Janet Fraser
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

December 23, 2011

Ms. Alanna Gillis
Acting Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Gillis:

RE: British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
Application to Suspend Retail Access Program

BC Hydro hereby applies to the BCUC to suspend the Retail Access Program. A draft Order is attached at Appendix A. This application is further to earlier BC Hydro correspondence on this topic dated February 1, 2011 and May 20, 2011, attached at Appendices B and C. BC Hydro seeks the relief requested herein pursuant to the *Utilities Commission Act,* sections 58-61.

As indicated would happen in the earlier correspondence, BC Hydro has undertaken a review of its Retail Access Program, including customer consultation. In consequence of that review, BC Hydro has concluded that the Retail Access Program is fundamentally flawed; that remedying those flaws is inappropriate at this time; and that the preferred course of action is to suspend the program. Note that no customer is now or has ever been a participant in the Retail Access Program.

At Appendix D is a November 21, 2011 letter from the Honourable Rich Coleman, Minister of Energy and Mines, to Mr. Dan Doyle, Chair of BC Hydro's Board of Directors (**Minister's Letter**). The Minister's Letter indicates the Province's support for BC Hydro's application, pending a review of industrial electricity policy over the next two years.

The balance of this application provides:

1. background to the Retail Access Program;
2. a description of the Program by reference to the application in which its initial approval was sought, and the tariff documents that constitute it;
3. an explanation of the fundamental deficiencies in the Program, and why suspending it is the preferred course of action; and

4. a proposal regarding the review process for this application.

1. Background

Retail access refers, generically, to the ability of a customer of a utility to take some or all of its electricity supply from competitive third-party service providers.[1] Retail access was, in this generic sense, a dominant electricity policy issue in British Columbia through most of the 1990s and the early part of the last decade, being the subject or driving force, in whole or part, of at least ten different proceedings.[2]

At a high-level, the policy debate regarding retail access was, and remains, the extent to which costs and benefits of retail access, and the associated risks, ought to be allocated between those customers who take some or all of their service to market (participating customers) and those who remain with a bundled utility service provider (non-participating customers). From a non-participant's perspective, retail access, in this generic sense, has the potential to provide long term benefits through the deferral of infrastructure investments, even though there may be short-term costs arising from lower revenue from participants. From the perspective of participating customers, retail access may be attractive when market or third-party supplies of electricity service are available at rates lower than embedded cost rates of the utility, with the potential for accompanying market price, volume and supply risk. In the 1990s it was thought that market prices would be less than BC Hydro's embedded cost rates, in the context of the then-evolving wholesale markets; it is currently true of BC Hydro rates in a limited number of circumstances; and it may in the future be true for BC Hydro rates in a broader range of circumstances than is currently the case.

Consideration by BC Hydro of these issues early in 2011, within the context of the existing Program and for the first time since the Program was initiated, suggested that the Program was unbalanced in favour of participants in current market circumstances, and led to the informal suspension of the Program on February 1, 2011 (Attachment B).[3]

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1 Retail access is different than "open access". The latter refers to a type of wholesale transmission service characterized by tariffs available on a non-discriminatory basis. However, open access wholesale transmission service is, generally, a condition of retail access.

2 British Columbia Electricity Market Review (1995); BC Hydro's Wholesale Transmission Service proceedings (1996 and 1998); BC Hydro's Real Time Pricing application (1996); British Columbia Task Force on Market Reform (1998); West Kootenay Power's Transmission Access and Access Principles proceedings (1999); BC Hydro's Application for Access Principles for Public, Municipal and Other Utilities (2000); the Task Force and Interim Report regarding Strategic Considerations for a New British Columbia Energy Policy (2001); and the Heritage Contract Enquiry (2003).

3 Consideration by BC Hydro earlier this year of the allocation of costs and benefits under the Retail Access Program was the basis of the current, informal suspension, but is not the basis of this application, as explained in section 3 below.

Appendix E to this application provides summary information regarding potential costs, benefits and risks of retail access and the Retail Access Program.

The Retail Access Program that is the subject of this application had its genesis in the 2002 Energy Plan. Policy action number 14 of the 2002 Energy Plan states as follows:

> Under new rate structures, large electricity consumers will be able to choose a supplier other than the local distributor.

The 2002 Energy Plan had four cornerstones, or high-level objectives, namely "low electricity rates and public ownership of British Columbia"; "secure, reliable supply"; "more private sector opportunities"; and "environmental responsibility and no nuclear power sources". Policy action number 14 regarding retail access was established to serve the objective of increased private sector involvement in provincial energy supply.[4]

Subsequently, retail access was included in the scope of the Heritage Contract Enquiry, conducted by the BCUC between April and October 2003.[5] The Terms of Reference to the Heritage Contract Enquiry required the BCUC to make recommendations to the Province relating to the terms and conditions of retail access for transmission voltage customers, including the "principles… under which large industrial or transmission rate customers wishing to obtain generation from alternate suppliers may decline to obtain service from BC Hydro or may apply to obtain service from BC Hydro thereafter".[6]

The only recommendation made by the BCUC in regard to retail access in the Heritage Contract Report was that BC Hydro should file an application encompassing retail access and industrial stepped rates within 30 days of the BCUC's approval of a new Open Access Transmission Tariff (**OATT**) for the British Columbia Transmission Corporation (**BCTC**).[7] There was no Provincial direction in response to this recommendation,[8] and in the end the application contemplated by the BCUC in the Heritage Contract Report – the Transmission Service Rate (**TSR**) Application – was filed by BC Hydro in March 2005.

The TSR Application was primarily in regard to the TSR stepped rate. However, its scope encompassed a number of other transmission-voltage rates and services, including the then-proposed Retail Access Program. The TSR Application, including the

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4 *Energy For Our Future: A Plan for BC* (November 2002), page 30, extract at Attachment F.

5 *In The Matter of British Columbia Hydro and Power Authority and An Inquiry Into A Heritage Contract for British Columbia Hydro and Power Authority's Existing Generation Resources and Regarding Stepped Rates and Transmission Access – Report and Recommendations* (October 17, 2003, Heritage Contract Report), extracts at Attachment G.

6 Appendix A to Heritage Contract Report, Attachment G.

7 Heritage Contract Report, recommendation number 25, page 80, Attachment G.

8 Heritage Special Direction No. HC2 was issued in November 2003, in response to the Heritage Contract Report, and prescribed most of the high-level rate design parameters of the Transmission Service Rate (**TSR**) stepped rate, but said nothing about retail access.

Retail Access Program proposal, was resolved after one round of information requests and a negotiated settlement, and the settlement agreement was later approved by BCUC Order No. G-79-05. The BCUC made no determinations regarding the Retail Access Program in the Reasons for Decision accompanying Order No. G-79-05, and the only outstanding issue regarding retail access arising from the proceeding was whether transmission voltage customers could, quite aside from the Retail Access Program, take part of their load to markets.[9] The TSR settlement agreement also required a three-year evaluation by the BCUC of the rates and services that arose from the TSR Application, by the end of 2009.[10]

On December 31, 2009,[11] the BCUC submitted its three-year report to the Province regarding the TSR program, including the Retail Access Program.[12] In the Executive Summary, the BCUC noted that:

> The TSR has not facilitated retail access from other electricity suppliers because BC Hydro is the lowest cost electricity provider and sourcing from other suppliers increases a firm's transaction costs and supply risk.

Although BC Hydro's most recent Shareholder's Letter of Expectations, issued in early 2011, includes the following statement:

> "… the Shareholder directs BC Hydro to take the following specific actions: … continue to plan, operate and maintain the transmission system in order to: … continue to enhance open access transmission tariffs that promote private sector opportunities in wholesale electricity supply and facilitate direct purchase of electricity by large users, subject to the approval of the BCUC"[13]

there has been little indication of continued support for retail access at the provincial policy level since the 2002 Energy Plan. Retail access is not mentioned in the 2007

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9 Paragraph 6.c of negotiated settlement agreement, Appendix B to Order No. G-79-05.

10 Paragraph 10 of negotiated settlement agreement, Appendix B to Order No. G-79-05.

11 After the settlement of the TSR Application in 2005, and before the Commission's 2009 TSR Report, retail access came before the Commission again in the December 2005 Transmission Service Outstanding Matters Application, by BC Hydro, for the purpose of clarifying that customers could take part of their load to market.

12 *British Columbia Utilities Commission Report to Government on the British Columbia Hydro and Power Authority Transmission Service Rate Program* (December 31, 2009, 2009 TSR Report, extracts at Attachment H). The 2009 TSR Report was the conclusion of a proceeding that was initiated by a September 30, 2009, report by BC Hydro; information requests on BC Hydro's report, and submissions by various parties.

13 The quoted sentence is at page 4 of the 2010/11 Shareholder's Letter of Expectations, extracts at Attachment I.

Energy Plan;[14] is not listed as one of the "government's energy objectives" in the 2008 amendments to the *Utilities Commission Act*;[15] and is not one of "British Columbia's energy objectives" in the *Clean Energy Act*.[16]

The Minister's Letter, issued on November 21, 2011, makes it apparent that provincial policy regarding retail access is now uncertain, and will be the subject, in part, of a comprehensive industrial electricity policy review by government.

2. Description of Retail Access Program

Retail Access Program in the TSR Application

The Retail Access Program is described at pages 1-36 to 1-43, and page 1-47, of the TSR Application, which are attached as Appendix J. The key elements, as described in the TSR Application, are as follows:

- A participating retail access customer must provide a schedule of energy deliveries from a third–party supplier (page 1-39, lines 24-25; page 1-40, lines 13-14).
- A participating customer continues to be supplied by BC Hydro (page 1-38, lines 17-18), and continues to pay its applicable demand charges (page 1-39, lines 4-6), but is invoiced for its metered load less the energy scheduled for delivery by the third party supplier/participating customer,[17] with an adjustment for losses (page 1-38, lines 24-26; page 1-41, lines 20-23).
- If actual energy deliveries differ from scheduled deliveries BC Hydro will absorb or make–up the difference in real time, but a participating customer must then pay a charge, or receive a credit, equal to the product of the difference and an "imbalance" rate (page 1-38, lines 19-23).
- Energy from a third-party retail supplier/participating customer is treated by BC Hydro as an "integrated network resource" (page 1-37, lines 23-24; page 1-38, lines 10-11 and 16-17).
- A third-party retail supplier/participating customer "must pay for all network upgrade and interconnection costs necessary for it to supply energy to a retail access customer" (page 1-38, lines 11 to 13).
- Supply or credit risk issues associated with the third party supply are "addressed between the customer and the supplier" (page 1-39, lines 2 to 3).

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[14] *The BC Energy Plan: A Vision for Clean Energy Leadership* (February 2007).

[15] *Utilities Commission Amendment Act, 2008*, S.B.C. 2008, chapter 13, section 1.

[16] S.B.C. 2010, chapter 22, section 2.

[17] Which of the third party supplier or the participating customer bears the delivery obligation to BC Hydro is unclear.

- Participating customers are required to stay on the Retail Access Program for a minimum of three years, and must provide notice one year in advance of ending their use of the Program (page 1-43, lines 2 to 8).
- Participating customers must provide notice to BC Hydro by February 15 of a given year, and must have signed a program agreement by March 15 of the year, to use the Retail Access Program for the period commencing on April 1 of the year (page 1-47, lines 5 to 7).

Retail Access Tariff

The specific relief sought by BC Hydro in the 2005 TSR Application in regard to the Retail Access Program was approval of the Retail Access Program Agreement – Tariff Supplement No. 71 (**TS No. 71**); Imbalance Charge for Retail Access – Rate Schedule 1890 (**RS 1890**); and certain retail access provisions in Transmission Service Stepped Rate – Rate Schedule 1823 (**RS 1823**). These three tariff documents are the cornerstones of the Retail Access Program and are attached for convenience, in their current form, at Appendices K, L and M, respectively. In addition, BC Hydro sought approval of related provisions in the Transmission Service Time of Use Rate Schedule 1825 and the Customer Baseline Load Determination Guidelines - Tariff Supplement No. 74. These tariff documents are collectively referred to as the Retail Access Tariff.[18]

The material elements of TS No. 71 are as follows:

- The tariff supplement is in the form of an agreement between BC Hydro and the participating customer. The third party supplier is not expressly a party to the arrangement, despite the description of the Program in the TSR Application, where in some cases the third party supplier would seem to have obligations vis-a-vis BC Hydro.[19]
- Section 1.2 states that TS No. 71 is supplemental to the ESA (Electricity Supply Agreement, Tariff Supplement No. 5), and that the ESA "shall govern the supply of Electricity to the Customer", consistent with the program description in the TSR Application.
- Section 2.1 states that TS No. 71 applies for a minimum three-year term, and that either BC Hydro or the customer may terminate with a one year notice period, consistent with the program description in the TSR Application. There is no express limitation on the right of either party to terminate, other than the notice period.
- Section 3 provides for a list of third party suppliers that the participating customer has contracted with, and the point (**Point of Receipt**) at which a third party "has contracted to deliver Electricity into the BC Hydro system".

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[18] The specific relief BC Hydro seeks in this application encompasses the entirety of the Retail Access Tariff – Refer to draft Order at Attachment A.

[19] See for example page 1-37, lines 4-7; page 1-38, lines 10-13; page 1-38, lines 24-26; and page 1-41, lines 22-23.

- Section 4.1 provides for the provision of information by the customer regarding the third party's delivery schedule ("Gross Scheduled Output", Appendix 1 to TS No. 71) and Appendix 1 is the vehicle by which the participating customer provides information regarding the third party's delivery schedule.
- Section 4.2 prescribes limits on the third party's delivery schedule.
- Section 4.3 provides for the participating customer to substitute a new three-year delivery schedule for one previously provided, with one year's notice.
- Section 5 provides that the tariff supplement is subject to RS 1890, regarding "imbalance charges" – a term not defined or referred to anywhere else in the tariff supplement.

RS 1890 provides as follows:

- It is available to RS 1823 customers who have "entered into a Retail Access Program Agreement" – being those customers who have provided the information regarding a third party's delivery schedule in the form of Appendix 1 to TS No. 71.
- Participating customers are either charged, or credited, an amount that in summary terms equals the product of a rate (in cents/kWh) and the difference between the scheduled energy deliveries implied by the Appendix to TS No. 71 and metered energy deliveries at the Point of Receipt referred to in TS No. 71.[20]

The provisions in RS 1823 regarding the Retail Access Program provide as follows:

Energy Determination under Retail Access:	If the Customer has entered into a Retail Access Program Agreement that is in effect, the quantity of Schedule 1823 energy is defined as the total metered kW.h consumption of the Customer's Plant less the Net Scheduled Output. The Net Scheduled Output is the Gross Scheduled Output adjusted by the Energy Loss Adjustment Factor of 6.28 per cent. The Net Scheduled Output and Gross Scheduled Output are as defined in the Retail Access Program Agreement. If the Net Scheduled Output is greater than the total metered kW.h consumption of the Customer's Plant, then the quantity of Schedule 1823 energy is zero.

The effect of this provision is to require BC Hydro to subtract from the amount of energy delivered to and metered at the customer's facility (not the Point of Receipt), for the purpose of billing under the TSR stepped rate, the product of the scheduled energy deliveries implied by the Appendix to TS No. 71 and (1.0000-0.0628). The 6.28 per cent

[20] Both the scheduled deliveries and the actual deliveries are adjusted by the "Energy Loss Adjustment Factor", set out in RS 1823 and definition section 1 of TS No. 71.

adjustment factor is ostensibly on account of the transmission line losses BC Hydro would incur between the Point of Receipt and the customer's facility.[21]

Unique Aspects of Retail Access Program: Undiminished Supply Obligation and Network Resource

Two elements of the Retail Access Program are particularly noteworthy in the context of this application, namely that the third-party/participating customer supply is treated by BC Hydro as an "integrated network resource",[22] and that BC Hydro's obligation to supply electricity service to participating customers is undiminished. These appear to be unique features of the Retail Access Program, relative to retail access in other jurisdictions.

Regarding BC Hydro's continued supply obligation, nothing in the program description in the TSR Application or in the Retail Access Tariff suggests that BC Hydro's supply obligation to a participating customer is attenuated. Further, BC Hydro's obligation to meet a participating customer's specified contract demand under its ESA [23] with BC Hydro is not reduced by an amount equivalent to the customer's third-party supply, nor is a participating customer relieved of the demand charges under the rate schedule applicable to it. Finally, section 1.2 of TS No. 71 provides that the ESA governs the supply of electricity to the customer. Accordingly, an issue potentially raised by this feature of the Program, but which is not the subject of this Application, is the degree to which non-participating customers might hope to benefit by the deferral of electricity system infrastructure, in light of an undiminished supply obligation by BC Hydro.[24]

Implications of Treating Retail Access Energy as a Network Resource

The treatment of third-party supply as an "integrated network resource" under the Program requires further background explanation, as it is this particular feature of the Program that raises the most difficulties, and in the main, causes BC Hydro to view the existing Program as fatally flawed.

The OATT provides for two types of open-access, non-discriminatory wholesale transmission service: namely Point-to-Point service (referred to as PTP service, under Part II of the OATT) and Network Integration Transmission Service (referred to as NITS, under Part III of the OATT). Under PTP service, an OATT customer may reserve available transmission capacity, and schedule energy deliveries, on specified

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[21] Page 1-42, lines 10-18, of the TSR Application, at Appendix M. Arguably, at least, the loss adjustment factor would seem to be inconsistent with the nature of the network resource designation, as described below. The 6.28 per cent loss adjustment is the same as that set out in Rate Schedule 10 – Real Power Losses, in BC Hydro's OATT.

[22] The receipt of energy by BC Hydro as an integrated network resource is described in the TSR Application, but not mentioned in the Retail Access Tariff.

[23] Electricity Supply Agreement, Tariff Supplement No. 5.

[24] Refer to Attachment E.

transmission paths. Under NITS, an OATT customer may designate a number of generation or supply side resources, and a number of loads, and serve its designated loads with its designated resources without specifying to the OATT service provider specific transmission paths. NITS often provides an efficient way for a utility to meet numerous load obligations from numerous resources. Currently, and when the TSR Application was filed, BC Hydro (in its capacity as a load-serving OATT customer) is a NITS customer of itself (in its capacity as an OATT service provider).[25]

It seems clear that the reference in the TSR Application to "integrated network resource" is a reference to NITS service and the use of the participating customer/third party supply by BC Hydro as a Network Resource under the NITS provisions of the OATT.

Network Resource is defined in the OATT[26] as follows:

> **1.26 Network Resource**
>
> Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Under the OATT, BC Hydro (in its capacity as an OATT customer) may only designate a retail access supply commitment from a participating customer or third party supplier as a Network Resource if:

- An application is made on OASIS[27] to designate the participating customer/third party supply as a Network Resource (section 30.2 of the OATT);
- The application describes, among other things, identification of the control area from which the electricity will originate, and the transmission arrangements on the external transmission system (section 29.2(e) of the OATT); and
- BC Hydro attests, when the application is made, that:

  > (1) the network customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the

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[25] From June 23, 2005 when BCTC's first OATT was approved, to July 5, 2010 when BCTC was integrated with BC Hydro, BC Hydro was a NITS customer of BCTC. Now BC Hydro is both a NITS customer, and the NITS service provider, under the OATT.

[26] Extracts from the OATT are attached at Attachment N.

[27] Open Access Same-time Information System, the system used by BC Hydro in its capacity as an OATT service provider to allow OATT customers to make transmission reservations.

> availability of transmission service under Part III of the Tariff and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.[28]

Following the application for designation of the participating customer/third party supply as a Network Resource, BC Hydro (in its capacity as OATT service provider) would determine whether a system impact study is required and, if so, follow the study procedures prescribed by the OATT, including studies regarding any new facilities required to designate the new supply as a Network Resource (sections 29.2(h), 32 and 32.1 of the OATT).

Further, in Order 890,[29] the Federal Energy Regulatory Commission (**FERC**) stated as follows:

> Network resources cannot be interrupted for economic reasons and third party transmission arrangements to deliver the resource to the network must be non-interruptible.

FERC's requirements that third party transmission arrangements to deliver a resource to the network must be non-interruptible means that firm transmission must be secured to the Point of Receipt by the participating customer or the third party supplier.

A final issue regarding the designation of a participating customer/third party supply as a Network Resource for the purpose of the Retail Access Program arises from section 28.6 of the OATT, as follows:

> **28.6 Restrictions on Use of Service**
>
> The Network Customer shall not use Network Integration Transmission Service for: (i) sales of capacity and energy to non-designated loads; or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System. The Transmission Provider shall specify any appropriate charges and penalties and all related terms and conditions applicable in the event that a Network Customer uses Network Integration Transmission Service or

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[28] Section 2 of BC Hydro's OATT Business Practices regarding designation of Network Resources.

[29] February 16, 2007, at para. 1091. FERC Order 890 provided significantly more clarity on the designation of Network Resources under the NITS provisions of the *pro forma* OATT than had previously been the case; it was issued about two years after the TSR Application was filed.

> secondary service pursuant to Section 28.4 to facilitate a wholesale sale that does not serve a Network Load. All related terms and conditions are specified in Attachment Q-2 and Tariff Supplement No. 3 of the Transmission Provider.

In other words, section 28.6 prohibits the use by BC Hydro of NITS to indirectly provide transmission service to a participating customer or third party.

In summary, the treatment of retail access energy under the Program as an "integrated network resource" implies significant restrictions on the type of third party supply that BC Hydro can accept, and its manner of dealing with such supply.

Conclusions Regarding Description of Retail Access Program

Bearing in mind that BC Hydro's bundled-service supply obligations to a participating customer under the Program are not diminished, and bearing in mind the restrictions on the use of NITS to deliver retail access energy, it is apparent that under the Retail Access Program BC Hydro does not, and indeed may not, deliver a participating customer's energy to the customer`s facility. Instead, under the Program, BC Hydro is simply receiving energy it would not otherwise have received, and paying for that energy, *in effect*, at the applicable bundled-service rate the participating customer is subject to.[30]

Thus, it follows that the Retail Access Program is better understood as a supply side program, rather than a retail access program, in the generic sense of the expression. To BC Hydro's knowledge, no other utility in North America buys wholesale energy, designates it as a Network Resource, integrates it with its other Network Resources to serve its bundled-load customers, and refers to the program as "retail access".

3. Flaws in the Retail Access Program and Reasons to Suspend

The Retail Access Program is deficient in a number of ways, but is fatally flawed insofar as the Retail Access Tariff simply does not effect the Program as it is described in the TSR Application.

Notably, TS No. 71 does not expressly impose any obligations on the participating customer, BC Hydro or the third party supplier; nor does it expressly grant any party any rights. In particular, neither the participating customer nor the third party are obliged to deliver energy to BC Hydro; BC Hydro is not obliged to receive any delivered energy;

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[30] There are no payment provisions *per se* in the Retail Access Tariff in regard to the third party supply, despite the requirement that BC Hydro take title as a condition of Network Resource designation. However, because the customer's RS 1823 metered energy volumes are reduced by scheduled retail access volumes, the customers gets a credit equal to the product of the scheduled energy and the applicable RS 1823 rate.

and nothing is said regarding the transfer of title to any electricity that might be delivered.

Further, TS No. 71 does not refer to, or align with, the provisions of the OATT that govern BC Hydro's ability to designate any delivered energy as a Network Resource – the basis upon which BC Hydro would deliver any energy it would receive, according to the Program description in the TSR Application. That is, the tariff supplement does not require energy to be delivered firm, on firm transmission; nor does it account for the studies and reinforcement costs that may have to be incurred by BC Hydro, in its capacity as a NITS customer, as a pre-condition to designating any retail access energy deliveries as a Network Resource; nor does it account for the time it will take to undertake such studies and effect a Network Resource designation; and nor does it require title of the electricity to pass to BC Hydro.

Assuming the objective was simply to effect the Retail Access Program as it was described in the TSR Application, without addressing the inherent allocation of costs, benefits and risks between participants and non-participants, or any other issues, the Retail Access Tariff would have to provide for the following:

- The participating customer would be obliged to deliver energy in accordance with the energy delivery schedule it provides.
- BC Hydro would be obliged to receive energy in accordance with the schedule provided, subject to the designation of the customer's energy delivery obligation as a Network Resource under the NITS provisions of the OATT, including:
    - the customer's obligation to deliver firm energy to the Point of Receipt;[31]
    - the customer's reservation of firm transmission capacity to the Point of Receipt, on account of its firm delivery obligation;
    - the transfer of title to the energy to BC Hydro at the Point of Receipt, upon delivery;
- The participating customer would be responsible for all study and system/facility upgrade costs required for BC Hydro to designate the participating customer/third party supply as a Network Resource.
- Participation in the Retail Access Program would be conditional, in all cases, upon the completion of necessary studies and upgrades, and the Network Resource designation.

BC Hydro might have been prepared to develop the tariff documents necessary to effect the Program as was originally envisioned, and the application in support, but for four reasons. First, effecting the necessary changes to the Retail Access Tariff is not a matter of simply amending it. Effecting the necessary changes would require a

[31] "Point of Receipt" is defined in TS No. 71 as "the point at which a Third Party Retail Supplier has contracted to deliver Electricity into the BC Hydro transmission system". "Point of Receipt" is also defined in the OATT, but in the context of PTP service only.

completely new set of tariff documents that are consistent with the central element of the scheme, namely the acceptance of the retail access energy as a Network Resource, and its delivery by BC Hydro to its Network Loads (not the customer), under the NITS provisions of the OATT. BC Hydro expects that the Program, properly effected, would look more clearly like the energy purchase arrangement it actually seems to be.

The second reason is that in BC Hydro's view, the requirement for firm energy deliveries and associated firm transmission reservations required by the OATT effectively means that no customers will partake of the Program. That is because there is virtually no wholesale electricity market in British Columbia; market prices in Alberta are frequently higher than the Tier 2 energy rate under RS 1823; and between British Columbia and the wholesale electricity markets in the United States, where market prices are lower than Tier 2 rates, there is a constrained transmission path that precludes economic deliveries of market energy on a firm basis. That is, to avail themselves of market opportunities outside of B.C. to displace BC Hydro service under the Retail Access Program participating customers would be obliged to pay for system upgrades necessary to allow them to make the firm energy and transmission commitments required by the Program, and the cost of such upgrades far outweighs any potential benefits. BC Hydro's views on the unlikeliness of this occurring were confirmed in stakeholder consultation sessions it held in the summer of 2011.[32]

The third reason BC Hydro does not support the development and review of retail access tariff documents that would effect the Retail Access Program is the Minister's Letter attached at Appendix D. The Province supports BC Hydro's desire to suspend the Retail Access Program, and this is a relevant factor. Of greater import, however, is the reference to the pending review of industrial rate policy, and policy direction, which renders any further work on the Program, at this time, of uncertain value.

A final consideration, in BC Hydro`s view, is that an application to put the Retail Access Program on a workable tariff-based footing is likely to bring to the fore the degree to which costs, benefits and risks are allocated under the Program between participants and non-participants.[33] That is, even if BC Hydro were to simply apply for approval of tariff documents that effected the Program as described in the TSR Application, it doubts that participants in any such proceeding would be content with the *status* quo regarding that allocation. Indeed, the appropriateness of the *status quo* was BC Hydro`s initial concern, when it informally suspended the Program earlier this year.[34] Revisiting that issue will not be a trivial matter.[35]

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[32] A summary of BC Hydro's recent consultation efforts in regard to the Retail Access Program is provided in Attachment O.

[33] The subject, in part, of Attachment E.

[34] Refer to Attachment B.

[35] Another issue which would likely make any hearing into a retail access application a significant matter is the problem of defining any different provisions for third party generators, marketers, and customer-owned generation.

Taken together, the considerable effort required to properly effect the Program; the unlikelihood of customers availing themselves of the Retail Access Program in the current circumstances; the possibility of pending government action on the topic; and the fact that any application to effect the Retail Access Program is likely to be non-trivial; suggests that any effort BC Hydro puts into developing a new or revised Retail Access Tariff at this time is likely to be a wasted effort. In the current cost-constraint environment, such efforts are unacceptable.

Nevertheless, BC Hydro acknowledges that retail access, in the generic sense, is likely to have appeal to customers, at least so long as embedded cost rates are perceived to be rising at a higher rate than market prices (Appendix E). Accordingly, BC Hydro proposes that it file a status report on retail access with the BCUC no later than the end of 2012. The report would outline any provincial energy policy developments that bear on retail access and BC Hydro's anticipated response to such developments. The draft Order appended to this application addresses this proposed report (Appendix A).

4. Process

BC Hydro has copied this application to the customers and entities noted below, and proposes the following process order:

- parties copied on this application be invited to provide their preliminary comments on the merits of this application, and their views on any necessary further process, to the BCUC, by January 16, 2012; and
- BC Hydro to respond by January 23, 2012.

Following the receipt of submissions, the BCUC would be in a position to either grant the relief requested, or establish such process as it thought necessary or desirable.

For further information, please contact Sylvia von Minden at 604-453-9244 or by e-mail at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

(for) Janet Fraser
Chief Regulatory Officer

jm/rh

Enclosure

…15/

Copy to: **Transmission Service Rate Customers**

BCSEA
Attention: William Andrews
wjandrews@shaw.ca

BCOAPO
Attention: Leigha Worth
lworth@bcpiac.com

CEBC
Attention: David Austin
daustin@securitieslaw.bc.ca

CEC
Attention: Christopher P. Weafer
cweafer@owenbird.com

COPE
Attention: Lori Winstanley
lwinstanley@cope378.ca

Attendees to the August 25, 2011 Workshop:

Bull Housser & Tupper LLP
Attention: Brian Wallace
rbw@bht.com

AMPC
Attention: Richard Stout
roninconsult@live.com

Morgan Stanley Capital Group
Attention: Lisa Cherkas
lisa.cherkas@morganstanley.com

Morgan Stanley Capital Group
Attention: Vina Yin
vina.yin@morganstanley.com

FortisBC Inc.
Attention: Sarah Wagner
electricity.regulatory.affairs@fortisbc.com

TransAlta
Attention: Lance Henderson
lance_henderson@transalta.com

Willis Energy Services Ltd
Attention: Paul Willis
pwillis@willisenergy.com

Pacific Western Energy Inc.
Attention: David Newlands
dnewlands@telus.net

Commercial Energy Consumers
Attention: David Craig
dwcraig@allstream.net

TransCanada
Attention: Chris Best
chris_best@transcanada.com

BCUC
Attention: Doug Chong
doug.chong@bcuc.com

BCUC
Attention: Alison Richter
alison.richter@bcuc.com

Attention: George Isherwood
george.isherwood@shaw.ca

List of Attachments

Application to Suspend Retail Access Program

BC hydro

Attachment

A

Draft Order

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

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

and

Application by British Columbia Hydro and Power Authority (BC Hydro)
regarding the Retail Access Program

BEFORE:

, 20

ORDER

WHEREAS:

A. BC Hydro filed an application in March 2005 regarding, among other things, its Retail Access Program;

B. The Retail Access Program was approved by BCUC Order No. G 79 05 and is reflected in the following BC Hydro tariff documents:

- Tariff Supplement No. 71;
- Rate Schedule 1890;
- certain Retail Access Program provisions in:
  - Rate Schedule 1823;
  - Rate Schedule 1825;
  - Tariff Supplement No. 74;

collectively referred to as the Retail Access Tariff;

C. On December 23, 2011 BC Hydro filed an application seeking to suspend the Retail Access Tariff (the Application); the application was copied to BC Hydro's transmission service rate customers; BCOAPO, AMPC, CEC, BCSEA, CEBC, COPE, Morgan Stanley, TransCanada and FortisBC;

D. The Application states, among other things, that;

BRITISH COLUMBIA UTILITIES COMMISSION
ORDER NUMBER G-

- the Retail Access Tariff was intended to, but does not, effect the Retail Access Program;
- amending the Retail Access Tariff so that it does effect the Retail Access Program is not trivial;
- a hearing into an application into a Retail Access Tariff that did effect the Retail Access Program would not be trivial;
- there is little likelihood that customers would avail themselves of the Retail Access Program, even if it was effected by a properly crafted Retail Access Tariff;
- the Province has indicated its support for the suspension of the Retail Access Program, pending a review of industrial rate policy;

E. [further recitals re. process]

NOW THEREFORE the Commission orders as follows:

1. The Retail Access Tariff is suspended;
2. BC Hydro shall in due course file with the Commission copies of Rate Schedule 1823, Rate Schedule 1825 and Tariff Supplement No. 74 reflecting paragraph 1. above;
3. BC Hydro shall, on or before December 31, 2012, file a report with the Commission, copied to participants in this proceeding, that addresses any provincial energy policy developments that bear on retail access, as that expression is used in the Application.

DATED at the City of Vancouver, in the Province of British Columbia, this day of , 20 .

BY ORDER

Application to Suspend Retail Access Program

BC hydro

Attachment

B

BC Hydro's Letter to Customers
(February 1, 2011)

BC hydro
FOR GENERATIONS

1 February 2011

Attention: Distribution

Via email

Re: Retail Access Program Agreement (Tariff Supplement No. 71) and
Rate Schedule 1890 (Transmission Service – Energy Imbalance)

As you may be aware, BC Hydro offers a Retail Access Program to transmission service rate customers. Retail access arose from the 2002 Energy Plan as it was anticipated that with the introduction of stepped rates there would be an incentive for BC Hydro transmission service rate customers to purchase from alternative suppliers, such as IPPs. Although the Retail Access Program has been available since April 2006, to date, no customers have exercised the option to participate.

The existing Retail Access Program requirements are contained in RS 1890 and Tariff Supplement No. 71 (Retail Access Program Agreement). The terms and conditions of retail access service have not been revised since April 2006 when the program was first introduced. Recently, it has come to BC Hydro's attention that there is a risk that the restrictions currently contained in the service may not adequately mitigate potential cost shifting amongst customers.

As such, BC Hydro wishes to advise its transmission service customers that it is reviewing the current terms and conditions of the Retail Access Program and is assessing whether any changes to this service may be required to mitigate the above-mentioned risk. During this period of review, BC Hydro has determined that it will not be able to process any requests for retail access service.

BC Hydro is committed to working with its customers and will seek input with respect to any revisions to the Retail Access Program that BC Hydro views are required once its review of this tariff is completed. If you have any questions or need clarification on the information provided in this letter, please contact your Key Account Manager.

Yours truly,
BC HYDRO

Jim Nicholson
Director, Customer Care

British Columbia Hydro and Power Authority
900 – 4555 Kingsway, Burnaby, B.C. V5H 4T8
bchydro.com

Application to Suspend Retail Access Program

BC hydro

Attachment

C

BC Hydro's Letter to the BCUC
(May 20, 2011)

BC hydro | 50
REGENERATION

Janet Fraser
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

May 20, 2011

Ms. Alanna Gillis
Acting Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Gillis:

RE: British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
Tariff Supplement No. 71 - Retail Access Program Agreement and
Rate Schedule 1890 - Transmission Service - Energy Imbalance

BC Hydro is writing to the BCUC further to its letter of February 1, 2011 in which it notified all transmission service customers that a review was being undertaken of the terms and conditions of the Retail Access Program (**the Program**). In its letter, BC Hydro also stated that it would not be able to process any requests for retail access service and that it would be seeking input with respect to any prospective revisions to the Program. The purpose of this letter is to provide an update on the status of BC Hydro's review.

BC Hydro has formed an internal working group to examine the Program in detail. The mandate of the group is to consider how to effectively implement the Program within the constraints of legislative policy direction; to ensure that the detailed requirements are clearly specified in the tariff such that there is certainty for those who enter into retail access agreements; and to ensure that ratepayers who do not take advantage or who are ineligible for the Program are not unduly harmed. The goal is to develop recommendations which will then be reviewed with customers, stakeholders and Government through a consultation process.

The Program has been available since April 2006. To date, no customer has exercised the option to participate. However, subsequent to its February 1, 2011 letter, BC Hydro was made aware of one mining customer who was considering using the Program. BC Hydro has had discussions with the customer and will be including the customer in stakeholder consultations.

BC Hydro expects to begin its consultations with customers and stakeholders by mid-summer, with an understanding that the BCUC wishes to have the Retail Access Program available to customers by April 1, 2012.

BC hydro

May 20, 2011
Ms. Alanna Gillis
Acting Commission Secretary
British Columbia Utilities Commission
Tariff Supplement No. 71 - Retail Access Program Agreement and
Rate Schedule 1890 - Transmission Service - Energy Imbalance

For further information, please contact Fred James at 604-623-4317 or by e-mail at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

(for) Janet Fraser
Chief Regulatory Officer

fj/ma

Copy to: Transmission Service Rate Customers

Application to Suspend Retail Access Program

BC hydro

Attachment

D

Letter from Minister Coleman
(November 21, 2011)

BRITISH COLUMBIA

NOV 2 1 2011

Mr. Dan Doyle
Chair
Board of Directors
BC Hydro
18th Floor, 333 Dunsmuir Street
Vancouver, BC V6B 5R3

Dear Mr. Doyle:

The purpose of this letter is to clarify the Shareholder's position regarding BC Hydro's Retail Access Program (Program).

I understand the Program was developed as a result of policy direction set in the 2002 Energy Plan, and that the purpose of the Program is to enable industrial electricity customers to access some or all of their power from the market. I also understand the Program has not been used to date.

Ministry of Energy and Mines (Ministry) staff have informed me that the British Columbia Utilities Commission (BCUC) provided a report to the provincial government on the Transmission Service Rate (TSR) on December 31, 2009. It recommended several potential revisions to the TSR, including the Program. Ministry staff have also advised me that BC Hydro suspended the Program due to design deficiencies that may prove detrimental to non-participating ratepayers.

As you know, the BC Hydro Review Panel submitted its Review Report (Report) to the Province on June 30, 2011. Recommendations 43 and 44 covered rate design objectives and priorities. As noted in my August 29, 2011 letter to you, it is my view these recommendations should be addressed after the conclusion of BC Hydro's 2012-2014 Revenue Requirements proceeding.

The provincial government expects to review the TSR and the industrial tariff over the next two years, given their age, the BCUC report and the Province's economic development priorities. This may include policy direction on the Program. The Province prefers to take an integrated approach to policy development, rather than address issues on a "one-off" basis. To this end, I am directing BC Hydro to extend the suspension of the Program until a comprehensive review of industrial electricity policy is complete.

.../2

Ministry of
Energy and Mines
and Minister Responsible for Housing

Office of the Minister

Mailing Address:
PO Box 9060 Stn Prov Govt
Victoria BC V8W 9E2

Mr. Les MacLaren, Assistant Deputy Minister, Electricity and Alternative Energy Division, will be the lead Ministry executive for this initiative. Mr. MacLaren and/or his staff will contact BC Hydro staff to discuss next steps in the near future.

Thank you for your support on this matter.

Sincerely yours,

Rich Coleman
Minister

pc: Mr. Les MacLaren
Assistant Deputy Minister
Electricity and Alternative Energy Division
Ministry of Energy and Mines

Application to Suspend Retail Access Program

BC hydro

Attachment

E

Costs, Benefits and Risks

Costs, Benefits and Risks

The purpose of this attachment is to provide summary information on the potential costs, benefits and risks of retail access, in the generic sense of the words, and the Retail Access Program in particular. This information is not the subject of this application and is not meant to provide an exhaustive or definitive analysis of those issues, but rather a sense of the scope of the issues. This illustrative analysis considers costs, benefits and risk both from the perspective of participating customers (those who would take some or all of their load to market) and non-participating customers. Further, potential participating customers are considered to be transmission voltage customers taking service under Rate Schedule 1823 (**RS 1823**). Finally, and for simplicity, this attachment only considers third-party supply to be from the wholesale market, and does not consider potential domestic Independent Power Producer or self-generation supply alternatives.

Retail Access for Participating Customers

Potential Benefits (Participating Customers)

The relative relationship between market prices and RS 1823 rates for Tier 1 and Tier 2 energy is a key factor in whether customers might be interested in retail access. Other factors include whether customers believe they will have annual Tier 1 or Tier 2 energy volumes available to displace with retail access energy, their level of understanding of wholesale electricity markets and the RS 1823 tariff, and their level of risk tolerance.

Figure 1 shows actual and forecast Tier 1 and Tier 2 energy rates, wholesale energy prices at the mid-Columbia trading hub (**Mid C**), and wholesale prices in the Alberta Power Pool (**AESO**), from F2007 to F2014. Forecast Mid C prices are annualized prices based on Amended Figure 4-1 of BC Hydro's Amended F12-F14 RRA. Forecast AESO prices are based on forward market prices as of April 6, 2011. Forecast Tier 1 and Tier 2 energy rates are calculated on the assumption that

BC Hydro receives approval for the rate increases requested in the Amended RRA and that the Tier 2 rate remains unchanged at $73.60/MWh.

Figure 1 Market Prices Compared to Tier 1 and Tier 2 Energy Rates

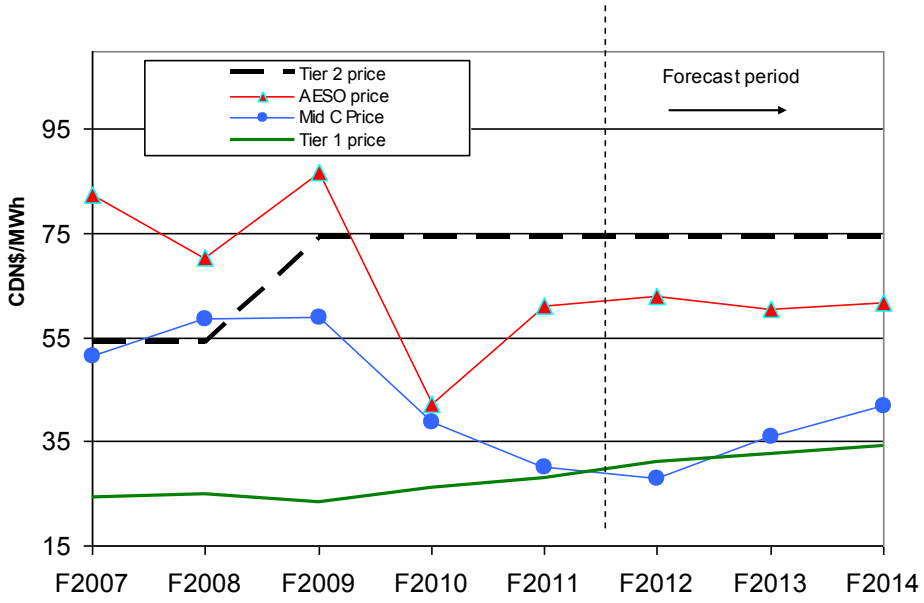


Table 1 shows actual Tier 1 and Tier 2 energy volumes for customers on RS 1823 for the period F2007 – F2011. The purpose is to illustrate the total "available Tier 2 energy" for the entire TSR class that would have been available for offset by retail access. For simplicity, energy volumes for customers served under RS 1823 Energy Charge A (**RS 1823A**) and RS 1827 are not included since they did not have a CBL and are not exposed to stepped rate energy billing.

Table 1 Tier 1 and Tier 2 Energy Volumes

Year	RS 1823 Tier 1 (GWh)	RS 1823 Tier 2 (GWh)
F2007	14,057	796
F2008	13,569	410
F2009	13,048	139
F2010	11,629	266
F2011	11,368	330

Table 2 below shows the range of potential gross savings that TSR customers may have realized, in the aggregate, for the F2007 to F2011 period.

For simplicity, AESO prices are not included in this analysis because they have been (and are forecast to remain) higher than Mid C prices.

Table 2 Potential Gross Retail Access Savings (Participating Customers)

	Tier 2 Rate (CDN$/MWh)	Mid C (CDN$/MWh)	Difference Between Tier 2 Rate and Mid C (CDN$/MWh)	Tier 2 energy volumes from Table 1 (GWh)	Potential Gross Savings (millions per year in CDN$)
F2007	54	51.40	2.6	796	2.06
F2008	54	58.49	–4.5	410	–1.85
F2009	73.6	55.89	17.7	139	2.46
F2010	73.6	36.70	36.9	266	9.82
F2011	73.6	28.40	45.2	330	14.92

The assessment of potential benefits of retail access for BC Hydro's transmission voltage customers takes a high-level annual view. The analysis does not account for incremental benefits that might accrue to customers who, under a particular retail access program, may be able to shift hourly or seasonal energy volumes between market and BC Hydro when it is economic to do so. Such arbitrage activity will in all cases be unique to the particular program, and is discussed in the section below regarding the Retail Access Program that is the subject of this application.

Potential Costs (Participating Customers)

The costs of retail access to participating customers are primarily the transaction costs[1] associated with accessing wholesale energy markets, and wholesale transmission costs, including energy imbalance, associated with delivering energy pursuant to open access transmission tariffs, such as BC Hydro's OATT. These costs would be borne either directly by participating customers, or indirectly through the use of wholesale marketing entities. It is difficult to assess what such costs

[1] An example of a transaction cost might be the expense of hiring a third party marketer to acquire and deliver retail access energy to the customer's site.

would be for the class of transmission voltage customers because it would depend a great deal on the particular circumstances of the market opportunities available and the customers' circumstances. However, BC Hydro believes it is reasonable to assume that internal and external transmission wheeling costs would total about $10/MWh, while transactional fees, for arranging the purchase and delivery of retail access energy, may be a further $10/MWh. The above high-level estimates are consistent with sample billing calculations provided to attendees of the August 25 workshop (refer to Attachment O-3).

Potential Risks (Participating Customers)

Customers face a number of risks if they choose to participate in retail access. These include market price risk; Tier 2 volume risk; and third party supply risk. Each is described briefly, below.

Market Price Risk

When customers choose to participate in retail access they do so based on their assumptions of future market prices. If market prices turn out to be higher than expected, customers will likely face higher energy costs than anticipated. Although recent market prices have been relatively low, BC Hydro believes it is possible that market prices could increase 50 per cent above current levels within the next three to five years.

Tier 2 Volume Risk

Participating retail access customers assume the risk, on a forward-looking basis, that they will have annual Tier 2 volumes to displace. Customer baselines (**CBLs**) under RS 1823 do not remain fixed year over year or within the year. They can, and frequently do, change. The risk to customers is that changes (e.g., curtailments, shutdowns, force majeure) in plant operations, that decrease annual energy purchases from BC Hydro below 90 per cent of the annual Billing CBL, will eliminate Tier 2 energy purchases in that Billing Year. Consequentially, the customer's annual scheduled retail access energy would displace Tier 1 energy rather than Tier 2 energy. Assuming the customer's delivered cost of retail access energy from a third

party are more expensive than the Tier 1 energy they would otherwise have purchased from BC Hydro, the result would be a financial loss. Further, because RS1823 energy is billed monthly against an Annual CBL, the customer will pay the Tier 1 rate for energy to the point in the Billing Year that energy consumption exceeds 90 per cent of the Billing CBL. This has potentially adverse effects on monthly cash flow if the cost of retail access energy is higher than the Tier 1 rate.

Refer to the sample billing calculations shown in Attachment O-3 for more information.

Third Party Supply Risk

Third party supply risk can arise if the participating customer's third party defaults on its supply obligation. Depending on the terms of the retail access arrangement, the participating customer may not have an unrestricted or cost-free right to resume bundled utility service. Under the Retail Access Program, customers face no such barriers and in fact, as noted, BC Hydro's supply obligation continues throughout the term of the customer's participation in the Program.

Summary Conclusions (Participating Customers)

The foregoing information and analysis supports the following conclusions:

- It would currently be economic for customers to displace Tier 2 volumes with market purchases, although such volumes are relatively small.
- Assuming all TSR customers had displaced all of their Tier 2 energy volumes between F2007 and F2011, the potential cost savings to customers from retail access, would have ranged from $0 to $15 million per year, before accounting for transmission costs, transaction costs, and potential arbitrage.
- Over the next few years, market prices are forecast to be close to Tier 1 rates, and both are rising at a similar rate. However, if market prices were to be lower than the prevailing Tier 1 rate, it may become economic for customers to displace Tier 1 volumes with market purchases.

Retail Access for Non-Participating Customers

Potential Benefits (Non-Participating Customers)

As noted in the background section of the application, non-participating customers can benefit from retail access to the extent that the utility's load-serving obligations are reduced, and infrastructure investments deferred. Under the Retail Access Program BC Hydro's load-serving obligations continue throughout, and as such, the potential benefits to non-participating customers are less certain than they might otherwise be.

Potential Costs (Non-Participating Customers)

When a retail access customer displaces annual Tier 2 purchases, BC Hydro loses revenue at $73.60/MWh on the margin (current Tier 2 rate). However, BC Hydro either reduces its own market purchases, or increases its own export sales, depending on whether it is in energy surplus or deficit, by amounts equal to the displaced volumes. For example, using the actual F2011 Mid C price of $28.40/MWh, BC Hydro would incur a negative gross margin of $45.20/MWh for each MWh of load displaced by retail access energy.

For illustrative purposes, assume that all F2011 actual Tier 2 energy purchases for TSR customers (330,000 MWh x $73.60/MWh) were displaced with retail access energy at actual Mid C market prices (330,000 MWh x $28.40/MWh). The negative gross margin would be 330,000 MWh x $45.20/MWh = $14.9 million. This would subsequently need to be collected from all BC Hydro customers through rates. Put simply, the $14.9 million benefit extracted by customers participating in retail access would be roughly equivalent to the $14.9 million cost that must be subsequently borne by non-participating customers.

In addition, short-term costs borne by non-participating customers can be magnified to the extent that particular program terms and conditions do not mitigate seasonal or hourly arbitrage opportunities. A discussion of arbitrage opportunities under the Retail Access Program is provided below.

Potential Risks (Non-Participating Customers)

Risks to non-participating customers of retail access turn on the likelihood that short-term costs are not offset by the benefit of deferral of more higher-cost infrastructure investments in the future. The less likely the long-term deferral benefit, the more likely it is that the short-term costs will outweigh any long-term benefits. In addition, non-participating customers are at risk to the extent to which the rules of the particular program provides arbitrage opportunities for participating customers.

Summary Conclusions (Non-Participating Customers)

The foregoing information and analysis supports the following conclusions:

- Under current market conditions, Tier 2 volumes, the Tier 2 rate, and the RS 1823 pricing methodology, there are some potential short-term costs to non-participating customers from retail access.
- Potential short-term costs to non-participants may increase in the future if market prices stay low, and increase at a lower rate than embedded costs rates.
- The potential short-term costs to non-participating customers from retail access are about $14.9 million before accounting for arbitrage opportunities, assuming F2011 Mid C prices and the displacement of all F2011 Tier 2 volumes.
- The potential long-term benefits to non-participating customers of retail access depend on the degree to which retail access allows for the deferral of higher cost infrastructure investments. Under the Retail Access Program, the likelihood of long-term benefits materializing are less likely than might otherwise be the case if BC Hydro's supply obligations to its retail access customers were reduced by the third-party supply arrangements of the customer.

Arbitrage Opportunities Under the Retail Access Program

Under the Program, and as discussed in the body of the application, BC Hydro will absorb or make–up any differences between actual energy deliveries and scheduled deliveries, in real time, and customers receive a credit or charge equal to the product

of the difference (in MWh) and an imbalance rate. The imbalance rates are set out in RS 1890, and rather than being equal to market prices, are based on the RS 1823 Tier 1 and Tier 2 rates. Further, BC Hydro schedules energy deliveries on an hourly basis, except in extraordinary circumstances, and thus the real time imbalance service is in effect provided on an hourly basis. However, TS No. 71 (Attachment K) does not require that the customer specify energy delivery schedules on an hourly basis. Instead, it specifies 16 different pricing periods per year, being all the hours in each of March to October (720 or 744 hours, depending on the month); the high-load hours in each of November to February (416, 432 or 384 hours, depending on the month, in a non-leap year) and all the low-load hours in each of November to February (304, 312 or 288 hours, depending on the month, in a non-leap year), and allows the customer to specify the total energy volumes to be delivered in each of those 16 pricing periods. By allowing for energy deliveries across such a large number of hours, while providing an hourly imbalance service at a rate other than the prevailing market price, the Retail Access Program creates opportunities for arbitrage in two primary ways,[2] referred to for convenience as "volume arbitrage" and "pricing arbitrage".[3]

Volume Arbitrage

Volume arbitrage refers to a situation where a participating customer delivers energy on other than an equal hourly, or "flat" , basis, but still delivers the total scheduled energy in a retail access pricing period.

A participating customer might schedule 1 MW per hour of retail access energy in the month of July. Since there are 744 hours in July the customer would nominate 744 MWh of energy for that month (in this case July would correspond to one of the 16 pricing periods under TS No. 71). Under the existing Program the customer could purchase and deliver to BC Hydro all 744 MWh of energy when market prices in July

[2] The difference between the hourly imbalance service and the multi-hour delivery periods also creates uncertainty that prevents BC Hydro from optimally arranging and scheduling its own domestic service and export trade transactions.

[3] Volume and pricing arbitration can both occur over a particular retail access period, although the estimates of potential economic impact from pricing arbitrage below assume that participating customers have to provide hourly flat schedule thus precluding volume arbitrage.

are low (overnight for example), and make no purchases and deliveries to BC Hydro when market prices are high. This type of arbitrage would effectively displace low-cost imports that would otherwise benefit all customers. Compared to a retail access scheme that required hourly delivery schedules from the participating customer, this type of activity would also negatively affect trade revenues as higher customer load during high priced hours would displace exports that BC Hydro (via Powerex) would otherwise have done. In addition, and because BC Hydro retains its full load-serving obligations under the Program, BC Hydro can't assume that its load obligations in any hour will in fact be displaced by some of the 744 MWh. In consequence, and relative again to a situation where hourly delivery schedules were required from the participating customer, some system capacity will be held back that would otherwise have been available for trade and the benefit of all customers.

Assuming 2010 Mid C prices, total retail access volumes of 50 MW, and maximum hourly volumes of 500 MW, BC Hydro estimates that volume arbitrage under the Retail Access Program could effectively cost non-participating customers about $5 million/year.

Pricing Arbitrage

Pricing arbitrage refers to a situation where a participating customer delivers more or less energy than scheduled, to profit from the difference between market prices and the imbalance rates in RS 1890.

For example, a participating customer might choose to deliver less energy to BC Hydro than it has scheduled if market prices exceed the imbalance rates and it can deliver the energy to market. In this situation the customer's financial gain is equal to the product of the volume of energy diverted to the market and the difference between the market price and the imbalance rate, less transmission (delivery) costs. Relative to a situation where imbalance rates equalled market prices, the customer's gain is BC Hydro's (i.e., non-participating customers') loss. A participating customer might also deliver more energy to BC Hydro than scheduled if market prices are less than the imbalance rates and it could deliver the energy to the Point of Receipt. In this case its gain would be equal to the product of the

incremental energy delivery to BC Hydro and the difference between the imbalance rates and the market prices, less transmission costs. Again, the customer's gain would be BC Hydro's (non-participating customers') loss, before accounting for transmission costs.

Using the same assumptions as described above for volume arbitrage, BC Hydro estimates pricing arbitrage under the Retail Access Program could effectively cost non-participating customers about $10 million/year. This analysis assumes that volume arbitrage is first eliminated by requiring customers to provide a flat hourly schedule.

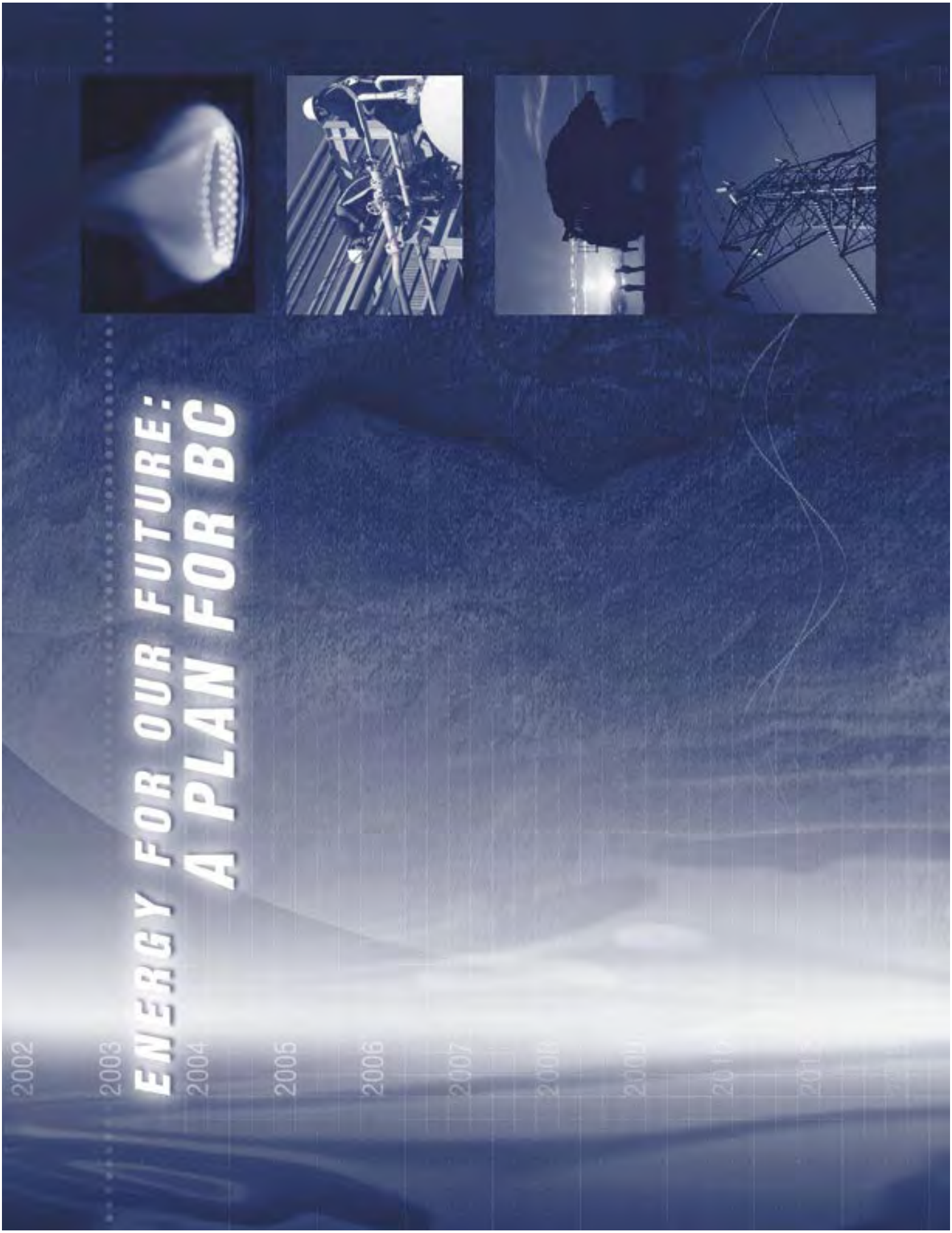
Application to Suspend Retail Access Program

BC hydro

Attachment

F

Extracts from the 2002 Energy Plan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of utility rates of return, and the adoption of performance-based regulation and alternative dispute resolution. To fulfill its mandate, the Commission will be strengthened by appointing two full-time Commissioners. The Utilities Commission Act will be amended to focus more on performance-based and results-based regulation, including negotiated settlements, and to define effective consumer participation.

MORE PRIVATE SECTOR OPPORTUNITIES

To increase the role of the private sector in energy supply, private power production will be encouraged, access to the transmission system will be improved, oil and gas investment will be supported, and some customers will be able to choose their suppliers.

INVESTMENT IN PRIVATE POWER

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

The private sector is well positioned for power development, given its ability to find entrepreneurial capital, efficiently build and operate facilities, and take on the associated risk. B.C.'s independent power producers (IPPs) have already demonstrated that they can come forward with cost-effective projects. With BC Hydro's participation limited to efficiency improvements and capacity upgrades at existing facilities, IPPs will be able to serve new domestic needs and explore opportunities in the export market. The intent will be to encourage the private sector to find a variety of innovative and economical ways to satisfy the growing demand for power.

BC Hydro's relative strengths lie in the operation of large-scale hydroelectric generation. While BC Hydro does not plan to invest in the construction of new hydroelectric facilities at the present time, any proposed new BC Hydro hydroelectric facility, such as Peace Site C, must be brought to Cabinet for approval before being considered by the Utilities Commission as a source of supply. Cabinet will then decide whether the project should be developed by BC Hydro or the private sector.

Policy Action #14 (new): Under new rate structures, large electricity consumers will be able to choose a supplier other than the local distributor.

New stepped pricing (see Conservation and Efficiency) will provide an incentive for large industrial or transmission rate customers to purchase from IPPs, or to self-generate, when they can do so less expensively than the utility's cost of new supply. These larger customers will be able to meet all or a portion of their consumption from private generation. This policy change introduces retail competition for large BC Hydro customers. Aquila Networks Canada already offers retail access to its industrial customers.

Policy Action #15 (new): The BC Hydro Transmission Corporation will improve access to the transmission system and enable IPP participation in US wholesale markets.

A new publicly owned entity, BC Hydro Transmission Corporation, will be responsible for planning, operating, and managing BC Hydro's transmission system. The transmission assets will continue to be owned by BC Hydro. The corporation will have a separate board of directors and will be regulated by

Actions under other strategic objectives that also support secure, reliable supply:

#1	A legislated heritage contract will preserve the benefits of BC Hydro's existing generation.
#13	The private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.
#15	The BC Hydro Transmission Corporation will improve access to the transmission system and enable IPP participation in US wholesale markets.
#18	Pre-tenure and land use planning, as well as northern road improvements, are improving access to oil and gas resources.
#19	Natural gas marketers will be allowed to sell directly to small volume customers, and will be licensed to provide consumer protection.
#21	New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.
#22	The Province will update and expand its Energy Efficiency Act, and will work with the building industry, governments and others to improve energy efficiency in new and existing buildings.
#23	The Utilities Commission Act will be amended to remove a disincentive for energy distributors to invest in conservation and energy efficiency.

Application to Suspend Retail Access Program

BC hydro

Attachment

G

Extracts from the 2003 Heritage Contract Report

IN THE MATTER OF

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

AND

AN INQUIRY INTO A HERITAGE CONTRACT FOR BRITISH COLUMBIA HYDRO AND POWER AUTHORITY'S EXISTING GENERATION RESOURCES AND REGARDING STEPPED RATES AND TRANSMISSION ACCESS

REPORT AND RECOMMENDATIONS

October 17, 2003

Before:

Robert H. Hobbs, Chair
Kenneth L. Hall, Commissioner
Paul G. Bradley, Commissioner

EXECUTIVE SUMMARY

The Government's Energy for Our Future: a Plan for BC ("Energy Plan") mandated that the BC Utilities Commission conduct an Inquiry to develop and refine certain policy areas relating to regulation of BC Hydro. The Inquiry concludes with this Report.

The Commission was requested to make recommendations on two key policy initiatives in the Energy Plan. First, benefits attributable to the existing low-cost generation of BC Hydro are to be secured for British Columbians by means of a Heritage Contract. Second, more efficient use of energy resources and private investment in new generation are to be fostered by a stepped rate structure for large commercial and industrial customers.

The Commission established a procedure designed to encourage public participation in the development of the requested recommendations. BC Hydro filed, as directed, a Proposal that became the subject of information sessions and workshops leading up to a public hearing. At the hearing the Commission Panel heard the views of consumer and industrial groups.

Three points enunciated at the Inquiry place the recommendations of the Commission Panel in context. First, BC Hydro's expressed concern in preparing its Proposal was maximization of the total amount of wealth to the province. The sharing of that wealth was deemed a secondary issue, and one that was largely left to the Government and the Commission. Second, BC Hydro's Proposal for a Heritage Contract had the support of almost all participants. Third, most participants believed that the recommendations should be focused on principles, with implementation details left to later Commission decisions.

The BC Hydro Proposal for the Heritage Contract between BC Hydro's Generation and Distribution arms was based on the revenue required by Generation to meet the embedded cost of supplying the energy of Heritage Resources to Distribution ("the Revenue Requirements model"). A salient feature of the Revenue Requirement model is that Generation remains subject to traditional regulatory oversight, with the opportunity for performance-based ratemaking ("PBR"). BC Hydro believes that the Revenue Requirements model ensures the appropriate alignment of interests of BC Hydro Distribution, BC Hydro Generation, and Powerex, and that such alignment is necessary for the efficient dispatch of the Heritage Resources and effective planning for new resources.

One intervenor, CBT Energy Inc., offered an alternative proposal similar to the contract adopted by Quebec. This form of Heritage Contract would specify a fixed quantity of heritage energy to be supplied at a fixed price over the duration of the contract ("The Fixed Price/Fixed Quantity model"). Its declared advantage is to afford greater

certainty for consumers. This model would, however, impose greater risk on BC Hydro, requiring a risk premium to be borne by consumers. A further feature of such a contract would be to remove the need to regulate BC Hydro Generation.

Customer advocates believe that the Revenue Requirements model ensures continuing congruence of risks and rewards, that is, it ensures risks and rewards are borne by customers. The Fixed Price/Fixed Quantity contract requires the problematic determination of fair compensation for the risks, and it does not ensure that full heritage benefits will remain with customers. For these reasons, together with strong support for ongoing regulation of BC Hydro Generation, customers unanimously support the Revenue Requirements model.

This Report endorses the preference of the customers and BC Hydro, and makes recommendations for the implementation of a Revenue Requirements model for the Heritage Contract. The proposed Heritage Contract is attached as an appendix to the report; the accounts necessary for implementation of this model are set forth in a proposed special direction.

One feature of the BC Hydro Proposal that warranted special attention was the substantial change in the determination and disposition of Trade Income. Trade Income is defined as the audited net income of Powerex. A significant change to the amount that may accrue to Government arises by virtue of an agreement between BC Hydro and Powerex ("The Transfer Pricing Agreement for Electricity and Gas"). The effect of this agreement is that Trade Income will no longer include revenues from the sale of surplus power, except for a profit expected to be realized by Powerex after paying BC Hydro an indexed price for surplus power. All Trade Income between $0 and $200 million accrues to the ratepayers. Because of its importance, three alternatives to BC Hydro's proposal for Trade Income are discussed in this Report.

The Report recommends BC Hydro's Trade Income proposal, with an additional recommendation for an incentive mechanism for Powerex, which would require approval by the Commission.

After the Heritage Contract, the second major area addressed in this Report is the design of a stepped rate structure for large commercial and industrial customers. The objective of such a system is to ensure the benefit of relatively low-cost energy through a Tier-1 block rate while reflecting higher cost of new supply in the Tier 2 block rate. The Report concludes that achieving the objectives of encouraging private sector investment in new supply and access by large electricity consumers to alternative suppliers is dependent on the success of stepped rates. This manifests itself in a recommendation that the Tier 2 rate should be based on the long-term costs and should be measured by expected acquisition costs.

This Report recommends implementation of stepped rates for large commercial and industrial customers and delineates principles for their determination. It further recommends concurrent implementation of time-of-use rates. Recognizing the innovative nature of stepped rates, the Report recommends a subsequent evaluation report to the Government.

The Energy Plan states that it is to be implemented by the end of 2004. Therefore, this Report identifies a schedule that has as its objective the implementation of retail access by the end of 2004.

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(Ex. 29, p. 7). BC Hydro agreed that the introduction of an appropriate energy imbalance charge would mitigate the risk of arbitrage (T6: 1314-18).

The JIESC acknowledges that developing opportunities for IPPs in BC to do business with industrial customers as contemplated in the Energy Plan will require resolving issues of price, shaping, quantity, availability, back-up or reserves, transmission and load imbalances. The JIESC also accepts that if industrial customers wish to go to a third party supplier, when that is possible, such customers must give reasonable notice before leaving and returning (JIESC Final Argument, p. 31).

The JIESC recommends that access principles be limited to specifying the notice that should be given before an industrial customer leaves or returns to BC Hydro supply, and that RS 1821 Demand Charges cover IPP deliveries to industrial customers until BCTC has approved tariffs. Additional transmission charges should be limited to symmetrical market-based imbalance charges (JIESC Final Argument, p. 31).

Competition from PowerSmart, CBG and Public Corporations

The IPPBC argues that entities, such as CBTE, Columbia Power Corporation and BC Hydro (through Powerex, PowerSmart, CBG and the like) that receive special advantages or support from the Government or taxpayers should not be allowed to compete with IPPs in the Tier 2 market. The CEC states that it is unfair competition for the IPPs if BC Hydro is financing some options and not others, but the CEC submits that the solution is not necessarily to eliminate all other competition to the IPPs. The CEC argues that BC Hydro should be required to finance all options equally on a non-discriminatory basis to all sources, and that BC Hydro should perhaps be required to restrict its funding initiatives and restrict its demand-side management (PowerSmart) activities to education, awareness and promotion (CEC Final Argument, p. 35).

The JIESC argues that PowerSmart and CBG initiatives result in projects being implemented which otherwise might not occur and that such targeted initiatives should be continued (JIESC Final Argument, p. 37).

4.2 Commission Panel Views

BC Hydro does not support implementation of retail access on an interim basis prior to amended BCTC transportation service tariffs being in place. BC Hydro has also indicated that it could file its terms and conditions for generation access principles shortly after BCTC's transportation service rates are in place allowing retail access to be implemented on a permanent basis, likely by December 2004. BC Hydro considers retail access to be

a complex issue with many implications, and cautions against implementing retail access on a piecemeal basis (T3: 628-629; T6: 1180-1181; BC Hydro Final Argument, p. 32). BC Hydro was generally supported in this regard by the BCOAPO (BCOAPO Final Argument, p. 13).

The JIESC, the IPPBC, CBTE and the CEC support implementing retail access more quickly. The CEC argues that the principles for retail access are available to the Inquiry and asks the Commission to recommend that BC Hydro be directed to bring forward retail access principles by March 31, 2004 based on the NITS tariff and that any customers who pursue retail access under the interim provisions be guaranteed to be able to use it for the duration of the project (CEC Final Argument, pp. 55, 82).

The IPPBC submits that there is a need for certainty in the rules for retail access (T2: 379). It agrees that temporary access principles are imperfect and would likely be a detriment to investment in new generation by IPPs, unless the Commission can provide interim retail access that allows the interim provisions to be maintained or "grandfathered" for those IPPs who engage in contracts to supply industrial customers under the interim provisions. The IPPBC indicates that there are several other conditions that it considers necessary before IPPs are likely to show interest in building new generation, including access to transmission capacity for domestic and export sales and access to BC Hydro's storage (T7: 1534-1535; T11: 2319-2323).

The Commission Panel recognizes and supports the wishes of larger volume customers and IPPs to have the option of retail access available to them as soon as possible. That such access should be made available to them is clearly an objective of the Energy Plan and the Terms of Reference. However, it is equally important that the introduction of retail access not be rushed forward in a way that may lead to its failure. The potential benefits or costs of implementing retail access on a short-term, interim basis depend on whether interim measures can be put in place that allow, in a practical sense, retail access to occur while preventing potential arbitrage opportunities and cost-shifting between customer classes.

For these reasons, the Commission Panel concludes that interim retail access principles are likely to remain mostly unused, and thus will do little to provide encouragement to IPPs and marketers to compete for the Tier 2 industrial load. Without resolution on final BCTC Transmission Service and Ancillary Service charges, the certainty looked for by IPPs will not be present. Furthermore, risks of cost shifting from IPPs or industrial customers to BC Hydro or other customer classes would exist. The Commission Panel outlines in Chapter 5 a schedule for filings required to implement permanent retail access.

The Commission Panel accepts the arguments of the JIESC that targeted programs such as PowerSmart and CBG

Recommendation #24

That an LGIC Order be issued, pursuant to section 4(1) of the Transmission Corporation Act, prescribing a date of March 1, 2004 if retail access is to be implemented prior to 2005.

Stepped Rates and Retail Access Scheduling

The Commission Panel recognizes that the success of retail access is largely dependent on the success of stepped rates. Retail access requires both an approved BCTC tariff, which provides for access to transmission voltage customers, and approved generation access principles, which establish the terms for transmission voltage customers to take third party supply.

The Commission Panel finds that very limited benefits can be expected to be derived from retail access prior to determinations related to access to transmission, which will be the subject of the BCTC application. For reasons stated below, the Commission Panel finds that the earliest practicable date for implementing retail access is the end of 2004.

BC Hydro believes that it would be premature to design generation access principles before the BCTC tariffs and the stepped rate design are known (Ex. 8-2, p. 10). Provided that the principles for stepped rates are established by reply of the Government to the Commission Panel's recommendations and that the BCTC tariffs are filed pursuant to the recommendation above, the Commission Panel concludes that BC Hydro can apply for the stepped rates, time-of-use rates, and generation access principles as part of the same filing and be approved by December 31, 2004.

The current ratemaking provisions of the UCA provide the Commission with the necessary jurisdiction to approve stepped rates. Given this jurisdiction, if the Government accepts the Commission Panel's recommendations on stepped rates, no further direction from the Government is required. The Commission would then proceed with the implementation of stepped rates.

The Commission Panel concludes that stepped rates, time-of-use rates and generation access principles should have the same effective date, so that transmission voltage customers can assess the full range of choice to be afforded to them.

Recommendation #25

That BC Hydro file an application, within 30 days of the Commission Decision in the BCTC tariff filing pursuant to section 4(1) of the Transmission Corporation Act, seeking approval for stepped rates, time-of-use rates and generation access principles, and PowerSmart and Customer Based Generation programs.

Rate Design Scheduling

BC Hydro has not changed its rate design since 1992. Undertaking a full rate design study after such a long period will require significant effort by BC Hydro, especially given the separation of Generation, Transmission, and Distribution, and the extended period of the rate freeze. It is reasonable to expect that there will be significant changes to BC Hydro's bundled rates, including changes to the allocation by customer class of the revenue requirement and to the billing determinants for each customer class.

BC Hydro contends that the BCTC transmission rates and the BC Hydro revenue requirements have implications for the design of BC Hydro's bundled rates (T11: 2341-2342). Therefore, both matters should be approved prior to the filing of the rate design application. The Commission Panel concludes that the filing of the rate design application should be delayed until late 2004 or early 2005, so that stepped rates and retail access tariffs can be approved prior to the end of 2004.

Recommendation #26

That BC Hydro file a rate design application prior to April 1, 2005.

Table 2: Anticipated Timeline of Future Filings

	2004				2005			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
BC Hydro Revenue Requirements	◆———	———	———→					
BCTC: Transmission Access		◆———	———	———→				
Stepped Rates, TOU Rates, Generation Access				◆——→				
Rate Design						◆———	———→	

5.5 Other Matters

Recommendation #27

That the determination of Generation Related Transmission Assets ("GRTAs") for the BC Hydro Wholesale Transmission Service rates, be accepted for the purposes of the BCTC tariff filing to be made pursuant to section 4(1) of the TCA, and that functionalization of GRTAs otherwise continue to be within the jurisdiction of the Commission.

Dated at the City of Vancouver, in the Province of British Columbia, this 16th day of October 2003.

Original signed by:
Robert H. Hobbs
Chair

Original signed by:
Kenneth L. Hall
Commissioner

Original signed by:
Paul G. Bradley
Commissioner

SCHEDULE A

TERMS OF REFERENCE

IN THE MATTER OF the Utilities Commission Act ("the *Act*")

and

IN THE MATTER OF Recommendations Relating to a Heritage Contract for BC Hydro's Existing Generation Resources, and to Stepped Rates and Transmission Access

WHEREAS, under Section 5(1) of the *Act*, the Lieutenant Governor in Council ("LGIC") may request the BC Utilities Commission ("BCUC" or "Commission") to provide advice on any matter the LGIC specifies; and

WHEREAS on November 25, 2002, the Province of British Columbia announced its new Energy Plan, the four cornerstones of which are: low electricity rates and public ownership of BC Hydro; secure and reliable energy supply; more private sector opportunities; and environmental responsibility and no nuclear power sources; and

WHEREAS the Energy Plan outlines several Policy Actions designed to ensure British Columbians have continued access to sufficient supplies of dependable low-cost electricity; and

WHEREAS the Energy Plan provides in Policy Action #5 that the Commission will once again regulate the rates charged by BC Hydro; and

WHEREAS the Energy Plan contemplates that the Commission should conduct an inquiry to develop and refine certain policy areas relating to regulation of BC Hydro prior to the commencement of its review of BC Hydro's rates and should submit a report to government describing changes to legislation and regulations that it believes are desirable in that connection; and

WHEREAS the Energy Plan contemplates a full review of BC Hydro's rate levels based on an application to be filed before March 31, 2004; and

WHEREAS the Energy Plan provides in Policy Action #1 that a legislated heritage contract will be created between BC Hydro's generation line of business and its distribution line of business for a term of ten years initially; and

WHEREAS the Energy Plan provides in Policy Action #2 that an appropriate level of trade revenues, net of incremental costs properly allocated by BC Hydro for internal management purposes, will continue to be assigned for rate-setting purposes to help maintain low and stable rates for BC consumers; and

WHEREAS trade revenues, net of incremental costs properly allocated by BC Hydro for internal management purposes, above $200 Million in any year will flow to the government for the benefit of all British Columbians; and

WHEREAS the Energy Plan contemplates large industrial or transmission rate customers and energy suppliers having access to transmission for the purpose of acquiring and providing energy for all or a portion of their needs based on principles to be established; and

WHEREAS the Energy Plan provides in Policy Direction #21 that new rate structures should be developed to send better price signals to large electricity consumers.

NOW THEREFORE the Commission shall conduct an inquiry pursuant to Section 5 of the *Act* in compliance with the following Terms of Reference:

1. The general purpose of the inquiry is to obtain the Commission's Recommendations on what changes, if any, should be made to legislation, regulations, special directions or special directives affecting BC Hydro and/or the Commission in order to implement the Energy Plan in connection with the issues identified in paragraphs 3 and 4 of these Terms of Reference.

   For greater certainty, the Commission shall provide Recommendations on whether the current rate stabilization account provided for in Special Direction 8 and Special Directive 4 should be eliminated and, if so, whether any alternative form of deferral account mechanism should be considered to implement the Commission's Recommendations with respect to paragraph 3 of the Terms of Reference, and on whether there is a need for revisions to paragraph 3 of Special Direction 8 to implement the Commission's Recommendations with respect to paragraph 4 of the Terms of Reference.

2. With respect to Policy Action #1 from the Energy Plan, the Commission shall make Recommendations concerning the terms and conditions which should be contained in a Heritage Contract based on the following assumptions:

   (a) The resources and obligations to which the Heritage Contract shall relate are those set out in Schedule A;

   (b) The classes of customers that are eligible to benefit from the Heritage Contract are those set out in Schedule B, as may be amended from time to time to reflect the introduction of new rate structures or options;

   (c) Except as expressly provided herein, the determination of rates for customers identified in Schedule B will not be considered until after the Commission's Recommendations have been provided to the Lieutenant Governor in Council pursuant to these Terms of Reference; and

   (d) The quantity of energy producible from the resources shall be determined assuming average water conditions for the duration of the Heritage Contract.

3. The Commission shall make specific Recommendations relating to the following matters concerning the Heritage Contract:

(a) The quantity of energy which will be available under the Heritage Contract;

(b) The cost of supplying the energy identified in subparagraph (a), including:

(i) All costs properly allocated to that activity by BC Hydro for internal management purposes;

(ii) An allowance for return on BC Hydro's equity invested in the assets identified in Schedule A; and

(iii) The portion, if any, of transmission assets that should be deemed to be "generation related" and which should be included in the heritage contract for costing purposes, and ultimately to be recovered in electricity rates of BC Hydro's distribution line of business;

(c) The price that BC Hydro's distribution line of business should be deemed to pay for the quantity of energy identified in subparagraph (a);

(d) Having regard for the considerations referred to in 3(h) below, the provisions that should be included in the Heritage Contract relating to capacity, shape, and scheduling flexibility to fairly allocate the benefits arising from the resources listed in Schedule A under average water arising from the resources listed in Schedule under average water conditions between the customers listed in Schedule B and BC Hydro;

(e) The principles and impacts of providing ancillary services requirements to BC Transmission Corporation;

(f) The extent to which the quantity, price or other terms or conditions relating to the acquisition of the heritage energy by the distribution line of business should vary during the initial ten-year term of the Heritage Contract:

(i) by reason of changed circumstance;

(ii) by reason of a determination that the allocation identified in subparagraph (b) is not appropriate;

(iii) by reason of capital maintenance or similar investments not intended to materially affect the productive capacity of the assets listed in Schedule A; and;

(iv) by reason of any other factor the Commission believes is important;

(g) The renewal provisions which should apply to the continuation of the Heritage Contract after the expiry of an initial ten-year term;

(h) The appropriate regulatory framework:

(i) which provides incentives to, and allows, BC Hydro and its affiliates and subsidiaries to make timely decisions to maximize trade revenues net of costs properly allocated by BC Hydro for internal management purposes in light of the determinations made pursuant to subparagraph (d); and

(ii) to allocate amounts of trade revenue, net of incremental costs properly allocated by BC Hydro for internal management purposes, up to a maximum of $200 million per year, between BC Hydro and customers listed in Schedule B in a manner that provides rewards to the party that takes the risk associated with realizing those rewards while minimizing the expenses and delays associated with regulatory oversight of activities relating to trade;

(i) The determination of the state date of the Heritage Contract including potential adjustments at the start of the Heritage Contract relating to capacity, shape and scheduling flexibility.

4. The Commission shall make specific Recommendations relating to any changes it believes are desirable in the rates of transmission voltage customers to accomplish the objectives set out in the Energy Plan, including:

(a) The terms and conditions that should govern existing and new large industrial or transmission rate customers' access to transmission for the purpose of acquiring power from other energy suppliers' generation;

(b) The detailed provisions of new stepped rate schedules as more fully described in the Energy Plan, including load aggregation by a customer with facilities at more than one location; and

(c) The principles which should govern the terms and conditions under which large industrial or transmission rate customers wishing to obtain generation from alternate suppliers may decline to obtain service from BC Hydro or may apply to obtain service from BC Hydro thereafter.

5. For the purpose of conducting this inquiry and obtaining stakeholder input, the Commission may seek and employ expert advice on various subjects and shall employ any or all of the powers provided to it under the *Act* and, in particular, may, in its sole discretion, employ diverse procedures to resolve specific issues within the Terms of Reference, including, as appropriate, workshops, mediation, dispute resolution mechanisms, pre-hearing conferences, and oral and written public hearings.

6. The Commission shall require BC Hydro to file by April 30, 2003 a proposal that identifies the detailed Recommendations and reasons that BC Hydro believes should be contained in the Commission's report to the Lieutenant Governor in Council.

7. The Commission shall invite comment on BC Hydro's proposal from all affected stakeholders and identify appropriate processes to consider it in compliance with paragraph 5.

8. The Commission shall submit a report to the Lieutenant Governor in Council by no later than October 17, 2003, listing its Recommendations and the reasons for the Recommendations, including proposed legislation, regulations, special directions to the Commission or special directives to BC Hydro, as it thinks fit.

9. The Commission shall consider any other matters that may be specified in supplementary Terms of Reference issued by the Lieutenant Governor in Council pursuant to Section 5 of the *Act*.

March 7, 2003

Application to Suspend Retail Access Program

BC hydro

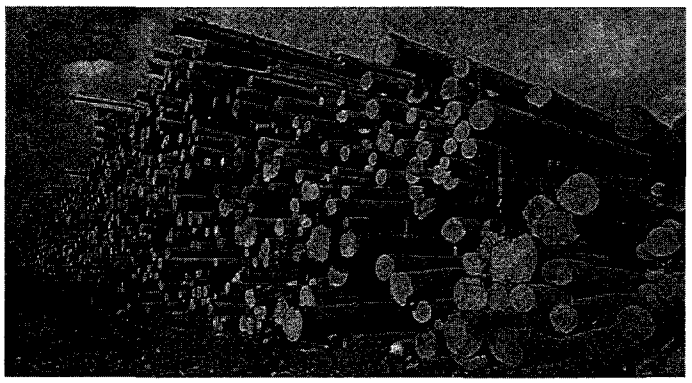
Attachment

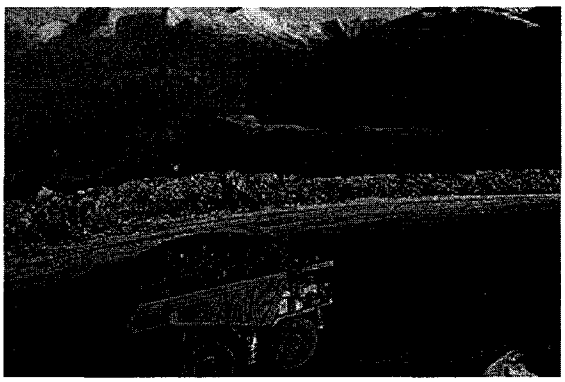
H

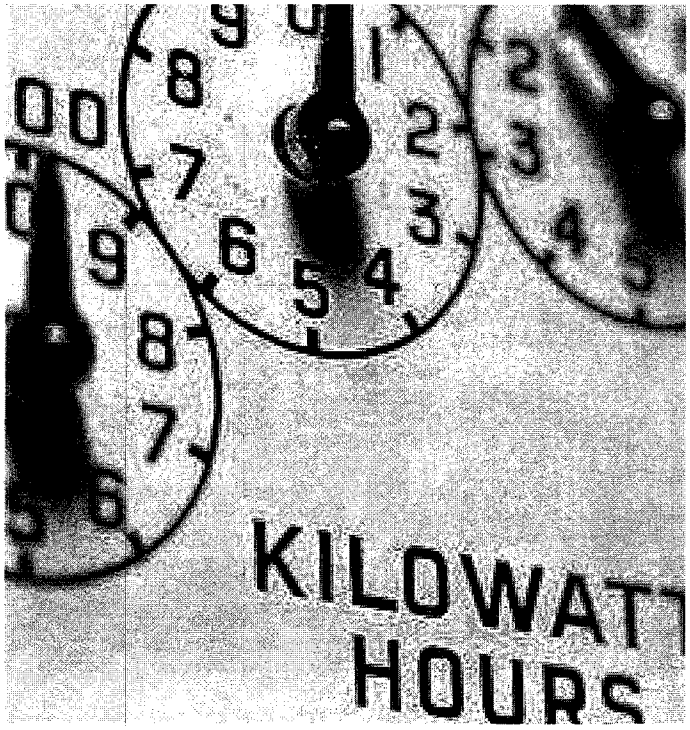
Extracts from the 2009 TSR Report

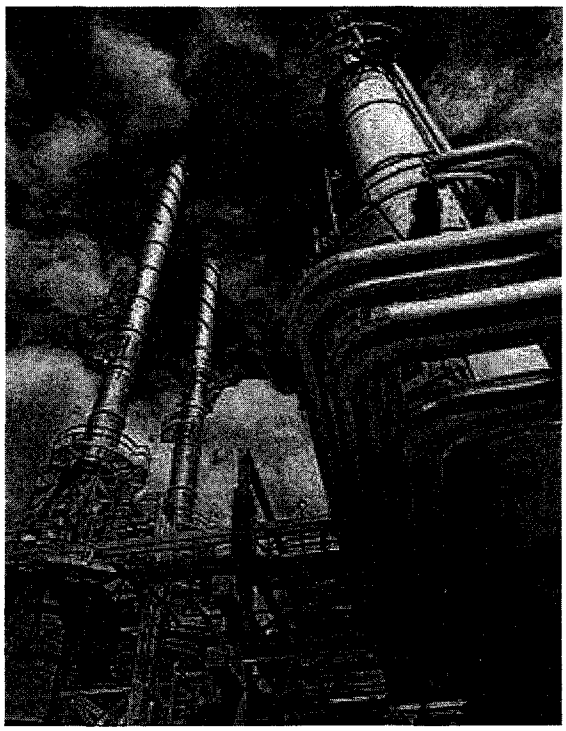
British Columbia Utilities Commission
Report to Government on the British Columbia Hydro and Power Authority Transmission Service Rate Program

December 31, 2009









Executive Summary

The Transmission Service Rate (TSR) program has been in place for three years, F2007-F2009. Recommendation 9 of the BC Utilities Commission's 2003 "Inquiry into a Heritage Contract for British Columbia Hydro and Power Authority's Existing Generation Resources and Regarding Stepped Rates and Transmission Access" requires the Commission to evaluate the program after three years. In February 2009, the Commission established the Terms of Reference for the evaluation, specifying eight questions to be addressed. The evaluation also provides recommendations for changes to Special Direction HC2 which was issued by Government in response to the Commission's 2003 report.

The TSR Program

The TSR applies to BC Hydro's largest industrial customers; a class that uses about one third of BC Hydro's total electric load. The TSR is a two-tier stepped rate, designed to incent conservation and be revenue neutral for the customer class and customer bill neutral at 100% of Customer Baseline Load (CBL). Each customer is designated an individual CBL based on historical usage and adjusted for annual energy activities. Customers are charged a lower Tier 1 rate up to 90% of CBL and a higher Tier 2 rate above 90% of CBL. The Tier 2 rate is set to signal BC Hydro's long-run cost of new energy supply, while the Tier 1 rate is calculated residually to maintain revenue neutrality for the customer class. The TSR program also has an optional Time of Use Rate and an Exempt Flat Rate which has been granted to specific customers.

Evaluation of the TSR Program

Economic Context

During the F2007-F2009 period, the international economy experienced a remarkable downturn. This recession caused TSR customers to reduce production and energy usage. The analysis of whether the TSR has elicited a conservation response for which it was designed, is clouded by the decreased energy usage caused by the recession.

Conservation Impact

The TSR facilitated conservation by incenting demand side management projects and encouraging companies to look for small savings at the operational or behavioural level. Although the recession may be responsible for some of the electricity savings seen since the TSR was implemented, the rate provides a financial conservation incentive to many industrial customers.

Cost Shifting

Costs have shifted from the TSR customer class to other customer classes but these costs shifts are either immaterial to the overall revenue generated by the class or are due to uncontrollable outside market events.

Retail Access

The TSR has not facilitated retail access from other electricity suppliers because BC Hydro is the lowest cost electricity provider and sourcing from other suppliers increases a firm's transactions costs and supply risk.

Time-of-Use Rate

No customers opted for the Time of Use rate because they view the rate as overly complicated and expect it to increase energy costs.

Elements Leading to Suboptimal Results

The revenue and customer bill neutrality principles of the rate limit the financial incentive to conserve and the TSR does not incent energy efficiency measures which specifically decrease energy use per unit of output. As well, the rate structure creates inconsistent customer bills and can bias cost benefit analyses against large project investments.

Other Considerations

Within the industrial class, firms vary in the extent to which they can respond to the TSR incentives. Surveyed companies reported that having company energy managers and help from BC Hydro Key Account Managers supported their conservation response to the TSR program.

Recommendations

BC Hydro contracted Innovologie Inc. to survey TSR customer opinions about the program. Respondents resoundingly reported a preference for the TSR not to be changed. The Commission agrees that the current TSR structure should not be significantly altered until either economic conditions stabilize or general Time of Use rates, in connection with smart metering initiatives, are put forward by BC Hydro. It is the Commission's position that any future changes to the TSR program should be made in consultation with stakeholders.

The Commission recommends the following changes to Special Direction HC2:

1. Heritage Contract Recommendation 8: Remove the principles that the Tier 1/Tier 2 split should be set at 90/10 and that the Tier 1 rate should be derived from the Tier 2 rate to achieve revenue neutrality. However, consistent with the position stated by TSR customers, the Commission does not support revising the TSR at this time. The Commission does support removing the two principles to add flexibility to the TSR program as a foundation for future program redesign; and

2. Heritage Contract Recommendations 9, 10 and 13: The Commission supports the removal of these three Recommendations as they are now outdated.

As well, the Commission recommends BC Hydro consider minor amendments to the program, including:

1. Removal of the requirement for customers to enter into three year contracts for retail access;

2. Implementation of a comprehensive sales and purchase policy to address the situation where customers are awarded contracts to supply energy to BC Hydro at a higher rate than the Tier 2 price; and

3. Development of cost-effective performance measurements for the TSR program.

If the TSR is revised at a future time, the Commission recommends BC Hydro consider the following:

4. Changes to the CBL determination methodology to:
   i. account for firms with variable production;
   ii. reward energy intensity (efficiency) savings;
   iii. allow customers to select energy years; and
   iv. supplement the current CBL adjustment process with the use of customer's average multi-year historical energy use.

If the above noted changes to Special Direction HC2 are accepted, the Commission recommends BC Hydro consider the following changes at a future time:

5. Modification of the Tier 2/Tier 1 split from 90/10 to a level that increases the conservation incentive; and

6. Modification of the calculation of the Tier 1 and 2 rates so conservation is not limited and costs are not shifted to other classes.

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Appendices

5. Has the transmission services stepped rate facilitated retail access by BC Hydro's transmission customers?

6. If no retail access has occurred, why not? Are there features of the transmission services stepped rate design that detract from the attractiveness of retail access?

The TSR has not facilitated retail access by the industrial customer class because there are costs and risks associated with third-party suppliers which are not associated with BC Hydro. The TSR itself (perhaps with the exception of current Tier 2 pricing) does not detract from the attractiveness of retail access.

5-6.1 BC Hydro is the Least-Cost Supplier

Retail access refers to the purchase of power from a supplier other than BC Hydro. Retail access is intended to permit customers to secure energy needs, which would otherwise be supplied by BC Hydro at Tier 2 rates, from alternative suppliers. BC Hydro notes that the TSR itself is not specifically designed to promote retail access[20] and that since the rate was implemented in 2006, no industrial customers have opted for retail access.[21]

Of the industry executives interviewed for the Innovologie Report, none expressed interest in obtaining electricity through contracts with Independent Power Producers (IPPs) or via the open market.

Generally, IPP-supplied energy is not competitively priced with the BC Hydro TSR Tier 2 rate[22,23] and most IPP power is already committed via contract to other customers.[24] As well, if IPP's have surplus energy available to sell, it is likely on a short-term, non-firm basis, and may be limited to small portions of the year. Energy with these characteristics is not suitable for TSR customers.

In F2009, the open market Mid-Columbia (Mid-C) hub prices ($60.81/MWh, including delivery charges) was lower than the Tier 2 rate ($73.60/MWh).[25,26] Actual Mid-C rates vary and reached an hourly maximum of $126.66/MWh during 2009. Without a fixed supply price, customers expose themselves to price risk. BC Hydro estimates that a fixed supply contract price would cost customers $64.40/MWh.[27] In contrast, BC Hydro supplied TSR energy at an average rate of $23.85/MWh in F2009.[28] Only customers expecting firm energy needs beyond the calculated

[20] Appendix E: BC Hydro Response to BCUC IR 30.2
[21] Appendix F, p. 5
[22] Appendix E: BC Hydro Response to BCUC IR 30.1
[23] Appendix C, Attachment 1, p. 24
[24] Appendix C, p. 20
[25] Appendix E: BC Hydro Response to BCUC IRs 8.1-8.3
[26] Appendix C, p. 20
[27] Appendix C, p. 23
[28] Appendix D, p. 19

CBL load (hence customers with increasing needs priced at the Tier 2 price of $73.60/MWh) might consider committing to retail access.

BC Hydro Tariff Supplement No. 71 requires customers to enter into a 36 month contract with supplier(s)[29] so customers would need confidence that their estimated future needs for what otherwise would be Tier 2 priced energy, would justify commitment to a three year contract. Especially during present economic uncertainties, no customers were willing to take such risk.

5-6.2 Financial Risks and Transaction Costs to Access Third-party Electricity

Even if the Mid-C or IPP price were competitive with the TSR, there remain risks associated with retail access that are avoided by sourcing from BC Hydro. Retail access requires customers to choose a supplier from amongst many, ensure that the supplier will have sufficient energy when needed, and arrange and pay for transmission. These requirements increase cost and uncertainty, and decrease the convenience for customers to use retail suppliers. The three year contract requirement also poses a considerable risk. Despite other barriers to retail access, the Commission is of the opinion that the three year retail access commitment requirement should be reviewed.

The combination of low supply and transaction costs from BC Hydro and price risks from market or IPP power make sourcing from BC Hydro the most appealing choice for industrial customers. It is not anticipated that under current conditions, industrial customers will opt for retail access in the foreseeable future.[30]

7. Why have no customers used the Time of Use Rate?

No customers have opted for the TOU rate because it adds complexity to the rate structure, offers low margins and presents cost risks. As well, customers must have certain operational characteristics to consider TOU rates including: sufficient flexibility in their production process to shift load from High Load Hours (HLH) to Low Load Hours (LLH), or from winter to other months; sophisticated load control systems; and product storage ability to cover intermittent production. The necessity of having certain operational characteristics and the complexity and risks presented by the TOU rate have resulted in no customers choosing the TOU since it was introduced in April 2006.

7.1 TOU Adds Complexity to an Already Complex Rate

The TOU rate creates four pricing periods, each with its own CBL. While conceptually a desirable structure to incent a decrease in energy consumption in the winter when demand for electricity peaks, the TOU adds complexity to the CBL structure. Some industry executives comment that the TSR rate, without the TOU overlay, is already complex, so it can be assumed that additional complexity is a deterrent for customers to choose the TOU rate.

[29] BC Hydro Electric Tariff Supplement No. 71, Term 2.1 (a), p. 3 of 8
[30] Appendix E: BC Hydro Response to BCUC IR 8.2

Application to Suspend Retail Access Program

BC hydro

Attachment

I

Extracts from the 2010/2011 Shareholder's Letter of Expectations

F12/F14 RRA - Appendix D

BRITISH COLUMBIA
The Best Place on Earth

SHAREHOLDER'S LETTER OF EXPECTATIONS

BETWEEN

THE MINISTER OF ENERGY
(AS REPRESENTATIVE OF THE SHAREHOLDER, THE GOVERNMENT OF BRITISH COLUMBIA)

AND

THE CHAIR OF THE BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
(AS REPRESENTATIVE OF BC HYDRO OR THE CORPORATION)

FOR 2011/12

PURPOSE

This Letter of Expectations between the Shareholder and BC Hydro is an agreement on their respective roles, responsibilities and corporate mandate, including high level strategic priorities, public policy issues and performance expectations as documented in the Shareholder's Expectations Manual for British Columbia Crown Agencies[1]. The Letter is the basis for the development of the BC Hydro's Service Plans and Annual Service Plan Reports, and is reviewed and updated annually. The Letter does not create

[1] The Province of British Columbia's Crown Agency Accountability System (http://www.gov.bc.ca/caro/publications/index.html) establishes guiding principles for the governance of Crown corporations. The Shareholder's Expectations Manual identifies roles and responsibilities for the Shareholder and Crown corporations, and provides for a Shareholder's Letter of Expectations (Letter) to be jointly developed.

1

- ensure that Board appointments to BC Hydro's subsidiaries comply with Board Resourcing and Development Office's Best Practice Guidelines and are approved by Cabinet; and
- comply with government's requirement that lobbyists not be engaged to act on behalf of BC Hydro in its dealings with government.

In addition, the Shareholder directs BC Hydro to take the following specific actions:

- support the Shareholder's implementation of the *Clean Energy Act* by pursuing actions to meet British Columbia's energy objectives as described in the *Act,* working in collaboration with the Shareholder, and report to staff of the Ministry of Energy on implementation and issues arising;
- actively pursue extra-Provincial energy trading markets and explore and identify opportunities to facilitate access for independent power producers to sell clean, renewable electricity in western North American markets;
- provide information to the Commission in a manner that allows the Commission to effectively review prudency of costs incurred to implement the measures in the *Clean Energy Act* and of measures and costs to achieve self-sufficiency.
- continue to plan, operate and maintain the transmission system in order to:
  - ensure sustained asset health, reliability and security of the transmission system;
  - ensure that there is adequate transmission capacity available to reliably serve domestic and electricity trade needs, and that all eligible transmission users have non-discriminatory access to this capacity, subject to approval by the Commission;
  - continue to enhance open access transmission tariffs that promote private sector opportunities in wholesale electricity supply and facilitate direct purchase of electricity by large users, subject to the approval of the Commission;
  - continue to enhance wholesale transmission rates that promote maximum use of the transmission grid through appropriate pricing, subject to the approval of the Commission;
  - continue to support the Shareholder in assessing and pursuing the potential for long-term economic expansion in the northeast region of British Columbia, and the ability to mitigate greenhouse gas emissions through new transmission expansions and the use of renewable, low-carbon electricity; and
- capture cost and operational efficiencies when integrating with British Columbia Transmission Corporation. In addition, continue to pursue and implement cost saving measures resulting from the cost structure review as directed in the Corporation's Shareholder's Letter of Expectations signed January 2010.

SHAREHOLDER'S RESPONSIBILITIES

The Shareholder is responsible for the legislative, regulatory and public policy framework in which Crown corporations operate. In order to meet these responsibilities and support achievement of government's performance expectations, the Shareholder will:

- issue performance management guidelines, including guidelines for Service Plans and Annual Service Plan Reports (http://www.gov.bc.ca/caro/publications/index.html); and

Application to Suspend Retail Access Program

BC hydro

Attachment

J

Extracts from the 2005 TSR Application

BC hydro

Richard Stout
Chief Regulatory Officer
Phone: (604) 623-4046
Fax: (604) 623-4407

March 10, 2005

Mr. Robert J. Pellatt
Commission Secretary
British Columbia Utilities Commission
PO Box 250
600 – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Pellatt:

RE: British Columbia Hydro and Power Authority ("BC Hydro")
Transmission Service Rate Application

Pursuant to the *Utilities Commission Act*, R.S.B.C. 1996, c.473, as amended and, in particular, to sections 58 and 61 thereof, BC Hydro hereby applies for an order of the British Columbia Utilities Commission approving the following:

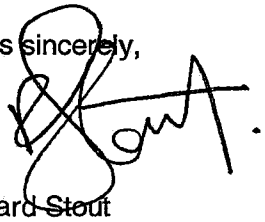
- Transmission Service Stepped Rate Schedule 1823, as a replacement for Rate Schedule 1821;
- Transmission Service Time-of-use (TOU) Rate Schedule 1825;
- Time-of-use Transmission Service Agreement, Electric Tariff Supplement No. 70;
- Transmission Service Rate for Exempt Customers Schedule 1827, as a replacement for Rate Schedule 1821;
- Transmission Service - Standby and Maintenance Supply Schedule 1880, as amended;
- Imbalance Charge for Retail Access Schedule 1890;
- Retail Access Program Agreement, Electric Tariff Supplement No. 71;
- Modified Demand Transmission Service Schedule 1852, as amended; and
- Termination of Transmission Service Rate Schedules.

The Application's scope and rationale are provided in Part 1 of this Application. Part 1 also includes an explanation of the terms and conditions of the rate schedules and retail access provisions that BC Hydro is seeking approval for.

Part 2 of this Application consists of Tab A to I setting out the aforementioned rate schedules, tariff supplements and amendments for which BC Hydro is seeking approval.

All communications in this proceeding are to be directed to the undersigned to the 17th Floor – 333 Dunsmuir Street, Vancouver, BC V6B 5R3. For transmittals by electronic mail please address to **regulatory.group@bchydro.com**.

Yours sincerely,



Richard Stout
Chief Regulatory Officer

Enclosure (20)

c. Joint Industry Electricity Steering Committee
BC Greenhouse Growers Association
Commercial Class Energy Customers of BC
United Flower Growers Cooperative Association
CBT Energy
Independent Power Association of British Columbia
BCOAPO
COPEU
BC Citizens for Public Power
FortisBC
City of New Westminster
University of British Columbia
Elk Valley Coal Corporation
British Columbia Transmission Corporation
Leader Mining
A. Wait
I. Minty
IBEW Local 258

BC hydro

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

TRANSMISSION SERVICE RATE APPLICATION

Submission to the
British Columbia Utilities Commission

March, 2005

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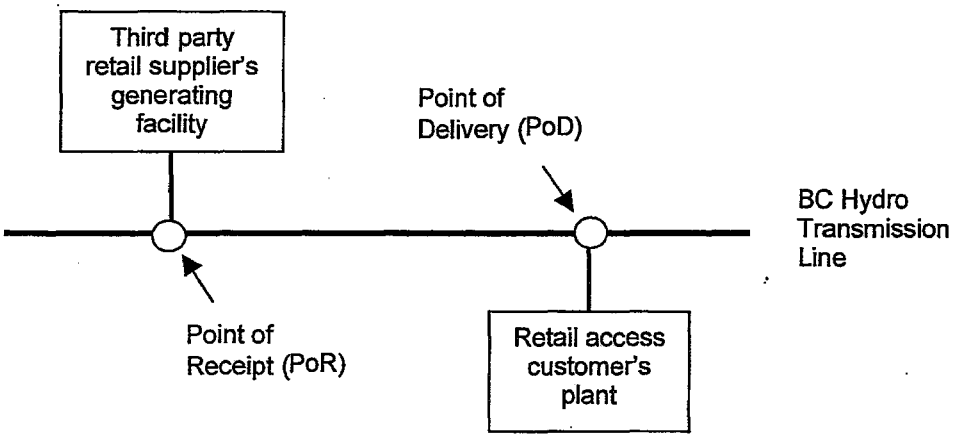
7.0 Retail Access

Per the BCUC Recommendations, BC Hydro proposes the following as its (generation) retail access model.

7.1. Interconnection Terms

Figure 8. Interconnection terms



The interconnection points depicted in Figure 8 are used throughout the following discussion on BC Hydro's proposed Retail Access model.

7.2. Third Party Retail Suppliers

For the purpose of the retail access proposal, a third party retail supplier is defined to be a power marketer, an independent power producer (IPP), or a customer who has on-site generation. However, for a customer with on-site generation capabilities, only its excess generation, as defined by Commission Order G-38-01, can be sold to other customers under retail access. The customer may use its existing point of interconnection as the

Point of Receipt (PoR) on BC Hydro's transmission grid for the sale of retail access energy.

The third party retail supplier can source the energy needed to serve the retail access customer via transactions in the wholesale market or its own physical generation. In all cases, the supplier is responsible for ensuring that the scheduled energy is delivered to BC Hydro's transmission grid at a PoR and that BC Hydro receives the proper data which verifies the quantity of energy delivered at the PoR. IPPs who are interconnected to BC Hydro's distribution grid are responsible for wheeling the energy to the transmission system using BC Hydro's RS1268. Customers with excess on-site generation are responsible for any system upgrades as well as having a revenue-class standard meter and any related telecommunication equipment installed on their generator(s). Depending on the location of the generator's meter and the actual PoR, there may need to be energy loss adjustments made to the meter readings to reflect the deemed output at the PoR.

System reinforcements may be required depending on the PoR and the quantity of energy from the third party supplier. Any such system reinforcements and the associated costs would be dealt with between the third party retail supplier and BCTC.

Practically, BC Hydro considers that there are two alternatives for a third party to participate as a retail supplier:

- It could use Point-to-Point transmission service under BCTC's OATT (Open Access Transmission Tariff) to deliver energy from a PoR to a Point of Delivery (PoD) at the retail access customer's interconnection to the grid; or

- It could, with BC Hydro's consent, provide energy to the retail access customer via BC Hydro as an integrated network resource.

7.3. Retail Access via OATT

Under OATT, the retail access customer would arrange for transmission service from BCTC and the energy from a third party supplier. BC Hydro does not have access to information regarding what transmission capacity the customer has booked on the system nor the quantity of energy delivered. As such, under this scenario, BC Hydro is proposing that the customer expose its full load to retail access. In the process, the retail access customer becomes a customer of BCTC and ceases to be a customer of BC Hydro.

7.4. Retail Access as an Integrated Network Resource

The principle upon which BC Hydro will accept a third party retail supplier as an integrated network resource, for the purpose of retail access, is that the third party retail supplier must pay for all network upgrade and interconnection costs necessary for it to supply energy to a retail access customer. To the extent that this principle is inconsistent with the to-be-approved OATT, BC Hydro will file for any variances necessary with the Commission for approval to ensure that the above principle is met.

Under this form of retail access, BC Hydro would treat the energy from the third party retail supplier as an integrated network resource. As such, the customer will continue to be supplied by BC Hydro.

If, for any reason, the third party retail supplier's output deviates from the schedule, BC Hydro would alter its operations on a real-time basis to accommodate such deviations (whether the supplier is over- or under-supplying at a point in time when compared to the schedule). The rate for providing this load imbalance service is set out in the proposed RS1890 (see Tab F). A discussion of the imbalance charge is in Section 7.5.

Under BC Hydro's retail access proposal, BC Hydro will invoice the customer for the customer's actual load less the scheduled loss-adjusted load supplied by the third party retail supplier. Any imbalance charges as a result of the output variations by the third

party retail supplier will also be billed to the customer (as a separate line item on its monthly invoice). BC Hydro considers that any supply or credit risk issues associated with the third party supply should be addressed between the customer and the supplier.

BC Hydro will continue to apply the transmission demand charge to the customer's full load. This is consistent with other customers who are being served by BC Hydro with its integrated network resources.

7.5. Imbalance Charge

The real-time price of electricity in the wholesale market varies within a day, and across months. This price variation is dependent on load requirements and supply availability at the time. The wholesale market prices typically reflect both BC Hydro's and the third party retail supplier's short-term opportunity costs.

While wholesale market prices change on a real-time basis, the energy prices of the Stepped Rate apply to all energy consumed by the customer throughout the year, irrespective of the timing of the consumption. As a result, third party retail suppliers may be able to arbitrage between the wholesale market and retail access under the Stepped Rate, by selling into the wholesale market when wholesale prices are higher than the Stepped Rate, and vice versa.

If a supplier did benefit from arbitraging between the wholesale market and its retail access contract, BC Hydro would then be responsible for serving more of the customer's energy requirements during high priced times in the wholesale market (when BC Hydro's opportunity cost is high) and less during low priced times (when BC Hydro's opportunity cost is low). In such a case, there would be a shift of costs to BC Hydro's non-participating customers, resulting in financial harm to non-participants.

To avoid this potential shift of costs to other customers, BC Hydro proposes that the customer provide an output schedule for its third party supplier. Any variances from this schedule would be subject to an imbalance charge that is reflective of BC Hydro's

opportunity cost. As the imbalance energy is provided on a real-time basis, BC Hydro believes that the Energy Imbalance Price as proposed by BCTC's Rate Schedule 106 (Energy Imbalance Service) is a reasonable and transparent proxy of its short-term opportunity cost.

However, due to complexity of the pricing structure of the proposed BCTC Energy Imbalance Price (i.e., one set of prices for small quantities of imbalance energy, which changes to a buy / sell structure if the deemed quantity is exceeded), BC Hydro is proposing that the TOU energy rate be its imbalance charge under retail access. The TOU charge has varying price levels by month and by daily HLH / LLH time periods.

7.6. Shape and Output Schedule from Third Party Retail Supplier

As mentioned above, the TOU energy prices vary across months and between the HLH and LLH periods within a day. Based on this definition as its near-term opportunity cost, BC Hydro will require the customer to provide an output schedule for its third party supplier containing a fixed quantity of energy for each pricing period in a three-year timeframe. Pricing periods are defined as the non-winter billing months and the HLH and LLH periods of the winter billing months (for a total of 16 pricing periods per year).

The output schedule forms part of the customer's Retail Access Program Agreement. To minimize arbitrage and for planning purposes, BC Hydro proposes that for each three year schedule in the Retail Access Program Agreement, the maximum total monthly scheduled output should be no greater than 120% of the minimum total monthly scheduled output.

With 1 year's notice, the customer may provide an updated output schedule for a three-year period going forward. The ratio of the maximum monthly energy output to the minimum monthly output would be applied to the new three-year schedule. In effect, the customer is committed to its schedule for one year with the remaining two years being an indicative schedule.

Changes to the schedule are applied on a Billing Year basis (April to March billing periods). Upon receipt of the 1 year's notice from the customer, the changes to the schedule will be applied to the Billing Year following the end date of the 1 year's notice.

For each pricing period, any aggregate deviations in output from the schedule (at the PoD) would be subject to the imbalance charge.

If the actual cumulative energy delivered by the third party retail supplier deviates significantly from its schedule, there may be additional costs borne by BC Hydro. BC Hydro can mitigate somewhat the volume risk on the up-side (when there is over-supply of retail access energy) by reducing the pricing incentive within the imbalance charge. This is discussed in more detail in Section 7.7.

For significant shortfalls from the supplier, there may be additional costs borne by BC Hydro for the incremental energy that is not sufficiently covered by the imbalance charge. However at the moment BC Hydro is unclear as to what additional costs may arise and the significance of these costs.

The net energy imbalance produced by third party retail suppliers may or may not be of a significant quantity. As such the volume risk may only be a minor issue. Therefore, BC Hydro proposes that the volume risk of imbalance energy be one of the items to be covered in its Evaluation Report[22].

7.7. Retail Access under the Stepped Rate and the TOU Rate

BC Hydro proposes to bill the customer, per RS1823 or RS1825, whichever is applicable, for energy consumed from BC Hydro as the difference between its actual consumption, per revenue meter readings, and the scheduled output from the third party retail supplier. On the same invoice, BC Hydro will also bill the customer for any imbalance charges as a result of output deviations from the scheduled retail access

[22] The evaluation report as directed by the Government in HSD #2 – BCUC Recommendation #9

energy (see Tab F). Both actual and scheduled output from the third party retail supplier are adjusted for energy losses to determine the deemed amounts at the PoD. The energy rates used for the imbalance charge are based on the TOU Tier 2 energy prices. However, if the actual cumulative imbalance energy (actual energy output less scheduled energy at PoD) for a pricing period is more than 10% of the scheduled retail access energy, then the excess imbalance energy beyond the 10% will only be credited at the TOU Tier 1 rate for the pricing period because of volume risk concerns due to over supply as discussed in Section 7.6.

7.8. Loss Adjustment

A loss adjustment is required to reflect transmission losses when energy moves through BC Hydro's transmission grid. Based on BCTC's Rate Schedule 110, a loss-adjustment factor of 6.28% will be applied to the energy between the PoR and the PoD. BC Hydro proposes that, for simplicity purposes, this energy loss-adjustment factor be applied to all retail access-related generation irrespective of the location of the PoR , where the third party retail supplier is interconnected, or the PoD site, where the retail access customer is interconnected.

For example, if 5 MWh were supplied at the PoR, then the loss adjusted energy deemed at the PoD would be 5 MWh * (1 – 0.0628) = 4.686 MWh.

7.9. CBL Modification Under Retail Access

Adjustments to the customer's CBL for retail access are proposed to be treated in a similar manner to customer-funded demand-side management projects. The quantity of retail access energy for the purposes of CBL adjustments is defined as net scheduled output at the PoD. Variations from schedule are dealt with through an imbalance charge and are not part of the CBL adjustment process. This will maintain the marginal pricing incentives for the customers who participate in retail access.

7.10. Retail Access Program Rules

From a planning perspective, it is desirable to have resources that can be counted on for a relatively longer duration in time. In addition, to fully assess the impact of retail access and its long-term viability, participation by the customer would also need to be of sufficient duration. As such, BC Hydro proposes that when a customer participates in retail access, the customer shall stay on retail access for a minimum of three years. In addition, for planning purposes, a return to BC Hydro service would require a minimum 1 year's notice.

The terms for exit from the retail access program are provided in the Retail Access Program Agreement (see Tab G).

9.0 Implementation

9.1. Implementation Date

BC Hydro proposes that RS1821 customers be on the Stepped Rate, the TOU Rate or on the Exempt Rate on the start of the customer billing period that starts closest to April 1, 2006.

9.2. CBL Determination

BC Hydro proposes to use the data from the 12 billing periods starting with the billing period that starts closest to January 1, 2005 to establish the initial CBLs. This will provide a three-month period (January 1, 2006 to March 31, 2006) to analyze the 2005 data, make any necessary adjustments to the metered data, and submit and obtain Commission approval of the initial CBLs prior to the implementation of the Stepped Rate, which starts with the billing period closest to April 1, 2006.

Customers wishing to have their CBLs aggregated should inform BC Hydro by February 15, 2006.

All initial CBL's for the Stepped Rate and TOU Rate will be sent to the Commission for approval by March 15, 2006.

Any subsequent CBL adjustments will also be sent to the Commission for approval.

A customer may raise any disagreement with respect to its CBL with the Commission. In the event that approval is not provided in time to bill, then BC Hydro will use the filed CBL for billing purposes and make any required billing adjustments, once approval has been granted, if the CBL approved by the Commission varies from that filed.

9.3. Stepped Rate and TOU Rate Option Choice

Customers on the Stepped Rate wishing to subscribe to the TOU Rate option must notify BC Hydro by February 15th and sign a TOU supplemental agreement by March 15th in

each year. Customers on TOU can go back onto the Stepped Rate after a 3-year minimum contract term and must provide BC Hydro with 1 year's notice of their intention to terminate their TOU agreement.

9.4. Retail Access

Customers may elect retail access effective on the start of the customer billing period that starts closest to April 1st if notice is provided to BC Hydro no later than February 15th, and if a signed retail access program agreement is provided by March 15th.

The Retail Access Program Agreement is included in Tab G of this Application.

To keep the administration simple, BC Hydro is proposing the following:

- There is no minimum or maximum load required to be served under retail access;
- The customer can elect to have more than one supplier serve its retail access load; and
- Similarly a single third party retail supplier can serve more than one retail access customer.

Application to Suspend Retail Access Program

BC hydro

Attachment

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Tariff Supplement No. 71

BC Hydro

BC Hydro
Electric Tariff
Supplement No. 71

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Electric Tariff Supplement No. 71

RETAIL ACCESS PROGRAM AGREEMENT

THIS RETAIL ACCESS PROGRAM AGREEMENT is referred to as the "Agreement" and is made to be effective on the _____ day of _____ 200__,

BETWEEN:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, a body corporate with its head office at 333 Dunsmuir Street, Vancouver, British Columbia

("B.C. Hydro")

AND: _____

_____

_____

("the Customer")

WHEREAS

A. B.C. Hydro is supplying or will supply Electricity to the Customer pursuant to an Electricity Supply Agreement (the "ESA") between B.C. Hydro and the Customer dated _____;

B. The Customer wishes to take Electricity supply for a portion of its Electricity requirement from third party retail supplier(s).

NOW THEREFORE, THIS AGREEMENT WITNESSES that the parties agree as follows:

BC Hydro

BC Hydro
Electric Tariff
Supplement No. 71

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1. INTERPRETATION

1.1 Definitions

(a) *"Billing Year"* means the 12 billing month period starting with the first day of the Billing Period which commences nearest to April 1st each year, and ending on the last day of the 12th Billing Period thereafter;

(b) *"Billing Period"* means a period of 27 to 35 consecutive days as more fully defined in the ESA.

(c) *"Gross Scheduled Output"* means, for any Third Party Retail Supplier, the amount of Electricity (KW.h) which that Third Party Retail Supplier has contracted to supply the Customer at the Point of Receipt as specified in Appendix 1.

(d) *"Gross Actual Output"* means the metered output (KW.h) at the Point of Receipt, or (if the output is not metered at the Point of Receipt or such information is not available) the output as confirmed by data provided by the British Columbia Transmission Corporation, supplied by the Third Party Retail Supplier to serve the Customer at the Point of Receipt.

(e) *"Net Scheduled Output"* means the product (KW.h) of the Gross Scheduled Output times (100% minus the Energy Loss Adjustment Factor, as set forth in Rate Schedule 1823 or 1825, whichever is applicable).

(f) *"Net Actual Output"* means the product (KW.h) of the Gross Actual Output times (100% minus the Energy Loss Adjustment Factor, as set forth in Rate Schedule 1823 or 1825, whichever is applicable).

(g) *"Point of Receipt"* means the point at which a Third Party Retail Supplier has contracted to deliver Electricity into the BC Hydro transmission system to serve the Customer as specified in section 3.1.

(h) *"Third Party Retail Supplier"* means a power marketer, independent power producer, or an existing BC Hydro customer who has excess generation (as defined by the British Columbia Utilities Commission Order G-38-01), who has contracted to supply Electricity to the Customer and who is listed in section 3.1 of this Agreement.

1.2 Interpretation

This Agreement is supplemental to the ESA. Except as specifically modified by this Agreement the ESA shall continue in full force and effect, and shall govern the supply of Electricity to the Customer. Any terms used in this agreement, and not otherwise defined herein, shall have the same meaning as in the ESA, and (without limitation) the provisions of the ESA relating to metering, billing andthe provision of notices, shall apply to anything done or to be done under this Agreement.

2. TERM

2.1 Term of Agreement

(a) This Agreement shall be in force for an initial term ("Initial Term") of three Billing Years commencing from the start of the Billing Year commencing nearest April 1, 20__ and, unless terminated at the end of the Initial Term in accordance with section 2.1(b), shall extend indefinitely on a Billing Year by Billing Year basis, until terminated at the end of any Billing Year in accordance with section 2.1(b).

(b) Either party may terminate this Agreement at the end of the Initial Term, or at the end of any subsequent Billing Year, by giving the other party not less than one year's notice of termination.

3. THIRD PARTY RETAIL SUPPLIER(S)

3.1 List of Third Party Retail Supplier(s)

The following is a list of Third Party Retail Supplier(s) under contract with the Customer to provide Electricity for a portion of the Customer's Electricity requirement under Retail Access:

Third Party Retail Supplier #1: _____

Point of Receipt: _____

Third Party Retail Supplier #2: _____

Point of Receipt: _____

[Other Third Party Retail Suppliers to be listed if applicable]

4. THIRD PARTY RETAIL SUPPLIER SCHEDULED OUTPUT

4.1 Quantity of Scheduled Output

The Gross Scheduled Output for each Third Party Retail Supplier listed in section 3.1 is set forth in Appendix 1 forming part of this Agreement. The Customer acknowledges that the information in Appendix 1 has been supplied by the Customer and that BC Hydro is relying on this information, and the Customer warrants that the information relating to each such Third Party Retail Supplier is correct.

4.2 Range of Scheduled Output Quantity

For each output schedule as set forth in Appendix 1, the highest entry in the "Total Gross Scheduled Energy" column may not in any case be greater than 120% of the lowest entry in that column.

4.3 Change of Scheduled Output

The Customer shall have the right, at the end of any Billing Year during the term of this Agreement, to substitute a revised three-year output schedule containing the information required by Appendix 1 for a further three-year period from the start of the next Billing Year. The Customer must in each case give BC Hydro not less than one years written notice of its intention to substitute a revised output schedule. Provided the revised output schedule complies with the scheduled output range limitation specified in section 4.2, the revised output schedule shall be substituted for the then existing Appendix 1 and shall form part of this Agreement. The Customer warrants that any information contained in a substituted Appendix 1 will be correct as of the date the substituted Appendix 1 takes effect.

5. RATE SCHEDULE 1890 – ENERGY IMBALANCE

This Agreement is subject to the terms of Rate Schedule 1890 – Energy Imbalance. Any energy imbalance charges or credits to which the customer is subject will be applied in accordance with Rate Schedule 1890.

6. CONFIDENTIALITY

The terms of this Agreement, and any information provided by one Party to the other Party under this Agreement, will be kept confidential by the Parties, except to the extent that: (i) release or disclosure is necessary to enable a Party to fulfill its obligations under this Agreement, (ii) information is already in the public domain or enters the public domain other than through actions of the Party disclosing the information, (iii) release or disclosure is consented to by the other Party, (iv) release or disclosure is required by applicable laws, rules or regulations. The Customer acknowledges that BC Hydro is subject to the *Freedom of Information and Protection of Privacy Act* (British Columbia) and that BC Hydro's non-disclosure obligations under this Agreement may be subject to the provisions of that Act.

BC Hydro

BC Hydro
Electric Tariff
Supplement No. 71

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IN WITNESS WHEREOF the parties hereto have signed this Retail Access Program Agreement as of the date first above written.

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

By: _____

Name: _____

Title: _____

Customer _____

By: _____

Name: _____

Title: _____

BC Hydro

BC Hydro
Electric Tariff
Supplement No. 71

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Effective

APPENDIX 1

Gross Scheduled Output for Third Party Retail Supplier #1:

Year / Month	*Gross Scheduled HLH Energy (kWh)*	*Gross Scheduled LLH Energy (kWh)*	*Total Gross Scheduled Energy (kWh)*
April 2006			
May 2006			
June 2006			
July 2006			
August 2006			
September 2006			
October 2006			
November 2006			
December 2006			
January 2007			
February 2007			
March 2007			
April 2007			
May 2007			
June 2007			
July 2007			
August 2007			
September 2007			
October 2007			
November 2007			
December 2007			
January 2008			
February 2008			

BC Hydro

BC Hydro
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March 2008	[redacted]	[redacted]	
April 2008	[redacted]	[redacted]	
May 2008	[redacted]	[redacted]	
June 2008	[redacted]	[redacted]	
July 2008	[redacted]	[redacted]	
August 2008	[redacted]	[redacted]	
September 2008	[redacted]	[redacted]	
October 2008	[redacted]	[redacted]	
November 2008			
December 2008			
January 2009			
February 2009			
March 2009	[redacted]	[redacted]	

Application to Suspend Retail Access Program

BC hydro

Attachment

L

Rate Schedule 1890

BC Hydro
Rate Schedules
Effective: 01 April 2008
Original Page 61

SCHEDULE 1890 – TRANSMISSION SERVICE – ENERGY IMBALANCE

Availability: For Customers supplied with Electricity under Schedule 1823 and 1825 who have entered into a Retail Access Program Agreement which is in effect, subject to the Special Conditions below.

Applicable in: Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.

Energy Charge / Credit: Winter Months

The Energy Charge / Credit is the sum of (i) the HLH Energy Imbalance Price times the HLH Incremental Energy, and (ii) the LLH Energy Imbalance Price times the LLH Incremental Energy.

Remaining Months

The Energy Charge / Credit is the Energy Imbalance Price times the Incremental Energy.

The Energy Charge / Credit is a charge to the Customer if the sum is greater than zero, and a credit to the Customer if the sum is less than zero.

Winter months are the 4 Billing Periods starting with the first day of the Billing Period, which commences nearest to November 1st each year, and ending on the last day of the 4th Billing Period thereafter. Remaining months are Billing Periods that are not within the Winter months.

Incremental Energy means:

An amount of energy equal to the Net Scheduled Output in a Billing Period minus the Net Actual Output in that Billing Period. For the Winter Months, this calculation is done separately for the HLH and LLH periods within a Billing Period.

Incremental Energy may, for each Billing Period, and, where applicable, for the HLH and LLH in a Billing Period, have a value greater than or less than zero. The terms Net Scheduled Output and the Net Actual Output are as defined in the Retail Access Program Agreement.

ACCEPTED: MAY 30 2008
ORDER NO. G-130-07

COMMISSION SECRETARY

BC Hydro
Rate Schedules
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Energy Imbalance Price:

Pricing Period	Tier 1 Price (¢ / kW.h)	Tier 2 Price (¢ / kW.h)	
Mar to Apr	3.108	7.269	
May to June	3.108	6.629	
July to Oct	3.108	7.269	
Nov to Feb	3.108	8.213 (HLH)	7.443 (LLH)

Pricing Period as used in the table above means (i) for the Winter months, the HLH or LLH as applicable, and (ii) for the Remaining months, all hours in the Billing Period.

Where the Incremental Energy is a positive number, the Energy Imbalance Price is the Tier 2 Price, for the respective Pricing Period.

Where the Incremental Energy is a negative number, for Incremental Energy between 0% and –10% of the Net Scheduled Output, the Energy Imbalance Price is the Tier 2 Price for the respective Pricing Period. For Incremental Energy less than -10% of the Net Scheduled Output, the Energy Imbalance price is the Tier 1 Price.

The HLH period is defined as the hours from 06:00 to 22:00 Monday to Saturday, except for Statutory Holidays. The LLH period is defined as all other hours.

Statutory Holidays for the purpose of this Schedule are New Years Day, Good Friday, Victoria Day, Canada Day, B.C. Day, Labour Day, Thanksgiving Day, Remembrance Day, and Christmas Day.

Special Conditions:

1. If the Customer's metered consumption in any Billing Period is less than the aggregate Net Actual Output of all Third Party Retail Suppliers listed in Appendix 1 to the Customer's Retail Access Program Agreement during that Billing Period, no Energy Imbalance charge is payable for that Billing Period. For the Winter Months, this determination is done separately for the HLH and LLH periods within a Billing Period.

2. Energy Imbalance service under this Schedule is available for Retail Access energy delivered by BCTC provided that the Customer authorizes BCTC to provide the hourly energy schedule booked with BCTC to BC Hydro, for billing purposes.

Note: The terms and conditions under which transmission service is supplied are contained in Electric Tariff Supplements 5 and 6.

ACCEPTED: May 18, 2011

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Taxes:	The rates contained herein are exclusive of the Goods and Services tax and the Social Services tax.
Rate Rider:	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Interim Increase:	Effective May 1, 2011 the Rates and Minimum Charge under these schedules include an increase of 8% before rounding, approved by BCUC Order No. G-72-11.

ACCEPTED: May 18, 2011

ORDER NO. G-72-11

ACTING COMMISSION SECRETARY

Application to Suspend Retail Access Program

BC hydro

Attachment

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Rate Schedule 1823

SCHEDULE 1823 – TRANSMISSION SERVICE – STEPPED RATE

Availability: For all purposes. Supply is at 60,000 volts or higher. Customers being supplied with electricity under Schedule 1825 (Transmission Service Time-of-use) may only revert to service under this Schedule as permitted under Schedule 1825.

Applicable in: Rate Zone 1 excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.

Rate: Demand Charge: $6.027 per kV.A of Billing Demand per Billing Period.

Plus

Energy Charge:

A. For new Customers and Customers that do not have a CBL by Order of the British Columbia Utilities Commission:

3.533 ¢ per kW.h for all kW.h per Billing Period

This rate will apply until the Customer has been supplied with Electricity under this Schedule for 12 Billing Periods or other period with the approval of the British Columbia Utilities Commission, after which the Customer will be supplied with Electricity at the Rate specified in Part B below.

B. For Customers with a CBL:

3.108 ¢ per kW.h applied to all kW.h up to and including 90% of the Customer's CBL in each Billing Year.

7.360¢ per kW.h applied to all kW.h above 90% of the Customer's CBL in each Billing Year.

Note: Customers previously supplied with electricity under Schedule 1825 will be subject to the rates in Part B above from the time the Customer commences taking service under this Schedule.

Billing Year: The Billing Year is the 12 billing month period starting with the first day of the Billing Period which commences nearest to April 1st in each year, and ending on the last day of the 12th Billing Period thereafter.

ACCEPTED: May 18, 2011

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Billing Demand:	The Demand for billing purposes shall be: 1. the highest kV.A Demand during the High Load Hours (HLH) in the Billing Period; or 2. 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or 3. 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant, whichever is the highest value, provided that for new Customers the Billing Demand for the initial 2 Billing Periods shall be the average of the daily highest kV.A Demands for the Customer's Plant. The HLH period is defined as the hours from 06:00 to 22:00 Monday to Saturday, except for Statutory Holidays. The LLH period is defined as all other hours. Statutory Holidays for the purpose of this Schedule are New Years Day, Good Friday, Victoria Day, Canada Day, B.C, Day, Labour Day, Thanksgiving Day, Remembrance Day and Christmas Day.
Monthly Minimum Charge:	$6.027 per kV.A of Billing Demand
Customer Baseline Load:	The Customer Baseline Load (CBL) is the Customer's historic annual energy consumption in kW.h as approved by the British Columbia Utilities Commission. The Customer's CBL will initially be determined by BC Hydro, and be subject to revision from time to time, in accordance with the criteria and procedures set forth in BC Hydro's "Customer Baseline Load (CBL) Determination Guidelines". All CBLs will be subject to final approval of the British Columbia Utilities Commission.
Aggregation of Customer Baseline Load:	A Customer having two or more operating plants may elect to have a single aggregated CBL determined for all or any combination of its operating plants in accordance with the CBL Determination Guidelines. Thereafter, BC Hydro will issue a single bill for all operating plants included in the aggregation, and the energy charge payable will be determined on the basis of the aggregated CBL. However, the Demand Charge will continue to be determined separately for each operating plant.

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Energy Determination under Retail Access:

If the Customer has entered into a Retail Access Program Agreement that is in effect, the quantity of Schedule 1823 energy is defined as the total metered kW.h consumption of the Customer's Plant less the Net Scheduled Output. The Net Scheduled Output is the Gross Scheduled Output adjusted by the Energy Loss Adjustment Factor of 6.28%. The Net Scheduled Output and Gross Scheduled Output are as defined in the Retail Access Program Agreement. If the Net Scheduled Output is greater than the total metered kW.h consumption of the Customer's Plant, then the quantity of Schedule 1823 energy is zero.

Special Conditions:

The following Special Conditions are applicable to this Schedule:

1. If any initial, revised, or aggregate CBL for a Customer has not been determined by BC Hydro and approved by British Columbia Utilities Commission by the time the CBL would become effective, BC Hydro may determine the CBL on an interim basis, and apply the CBL so determined for purposes of any Billing Periods and bills rendered to the Customer until such time as the CBL has been finally determined and approved by the British Columbia Utilities Commission, whereupon BC Hydro will make any necessary billing adjustments.

2. If a Customer taking service at the rates in Part B of the Energy Charge rate section above terminates service under this Schedule prior to the end of a Billing Year, the Customer's CBL or aggregate CBL will be prorated for the portion of the Billing Year during which the Customer was taking service, and the prorated CBL or aggregate CBL will be used for purposes of applying the rates in Part B to all electricity consumption during the Billing Year up to the time of termination. BC Hydro will make any necessary billing adjustments and bill the Customer for the difference (if any) owing.

Taxes:

The rates and minimum charge contained herein are exclusive of the Goods and Services tax and Social Services tax.

Note:

The terms and conditions under which transmission service is supplied are contained in Electric Tariff Supplements 5 and 6.

Rate Rider:

The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Interim Increase:

Effective May 1, 2011 the Rates and Minimum Charge under these schedules include an increase of 8% before rounding, approved by BCUC Order No. G-72-11.

ACCEPTED: May 18, 2011

ORDER NO. G-72-11

ACTING COMMISSION SECRETARY

Application to Suspend Retail Access Program

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OATT Extracts

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Open Access Transmission Tariff (OATT)

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COMMISSION SECRETARY

PART I. COMMON SERVICE PROVISIONS

1. Definitions

1.1 Affiliate

With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

1.2 Ancillary Services

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.3 Annual Transmission Costs

The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider or modified by the Commission.

1.4 Application

A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.4.1 Business Day

Monday through Friday, excluding Statutory Holidays.

1.4.2 Calendar Day

Any day including Saturday, Sunday or a Statutory Holiday.

1.5 Commission

The British Columbia Utilities Commission.

1.6 Completed Application

An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.7 Control Area

An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(a) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(d) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.8 Curtailment

A reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

1.9 Delivering Party

The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.10 Designated Agent

Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.11 Direct Assignment Facilities

Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and may require Commission approval.

1.11.1 Direct Damages

Direct damage or loss excluding loss of profit, loss of revenue, loss of production, loss of earnings, loss of contract or any other incidental, consequential, punitive, special, exemplary, or indirect loss or damage whatsoever.

1.12 Eligible Customer

(i) Any electric utility (including the Transmission Provider and any power marketer or US Federal power marketing agency), or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in Canada, the United States or Mexico; however, such entity is not eligible for transmission service that would be prohibited by Section 212(h)(2) of the US Federal Power Act; and (ii) Any retail customer taking unbundled transmission service for all or part of its energy purchase pursuant to a provincial requirement that the Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider, is an Eligible Customer under the Tariff.

1.12.1 Energy Resource Interconnection Service

An Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or non-firm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey Transmission Service.

1.13 Facilities Study

An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.14 Firm Point-To-Point Transmission Service

Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.15 Good Utility Practice

Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including any reliability

standards adopted by the Commission pursuant to section 125.2 of the British Columbia Utilities Commission Act.

1.16 Interruption

A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.17 Load Ratio Share

Ratio of a Network Customer's monthly Network Load to the Transmission Provider's monthly Transmission System load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III of the Tariff and calculated on a monthly basis.

1.18 Load Shedding

The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.19 Long-Term Firm Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one (1) year or more.

1.20 Reserved

1.21 Network Customer

An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.22 Network Integration Transmission Service

The transmission service provided under Part III of the Tariff.

1.23 Network Load

The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load. If a Network Customer designates only part of the load at a discrete Point of Delivery, the Network Customer and the Transmission Provider must agree on a metering procedure to separate the part of load that is served by the Network Customer's NITS and the part of load that is served by a separate Point-To-Point Transmission Service. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.24 Network Operating Agreement

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.25 Network Operating Committee

A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical

considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.26 Network Resource

Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

1.26.1 Network Resource Interconnection Service

An Interconnection Service that allows the Interconnection Customer to integrate its Generating Facility with the Transmission Provider's Transmission System in the same manner as all other Network Resources. Network Resource Interconnection Services in and of itself does not convey Transmission Service.

1.27 Network Upgrades

Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.28 Non-Firm Point-To-Point Transmission Service

Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one (1) hour to less than one (1) year.

1.29 Non-Firm Sale

An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

1.30 Open Access Same-Time Information System (OASIS)

An information system operated by or for the Transmission Provider that satisfies North American industry standards (including those prescribed for US electric utilities by the Federal Energy Regulatory Commission (FERC)) and all Commission requirements (including standards of conduct).

1.31 Part I

Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.32 Part II

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.33 Part III

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.34 Parties

The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.35 Point(s) of Delivery

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.36 Point(s) of Receipt

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.37 Point-To-Point Transmission Service

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.38 Power Purchaser

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.39 Pre-Confirmed Application

An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

1.40 Receiving Party

The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.41 Regional Transmission Group (RTG)

A voluntary organization of transmission owners, transmission users and other entities formed to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.42 Reserved Capacity

The maximum amount of capacity of energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.43 Service Agreement

The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for Long-Term Firm Point-To-Point or Network Integration Transmission Service under the Tariff, and any requests for Short-Term Firm or Non-Firm Point-To-Point Transmission Service made pursuant to an Umbrella Agreement and confirmed over the Transmission Provider's OASIS.

1.44 Service Commencement Date

The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.45 Short-Term Firm Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service under Part II of the Tariff with a minimum term of one (1) hour and a maximum term of less than one (1) year.

1.46 Reserved

1.47 System Impact Study

An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service; and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.48 Third-Party Sale

Any sale for resale to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.49 Transmission Customer

Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement; (ii) receives service under an Umbrella Agreement; or (iii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.50 Transmission Provider

The British Columbia Hydro and Power Authority (BC Hydro).

1.51 Transmission Provider's Monthly Transmission System Peak

The maximum firm usage expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis, of the Transmission Provider's Transmission System in a calendar month.

1.52 Transmission Service

Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis and Network Integration Transmission Service provided under Part III of the Tariff.

1.53 Transmission System

The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.

1.54 Umbrella Agreement

An agreement between the Transmission Provider and an Eligible Customer which provides all the information necessary to enable such Eligible Customer to receive Short-Term Firm or Non-Firm Point-To-Point Transmission Service under this Tariff without the necessity of first executing a Service Agreement. A form of Umbrella Agreement is attached as Attachment A.

1.55 Working Day

Any day in the week excluding weekends and as specified in the Transmission Provider's business practices.

1.56 $ or Dollar

All dollar amounts in the Tariff are in Canadian dollars unless otherwise specified.

PART III. NETWORK INTEGRATION TRANSMISSION SERVICE

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load. Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff.

28. Nature of Network Integration Transmission Service

28.1 Scope of Service

Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

28.2 Transmission Provider Responsibilities

The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider shall include the Network Customer's Network Load in its

Transmission System planning and shall, consistent with Good Utility Practice and Attachment K, and in accordance with Attachment P, endeavour to construct and place into service sufficient transfer capability to deliver the Network Customer's Network Resources to serve its Network Load.

28.3 Network Integration Transmission Service

The Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads.

28.4 Secondary Service

The Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Secondary service shall not require the filing of an Application for Network Integration Transmission Service under the Tariff. However, all other requirements of Part III of the Tariff (except for transmission rates) shall apply to secondary service. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff.

28.5 Real Power Losses

Real Power Losses are associated with all transmission service. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are set out in Rate Schedule 10.

28.6 Restrictions on Use of Service

The Network Customer shall not use Network Integration Transmission Service for: (i) sales of capacity and energy to non-designated loads; or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System. The Transmission Provider shall specify any appropriate charges and penalties and all related terms and conditions applicable in the event that a Network Customer uses Network Integration Transmission Service or secondary service pursuant to Section 28.4 to facilitate a wholesale sale that does not serve a Network Load. All related terms and conditions are specified in Attachment Q-2 and Tariff Supplement No. 3 of the Transmission Provider.

29. Initiating Service

29.1 Condition Precedent for Receiving Service

Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that: (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff; (ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 29.3 and 29.4; (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission; and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G.

29.2 Application Procedures

An Eligible Customer requesting service under Part III of the Tariff must submit an Application, which shall include a deposit approximating the charge for one month of service in accordance with Attachment L, to the Transmission Provider as far as possible in advance of the month in which service is to commence. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications must be submitted by entering the information listed below on the Transmission Provider's OASIS. If the Transmission Provider's OASIS is not functioning, a Completed Application may be submitted by: (i) transmitting the required information to the Transmission Provider by telefax; or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall provide all of the information listed below together with such other information as may be required by the Commission:

(a) The identity, address, telephone number, email address and facsimile number of the party requesting service;

(b) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(c) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(d) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (c) above;

(e) A description of Network Resources (current and 10-year projection). For each on-system Network Resource, such description shall include:

i. Unit size and amount of capacity from that unit to be designated as Network Resource

ii. VAR capability (both leading and lagging) of all generators

iii. Operating restrictions

1. Any periods of restricted operations throughout the year

2. Maintenance schedules

3. Minimum loading level of unit

4. Normal operating level of unit

5. Any must-run unit designations required for system reliability or contract reasons

iv. Approximate variable generating cost ($/MWH) for redispatch computations

v. Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Control Area, where only a portion of unit output is designated as a Network Resource;

For each off-system Network Resource, such description shall include:

vi. Identification of the Network Resource as an off-system resource

vii. Amount of power to which the customer has rights

viii. Identification of the control area from which the power will originate

ix. Delivery point(s) to the Transmission Provider's Transmission System

x. Transmission arrangements on the external transmission system(s)

xi. Operating restrictions, if any

1. Any periods of restricted operations throughout the year
2. Maintenance schedules
3. Minimum loading level of unit
4. Normal operating level of unit
5. Any must-run unit designations required for system reliability or contract reasons
6. Approximate variable generating cost ($/MWH) for redispatch computations;

(f) Description of Eligible Customer's transmission system:

i Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the Transmission Provider

ii. Operating restrictions needed for reliability

iii. Operating guides employed by system operators

iv. Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources

v. Location of Network Resources described in subsection (e) above

vi. 10 year projection of system expansions or upgrades

vii. Transmission System maps that include any proposed expansions or upgrades

viii. Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(g) Service Commencement Date and the term of the requested Network Integration Transmission Service. The minimum term for Network Integration Transmission Service is one (1) year;

(h) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the Network Resources listed pursuant to Section 29.2(e) satisfy the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis; and

(i) Any additional information required of the Transmission Customer as specified in the Transmission Provider's planning process established in Attachment K.

Subject to Attachment M-2, unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) Calendar Days of receipt. The acknowledgment must include a date by which a response will be sent to the Eligible Customer. Subject to Attachment M-2, if an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) Calendar Days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful fifteen (15) Calendar Days after notifying the Eligible Customer of the deficiencies, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with its standards of conduct as approved by the Commission.

29.3 Technical Arrangements to be Completed Prior to Commencement of Service

Network Integration Transmission Service shall not commence until the Transmission Provider and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. Subject to Attachment M-2, the Transmission Provider shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities

The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of

each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

30. Network Resources

30.1 Designation of Network Resources

Network Resources shall include all generation owned, purchased or leased by the Network Customer designated to serve Network Load under the Tariff. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

30.2 Designation of New Network Resources

The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made through the Transmission Provider's OASIS by a request for modification of service pursuant to an Application under Section 29. This request must include a statement that the new network resource satisfies the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) The Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a

non-interruptible basis. The Network Customer's request will be deemed deficient if it does not include this statement and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.3 Termination of Network Resources

The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource at any time but should provide notification to the Transmission Provider as soon as reasonably practicable.

30.4 Operation of Network Resources

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its designated Network Load, plus Non-Firm Sales delivered pursuant to Part II of the Tariff, plus losses, plus power sales under a reserve sharing program. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of the Transmission Provider to respond to an emergency or other unforeseen condition, which may impair or degrade the reliability of the Transmission System. For all Network Resources not physically connected with the Transmission Provider's Transmission System, the Network Customer may not schedule delivery of energy in excess of the Network Resource's capacity, as specified in the Network Customer's Application pursuant to Section 29, unless the Network Customer supports such delivery within the Transmission Provider's Transmission System by either obtaining Point-to-Point Transmission Service or utilizing secondary service pursuant to Section 28.4. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Network Customer's schedule at the delivery point for a Network Resource not physically interconnected with the Transmission Provider's Transmission System exceeds the Network Resource's designated capacity, excluding energy delivered using secondary service or Point-to-Point Transmission Service.

30.5 Network Customer Redispatch Obligation

As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network Customers, and the Transmission Provider.

30.6 Transmission Arrangements for Network Resources Not Physically Interconnected With the Transmission Provider

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 Limitation on Designation of Network Resources

The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

30.8 Use of Interface Capacity by the Network Customer

There is no limitation upon a Network Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads .

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However, a Network Customer's use of the Transmission Provider's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

30.9 Network Customer Owned Transmission Facilities

The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider to serve its power and transmission customers. For facilities added by the Network Customer subsequent to the date new rate schedules of the Transmission Provider implementing the proposed revisions herein are made effective by the Commission, the Network Customer shall receive credit for such transmission facilities added if such facilities are integrated into the operations of the Transmission Provider's facilities; provided however, the Network Customer's transmission facilities shall be presumed to be integrated if such transmission facilities, if owned by the Transmission Provider, would be eligible for inclusion in the Transmission Provider's annual transmission revenue requirement as specified in Attachment H. Calculation of any credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

31. Designation of Network Load

31.1 Network Load

The Network Customer must designate the individual Network Loads on whose behalf the Transmission Provider will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

31.2 New Network Loads Connected With the Transmission Provider

The Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made by a request for a modification of service pursuant to a new Application under Section 29. The Transmission Provider will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section 32.4 and shall be charged to the Network Customer in accordance with Commission policies.

31.3 Network Load Not Physically Interconnected With the Transmission Provider

This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Provider. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Provider's Transmission System, the Network Customer shall have the option of: (i) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load; or (ii) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made by a request for modification of service pursuant to a new Application under Section 29.

31.4 New Interconnection Points

To the extent the Network Customer desires to add a new delivery point or interconnection point between the Transmission Provider's Transmission System and a

Network Load, the Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable.

31.5 Changes in Service Requests

Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (e.g. the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network Customer as reflected in the Service Agreement. However, the Transmission Provider must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

31.6 Annual Load and Resource Information Updates

The Network Customer shall provide the Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff including, but not limited to, any information provided under section 29.2(i) pursuant to the Transmission Provider's planning process in Attachment K. The Network Customer also shall provide the Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide reliable service.

32. Additional Study Procedures For Network Integration Transmission Service Requests

32.1 Notice of Need for System Impact Study

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. Subject to Attachment M-2, if the Transmission Provider determines that a System Impact Study is not necessary, the Transmission Provider shall within thirty (30) Calendar Days of receipt of a Completed Application tender a Service Agreement and, within fifteen (15) Calendar Days of the tendering of the Service Agreement, the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement, or the Application shall be deemed terminated and withdrawn. Subject to Attachment M-2, if the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. Subject to Attachment M-2, in such cases, the Transmission Provider shall within thirty (30) Calendar Days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it with a refundable deposit of $50,000 in accordance with Attachment L to the Transmission Provider within fifteen (15) Calendar Days. If the Eligible Customer elects not to execute the System Impact Study Agreement or not to provide the required deposit in accordance with Attachment L, its Application shall be deemed withdrawn and its deposit shall be returned pursuant to Section 17.3.

32.2 System Impact Study Agreement and Cost Reimbursement

(a) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(b) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible Customers.

(c) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

32.3 System Impact Study Procedures

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) Calendar Day period or as otherwise agreed to with the Network Customer. The System Impact Study shall identify (1) any system constraints, identified with specificity by transmission element or flowgate, (2) redispatch options (when requested by an Eligible Customer) including, to the extent possible, an estimate of the cost of redispatch, (3) available options for installation of automatic devices to curtail service (when requested by an Eligible Customer), and (4) additional Direct Assignment

Facilities or Network Upgrades required to provide the requested service. For customers requesting the study of redispatch options, the System Impact Study shall (1) identify all resources located within the Transmission Provider's Control Area that can significantly contribute toward relieving the system constraint and (2) provide a measurement of each resource's impact on the system constraint. If the Transmission Provider possesses information indicating that any resource outside its Control Area could relieve the constraint, it shall identify each such resource in the System Impact Study. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) Calendar Days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement, or the Application shall be deemed terminated and withdrawn.

32.4 Facilities Study Procedures

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) Calendar Days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the

Eligible Customer shall execute the Facilities Study Agreement and return it with a refundable deposit of $100,000 in accordance with Attachment L to the Transmission Provider within fifteen (15) Calendar Days. If the Eligible Customer elects not to execute the Facilities Study Agreement or not to provide the required deposit in accordance with Attachment L, its Application shall be deemed withdrawn and its deposit shall be returned pursuant to Section 17.3. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) Calendar Day period or as otherwise agreed to with the Network Customer. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of: (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer; (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades; and (iii) the time required to complete such construction and initiate the requested service. As soon as the Facilities Study is complete, the Transmission Provider shall make a copy of the completed Facilities Study available and tender a Service Agreement to the Eligible Customer. The Eligible Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades in accordance with Attachment O and consistent with commercial practices as established under the laws of Canada and the Province of British Columbia. After being tendered with a Service Agreement, the Eligible Customer shall have sixty (60) Calendar Days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

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32.5 Penalties for Failure to Meet Study Deadlines

Section 19.9 defines penalties that apply for failure to meet the study completion due diligence deadlines for System Impact Studies and Facilities Studies under Part II of the Tariff. These same requirements and penalties apply to service under Part III of the Tariff.

33. Load Shedding and Curtailments

33.1 Procedures

Prior to the Service Commencement Date, the Transmission Provider and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System. The Parties will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission Provider will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

33.2 Transmission Constraints

During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate among any Network Customer's use of the Transmission System to serve its designated Network Load.

33.3 Cost Responsibility for Relieving Transmission Constraints

Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, the Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

33.4 Curtailments of Scheduled Deliveries

If a transmission constraint on the Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Transmission Provider determines that it is necessary to curtail scheduled deliveries, the Parties shall curtail such schedules in accordance with the Network Operating Agreement.

33.5 Allocation of Curtailments

The Transmission Provider shall, on a non-discriminatory basis, curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any curtailment will be shared by the Network Customers in proportion to their respective Load Ratio Shares.

33.6 Load Shedding

To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for the Network Customer to shed load, the Network Customer shall shed load in accordance with previously established procedures under the Network Operating Agreement.

33.7 System Reliability

Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to curtail Network Integration Transmission Service without liability on the Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the Transmission Provider, consistent with Good Utility Practice, also may curtail Network Integration Transmission Service in order to: (i) limit the extent or damage of the adverse condition(s) or disturbance(s); (ii) prevent damage to generating or transmission facilities; or (iii) expedite restoration of service. The Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such curtailment. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

34. Rates and Charges

The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs pursuant to this Tariff, along with the following:

34.1 Monthly Demand Charge

The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Transmission Provider's Annual Transmission Revenue Requirement specified in Attachment H.

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34.2 Determination of Network Customer's Monthly Network Load

The Network Customer's monthly Network Load is its hourly load expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) coincident with the Transmission Provider's Monthly Transmission System Peak.

34.3 Determination of Transmission Provider's Monthly Transmission System Load

The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.

34.4 Redispatch Charge

The Network Customer shall pay a Load Ratio Share of any redispatch costs allocated among the Network Customers pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network Customer for redispatch costs in accordance with Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

34.5 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Network Customer pursuant to this Tariff in accordance with the terms, conditions and procedures approved by the Commission.

35. Operating Arrangements

35.1 Operation Under the Network Operating Agreement

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

35.2 Network Operating Agreement

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to: (i) operate and maintain equipment necessary for integrating the Network Customer within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment); (ii) transfer data between the Transmission Provider and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for redispatch required under Section 33, voltage schedules, loss factors and other real time data); (iii) use software programs required for data links and constraint dispatching; (iv) exchange data on forecasted loads and resources necessary for long-term planning; and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either: (i) operate as a Control Area under applicable reliability standards adopted by the Commission; or (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider; or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies applicable

reliability requirements. The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G.

35.3 Network Operating Committee

A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

Application to Suspend Retail Access Program

BC hydro

Attachment

O

Stakeholder Consultation

Stakeholder Consultation

BC Hydro conducted two formal consultations in the course of its review of the Retail Access Program, one on July 14, 2011 with the Association of Major Power Customers (**AMPC**), and a further session on August 25, 2011 to which the customers and stakeholders listed in Table 1 below were invited, and many of whom attended:

Table 1 August 25, 2011 Workshop Invitees

August 25 Retail Access Workshop	
Invited	**Attended**
Acre	No
Ainsworth	No
Air Liquide	No
AltaGas	No
AMPC	Yes
Apache	No
ATCO	No
BCOAPO	No
BCSEA	No
BCUC Staff	Yes
Brookfield	No
Canexus	No
Canfor	No
Cargill	No
Catalyst Paper	Yes (online)
ChemTrade	No
Chevron	No
Commercial Energy Consumers (CEC)	Yes
EnCana	Yes
Epcor	No
FortisBC	No
LaFarge	No
Maxim Power	No
Metro Vancouver	Yes
Morgan Stanley	Yes

August 25 Retail Access Workshop	
Invited	**Attended**
Pacific Western Energy	Yes
Shell Canada	Yes
Teck Resources	Yes
Toyota	No
TransAlta	Yes (online)
TransCanada	Yes
West Fraser	Yes (online)
Westshore Terminals	No
Willis Energy	Yes

The consultation materials for the July 14 and August 25 sessions are included in this attachment.

Summary of the July 14 Consultation with AMPC

About 15 people attended this workshop including representatives from various AMPC member companies along with individuals providing legal and consulting services to AMPC. Representatives from BC Hydro explained the structure of the existing Retail Access Program and described BC Hydro's then-current thinking on changes to the program. Generally, AMPC attendees questioned why BC Hydro could not implement retail access under the existing program framework. AMPC attendees also questioned how retail access would interact with customer site aggregation[1] and how BC Hydro would treat energy imbalances in the event of a sustained drop in customer load.

Summary of the August 25 Consultation with a Broader Group of Stakeholders

Since many attendees were non-industrial customers, BC Hydro's approach at this consultation session was to first provide more historical background and give

[1] RS 1823 customers with two or more operating plants can aggregate their plants for the purposes of determining a CBL. For more information refer to section 5.0 of Tariff Supplement No. 74 (the **CBL Determination Guidelines**) and the RS 1823 rate schedule.

participants a higher level overview of retail access in the province. Generally, attendees from AMPC expressed the view that BC Hydro should conduct a "pilot program" to gain experience within the existing retail access structure. Generally, third party marketers emphasized that import transmission into B.C. is constrained. As a result, these attendees felt that customers would be precluded from accessing external markets if retail access energy was required to be imported using firm transmission.

Some examples of discussion points raised during the session include:

- the interaction between OATT charges and customer demand charges billed on RS 1823.
- whether the Retail Access Program was originally created to facilitate purchases from IPPs as opposed to the market.
- whether customers should be allowed to purchase more retail access energy during periods of lower market prices (low load hour periods for example) and less during periods of higher market prices (high load hour periods for example).

In addition to the formal consultation sessions on July 14, 2011 and August 25, 2011, BC Hydro also:

- outlined potential retail access issues in a February 10, 2011 meeting with AMPC regarding the TSR stepped rate.
- met with a customer on March 12, 2011 regarding their potential interest in the Retail Access Program.
- consulted with BCUC staff on November 22, 2011 regarding, among other things, this application.
- advised the customers and stakeholders listed in Table 1, by email, of its intention to apply to suspend the Retail Access Program.

RETAIL ACCESS PROGRAM UPDATE

UPDATE PRESENTATION TO AMPC JULY 14TH, 2011

PRESENTERS:

Fred James (fred.james@bchydro.com)

And

Justin Miedema (justin.miedema@bchydro.com)

BC hydro
FOR GENERATIONS

For Discussion Purposes Only

WHAT IS THE RETAIL ACCESS PROGRAM?

1. Program intent was to enable customers to purchase **a portion** of their energy supply from third party suppliers:
   - → a domestic IPP;
   - → the Alberta or US market; and
   - → a BC customer with excess self-generation.
2. Comprised of an agreement (Tariff Supplement No. 71) and an Energy Imbalance Rate Schedule (RS 1890).
3. Customer remains a BC Hydro customer and retains their existing Electricity Supply Agreement.

Alternative to the Retail Access Program:

- Customers may choose to purchase their entire load from third party suppliers via the Open Access Transmission Tariff (OATT) and market purchases.

BACKGROUND

How and why was the Retail Access Program created?

2002- BC Energy Plan

- Policy Action #14 states that *"new stepped pricing will provide an incentive for large industrial or transmission rate customers to purchase from IPPs, or to self-generate".*

2005 – TSR proceeding

- BC Hydro included a retail access program proposal as part of the 2005 TSR rate application
- The focus of the proceeding was the development of the stepped rate.
- At the time, BC Hydro's expectation was that BC based IPPs would most likely sell to customers as market prices were relatively high compared to the RS 1821 rate.

2009 – TSR 3 Year Summary Report

- The retail access program was discussed at length and commented on in the report by the BCUC to government (December 31, 2009)

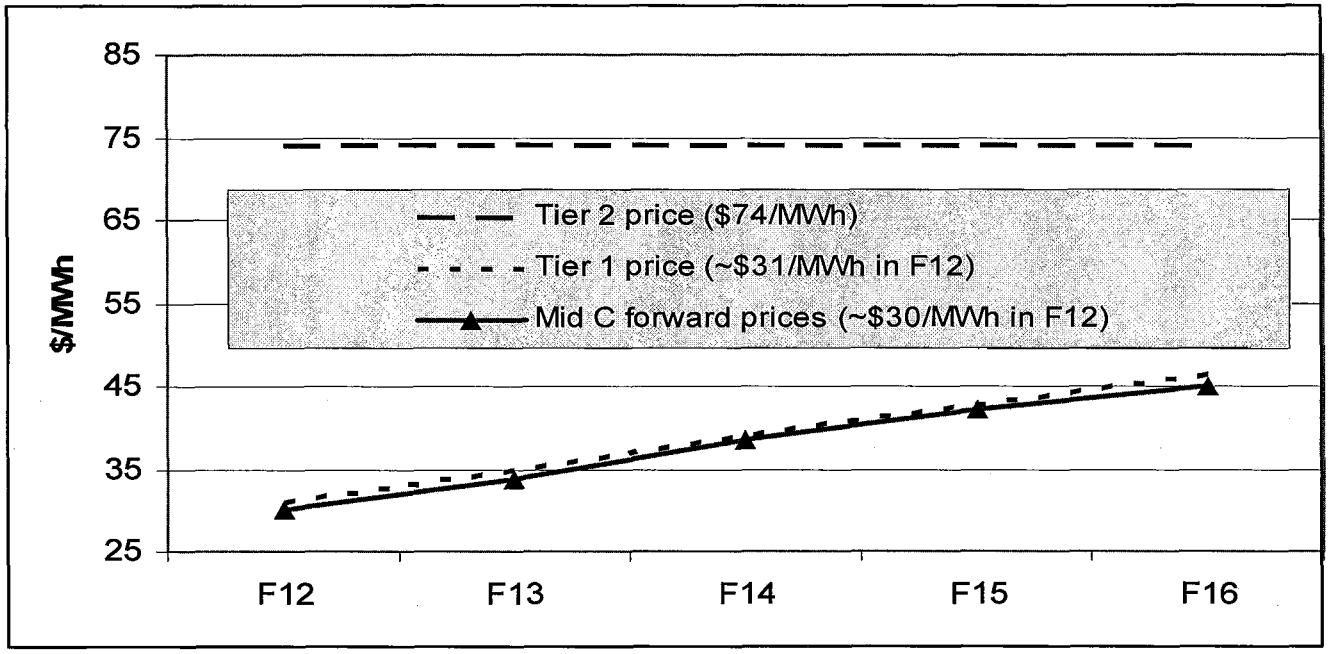
2006 – 2010

- No customers have participated in the program.

BC HYDRO'S REVIEW

Why review the Retail Access Program now?

1. Customer interest in retail access is increasing:
   - BC Hydro rates may rise faster than market prices,
   - The original program was tailored towards third party supply from a BC IPP rather than an external market.



Assumes:

- No transmission costs
- Fixed tier 2 price
- Mid C forward prices from BC Hydro Generation

BC hydro REGENERATION

For Discussion Purposes Only

BC HYDRO'S REVIEW

Why review the Retail Access Program now?

2. The market has changed significantly in that most purchases will likely be made outside of BC.
3. BC Hydro has identified arbitrage opportunities that will potentially harm non-participating ratepayers.
   - Volume arbitrage: an example would be a supplier under delivering in high priced hours and over-delivering in low priced hours with over/under delivery volumes balancing to zero over a month. Tariff needs to be revised to only hourly scheduling.
   - Pricing arbitrage: an example would be a customer paying the tier 2 price to acquire BC Hydro imbalance energy while their supplier, at the same time, redirects supply to a higher market prices.
   - Arbitrage harms existing ratepayers because it increases the frequency of energy imbalances and results in BC Hydro holding additional real time capacity in reserve to backstop customer energy purchases from third party suppliers.

BC HYDRO'S REVIEW

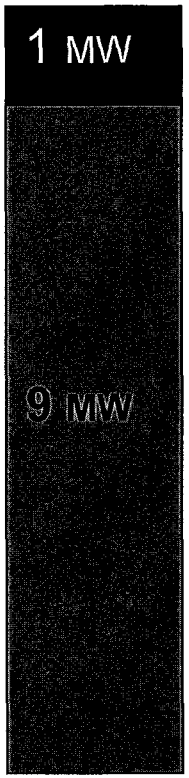
Why review the Retail Access Program now?

4. There is a need to implement billing and energy accounting procedures.
    - There is no process in place to properly account and bill for retail access energy that is purchased from third party suppliers
5. Carbon Liabilities are unclear.
6. Eliminate double counting (ex. OATT charges vs. demand charges)

For Discussion Purposes Only

[redacted]

EXAMPLE OF

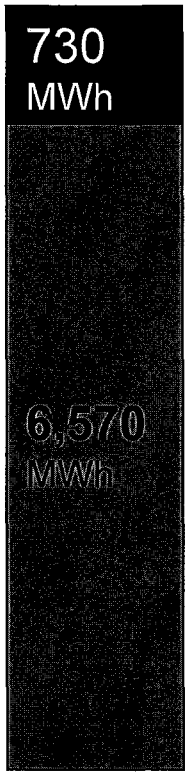


Purchases from a Third party

X 730 hours

Purchases from BC Hydro

10 MW demand charge



Billed Energy purchased from BC Hydro

10 MW billed demand

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BACKGROUND TIMELINE AND SCHEDULE MOVING FORWARD

January 2011	A customer expressed interest in serving part of their load through retail access.
February 2011	BC Hydro advised all TSR customers that BC Hydro would be reviewing the program because of an identified cost shifting risk among customer classes.
March 2011	BC Hydro commenced its program review
Summer 2011	BC Hydro intends to consult with: *AMPC & other Transmission Customers *Other Ratepayer groups (BCOAPO, CECBC, BC SEA) *Other interested parties (IPPs, marketers, etc)
Fall 2011	BC Hydro files an application with the BCUC to amend the program to be available on April 1, 2012.

CHANGES TO THE EXISTING AGREEMENT

BC Hydro's Current Thinking

Existing Retail Access Program	Proposed Changes
3 year agreement with 1 year notice provisions to change volumes	1 year agreement with fixed volumes for the 1 year term
Ability to shape monthly volumes via the 120% rule	Flat hourly block will be required across all months
No requirement to schedule firm energy	Firm energy will be required.
Energy imbalances are: • measured monthly and seasonally • charged monthly • settled monthly. • Priced at Tier 2 or Tier 1 of the stepped rate	Energy imbalances are: • measured hourly • charged hourly • settled monthly. • Priced at prevailing market prices (similar to Schedule 6 of the OATT)

CHANGES TO THE EXISTING AGREEMENT

BC Hydro's Current Thinking

Existing Agreement	Proposed Changes
No clarity on whether customers importing from a third party marketer deliver to the border or "inside" the BC Hydro system.	Customers importing power will be required to secure Point to Point transmission from either the AB-BC border or the US-BC border into the BC Hydro system.
No credits for OATT related charges	If the customer pays their full RS 1823 demand charge, the customer will be credited for OATT related charges associated with bringing electricity from the border into the BC Hydro system.
No clarity on whether the third party supplier or BC Hydro incurs carbon liability from importing	Customers will be responsible for any carbon liabilities associated with their retail access purchases.

CHANGES TO THE EXISTING AGREEMENT

BC Hydro's Current Thinking

Existing Agreement	Proposed Changes
No restriction on volumes purchased from third party suppliers	A volume cap of 50 MW/hour is proposed (438 GWh/year). This is substantially higher than actual tier 2 sales in the past three years . The cap will reduce risk for non-participating ratepayers, ensure transmission customers can access meaningful quantities of retail access energy, and ensure that substantial load remains with BC hydro to cover fixed demand related costs.

WHAT STAYS THE SAME?

Existing program
NITS, rather than Point to Point transactions through the OATT, continues to be used to facilitate transmission across the BC Hydro system.
Backup capacity is priced at the customer's demand charge (pricing based on embedded cost).
Retail access can offset metered energy and it does not result in a downward adjustment to the customer's CBL.

NEXT STEPS

- Next consultation session will be in August with a broader group of stakeholders.
- BC Hydro wants to hear your ideas and suggestions.
- You can email these to BC Hydro at justin.miedema@BChydro.com or call 604-623-4336.

RETAIL ACCESS PROGRAM

AUGUST 25, 2011

PRESENTERS:

David Keir, Transmission Rates Manager, (david.keir@bchydro.com)

Fred James, Rates and Tariff Manager, (fred.james@bchydro.com)

Justin Miedema, Regulatory Specialist, (justin.miedema@bchydro.com)

BC hydro
FOR GENERATIONS

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AGENDA

Welcome and Introduction

Part 1:	Existing Retail Access Program Overview
10:15:	Coffee break
Part 2:	BC Hydro Review of Retail Access Program
Part 3:	Issues that BC Hydro has identified
Part 4:	Open Forum Discussion
12 noon:	Finish

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POLICY DRIVERS

2002 - BC Energy Plan

Policy Action #14:

"Under new rate structures, large electricity consumers will be able to choose a supplier other than the local distributor".

Policy Action #21:

"New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency".

2003 – Heritage Contract Inquiry (Stepped Rates + Transmission Access)

"This policy action contemplates that new stepped pricing will provide an incentive for large industrial transmission rate customers to purchase from IPPs, or to self-generate, when they can do so less expensively than the Utility's cost of new supply."

- **Marginal price signal for conservation, self-generation and retail access**
- **Foster IPP investment and create competition for Tier 2 energy block**

BACKGROUND: TSR Proceeding

2005 – Transmission Service Rate (TSR) proceeding

- Stepped Rate (RS1823) approved by Negotiated Settlement
- New portfolio of transmission rate schedules: RS1823, RS1825, RS1827, RS1890
- New tariff supplements: TS No. 71 (Retail Access) + TS No. 74 (CBL Guidelines)

2009 – TSR 3 Year Summary Report (Sep 2009)

- Retail access program discussed at length per Question 3 of Terms of Reference:

  "If no retail access has occurred, why not? Are there features of the TSR that detract from the attractiveness of retail access?"

- Commission's TSR Evaluation report to government (December 31, 2009)

  "The combination of low supply and transaction costs from BC Hydro, and price risks from market or IPP power, make sourcing from BC Hydro the most appealing choice …"

2011 – Shareholder Letter of Expectations

Directs BC Hydro (previously BCTC) to "enhance Open Access Transmission Tariffs" to "facilitate direct purchase of electricity by large users".

SUMMARY: Retail Access Results

F2007 – F2012

- Declining Tier 2 volumes / complex terms and conditions / risks outweigh benefits
- No customer participation … evolving circumstances … BC Hydro review of program

RETAIL ACCESS & STEPPED RATES MARRIAGE

About the Stepped Rate

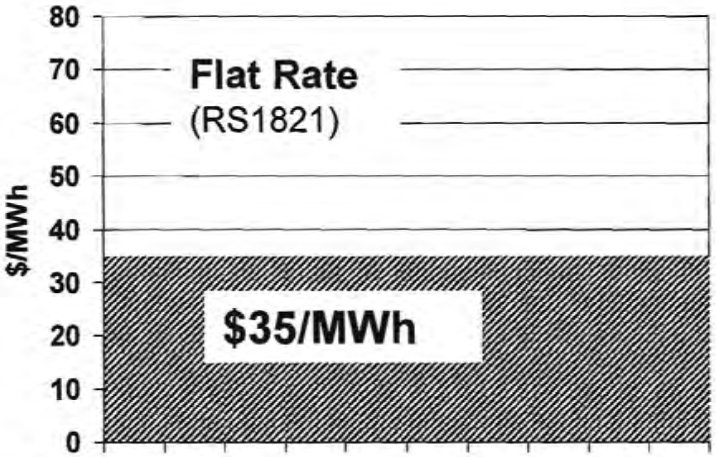
- Requires establishment of an annual customer baseline load (CBL)
- Stepped Rate (RS1823) is bill neutral with the prior Flat Rate (RS1821) at 100% of customer-specific CBL consumption …
- 90% of CBL priced at lower Tier 1 Rate … 10% of CBL priced at higher Tier 2 Rate

About the Retail Access Program

Intent to enable customers to purchase T2 energy block from third party suppliers:

- Domestic IPP's
- TSR customers with excess self-generation (per G-38-01)
- US or Alberta market (via power marketer)

BACKGROUND: Stepped Rate Design



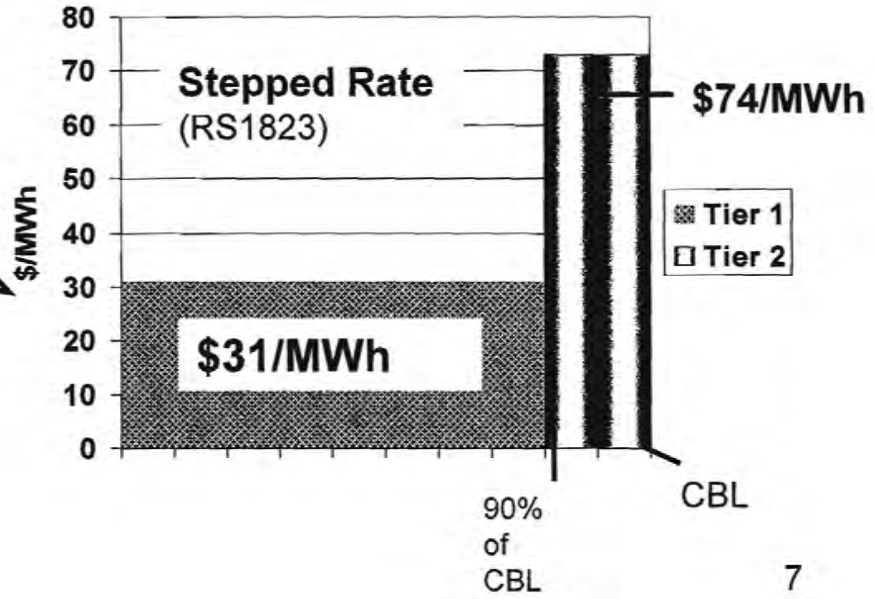
Bill neutral at 100% of CBL consumption

100% x RS1821

=

90% x T1 + 10% x T2

(Current Interim Rates)



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BACKGROUND: Stepped Rate Results

- **Adjustments**: CBL is dynamic (not static) … subject to annual adjustment and reset
- **Billing**: CBL is an annual baseline for energy billing purposes … customers purchase Tier 1 energy until cumulative purchases reach 90% of the CBL … Tier 2 thereafter.
- **Aggregation:** Customers with multiple sites can aggregate CBLs.
- **Results:** Customers have reduced / eliminated Tier 2 energy purchases.

TSR CUSTOMER ENERGY SALES**	cal 2005	F2007	F2008	F2009	F2010
*** excludes FortisBC and RS1827 customers*	GWh	GWh	GWh	GWh	GWh
Final CBL		**15,916**	**15,677**	**14,822**	**13,143**
RS1823 - Tier 1 energy sales		14,057	13,569	13,048	11,629
RS1823 - Tier 2 energy sales		**796**	**410**	**139**	**266**
RS1823A energy sales		396	711	441	654
Total Rate 1823 Energy Sales (GWh)	**15,375**	**15,249**	**14,690**	**13,628**	**12,549**
Tier 2 (% of energy sales)		5.2%	2.8%	1.0%	2.1%
Tier 2 capacity (MW)		**90.9**	**46.8**	**15.9**	**30.4**

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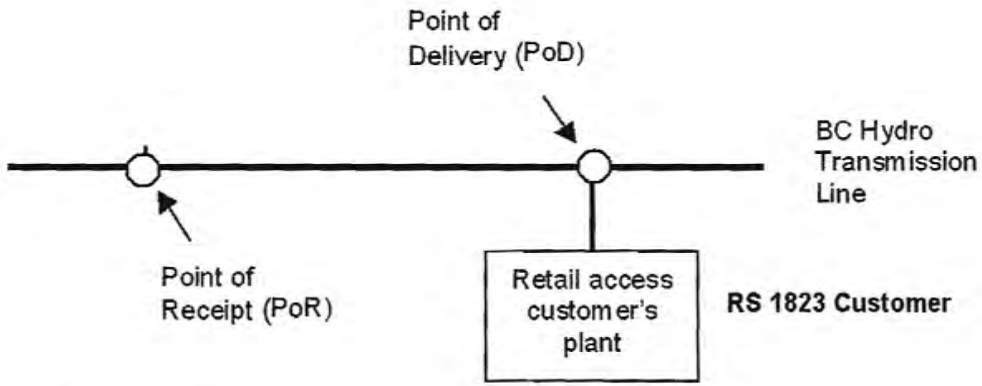
SUMMARY: Retail Access Program

1. Comprised of a Program Agreement (Tariff Supplement No. 71) and Energy Imbalance Rate Schedule (RS 1890)
2. Billing and CBL treatment pursuant to RS1823 and CBL Determination Guidelines (Tariff Supplement No. 74) .
3. Customer remains a BC Hydro customer - retains their existing Contract Demand and Electricity Supply Agreement.

For retail access to make economic sense … customer requires a stable (3yr) forecast block of Tier 2 energy and sufficient price differential between market prices and the Tier 2 Rate

Retail Access Program (how it works)



TERM + CHANGES

- TS No. 71 = 3 year term between RS1823 customer and BC Hydro
- Monthly firm scheduled output (subject to 20% variability over 36 month term)
- Annual ability to change volumes for subsequent 3-yr term

ENERGY DELIVERY

- Customer contracts directly with 3rd party supplier
- Retail access energy "delivered" to Point-of-Receipt (POR) into BCH system
- TSR customer "receives" retail access energy at Point-of-Delivery (POD)
- 6.28% "energy loss adjustment factor" deemed to cover treatment of retail access energy as an integrated network resource (*equal to 6.7% losses at POD*)

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Monthly Output Schedule (shape) x 36 months

Range of Scheduled Output	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR
110%												
100%												
90%												
80%												
70%												
60%												
50%												
40%												
30%												
20%												
10%												
Gross Scheduled Output (MW.hr)	1.1	1.1	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	1.0
Hours per month	720	744	720	744	744	720	744	720	744	744	672	744
Gross Scheduled Energy (MWh)	**792**	**818**	**720**	**744**	**744**	**720**	**744**	**648**	**670**	**670**	**605**	**744**

Section 4.2 of Program Agreement

"For each output schedule as set forth in Appendix 1, the highest entry in the "Total Gross Scheduled Energy" column may not in any case be greater than 120% of the lowest entry in that column."

Monthly Output Schedule (Hourly shape?)

HLH	396	1.1	435.6
LLH	324	1.1	356.4
	720		**792**

This is reasonable

HLH	0	0	0
LLH	324	2.4	792
	324		**792**

This is unreasonable

HLH	0	0	0
LLH	1	792.0	792
	1		**792**

This is unreasonable

RS1823 Energy Billing and Imbalances

RS1823 ENERGY BILLING

Retail Access Program Agreement = Monthly Gross Scheduled Energy

Net Scheduled Output = Gross Scheduled Output * (100% – 6.28%)

Monthly Billed energy = Metered energy – Net Scheduled Output

RS1890 IMBALANCES

"Incremental Energy" = Net Scheduled Output – Net Actual Output

Positive incremental energy = underage = charge

Negative incremental energy = overage = credit

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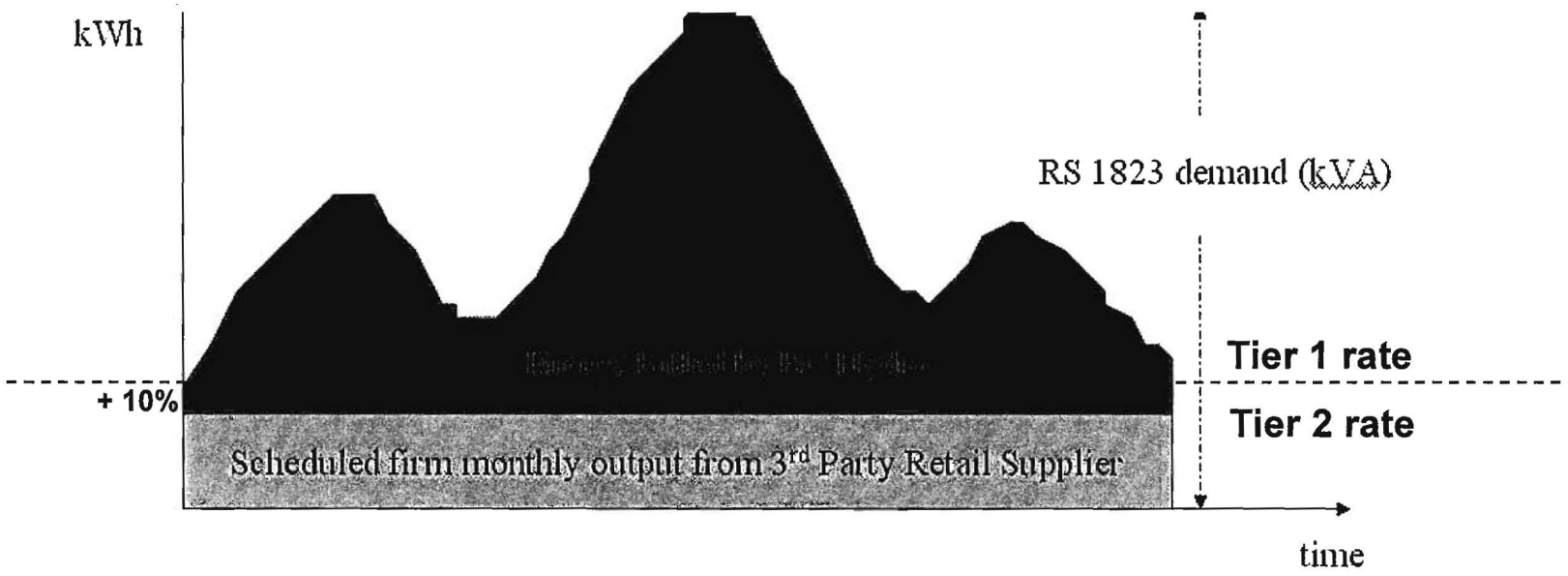
RS1890 – ENERGY IMBALANCE



Variances between actual and scheduled output:

- "Underage" = Charge at prevailing Tier 2 Rate
- "Overage" = Credit
- First 10% overage = Tier 2 Rate, Tier 1 thereafter

F2012 IMBALANCE RATES (RS1890)		
Pricing Period	Hours	$/MWh
Tier 1 (all hours)		31.07
Tier 2 - Winter HLH	1,600	82.13
Tier 2 - Winter LLH	1,280	74.43
Tier 2 - Spring	1,464	68.29
Tier 2 - Remainder	4,416	72.69
	8,760	
Tier 2 weighted ave	73.60	

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Imbalances calculated monthly or hourly?

DAILY PROFILE	Net Scheduled	Net Actual	Imbalance	Overage credit	Overage credit	Underage Charge
Hour	MW.hr	MW.hr	MWh	First 10% MWh	Balance MWh	MWh
				Prevailing T2 Rate	*T1 Rate*	*Prevailing T2 Rate*
1	10.0	10.0	(0.0)			
2	10.0	9.0	1.0			1.0
3	10.0	8.0	2.0			2.0
4	10.0	7.0	3.0			3.0
5	10.0	6.0	4.0			4.0
6	10.0	5.0	5.0			5.0
7	10.0	4.0	6.0			6.0
8	10.0	3.0	7.0			7.0
9	10.0	2.0	8.0			8.0
10	10.0	1.0	9.0			9.0
11	10.0	10.0	(0.0)			
12	10.0	11.0	(1.0)	1.0	-	
13	10.0	12.0	(2.0)	1.0	1.0	
14	10.0	13.0	(3.0)	1.0	2.0	
15	10.0	14.0	(4.0)	1.0	3.0	
16	10.0	15.0	(5.0)	1.0	4.0	
17	10.0	16.0	(6.0)	1.0	5.0	
18	10.0	17.0	(7.0)	1.0	6.0	
19	10.0	18.0	(8.0)	1.0	7.0	
20	10.0	19.0	(9.0)	1.0	8.0	
21	10.0	10.0	(0.0)			
22	10.0	10.0	(0.0)			
23	10.0	10.0	(0.0)			
24	10.0	10.0	(0.0)			
MWh	**240.0**	**240.0**	**(0.0)**	**9.0**	**36.0**	**45.0**

Total credits	$	1,781
Total charges	$	(3,312)
Net DAILY credit (charge)	**$**	**(1,531)**

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Billing Examples

See worksheet:

Scenario 1:

CBL = 900 GWh

Metered site energy = 900 GWh

Scenario 2:

CBL = 950 GWh

Metered site energy = 900 GWh

Communications / Consultation

- Letter sent to TSR customers: 02 Feb 2011
- Letter sent to Commission: 20 May 2011
- Tariff is silent / lacks clarity in some key areas
- Better to establish terms and conditions in advance
- Customer / industry consultation / feedback required
    1. AMPC meeting: 14 July 2011
    2. Stakeholder Workshop: 25 August 2011

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Retail Access Program: KEY ISSUES

- BC Hydro has identified 10 issues where: (1) the existing retail access tariff is silent; or (2) the interpretation is uncertain.
- Issues not contemplated with sufficient diligence in 2005 Application … untested due to lack of participation … or have emerged as new issues

1. Notice period / start date
2. Term of the Agreement
3. Scheduled energy shape (flat monthly / flat hourly)
4. Energy imbalance calculation (monthly / hourly)
5. Risk Allocation
6. Designated Point-of-Receipt (POR)
7. Firm Energy and Firm Transmission
8. Coordination of BC Hydro's NITS Agreement
9. Carbon liabilities
10. Energy accounting and billing (potential duplication of charges)

BC Hydro's Review of the Retail Access Program

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WHY IS BC HYDRO REVIEWING THE PROGRAM?

- By early 2011, BC Hydro observed that changes in markets and the business environment may have increased the financial risks and cost shifting that can arise from retail access – eg:
    - RS 1890 arbitrage
    - carbon liability
    - flat vs. monthly delivery
- No customers have used Retail Access since its introduction in 2005
- In fact, by 2005 it was apparent that few if any would, given change in economics (i.e. embedded cost < marginal cost)

WHY IS BC HYDRO REVIEWING THE PROGRAM?

February 2, 2011 letter to customers advised of informal, temporary suspension pending review of financial risks/cost shifting:

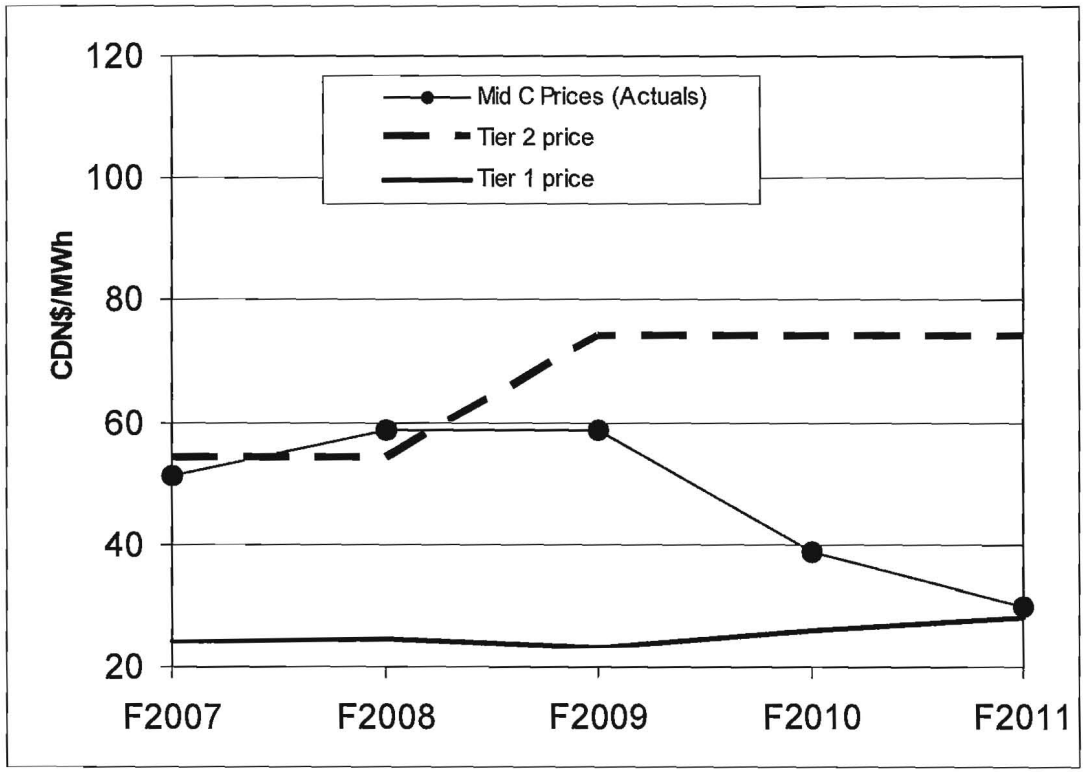
- copied to BCUC

Since February, BCH has been:

- reviewing/quantifying financial risk/cost shifting
- looking at developing business practices and procedures that support the service - never developed previously given no customers
- reviewing the tariff components of the program to ensure that they do what they are intended to do

BC HYDRO'S REVIEW

Historic Market Pricing vs. BC Hydro TSR rates



Notes:

* No transmission costs included
* All prices included mid-C are in CDN$.
* Tier 2 of the stepped rate was re-priced in F2009 from $54/MWh to $74/MWh.

Conclusion

Retail access from the US market has started to become more economic because since F2009, the mid-C price has fallen further below the Tier 2 rate.

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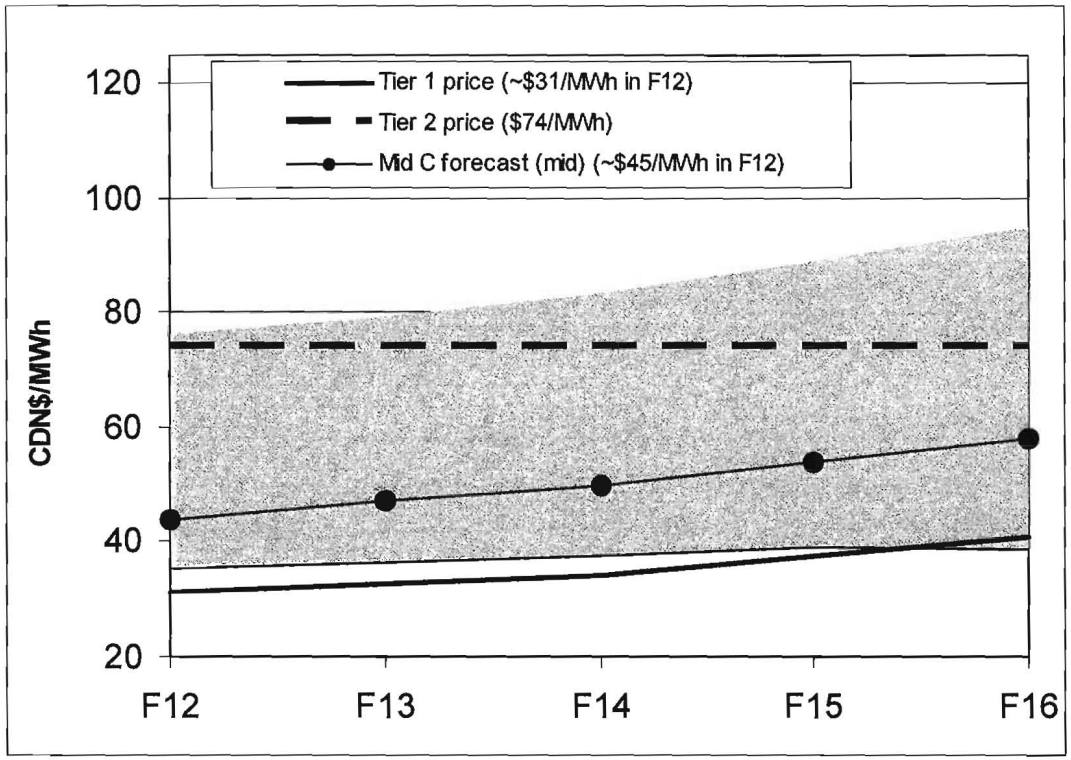
BC HYDRO'S REVIEW

Forecast Market Pricing vs. BC Hydro TSR rates



Graph Assumes:

- No transmission costs
- Fixed tier 2 price
- Mid C prices from BC Hydro's price forecast
- US$/CDN$ parity

Conclusion

Retail access from the US market is likely economic because the mid BCH price forecast is substantially below the tier 2 price.

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Range of BC Hydro's electricity price forecasts

[redacted]

Issues that BC Hydro has identified

ISSUE: RISK ALLOCATION

- With emerging interest in retail access, primarily due to market dynamics, it is important to ensure that the intent and design of the retail access program works today – and tomorrow.
- BC Hydro wants to ensure that retail access participants do not receive an undue financial benefit at the expense of non-participating ratepayers.
- Any retail access program requires BC Hydro to balance rate design principles with public policy objectives and ratepayer risks.
- There are trade-offs and compromises and BC Hydro wants to find the right balance.

[redacted]

ISSUE: RISK ALLOCATION

Some examples of harm to non-participants:

- BC Hydro backstops a retail access customer's volumes during high load hours while the 3rd party supplier may only deliver during low load hours **(Intra-day Arbitrage)**
- The retail access customer purchases more energy from a 3rd party supplier when prices are low during the spring freshet and less energy in the winter when market prices are typically higher. **(Seasonal Arbitrage)**
- A 3rd party supplier decides to sell to other higher priced markets rather than the 3rd party supplier **(Pricing Arbitrage).**
  - Results in an "underage" imbalance that BC Hydro may need to serve on short notice.

[redacted]

ISSUE: TERM OF THE AGREEMENT

The existing retail access agreement has a minimum three year term.

At the conclusion of the 3-year TSR review in 2009, the BCUC suggested that a one year retail access agreement may be appropriate.

Retail access may have long term value for non-participating ratepayers if future resource acquisitions could be deferred. If this was a program objective a longer term agreement may be required.

BC Hydro's current thinking:

Program agreement could have a one year term.

ISSUE: FIRM ENERGY AND FIRM TRANSMISSION

- The existing program is silent on the firmness of a customer's obligation to deliver electricity.

- If customers purchase firm energy and firm transmission from their suppliers there should be a reduction in energy imbalances.

BC Hydro's current thinking:

Firm energy schedules will be required

Firm transmission schedules will be required

[redacted]

ISSUE: DESIGNATED POINT OF RECEIPT (POR)

The existing retail access agreement defines a Point of Receipt (POR) as:

"the point at which a Third party supplier has contracted to deliver electricity into the BC Hydro transmission system to serve the Customer"

(Source: The Retail Access Agreement – aka: Tariff Supplement 71)

The existing tariff is silent on eligible delivery points.

BC Hydro's current thinking:

Energy will be required to be delivered "into" the system meaning the border would not be considered an acceptable POR

ISSUE: COORDINATION OF BC HYDRO'S NITS AGREEMENT

For BC Hydro to designate a network resource, it seems that BC Hydro must have title to the electricity. Currently, there is no mechanism (eg contract) in the Retail Access program that transfers title from the customer to BC Hydro.

BC Hydro's current thinking:

We are investigating whether title transfer is in fact required.

If title transfer is required, whether it can be effected with a simple mechanism; and what if any regulatory or legal issues arise from a title transfer.

ISSUE: CARBON LIABILITY

- Under the proposed Cap & Trade framework, carbon liability will fall on the first jurisdictional deliverer of electricity into BC.

BC Hydro's current thinking:

- BC Hydro will not take on carbon liability as a result of customers importing energy through retail access.

Requiring customers to deliver "into" the BCH system would clarify that BC hydro is not liable for the carbon

ISSUE: BILLING AND ACCOUNTING

If customers are required to bring energy "into" the BC Hydro system they may need to purchase Point to Point transmission under BC Hydro's OATT.

If BC Hydro continued to charge retail access customers a full demand charge (which is intended to cover generation and transmission demand related costs) and then applied PTP transmission charges on top, BC Hydro may be collecting twice for the same services.

BC Hydro's current thinking:

If the customer pays their full RS 1823 demand charge, the customer will be credited for OATT related charges associated with bringing electricity from the border into the BC Hydro system.

Open Forum

(No Gladiators)

BC hydro | REGENERATION

RECALL THE LIST OF KEY ISSUES:

1. Notice period / start date
2. Term of the Agreement
3. Scheduled energy shape (flat monthly / flat hourly)
4. Energy imbalance calculation (monthly / hourly)
5. Risk Allocation
6. Designated Point-of-Receipt (POR)
7. Firm Energy and Firm Transmission
8. Coordination of BC Hydro's NITS Agreement
9. Carbon liabilities
10. Energy accounting and billing (potential duplication of charges)

NEXT STEPS

- In Fall 2011 BC Hydro may either:
  1) Develop retail access business practices to make the existing program operational. These practices would likely address many of the issues mentioned in this presentation.
  2) File an application with the BCUC to amend the program as soon as possible.
  3) File an application to suspend the tariff and redesign the retail access program.
- **We are thinking through which path is more appropriate.**
- BC Hydro will consider comments received at this consultation session.
- BC Hydro wants to hear your ideas and suggestions.
- You can email these to BC Hydro at justin.miedema@BChydro.com or call 604-623-4336.

Fiscal Year	Month	Metered Energy	Metered Demand	Gross Scheduled Output		Net Scheduled Output		Gross Actual Output		Net Actual Output	
		MWh	MVA	MW.hr	MWh	MW.hr	MWh	MW.hr	MWh	MW.hr	MWh
2010	Apr	75,000	119.33	10.67	7,682	10.00	7,200	10.67	7,682	10.00	7,200
2010	May	77,000	114.86	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
2010	Jun	67,000	113.55	10.67	7,682	10.00	7,200	10.67	7,682	10.00	7,200
2010	Jul	74,000	111.53	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
2010	Aug	76,000	116.78	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
2010	Sep	73,000	115.81	10.67	7,682	10.00	7,200	10.67	7,682	10.00	7,200
2010	Oct	78,000	118.48	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
2010	Nov	78,000	120.06	10.67	7,682	10.00	7,200	10.67	7,682	10.00	7,200
2010	Dec	73,000	119.79	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
2010	Jan	80,000	121.81	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
2010	Feb	72,000	121.64	10.67	7,170	10.00	6,720	10.67	7,170	10.00	6,720
2010	Mar	77,000	120.60	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
		900,000			**93,469**		**87,599**		**93,469**		**87,599**

% Annual load increase (decrease)	0%	**900,000**
Customer CBL	**900,000**	
Metered energy as % of CBL	100.0%	

F2012 Interim Rates	**$/MWh**
Tier 1 energy	31.07
Tier 2 energy	73.60
RS1823A energy	35.33
Demand ($/MVA)	5,581

Case 1: No Retail Access	**MWh**	**Energy Bill $**
Tier 1 energy	810,000	25,166,700
Tier 2 energy	90,000	6,624,000
	900,000	**31,790,700**

Case 2: With Retail Access	**MWh**	**Energy Bill $**
Total metered energy	900,000	
Net retail access energy	(87,599)	
Total billed energy	**812,401**	
Tier 1 energy	810,000	25,166,700
Tier 2 energy	2,401	176,689
	812,401	**25,343,389**
RS1823 bill savings *(excludes imbalance charge/credit, rate rider, taxe*		6,447,311

Illustrative Retail access energy economics

est. average market price ($/MWh)	40.00	
est. Delivery to BCH border ($/MWh)	5.00	
est. Delivery INTO BCH system ($/MWh)	5.00	
Nominal cost of delivered RA energy ($/MWh)	**50.00**	
Gross actual energy delivered to POR (MWh)	93,469	
Total 3rd party marketer cost ($)	4,673,460	
TSR customer unit energy buy price ($/MWh)	60.00	*per contract with 3rd party supplier*
TSR customer energy purchased at POD (MWh)	87,599	
Customer RA energy cost ($)	5,255,960	
Gross 3rd party supplier margin	582,500	
Gross TSR customer margin	1,191,351	

DAILY PROFILE Hour	Net Scheduled MW.hr	Net Actual MW.hr	Imbalance MWh	Overage credit First 10% MWh	Overage credit Balance MWh	Underage Charge MWh
				Prevailing T2 Rate	*T1 Rate*	*Prevailing T2 Rate*
1	10.0	10.0	(0.0)			
2	10.0	9.0	1.0			1.0
3	10.0	8.0	2.0			2.0
4	10.0	7.0	3.0			3.0
5	10.0	6.0	4.0			4.0
6	10.0	5.0	5.0			5.0
7	10.0	4.0	6.0			6.0
8	10.0	3.0	7.0			7.0
9	10.0	2.0	8.0			8.0
10	10.0	1.0	9.0			9.0
11	10.0	10.0	(0.0)			
12	10.0	11.0	(1.0)	1.0	-	
13	10.0	12.0	(2.0)	1.0	1.0	
14	10.0	13.0	(3.0)	1.0	2.0	
15	10.0	14.0	(4.0)	1.0	3.0	
16	10.0	15.0	(5.0)	1.0	4.0	
17	10.0	16.0	(6.0)	1.0	5.0	
18	10.0	17.0	(7.0)	1.0	6.0	
19	10.0	18.0	(8.0)	1.0	7.0	
20	10.0	19.0	(9.0)	1.0	8.0	
21	10.0	10.0	(0.0)			
22	10.0	10.0	(0.0)			
23	10.0	10.0	(0.0)			
24	10.0	10.0	(0.0)			
MWh	**240.0**	**240.0**	**(0.0)**	**9.0**	**36.0**	**45.0**

F2012 IMBALANCE RATES (RS1890)			**$ 662**	**$ 1,119**	**$ (3,312)**
Pricing Period	**Hours**	**$/MWh**			
Tier 1 (all hours)		31.07		Total credits	$ 1,781
Tier 2 - Winter HLH	1,600	82.13		Total charges	$ (3,312)
Tier 2 - Winter LLH	1,280	74.43		**Net DAILY credit (charge)**	**$ (1,531)**
Tier 2 - Spring	1,464	66.29			
Tier 2 - Remainder	4,416	72.69			
	8,760				
Tier 2 weighted ave	**73.60**				

Flat Hourly (all hours)	**Hours**	**MW.hr**	**Total MWh**
HLH	396	1.1	435.6
LLH	324	1.1	356.4
			792

Shaped hourly (LLH only)	**Hours**	**MW.hr**	**Total MWh**
HLH	0	-	0
LLH	324	2.4	792
			792

Single Hour (LLH only)	**Hours**	**MW.hr**	**Total MWh**
HLH	0	-	0
LLH	1	792.0	792
			792

SCENARIO 1: CBL = 900 GWH

	Month	Metered Energy	Metered Demand	Gross Scheduled Output		Net Scheduled Output		Gross Actual Output		Net Actual Output	
		MWh	MVA	Ave. MW	MWh	Ave MW	MWh	Ave MW	MWh	Ave MW	MWh
2011	Apr	75,000	119	10.67	7,682	10.00	7,200	10.67	7,682	10.00	7,200
2011	May	77,000	115	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
2011	Jun	67,000	114	10.67	7,682	10.00	7,200	10.67	7,682	10.00	7,200
2011	Jul	74,000	112	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
2011	Aug	76,000	117	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
2011	Sep	73,000	116	10.67	7,682	10.00	7,200	10.67	7,682	10.00	7,200
2011	Oct	78,000	118	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
2011	Nov	78,000	120	10.67	7,682	10.00	7,200	10.67	7,682	10.00	7,200
2011	Dec	73,000	120	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
2012	Jan	80,000	122	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
2012	Feb	72,000	122	10.67	7,170	10.00	6,720	10.67	7,170	10.00	6,720
2012	Mar	77,000	121	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
		900,000			**93,469**		**87,599**		**93,469**		**87,599**
% Annual load increase (decrease)	0%	900,000									

Customer CBL	**900,000**
Metered energy as % of CBL	100.0%

F2012 Current Rates	**$/MWh**
Tier 1	31.07
Tier 2	73.60
RS1823A	35.33
Demand ($/MVA)	5,581

Case 1: No Retail Access	**MWh**	**RS1823 Energy Bill $**	**RS1823 Demand Bill $**
Tier 1 energy	810,000	25,166,700	
Tier 2 energy	90,000	6,624,000	
	900,000	**31,790,700**	**7,892,846**

Case 2: With Retail Access	**MWh**	**RS1823 Energy Bill $**	**RS1823 Demand Bill $**
Total metered energy	900,000		
Net Scheduled Output	(87,599)		
Total billed energy	**812,401**		
Tier 1 energy	810,000	25,166,700	
Tier 2 energy	2,401	176,689	
	812,401	**25,343,389**	**7,892,846**
Gross RS1823 energy bill savings (excludes imbalances, rate rider, taxes)		**6,447,311**	

Illustrative Retail Access Energy Economics (no imbalances)

Average market price ($/MWh)	35.00	
Delivery to BCH border ($/MWh)	5.00	
OATT Delivery into BCH system ($/MWh)	5.00	
OATT Ancillary charges ($/MWh)	5.00	
Nominal cost of delivered RA energy ($/MWh)	**50.00**	
Gross actual energy delivered to POR (MWh)	93,469	
Gross 3rd party supplier cost ($)	4,673,460	
TSR customer unit energy buy price ($/MWh)	60.00	*per contract with 3rd party supplier*
TSR customer - Net energy purchased at POD (MWh)	87,599	
Customer RA energy cost ($)	5,255,960	
Gross 3rd party supplier margin	582,500	
Gross TSR customer margin	1,191,351	

Monthly Cashflow - No Retail Access

		Days/Month	Monthly Metered MWh	RA Energy MWh	Net Energy Purchases	Accumulated energy purchases	BCH T1$	BCH T2$	RA$	Imbalance $	Total $	Demand MVA	Demand $	Total RS1823 Bill $
2011	Apr	30	75,000	0	75,000	75,000	2,330,250	-	-	-	2,330,250	119	665,970	
2011	May	31	77,000	0	77,000	152,000	2,392,390	-	-	-	2,392,390	115	641,022	
2011	Jun	30	67,000	0	67,000	219,000	2,081,690	-	-	-	2,081,690	114	633,700	
2011	Jul	31	74,000	0	74,000	293,000	2,299,180	-	-	-	2,299,180	112	622,466	
2011	Aug	31	76,000	0	76,000	369,000	2,361,320	-	-	-	2,361,320	117	651,755	
2011	Sep	30	73,000	0	73,000	442,000	2,268,110	-	-	-	2,268,110	116	646,347	
2011	Oct	31	78,000	0	78,000	520,000	2,423,460	-	-	-	2,423,460	118	661,237	
2011	Nov	30	78,000	0	78,000	598,000	2,423,460	-	-	-	2,423,460	120	670,044	
2011	Dec	31	73,000	0	73,000	671,000	2,268,110	-	-	-	2,268,110	120	668,537	
2012	Jan	31	80,000	0	80,000	751,000	2,485,600	-	-	-	2,485,600	122	679,844	
2012	Feb	28	72,000	0	72,000	823,000	1,833,130	956,800	-	-	2,789,930	122	678,884	
2012	Mar	31	77,000	0	77,000	900,000	-	5,667,200	-	-	5,667,200	121	673,041	
		365			**900,000**		**25,166,700**	**6,624,000**	-	-	**31,790,700**		**7,892,846**	**39,683,546**

Monthly Cashflow - with Retail Access

		Days/Month	Monthly Metered MWh	RA Energy MWh	Net Energy Purchases	Accumulated energy purchases	BCH T1$	BCH T2$	RA$	Imbalance $	Total $	Cashflow	Demand MVA	Demand $	Total RS1823 Bill $
2011	Apr	30	75,000	7,200	67,800	67,800	2,106,548	-	431,997	-	2,538,544	(208,294)	119	665,970	
2011	May	31	77,000	7,440	69,560	137,360	2,161,231	-	446,397	-	2,607,628	(215,238)	115	641,022	
2011	Jun	30	67,000	7,200	59,800	197,160	1,857,988	-	431,997	-	2,289,984	(208,294)	114	633,700	
2011	Jul	31	74,000	7,440	66,560	263,720	2,068,021	-	446,397	-	2,514,418	(215,238)	112	622,466	
2011	Aug	31	76,000	7,440	68,560	332,280	2,130,161	-	446,397	-	2,576,558	(215,238)	117	651,755	
2011	Sep	30	73,000	7,200	65,800	398,080	2,044,408	-	431,997	-	2,476,404	(208,294)	116	646,347	
2011	Oct	31	78,000	7,440	70,560	468,640	2,192,301	-	446,397	-	2,638,698	(215,238)	118	661,237	
2011	Nov	30	78,000	7,200	70,800	539,440	2,199,758	-	431,997	-	2,631,754	(208,294)	120	670,044	
2011	Dec	31	73,000	7,440	65,560	605,001	2,036,951	-	446,397	-	2,483,348	(215,238)	120	668,537	
2012	Jan	31	80,000	7,440	72,560	677,561	2,254,441	-	446,397	-	2,700,838	(215,238)	122	679,844	
2012	Feb	28	72,000	6,720	65,280	742,841	2,028,251	-	403,197	-	2,431,448	358,482	122	678,884	
2012	Mar	31	77,000	7,440	69,560	812,401	2,086,642	176,689	446,397	-	2,709,728	2,957,472	121	673,041	
		365		**87,599**	**812,401**		**25,166,700**	**176,689**	**5,255,960**	-	**30,599,349**	**1,191,351**		**7,892,846**	**33,236,235**

SCENARIO 2: CBL = 950 GWH

	Month	Metered Energy	Metered Demand	Gross Scheduled Output		Net Scheduled Output		Gross Actual Output		Net Actual Output	
		MWh	MVA	Ave. MW	MWh	Ave MW	MWh	Ave MW	MWh	Ave MW	MWh
2011	Apr	75,000	119	10.67	7,682	10.00	7,200	10.67	7,682	10.00	7,200
2011	May	77,000	115	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
2011	Jun	67,000	114	10.67	7,682	10.00	7,200	10.67	7,682	10.00	7,200
2011	Jul	74,000	112	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
2011	Aug	76,000	117	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
2011	Sep	73,000	116	10.67	7,682	10.00	7,200	10.67	7,682	10.00	7,200
2011	Oct	78,000	118	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
2011	Nov	78,000	120	10.67	7,682	10.00	7,200	10.67	7,682	10.00	7,200
2011	Dec	73,000	120	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
2012	Jan	80,000	122	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
2012	Feb	72,000	122	10.67	7,170	10.00	6,720	10.67	7,170	10.00	6,720
2012	Mar	77,000	121	10.67	7,938	10.00	7,440	10.67	7,938	10.00	7,440
		900,000			**93,469**		**87,599**		**93,469**		**87,599**
% Annual load increase (decrease)	0%	900,000									

Customer CBL	**950,000**
Metered energy as % of CBL	94.7%

F2012 Current Rates	**$/MWh**
Tier 1	31.07
Tier 2	73.60
RS1823A	35.33
Demand ($/MVA)	5,581

Case 1: No Retail Access	**MWh**	**RS1823 Energy Bill $**	**RS1823 Demand Bill $**
Tier 1 energy	855,000	26,564,850	
Tier 2 energy	45,000	3,312,000	
	900,000	**29,876,850**	**7,892,846**

Case 2: With Retail Access	**MWh**	**RS1823 Energy Bill $**	**RS1823 Demand Bill $**
Total metered energy	900,000		
Net Scheduled Output	(87,599)		
Total billed energy	**812,401**		
Tier 1 energy	812,401	25,241,289	
Tier 2 energy	-	-	
	812,401	**25,241,289**	**7,892,846**
Gross RS1823 energy bill savings *(excludes imbalances, rate rider, taxes)*		**4,635,561**	

Illustrative Retail Access Energy Economics (no imbalances)

Average market price ($/MWh)	35.00	
Delivery to BCH border ($/MWh)	5.00	
OATT Delivery into BCH system ($/MWh)	5.00	
OATT Ancillary charges ($/MWh)	5.00	
Nominal cost of delivered RA energy ($/MWh)	**50.00**	
Gross actual energy delivered to POR (MWh)	93,469	
Gross 3rd party supplier cost ($)	4,673,460	
TSR customer unit energy buy price ($/MWh)	60.00	*per contract with 3rd party supplier*
TSR customer - Net energy purchased at POD (MWh)	87,599	
Customer RA energy cost ($)	5,255,960	
Gross 3rd party supplier margin	582,500	
Gross TSR customer margin	(620,399)	

Monthly Cashflow - No Retail Access

		Days/Month	Monthly Metered MWh	RA Energy MWh	Net Energy Purchases	Accumulated energy purchases	BCH T1$	BCH T2$	RA$	Imbalance $	Total $	Demand MVA	Demand $	Total RS1823 Bill $
2011	Apr	30	75,000	0	75,000	75,000	2,330,250	-	-	-	2,330,250	119	665,970	
2011	May	31	77,000	0	77,000	152,000	2,392,390	-	-	-	2,392,390	115	641,022	
2011	Jun	30	67,000	0	67,000	219,000	2,081,690	-	-	-	2,081,690	114	633,700	
2011	Jul	31	74,000	0	74,000	293,000	2,299,180	-	-	-	2,299,180	112	622,466	
2011	Aug	31	76,000	0	76,000	369,000	2,361,320	-	-	-	2,361,320	117	651,755	
2011	Sep	30	73,000	0	73,000	442,000	2,268,110	-	-	-	2,268,110	116	646,347	
2011	Oct	31	78,000	0	78,000	520,000	2,423,460	-	-	-	2,423,460	118	661,237	
2011	Nov	30	78,000	0	78,000	598,000	2,423,460	-	-	-	2,423,460	120	670,044	
2011	Dec	31	73,000	0	73,000	671,000	2,268,110	-	-	-	2,268,110	120	668,537	
2012	Jan	31	80,000	0	80,000	751,000	2,485,600	-	-	-	2,485,600	122	679,844	
2012	Feb	28	72,000	0	72,000	823,000	2,237,040	-	-	-	2,237,040	122	678,884	
2012	Mar	31	77,000	0	77,000	900,000	994,240	3,312,000	-	-	4,306,240	121	673,041	
		365			**900,000**		**26,564,850**	**3,312,000**	**-**	**-**	**29,876,850**		**7,892,846**	**37,769,696**

Monthly Cashflow - with Retail Access

		Days/Month	Monthly Metered MWh	RA Energy MWh	Net Energy Purchases	Accumulated energy purchases	BCH T1$	BCH T2$	RA$	Imbalance $	Total $	Cashflow	Demand MVA	Demand $	Total RS1823 Bill $
2011	Apr	30	75,000	7,200	67,800	67,800	2,106,548	-	431,997	-	2,538,544	(208,294)	119	665,970	
2011	May	31	77,000	7,440	69,560	137,360	2,161,231	-	446,397	-	2,607,628	(215,238)	115	641,022	
2011	Jun	30	67,000	7,200	59,800	197,160	1,857,988	-	431,997	-	2,289,984	(208,294)	114	633,700	
2011	Jul	31	74,000	7,440	66,560	263,720	2,068,021	-	446,397	-	2,514,418	(215,238)	112	622,466	
2011	Aug	31	76,000	7,440	68,560	332,280	2,130,161	-	446,397	-	2,576,558	(215,238)	117	651,755	
2011	Sep	30	73,000	7,200	65,800	398,080	2,044,408	-	431,997	-	2,476,404	(208,294)	116	646,347	
2011	Oct	31	78,000	7,440	70,560	468,640	2,192,301	-	446,397	-	2,638,698	(215,238)	118	661,237	
2011	Nov	30	78,000	7,200	70,800	539,440	2,199,758	-	431,997	-	2,631,754	(208,294)	120	670,044	
2011	Dec	31	73,000	7,440	65,560	605,001	2,036,951	-	446,397	-	2,483,348	(215,238)	120	668,537	
2012	Jan	31	80,000	7,440	72,560	677,561	2,254,441	-	446,397	-	2,700,838	(215,238)	122	679,844	
2012	Feb	28	72,000	6,720	65,280	742,841	2,028,251	-	403,197	-	2,431,448	(194,408)	122	678,884	
2012	Mar	31	77,000	7,440	69,560	812,401	2,161,231	-	446,397	-	2,607,628	1,698,612	121	673,041	
		365		**87,599**	**812,401**		**25,241,289**	**-**	**5,255,960**	**-**	**30,497,249**	**(620,399)**		**7,892,846**	**33,134,134**