

3.3.1 Non-Recallable Point to Point Service

In addition to the broader questions of principle discussed above, several parties had concerns with respect to specific design elements of the rates. The Industrial Customers questioned the need for different peak capacity calculations to establish the Network and Point to Point Service rates. The Industrial Customers noted that the Network Service rate is based on the average 12 monthly peak hour consumptions, while the long-term, non-recallable Point to Point Service rate is based on the forecast of B.C. Hydro's annual hourly peak consumption. As indicated earlier, B.C. Hydro indicated that the difference in the two approaches reflects the fact that Point to Point Service gives the customer the right to use a specified contract path while Network Service affords no similar right. However, this argument was rejected by the Industrial Customers, who suggested that the difference in treatment is based on a desire by B.C. Hydro to make Point to Point Service rates less financially onerous than Network Service rates (T: 2816).

Other customers suggested that non-recallable Point to Point Service rates should be discounted from their embedded cost. Enron Capital and Trade Resources Canada Corp. ("ECT Canada") stated that, if capacity is not being utilized because the price of non-recallable transmission exceeds its value in the marketplace, measures ought to be taken to bridge the gap between the tariff price and the market value (T: 2763).

B.C. Hydro rejected the notion of discounting the rate for non-recallable Point to Point Service from its embedded cost (T: 2543). B.C. Hydro noted that one of its key objectives is to enhance use of its transmission system but doubted that this would be accomplished through discounting non-recallable Point to Point Service rates. In support of this position, B.C. Hydro indicated that there is currently limited demand for non-recallable service and that this is unlikely to change over the near term (T: 2544). Further, B.C. Hydro indicated that most potential users of the transmission system can purchase transmission on a recallable basis without the expectation of significant curtailment (T: 2544). Accordingly, discounting non-recallable rates would simply provide a benefit to those few customers who need non-recallable service without enhancing the use of the transmission system. B.C. Hydro suggested that, until there is significant demand for longer term recallable service, discounting non-recallable service would simply be a "pointless sacrifice of transmission margin" (T: 2547).

In response to these arguments, ECT Canada stated that the lack of demand for longer term recallable transmission capacity is a reflection of the short-term nature of the energy market and that rates structures which accommodate this reality should be promoted (T: 2765).

3.3.2 Recallable Point to Point Service

As discussed earlier, the short-term recallable Point to Point Service rate is established on a day ahead basis and is equal to one-quarter of the difference between the COB peak hour electricity price and the cost of producing peak electricity in Alberta, converted to electricity at an assumed heat rate plus 20% losses. In addition, recallable service is allocated to customers on a first-come first-served basis and may be reserved for periods ranging up to one year, although take or pay conditions are attached.

Several parties expressed concern with the pricing of recallable Point to Point Service. ECT Canada suggested that the current formula could result in the prices for recallable service being in excess of the market clearing pricing (T: 2766) and suggested that B.C. Hydro review the formula to ensure maximum use of the transmission system.

The Industrial Customers expressed concern that recallable service is being priced to minimize the charges imposed on B.C. Hydro for export sales, with the result being that recallable service users will not contribute a fair return to the system (T: 2816). Accordingly, the Industrial Customers suggested that the recallable service be priced based on some relationship to non-recallable service that will ensure an adequate return.

Gridco also suggested that the method of pricing recallable service, including the ability to reserve capacity on a first come first served basis, is inappropriate. In particular, Gridco maintained that this design allows Powerex to reserve all the capacity on the intertie between British Columbia and Alberta and so restrict access to the Alberta Power Pool. Gridco suggested that this allows Powerex to unfairly monopolize the economic rent associated with the constrained transmission capacity (Exhibit 35, p. 3).

To solve this problem, Gridco suggested that no party be allowed to reserve recallable transmission more than one day in advance of use. In addition, Gridco suggested that a floor price be established for the service, but that when the British Columbia-Alberta intertie is constrained, capacity on both the British Columbia and Alberta sides of the intertie be auctioned simultaneously on an hourly basis (T: 2096). The economic rent generated could then be equitably divided for the benefit of rate payers in both jurisdictions and would not allow any party to receive what is effectively non-recallable capacity at recallable rates (T: 2099).

In response to the Gridco proposal, B.C. Hydro stated that the daily auction approach requires many bidders and a functioning energy pool and would not be adequate in a system dominated by bilateral arrangements which require committed transmission space for blocks of time (T: 2602). Furthermore, B.C. Hydro suggested that, except in times of constraint, the auction approach would lead to lower rates and a resulting loss of contribution to the transmission revenue requirement (T: 2602). In addition, B.C. Hydro expressed concerns that the problems faced by Alberta, due to the lack of harmony between the Alberta and B.C. Hydro approaches, would be experienced by B.C. Hydro in respect of the Bonneville Power Authority ("BPA") if the auction approach was adopted since BPA does not use the auction approach to ration space on its side of the B.C. Hydro-BPA intertie (T: 2602). Therefore, B.C. Hydro stated that the first come first served approach, with prices determined based on the formula as opposed to the complexity of an auction, is a better approach for British Columbia.

B.C. Hydro argued that unilateral action by the regulator in either jurisdiction would be unlikely to assist in this process (T: 2864). Instead, B.C. Hydro suggested that the Commission make its decision based on its assessment of the appropriateness of the tariffs for general use in British Columbia and that, if its decision in this regard continues to provide problems at the Alberta interface, then the concerned utilities should be encouraged to work those out and seek approval for any special rules on the intertie which they have concluded are necessary.

Counsel for IPES argued that access to intertie capacity is critically important to independent generators, particularly without access to a spot market in British Columbia. IPES felt that the terms of access to limited capacity must be changed to ensure that third parties are not unfairly disadvantaged relative to B.C. Hydro's Power Supply division. They suggested an auction system should be considered and the take-or-pay provisions modified to eliminate the advantage currently held by B.C. Hydro (T: 2707).

The Industrial Customers also expressed concern that the Terms and Conditions allow B.C. Hydro to monopolize recallable capacity, effectively obtaining firm capacity at a non-firm rate (T 2814).

3.4 Commission Determination

Based on the evidence and argument presented with respect to this Application, it is the Commission's judgment that there is a need to develop more efficient pricing signals than those which are contained in the proposed B.C. Hydro rates. In particular, the Commission's judgment is that the rates charged for wholesale transmission service should reflect the marginal costs of providing service on a regional basis.

In coming to this conclusion, the Commission has considered B.C. Hydro's argument that more efficient price signals are not needed at this time. However, the Commission finds that the Utility has failed to prove its case that it will not face any transmission constraints which might be mitigated through price signals that encourage the siting of generation to particular locations. Moreover, the Commission does not accept B.C. Hydro's argument that locationally efficient price signals are not needed until such time as transmission constraints occur.

As indicated earlier, the Commission's responsibility under the Act is to set rates which are fair, just and reasonable. It is the Commission's judgment that this means rates that attempt to signal at least, in part, the costs of incremental changes in the use of various components of the B.C Hydro system. The Commission notes that IPABC proposed congestion pricing (i.e., short-run marginal costs) as a mechanism to provide signals to encourage appropriate siting of new generation and appropriate investment in new transmission. Given current transmission planning criteria, the Commission is not convinced that such a method provides these signals in the near term or will result in sufficiently strong signals in the longer term.

Accordingly, the Commission directs B.C. Hydro to apply for new rates for wholesale transmission service which reflect long-run marginal costs and locational considerations, by January 1, 1997. Based on the evidence and argument in this proceeding, the Commission suggests that an appropriate starting point is the methodology used to estimate the long-run incremental cost estimates by region as developed in the CONES Report. The rates must be designed to collect the full transmission revenue requirement. This dual requirement to recover full embedded cost and to signal the incremental cost of transmission between various locations on the British Columbia grid could be met by a pricing structure that includes an access charge, by scaling non-recallable tariffs, or by such other method as B.C. Hydro may develop. The Application should also address any other necessary changes to the tariffs as a result of this direction.

In the meantime, the Commission accepts the methodology which gave rise to the rate forms proposed in the current application with respect to Network Service and non-recallable Point to

Point Service. However, the actual dollar amount of the rates must be adjusted in line with the determinations set out in Chapter 2 of this Decision and filed with the Commission no later than September 1, 1996. Such rates will be retroactive to January 31, 1996.

With respect to B.C. Hydro's proposal for pricing recallable service, the Commission agrees with the Utility that the price should be related to the value of the service. The Commission notes that this is also consistent with the position of several of the intervenors, who argued that the price differential between two nodal points provides the appropriate measure of the marginal value of transmission. However, the Commission is concerned that, as acknowledged by B.C. Hydro, the proposed index, which is based on a generic Alberta generator and the COB price, is not ideal. **Accordingly, the Commission directs B.C. Hydro to examine methods for developing a more satisfactory index (or indices), with the goal of obtaining more precise indicators of the value of transmission over various segments of its transmission grid. The results of this examination are to be filed with the Commission as part of the January 1, 1997 Application.**

In the meantime, the Commission accepts B.C. Hydro's recallable pricing proposal as filed for the B.C. Hydro transmission system with the exception of the B.C. Hydro-Alberta intertie. With respect to the intertie, the Commission accepts the proposal put forward by Gridco for a simultaneous hourly auction when the B.C. Hydro-Alberta intertie, is constrained. In the absence of a constraint, the Commission directs that the recallable pricing proposal put forward by B.C. Hydro apply.

4.0 DESIGN OF ANCILLARY SERVICES AND ENERGY IMBALANCES RATES

4.1 Ancillary Services

4.1.1 General Description

Ancillary Services support and maintain the reliable operation of the transmission system during the delivery of electric power from source to load. The Ancillary Services charges offered in the Application recover only the costs of the energy component of providing these services. The static equipment costs are rolled-in to the transmission revenue requirement (e.g., remote transmission lines, step-up transformation facilities, etc.) (Exhibit 1A, p. W-E-3).

Generally, B.C. Hydro defined Ancillary Services in a manner similar to the definitions found within the FERC NOPR but departed from the pro-forma tariff in a number of significant details. B.C. Hydro bundled Load Following, System Protection and Reactive Power/Voltage Control into a single schedule and borrowed FERC's proposed pricing. Also consistent with FERC's Stage One filing, B.C. Hydro has not unbundled scheduling and dispatch services as a separate offering but rather includes these services, at no additional cost, to customers purchasing transmission services. However, unlike FERC, B.C. Hydro has not offered Energy Imbalances as an optional service but has included it in a clause contained in both transmission service schedules. Additionally, Loss Compensation is offered with substantially different terms and conditions than those proposed by FERC.

As proposed in the Application, all customers would have to secure adequate ancillary services subject to the prevailing terms of transmission standards and existing agreements where they exist, but customers would not be obligated to purchase them from B.C. Hydro. A customer not purchasing ancillary services would be afforded less tolerance (i.e., narrower band) on imbalances than a customer who purchased Load Following services bundled in Schedule 2002.

4.1.2 Ancillary Services-Schedule 2002

B.C. Hydro bundled three services: Load Following, System Protection, and Reactive Power/Voltage Control and offered them under a single tariff. B.C. Hydro provides Load Following Services to balance supply resources with load, continuously and automatically, by changing the output of on-line resources to match moment-by-moment changes in load (Exhibit 1A, p. W-E-3). If there are unscheduled outages of transmission or interruption of generation supply, System Protection Services (Operating Reserve) are necessary to maintain the integrity of transmission facilities according to criteria that are appropriate for a region. B.C. Hydro complies with the North West Power Pool's criteria of a 5% reserve margin for hydroelectric plants and a 7% reserve margin for thermal plants (Exhibit 1A, p. W-E-3). For Reactive Power/Voltage Control Services, B.C. Hydro operates certain generation facilities, as well as dispersed static facilities, to produce or absorb reactive power to maintain transmission voltages within acceptable limits in the region.

To price the bundled services in Schedule 2002, B.C. Hydro simply converted FERC's suggested charge to Canadian dollars (Exhibit 8) using an exchange rate of $.75 US = $1.00 CDN. The resulting rate is 0.13¢ CDN per kWh of energy delivered under Rate Schedules 2000 or 2001 (Exhibit 1A, p. W-E-1-1). The Utility argued that this rate is appropriate because B.C. Hydro lacks the detailed costing information necessary to develop an unbundled rate any further. When requested, B.C. Hydro responded with preliminary estimates for the cost of load following, operating reserve and generation reactive power/voltage control (Exhibit 1B, BCUC IR1, Q-57-1-4). The cost estimates are .054¢/kWh for operating reserve and .021¢/kWh for load following. No estimates were offered for generation shedding, dispatch for voltage stability or for reactive power/voltage control. Given the uncertainties of cost information, B.C. Hydro argued that the .13¢/kWh charge is appropriate.

In final argument, WKP requested the Commission to direct B.C. Hydro to unbundle Ancillary Services further and derive separate cost estimates for each individual service (T: 2728). Although WKP recognized that B.C. Hydro may require additional time to unbundle and determine costs for each service, WKP's witnesses testified that they did not believe that it would be an insurmountable task (T: 2339). However, WKP did not specify to which ancillary services it would like access on an unbundled basis. Similarly, the Industrial Customers argued that it appeared that the Ancillary Services offered by B.C. Hydro are more expensive than similar services offered elsewhere and requested that B.C. Hydro be required to offer a full range of ancillary services at market-based prices (T: 2813). In response, B.C. Hydro stated that, where a customer does not require all the bundled components, it would be willing to negotiate an appropriate rate for further unbundled services (T: 2562).

B.C. Hydro has not unbundled scheduling and dispatch services as a separate tariff, but rather includes these services, at no additional cost, to customers purchasing transmission services. FERC's suggested generic tariffs in the NOPR do not include a separate charge for scheduling and dispatch (Exhibit 8, p. 300). Scheduling is the control room procedure used to establish a predetermined use of generation resources and transmission facilities to meet anticipated load. Dispatching is the control room operation of all generation resources and transmission facilities on a real-time basis to meet load within the service territory (Exhibit 8, Appendix B, Original Sheet No. 77).

4.1.3 Commission Determinations

The Commission is not convinced that the difficulties associated with determining the cost of ancillary services warrant a departure from a cost-based method of rate determination.

Therefore, the Commission directs B.C. Hydro to refile an Application with rates for Ancillary Services based on an estimation of costs by January 1, 1997.

At the present time, the Commission does not require any further unbundling of these services, nor does it require the unbundling of Scheduling and Dispatch Services. The Commission finds all other Terms and Conditions under Schedule 2002 acceptable.

The Commission determines that if a customer wishes to exclude any single service from the bundled package in Schedule 2002, B.C. Hydro must be willing to bring before the Commission an unbundled rate based on costs at that time.

4.1.4 Loss Compensation-Schedule 2003

Loss Compensation Services are energy and capacity additions necessary to cover losses over B.C. Hydro's transmission system. B.C. Hydro's unbundled Loss Compensation Service proposal contains substantially different conditions than those suggested by FERC in the NOPR.

Schedule 2003 contains two elements: a capacity charge and an energy charge. The capacity charge is based on the reserved capacity for Point to Point Services or billed kW for Network Services, multiplied by an estimated loss factor. The minimum term of the Capacity Charge is the shorter of 12 months or the contract term on a take or pay basis. B.C. Hydro will determine the estimated loss factor in advance by the locations of the generators and loads. The energy charge is a variable charge per kWh of delivered energy net of losses.

In final argument, B.C. Hydro stated that the take or pay restrictions on the capacity charge are necessary for administrative ease and to meet planning requirements. Specifically, the Utility argued that, to set aside capacity to cover losses based on contract requirements, Power Supply must be able to consider the contract requirements in planning generation capacity requirements (T: 2563).

With respect to the loss factor, B.C. Hydro proposes to apply an incremental loss factor for the first four years of the contract and apply average losses thereafter. The incremental loss factor will be calculated using power flow simulations and will be based on the differences in power flows between a base case and a change case that includes the additional transaction (Exhibit 1B, BCUC IR1, Q-28-8). Loss factors for both high and low load hours will be posted seasonally to an electronic Bulletin Board. For customers taking Point to Point Service, loss factors will be calculated for all requested point of receipt/point of delivery pairs. For Network Service, customers will be charged for average losses between all points of receipt and delivery. B.C. Hydro estimates its average system losses will vary between 5% and 9%.

Most intervenors agreed with B.C. Hydro's proposal to use estimated incremental loss factors between points of delivery and receipt (T: 2709). However, there was concern over limiting the use of incremental losses to only four years, the absence of credit or compensation when a transaction results in a reduction in losses, and the indices used to determine the capacity and energy charges.

B.C. Hydro submitted that it is appropriate to charge customers incremental losses for the first four years of a contract and average losses thereafter for efficiency and fairness reasons. In the Application, B.C. Hydro specified the following principles (Exhibit 1A, p. W-P-GDM-2):

- captive customers should not bear the increases in losses from short and medium term transactions;

- transmission customers who want to wheel from the same points of receipt to the same points of delivery should have the same loss treatment; and

- after a certain amount of time, a new transmission customer should be treated the same as captive customers.

In final argument, IPES argued that there is no valid reason for limiting the use of incremental losses to four years (T: 2709). Indeed, B.C. Hydro witnesses agreed that there is "... no magic behind the four years. It's a trade-off number and it's to try and balance efficiency versus some sort of ease of implementation and fairness." (T: 1072).

In cross-examination, IPES questioned whether the proposed loss provision leads to the same treatment for customers who have the same receipt and delivery points but whose contract duration is different. B.C. Hydro witnesses agreed that, under the Application, if a customer contracts for eight years, the customer would be charged system average losses after the fourth year; however, if the customer contracts for an initial four years and then recontracts for an additional four years, the customer would be charged incremental losses for the entire eight years (T: 116). Mr. Dobson-Mack, a witness for B.C. Hydro, agreed that there may be a problem with the way the contract is structured, but noted that there may be risks associated with taking contracts on a four-year basis (T: 1073).

IPES also suggested that it is not appropriate to withhold credits for counterflow transactions which reduce system losses. B.C. Hydro argued that it is inappropriate to offer such credits because all transactions cause losses, when viewed in isolation (Exhibit 1A, p. W-P-GDM-4). However, Mr. Fussell, a witness for B.C. Hydro, agreed that given the existing system the benefits of specific counterflow transactions would be captured by all B.C. Hydro customers (T: 1074).

As explained in Chapter 3 of this Decision, B.C. Hydro proposed energy and capacity charges that are market based. Specifically, B.C. Hydro indicated that its loss compensation charge would be the higher of: (1) the marginal running cost of B.C. Hydro's generating plants, including opportunity cost as determined by the ability of the B.C. Hydro system to store energy for a later, more beneficial use; (2) the cost of importing from other systems; or (3) the price others are willing to pay (Exhibit 1B, BCUC IR1, Q-38-2).

B.C. Hydro did not identify how it will determine the marginal running cost, what index it will use as the cost of importing, or how it will determine the price others are willing to pay. Neither did B.C. Hydro specify whether it would use the same indices for both capacity and energy charges.

Counsel for Commission staff questioned B.C. Hydro as to whether the Utility would consider using Powerex prices as an index for energy prices in a similar way to that which is being proposed in the Industrial Services Option Application. In its final argument, B.C. Hydro responded that it is willing to use "... Powerex prices on the understanding that Transmission customers would be purchasing firm energy and that B.C. Hydro would only offer loss compensation when it has sufficient capacity and energy available." (T: 2563).

4.1.5 Commission Determinations

The Commission directs the Utility to eliminate the asymmetric treatment of reduced losses and requires the utility to compensate a wholesale transmission customer if it can be shown that losses on the system are reduced because of the customer's transaction.

The Commission does not accept that loss factors based on incremental losses should be limited to four years, a term that B.C. Hydro admits was chosen arbitrarily. In the Commission's judgment, B.C. Hydro has failed to prove that the nature of the service changes after the fourth year. **Therefore, the Commission directs the Utility to eliminate this condition and estimate the losses for wholesale transmission based on an Incremental Loss Factor, updated on an on-going basis.**

As indicated earlier, B.C. Hydro agreed to index the loss compensation charges to Powerex prices on the condition that it would only offer loss compensation services when it has sufficient capacity and energy available. This response leaves the impression that the Utility would not offer loss compensation services on a firm basis if using Powerex prices.

In the Commission's judgment, the suggestion to use Powerex prices to price losses does not differ materially from B.C. Hydro's options 2 and 3 since Powerex buy and sell prices would be likely candidates to use for determining the cost of importing energy and capacity from other systems or for determining the price others are willing to pay for incremental energy and capacity.

Moreover, the design of the rate with a take or pay capacity charge (effectively a fixed charge) ensures recovery of generation capacity costs. Therefore, in the Commission's judgment, the Powerex price for interruptible energy is an appropriate index to use for pricing energy for firm loss compensation services.

Based on the evidence, the Commission is not satisfied that there is sufficient clarity regarding the indices to accept the loss compensation schedule in the Application. The Commission directs B.C. Hydro, as part of the September 1, 1996 filing, to submit for approval the indices it intends to use for the price of capacity and for the price of energy.

Until such approval is given, the Commission will allow B.C. Hydro to continue using the approved interim schedule, provided that the Utility posts the prices for capacity and energy that it is currently using on the electronic bulletin board along with the Incremental Loss Factors.

4.2 Energy Imbalance Charges

4.2.1 Description and Discussion of Proposal

A negative energy imbalance occurs when load under contract from a specific generator exceeds the generator's deliveries into the system, after adjustment for energy losses. B.C. Hydro proposes that when this occurs, B.C. Hydro Power Supply will supply the required incremental energy and charge for the service according to a clause contained in both the Point to Point and Network Services schedules. The exact wording of the clause was modified over the course of the hearing with B.C. Hydro's final position provided in Exhibit 25, but includes penalties for negative imbalances which exceed specific limits (T: 2552).

B.C. Hydro proposes to allow customers purchasing Ancillary Services under Schedule 2002 a 5% cumulated imbalance carry forward from month to month (the billing period) and a 10% hourly imbalance. Proposed charges for negative imbalances beyond the 10% hourly limit and the 5% billing period limit are:

- 2.599 cents per kWh for electricity required to reduce an hourly negative imbalance to 10%;

- 2.599 cents per kWh for electricity required to reduce the cumulated negative energy imbalance determined at the end of the billing period to 5%; and

- 7.401 cents per kWh for electricity required to reduce the cumulated negative energy imbalance determined at the end of the billing period to 10%. (Exhibit 25)

In the absence of other agreements (e.g., WSCC rules, etc.) B.C. Hydro proposes to charge customers not purchasing Ancillary Services 10.0 cents per kWh when the imbalance exceeds 1.5% of energy delivered within the hour and month (Exhibit 1A, p. W-D-1-40).

For both those customers purchasing Ancillary Services and those not purchasing Ancillary Services, energy imbalances at the end of the contract period must be zero (Exhibit 1A, p. W-C-1-34).

B.C. Hydro justified the different treatment of these two groups of customers on the grounds that customers who do not purchase Ancillary Services are not paying for load following services and therefore must maintain instantaneous balance between generation and load.

In designing the energy imbalance charge, B.C. Hydro did not follow the FERC NOPR. The FERC NOPR suggests that imbalances outside a 1.5% band, on an hourly basis, be subject to a charge of US 10 cents/kWh (Exhibit 8, p. 300). FERC also proposed to settle imbalances within the band with energy in kind or at the actual incremental cost of the energy provided and positive imbalances at the actual decremental cost.

B.C. Hydro did not propose to grant a credit for positive energy imbalances outside the allowable band. Mr. Fussell stated that it is not clear that there is any benefit to B.C. Hydro or its customers if a transmission customer provides more energy than specified in the transmission contract (T: 1627 and 1628). Indeed, B.C. Hydro indicated that when a transmission customer supplies extra energy into the system, it results in B.C. Hydro Power Supply having idle generation, which increases the costs to customers who pay the bundled rate (T: 2552). As a result, B.C. Hydro argued that the energy imbalance penalty is necessary to encourage customers to predict their needs accurately.

With respect to negative imbalances, B.C. Hydro stated that the energy imbalance service is not intended to be a standby service so that the inclusion of penalties is appropriate. Specifically, B.C. Hydro equated the energy imbalance service to load following and held that if wholesale transmission customers are going to incur large swings in load, B.C. Hydro Power Supply would have to carry additional load following generation.

IPES argued that there is no need for such restrictive provisions and that the penalties imposed do not reflect the costs to B.C. Hydro caused by imbalances. IPES claimed that the energy imbalance provisions discriminates against small suppliers who do not have the range of resources to protect against imbalances at all times, or the scale of operations to acquire standby service from third parties at competitive rates. IPES recommended that B.C. Hydro be directed to develop energy imbalance provisions based on costs and that, unless B.C. Hydro can demonstrate extraordinary planning costs, energy imbalances be charged or credited at the prices at which B.C. Hydro is willing to make power available to its domestic customers through the recently filed Industrial Service Options Application (T: 2711). In response, B.C. Hydro stated that these prices do not include the generation capacity cost necessary to follow load and balance the system so that the recommendation that these prices be used for to charge for energy imbalances is inappropriate.

4.2.2 Commission Determinations

Based on the evidence and argument presented, it is the Commission's judgment that B.C. Hydro has not sufficiently demonstrated that positive imbalances, at least within a narrow band, should not receive compensation. Furthermore, although the Commission agrees that energy imbalance provisions should not provide customers with incentives to deviate substantially from their specified contract demands for transmission services, it is the Commission's judgment that the proposed provisions are too onerous. Finally, it is the Commission's view that the penalty for imbalances in excess of some specified limit should include a deterrent.

Therefore, for customers purchasing Ancillary Services, the Commission accepts the provisions as set out in Exhibit 25 with the following exceptions:

- **for cumulative positive balances greater than 5% and up to 10%, a credit equal to the Utility's decremental cost of energy, after taking into account the full inconvenience to B.C. Hydro of unanticipated energy supply, for electricity that is in excess of the 5% limit at the end of the billing period. For cumulative positive balances greater than 10% no additional credit will be applied; and**

- **for cumulative negative balances greater than 10%, an energy imbalance charge of 2.599 cents per kWh, plus a 25% penalty, for electricity required to reduce the cumulated negative energy imbalance determined at the end of the billing period to 10%.**

For customers not purchasing Ancillary Services and in the absence of other agreements (e.g., WSCC rules, etc.), the Commission directs B.C. Hydro to apply an energy imbalance charge equal to 2.599 cents per kWh, plus a 25% penalty when the imbalance exceeds 1.5% of energy delivered within the hour and month. No credit is to be applied for positive imbalances.

4.3 Additional Ancillary Services Requested

4.3.1 Description and Discussion of Services Requested

IPES and the Industrial Customers argued that B.C. Hydro's offering of Ancillary Services is incomplete. These intervenors requested that B.C. Hydro be directed to offer standby or backup services, instead of the energy imbalance penalty discussed above, and storage services that would permit customers to shape load (Exhibit 40A, p. 5; T: 2216 and 2217). Both parties argued that these additional services are necessary for fair competition in the wholesale market, an objective identified by B.C. Hydro in the Application, and that these services must be competitively priced if this objective is to be achieved. With the exception of competitive prices, neither party articulated what additional characteristics these services should have to make them superior to the current service offerings.

Similarly, IPABC argued that transmission service should be defined to include access to efficiently priced energy services such as back-up, imbalances storage, shaping storage, etc. (Exhibit 29, p. 2). Dr. Ruff stated that defining transmission service as something separate from the energy market is inconsistent with both the physics and the economics of the interconnected electricity system. He argued that by defining transmission service as something separate, vertically integrated utilities are trying to exclude competitors from the dispatch/spot trading system and capture a large competitive advantage (Exhibit 29, pp. 6 and 7).

In response to these concerns, B.C. Hydro stated that parties are free to make private arrangements with B.C. Hydro for storage (T: 2539) although it is currently done on an *ad hoc* basis rather than through a tariff (T: 505), with the terms and conditions generally not publicly known. In addition, B.C. Hydro stated that the provision of these services through a tariff would act to advance competitors' positions relative to B.C. Hydro's position. The Utility argued that it is not compelled by legislation or regulatory order to make its resources available to its competitors any more than its competitors are compelled to make their resources available to B.C. Hydro. Finally, B.C. Hydro argued that the requested services are related to generation and not transmission and that "... this Commission is not charged with taking steps to regulate competition as amongst generators in British Columbia. Its sole responsibility is to balance the interest of the generators which it regulates with the ratepayers who purchase from them." (T: 2543).

4.3.2 Commission Determinations

Based on the evidence and argument before it, the Commission does not believe that this issue is an integral component of the Wholesale Transmission Services Application. However, this is an issue that B.C. Hydro and the Commission may wish to examine in future as a potential means of making the total B.C. system more efficient.

5.0 TERMS AND CONDITIONS OF TRANSMISSION RATES

Although much of the focus of the hearing concerned the determination of the transmission revenue requirement, as discussed in Chapter 2, and the form of the rates to collect the requirement, as discussed in Chapter 3, several parties expressed concern with respect to certain specific Terms and Conditions proposed by B.C. Hydro for accessing both the Network and Point to Point Services. It was noted that many of the Terms and Conditions contained in the Application mimicked the terms and conditions contained in the FERC pro forma tariffs.

5.1 Eligibility/Availability Conditions

The Application states that wholesale transmission service is available to eligible customers defined as:

(1) B.C. Hydro (for its own Network Service use or Point to Point Service use of its Transmission System);

(2) any other electric utility or any other person generating electric energy for sales to utilities for ultimate consumption within B.C. Hydro's control area (Network Service, Point to Point Service) or for sale in the export market (Point to Point Service); and

(3) any designated agent for an eligible customer (Exhibit 1A, p. W-C-1-8; p. W-D-1-9).

In addition, Schedule 2000 (Network Service) and Schedule 2001 (Point to Point Service) state that wholesale transmission of electricity is only available to other transmission providers if satisfactory reciprocal access is made available to B.C. Hydro on comparable terms and conditions. Further, Schedule 2001 (Point to Point Service) states that eligible customers can only access the Point to Point Service for transmission demand that is in excess of any contract demand specified in any other power purchase agreement or Network Service (Rate Schedule 2000) with B.C. Hydro. Finally, the Application states that any entity not providing electric service to ultimate customers as of November 10, 1995, or not a 'public utility' within the definition of the Utilities Commission Act, is not eligible for service under either of the proposed transmission services.

During the hearing there was significant discussion as to how the eligibility conditions would be applied. ECT Canada stated that the Terms and Conditions should be amended to make clear that an otherwise eligible independent power marketer will be considered an "Eligible Customer". Further, ECT Canada argued that an independent power marketer should not be denied service simply because a party with whom the marketer has transacted owns transmission assets to which B.C. Hydro does not have access (T: 2758). In support of its position, ECT Canada stated that it does not have the power to force other parties to provide reciprocal access, that denial of transmission to independent marketers will reduce system use, and that the clause, as written, will be burdensome, since it will require independent marketers to inform B.C. Hydro of the source of power and intended market for every transaction. Finally, ECT Canada stated that it is unclear that the provision will apply to the B.C. Hydro Power Supply Division ("Power Supply") and it would be unfair to allow Power Supply to carry out a transaction with a party who is not providing reciprocity if the same ability is not extended to independent marketers (T: 2759).

IPES suggested that the proposed eligibility conditions would deny existing wholesale utilities open access since the Point to Point Service is only available for amounts of capacity and energy in excess of existing contract demand (T: 2691). Similarly, the Industrial Customers took exception to the requirement that a current customer must use their full contract demand before accessing wholesale transmission service. The Industrial Customers argued that this requirement is effectively an attempt to change retroactively the terms of the electricity sales agreements with the existing wholesale customers and that if B.C. Hydro wishes to make changes to those agreements, it should be done in a separate proceeding and not in conjunction with the current application.

In response to these concerns, Mr. Harrison, a policy witness for B.C. Hydro, indicated that where a customer has a contract for service which allows sufficient flexibility for the customer to take wholesale transmission services, the Terms and Conditions associated with the Wholesale Transmission Services would not preclude the customer from doing so (T: 220), provided other requirements, such as the reciprocity conditions are met. In addition, B.C. Hydro indicated that it would allow either of its two existing wholesale customers, WKP and New Westminster, to leave their existing contracts entirely and contract instead for wholesale transmission services under the proposed tariffs, within 60 days of the issuance of the BCUC's Decision respecting this Application (T: 1561).

In response to this proposal, New Westminster indicated that 60 days is insufficient time in which to consider its options (T: 1928). Furthermore, New Westminster indicated that it does not think its current contract prevents it from taking advantage of other opportunities (T: 1935). Finally, New Westminster expressed concern about the economic viability of wholesale transmission at the proposed rates (T: 1949).

With respect to the prohibition against service to new municipal utilities, B.C. Hydro indicated that it has been included "... to prevent the formation of municipal utilities purely for the purpose of allowing retail customers to have access to the proposed rates." (Exhibit 1B, BCUC IR1, Q-15). However, Mr. Harrison acknowledged that if a new municipal utility is formed for legitimate reasons, B.C. Hydro would consider providing it with wholesale transmission service. Mr. Harrison indicated that it would be entirely within B.C. Hydro's discretion whether or not to seek an amendment to the proposed tariff. (T412).

The Commission accepts the eligibility conditions put forward by B.C. Hydro but directs the Utility to make clear that the definition of an Eligible Customer includes otherwise eligible independent marketers. The Commission confirms that, where an independent marketer has a transaction with an entity that owns transmission assets, those assets must be available to B.C. Hydro on a reciprocal basis. If this were not the case, transmission owning entities could use independent marketers to circumvent the reciprocity requirements imposed on them directly.

The Commission confirms that where existing contracts allow customers access to alternate supplies, nothing in the Network Service or Point to Point Service tariffs will be seen as abrogating this right. Further, the Commission accepts the inclusion in the tariff of the restriction on service to new municipal utilities; however, the Commission will be vigilant in ensuring that this provision is not used to restrict service to legitimate claimants.

5.2 Stacking Provisions

As indicated above, Schedule 2001 states that Point to Point Service is available only for the amounts of capacity and energy in excess of Network Service, taken under the terms of Rate Schedule 2000, with B.C. Hydro. B.C. Hydro indicated that this provision, which was described as effectively "stacking" the Point to Point Service on top of the Network Service (T: 416), is required in order for the Utility to achieve its revenue requirement, since the Point to Point Service rate is lower than the Network Service rate (Exhibit 1B, BCUC IR1, Q-18). If the order of service were to be reversed, B.C. Hydro indicated that both the Point to Point Service and Network Service rates would need to be redesigned and that both sets of rates would need to increase since the billing determinants would change (T: 1585).

The Commission accepts the stacking provisions as included in the Terms and Conditions associated with Network and Point to Point Services.

5.3 Reassignment Provisions

The Application does not provide for reassignment of Network Service although reassignment of non-recallable Point to Point Service is allowed. B.C. Hydro indicated that the difference in treatment results from the fact that Point to Point Service involves reserved capacity on a defined route between defined points of receipt and delivery while Network Service assumes that transmission can be from a variety of receipt points and/or to a variety of delivery points. B.C. Hydro stated that if a Network Service customer were to reassign its service to a third party, and that party had different points of receipt and delivery, the transmission system limits related to servicing the third party could be different (T: 443).

IPABC raised the question of reassignment of Network Service when an IPP facility changed ownership. B.C. Hydro admitted that they had not considered that specific situation, although Mr. Fussell indicated that he did not see an immediate concern with such reassignment (T: 1160-1162).

The Commission accepts that reassignment of Network Service to most third parties may pose operational problems for B.C. Hydro. However, the Commission can not identify where such problems would occur if an IPP facility changed ownership provided the use of the transmission system did not otherwise change. Accordingly, the Commission accepts the reassignment provisions associated with Network Service subject to a revision to allow for change to IPP ownership.

5.4 Billing Demand Formula

The proposed Network Service tariff contains ratcheted billing demand formula which mimic the ratchets contained in Rate Schedule 1821 and Rate Schedule 3808. Although no ratchet provisions are contained in the FERC pro forma tariffs, B.C. Hydro stated that they were introduced to ensure that customers using the network transmission service made a reasonable contribution towards peak costs (T: 1021).

The Commission accepts the ratchet provisions included in Rate Schedule 2000 (Network Service).

5.5 Net Billing

Section 1.13 of the Terms and Conditions associated with Network Services states that a transmission customer's network load shall not be reduced to reflect any portion of such load served by the output of any generating facilities owned, or generation purchased by, the transmission customer. In prefiled evidence, the Interior Municipal Electrical Utilities ("IMEU") suggested that a credit should be given to customers which have self-generation since the reliability required from the network is reduced whenever a customer has self generation at the load site (T: 540).

In response to this suggestion, B.C. Hydro indicated that it plans to revise the network rate so that it would directly reflect any self-generation and to bill customers only to the extent they were using B.C. Hydro facilities (T: 1023). In the light of this proposal, B.C. Hydro stated that it plans to delete from the Terms and Conditions associated with Network Service, section 5.7 relating to Transmission Customer-owned transmission facilities, since it would no longer be necessary (T: 1710).

The Commission directs B.C. Hydro to revise the Terms and Conditions associated with Rate Schedule 2000 to bill customers only to the extent that the customers are using B.C. Hydro facilities.

5.6 Redispatch

Section 8.2 of the Terms and Conditions associated with Network Service states that B.C. Hydro reserves the right, during any period that a transmission constraint is deemed to exist, to take whatever actions it considers reasonably necessary to maintain system reliability and avoid interruption of service. Such actions may include redispatching resources on a least-cost basis, including reductions in transactions outside of B.C. Hydro's control area, without regard to the ownership of such facilities. Section 8.3 states that where such redispatch procedures are implemented, the total cost impact of the procedures will be determined and B.C. Hydro and the transmission customer will each bear a proportionate share of the total redispatch cost impact based on the ratio of maximum hourly load for the entire month rather than the ratio of loads during the time at which the constraint occurs.

Counsel for the Commission staff suggested that such a cost sharing procedure could act to blunt the signal to redispatch according to least cost. In response, B.C. Hydro agreed that cost-sharing could be done based on the ratio of loads during the specific time that redispatch took place but that it would add to the administrative complexity. Furthermore, B.C. Hydro indicated that in the near term it would probably be looking only at redispatching different B.C. Hydro Power Supply hydro units so that there would not be any effective difference in cost. (T: 1615-1618).

B.C. Hydro noted that a provision in the Terms and Conditions allows transmission customers to audit (at their own expense) particular redispatch events if there is a concern about the procedure. B.C. Hydro agreed that if the redispatch is done on other than an emergency basis and it is found that B.C. Hydro resources have been redispatched in preference to lower cost alternatives, the customer should not pay the cost of the audit (T: 1620).

B.C. Hydro testified that it had not considered alternatives to an audit or the possibilities of imposing penalties where inappropriate redispatching may have taken place. Similarly, B.C. Hydro indicated that it had not examined the possibility that the holder of non-recallable service might be willing to accept compensation for voluntary curtailment of service at a cost to B.C. Hydro which might be less than the cost of redispatch. Although B.C. Hydro saw complexities in such an arrangement that might be difficult for an operator to manage in a short time frame, it agreed that if an advantage is seen for such an arrangement, it might be an option for future consideration (T: 1626).

The Commission directs B.C. Hydro to amend the Terms and Conditions associated with redispatch to reflect usage during the specific hours for which the redispatch took place. The Terms and Conditions should also be amended to show that where an audit shows that B.C. Hydro resources have been redispatched in preference to lower cost alternative, for other than emergency reasons, the cost of the audit shall be borne by B.C. Hydro.

5.7 Right of First Refusal

As indicated earlier, Point to Point Service customers are allowed to reassign their wholesale transmission capacity rights to others. However, under the Terms and Conditions proposed with this service, B.C. Hydro has a right of first refusal. A number of intervenors questioned the fairness of such a policy, which B.C. Hydro justified on the grounds that it prevented speculation and hoarding.

In response to these concerns, B.C. Hydro agreed to reconsider the need for the provision. B.C. Hydro stated that its primary need is to be informed of the loads which are going to be placed on the system. As a result, B.C. Hydro needs to know who has the Point to Point Service at any point in time to assure system reliability. B.C. Hydro stated that it does not wish to encourage a speculative market in transmission but, on review, believes that the take or pay provision connected with Point to Point Service would avoid that in most circumstances. Accordingly, B.C. Hydro concluded that a notification provision when transmission capacity is transferred is sufficient provided that after a year or two of experience, if it found there were abuses it may wish to revisit the right of first refusal at that time. (T: 1564).

The Commission directs B.C. Hydro to replace the right to first refusal contained in the Terms and Conditions with a notification requirement.

5.8 Interruption of Recallable Service

The Application states that short-term Point to Point Recallable Service may be interrupted at any time for any not unduly discriminatory reason, including "... the emergence of other transactions more beneficial to B.C. Hydro." (Exhibit 1A, p. W-C-1-10). B.C. Hydro stated that more beneficial transactions will be assessed from the point of view of the B.C. Hydro Transmission and Distribution Division ("T&D") only and are defined as any non-recallable service regardless of who has purchased the service (T: 1305).

BPA stated that the provision is not acceptable since it gives no indication of how B.C. Hydro will decide which recallable transactions will be interrupted in favour of a non-recallable transaction. BPA expressed concern that this could allow T&D to favour one party over another or a particular recallable transaction of a party over another. BPA suggested that this ability could be used to give an unfair advantage to B.C. Hydro Power Supply.

To overcome this problem, BPA proposed that B.C. Hydro be required to forecast the amount of non-recallable transmission it thinks it can sell and stand by the forecast. BPA reasoned that this provides certainty to the market and is unlikely to drive up artificially the need for non-recallable transmission services. BPA recommended that the Commission require B.C. Hydro to eliminate the ability of T&D to curtail recallable transmission transactions for economic reasons and eliminate the restrictions on assignment of contracts of less than one month (T: 2650).

In response to this concern, B.C. Hydro indicated that recallable transmission will be recalled on a last contracted first recalled basis and has no objections to tariff amendments which make this clear (T: 2878).

The Commission agrees with BPA that the current provisions with respect to recallable service need to be amended to clarify how recallable transactions will be interrupted when a non-recallable transaction requires transmission service so that the potential of discriminatory treatment is avoided. However, in the Commission's judgment, the solutions proposed by BPA are unnecessarily restrictive and could lead to the perverse result in which recallable transmission is given priority over non-recallable transmission simply because the recallable request occurs earlier.

Accordingly, the Commission directs B.C. Hydro to amend the Terms and Conditions associated with recallable transmission to make clear that recallable transmission will be interrupted on a last contracted first recalled basis.

6.0 IMPLEMENTATION ISSUES

6.1 The Relationships of B.C. Hydro Transmission and Distribution to B.C. Hydro Power Supply and Powerex

During the course of the hearing, several parties expressed concern about the relationships between B.C. Hydro T&D, B.C. Hydro Power Supply and Powerex. Generally, participants expressed concern as to whether the wholesale transmission service tariffs would be applied by T&D to Power Supply and Powerex in the same manner as to non-B.C. Hydro users of the transmission system. In other words, T&D might use its position as the monopoly provider of transmission service to enhance Power Supply's marketing position or that of its marketing agent, Powerex.

In its evidence, B.C. Hydro indicated that its Application met what was occasionally referred to during the hearing as "the Golden Rule of Comparability", namely that the proposed tariffs offer third parties access on the same or comparable basis, and under the same or comparable Terms and Conditions, as B.C. Hydro's own use of its system (T: 64). Mr. Harrison stated that this is the most important rule with respect to the provision of wholesale transmission (T: 278).

Accordingly, B.C. Hydro stated that it charges itself the Network Service rate for its sales to its own domestic customers and the Point to Point Service rate for its export sales, as these rates would be applied to others. In regard to exports, Mr. Harrison stated that B.C. Hydro sells system surplus to Powerex at the border and charges itself either the recallable or non-recallable Point to Point Service rate depending on the nature of the service requested by Powerex (Exhibit 1A, p. W-I-DAH-10). However, Mr. Harrison also indicated, that while the rates contained in the wholesale transmission service tariffs are applied by T&D to Power Supply, not all the provisions of the tariff are applied (T: 427). For example, although T&D intends to require a contract demand from Power Supply and apply the ratchet provisions associated with contract demand, Mr. Garnett, a witness for B.C. Hydro, expressed reservations about applying the energy imbalance provisions since it is Power Supply who supplies the energy imbalance service through T&D (T: 1602-1604).

With respect to the concern that Power Supply and/or Powerex might receive an advantage from the fact that these entities are part of the same corporate entity as T&D, B.C. Hydro rejected the proposition that de-integration of the Utility is necessary and instead suggested that functional separation of the Utility's various components is sufficient (Exhibit 1A, p. W-J-YM[P1]-2). In addition, Mr. Mansour indicated that B.C. Hydro is developing a protocol to ensure that Power Supply is not afforded any undue advantage (Exhibit 1A, p. W-J-YM[P1]-3). The protocol consists of a plan for separation of function of personnel between T&D, Power Supply and Powerex and the development of a Code of Conduct for T&D

personnel. The relationships between T&D and Power Supply and between T&D and Powerex are defined in detail in a draft agreement between T&D and Power Supply (Exhibit 13) and in the Powerex Transfer Pricing Agreement (Exhibit 10).

The Application identified several important elements in the plan for functional separation. These include the physical separation of the personnel of Powerex, Power Supply and Grid Operations (a part of T&D), separation of the data bases common to Powerex, Power Supply and T&D, and having Grid Operations undertake the accounting for the Control Area instead of Powerex (Exhibit 1A, pp. W-R-DAC-2 and 3). As a result, under the new formulation, T&D will have sole responsibility for transmission and dispatch, instead of sharing the responsibility with Powerex as was the case previously.

Several parties questioned whether the physical separation of personnel would be sufficient to impede the flow of information between T&D and the other arms of B.C. Hydro. Mr. Cave, a witness for B.C. Hydro, indicated that Grid Operations staff would have no more contact with the other arms of B.C. Hydro than they would with any other users of the system. For example, he noted that Powerex and Power Supply will supply T&D with necessary energy supply schedules but so will IPPs who plan to use the system (T: 1478). As well, Mr. Cave testified that, in future, the only contact between the control room at the system control centre and Powerex or Power Supply staff will occur when Powerex or Power Supply are requesting to purchase transmission (T: 1314 and 1315). Mr. Harrison stated that senior managers in T&D, who participate in the broader decision-making at B.C. Hydro, will not have day-to-day access to information about daily dispatch decisions (T: 148 and 149).

With respect to the separation of databases, B.C. Hydro indicated that Power Supply and Powerex would have no information not made available to all users of the system through the electronic bulletin board, except insofar as such information pertained directly to the use of the system by Power Supply or Powerex. Likewise, other users of the system would have the ability to access selectively the new data for information that pertained directly to their use (T: 1323).

With respect to the Code of Conduct, Mr. Cave indicated that it is focused on Grid Operations employees who have access to confidential, commercially sensitive information (T: 1374) but that it has been circulated to each and every person in the T&D group and that informal discussion on the Code has been held with many of the staff (T: 1504). He stated that the primary goal of the Code is to maintain confidential all sensitive information that, if divulged, might unfairly advantage competing electricity marketers (T: 1321).

Mr. Cave stated that the Code of Conduct was in addition to the current B.C. Hydro Conflicts Policy, but added that he did not believe there would be any inconsistency between the two policies (T: 1375). Mr. Cave stated that he believed the Code to be enforceable (T: 1386) and that each manager in Grid

Operations would have responsibility for enforcement. If an employee did have concerns about the operation of the Code, it would be the employee's specific manager who would initially address the concerns. However, in the final analysis, any interpretation of the Code would be the responsibility of the Manager of Grid Operations and Interutility Affairs.

IPABC suggested that, despite efforts by T&D to keep transmission information private, there are numerous ways in which leakages could occur. For example, IPABC noted that, under the terms of the tariffs, potential users of the system can request B.C. Hydro to undertake transmission studies. Accordingly, IPABC suggested that parties with 'deep pockets' could obtain more knowledge about the system than parties who are more financially constrained. IPABC suggested that the solution is to make all transmission information available at nominal cost (T: 2604). In addition, IPABC requested that the Commission direct B.C. Hydro to make all the Terms and Conditions in the tariff directly applicable to its own use of the system (T: 2610).

ECT (Canada) stated that it is "somewhat reassured" by B.C. Hydro's commitment not to allow Power Supply to produce at a loss in order to permit Power Supply to make a contribution to T&D profits. However, ECT Canada suggested that a mechanism is needed which would allow interested parties to ensure that inappropriate transactions have not taken place (T: 2761). Similarly, the CAC (B.C.) et al. expressed concerns that the functional separation and Code of Conduct are insufficient to prevent self-dealing between the various arms of B.C. Hydro. Accordingly, the CAC (B.C.) et al. suggested that B.C. Hydro carry out regular audits of its Power Supply and Powerex sales to ensure that generation is not being made available below operating costs (T: 2629). Furthermore, the CAC (B.C.) et al. suggested that reports of the audits should be made to the Commission.

Similarly, BPA expressed concern that Powerex might sell at a price which does not fully reflect the cost of transmission (T: 2642). BPA suggested that all transactions by Powerex or Power Supply be booked separately on a transaction by transaction basis to ensure transparency (T: 2648).

In response to this suggestion, B.C. Hydro stated that implementation of BPA's suggestion would take away Power Supply's ability to aggregate contracts and its ability to use the transmission system efficiently. This would reduce Power Supply's ability to compete in the market, since other transmission customers, including BPA would retain the ability to aggregate (T: 2856).

6.2 Commission Determination

Based on the evidence and argument before it, the Commission directs B.C. Hydro to apply all the Terms and Conditions of the Network and Point to Point Services to itself except where to do so is patently unreasonable. In those cases, where B.C. Hydro feels the application is unreasonable, B.C. Hydro is directed to apply to the Commission for relief from the provisions. The Application should state specifically which conditions should not apply and why they should not apply.

DATED at the City of Vancouver, in the Province of British Columbia, this 26th day of June, 1996.

Original signed by:
Dr. Mark K. Jaccard

Original signed by:
Kenneth L. Hall, P.Eng.
Commissioner

Original signed by:
Dr. Paul G. Bradley
Commissioner

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IN THE MATTER OF
the Utilities Commission Act, S.B.C. 1980, c. 60, as amended

and

An Application by British Columbia Hydro and Power Authority
for Approval of an Application for Wholesale Transmission Services

BEFORE:	M.K. Jaccard, Chairperson; and) K.L. Hall, Commissioner; and) P.G. Bradley, Commissioner)	June 25, 1996

O R D E R

WHEREAS:

A. On November 10, 1995 British Columbia Hydro and Power Authority ("B.C. Hydro") filed an application to provide wholesale transmission services within its service area ("the Application"); and

B. The Commission, by Order No. G-109-95, approved the applied for tariffs on an interim basis, effective January 31, 1996, and issued a Regulatory Timetable which set down the public hearing to commence March 4, 1996; and

C. The Commission heard evidence and argument regarding the Application at the hearing.

NOW THEREFORE the Commission orders B.C. Hydro to comply with the Commission's Decision.

DATED at the City of Vancouver, in the Province of British Columbia, this 25th day of June, 1996.

BY ORDER

Original signed by Author

Dr. Mark K. Jaccard
Chairperson

APPEARANCES

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D. AUSTIN	Independent Power Association of British Columbia
D. CRAIG	Consolidated Management Consultants
M.P. DOHERTY J. QUAIL	The Consumers' Association of Canada (B.C. Branch) British Columbia Old Age Pensioners' Organization Council of Senior Citizens' Organizations of B.C. Federated Anti-Poverty Groups of B.C. Senior Citizens' Association of B.C. West End Seniors' Network
G. FUQUA	Bonneville Power Administration
J. CAMPBELL	Himself
C. REARDON D. FOLEY	British Columbia Energy Coalition
C.B. JOHNSON	Inland Pacific Energy Services Ltd.
R. HOBBS	West Kootenay Power Ltd.
C. CALGER P. MAQUIRE	Enron Capital & Trade Resources Canada
R.J. MCDONELL J. JANSEN	Grid Company of Alberta Inc.
J.D.V. NEWLANDS	Fording Coal Ltd.
R.B. WALLACE	Council of Forest Industries of British Columbia Mining Association of B.C. Electro-Chemical Producers
R. TARNOFF	Natural Resources Industries
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T. BERRY	Consultant
ALLWEST COURT REPORTERS LTD.	Court Reporters & Hearing Officer

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