BC HYDRO 10th Floor 4555 Kingsway, Burnaby, BC V5H 4T8
Central Park Place (CPP)

FOR GENERATIONS

ENGAGEMENT SUMMARY REPORT

BC HYDRO
TRANSMISSION SERVICE CUSTOMERS

RATE DESIGN FEEDBACK

FROM MAY/JUNE 2014
CUSTOMER ENGAGEMENT WORKSHOPS

FINAL August 21st , 2014

Contents

INTRODUCTION

BACKGROUND

Magnolia Communications ("**Magnolia"**) was retained by BC Hydro to organize and run a province-wide series of Customer Engagement Workshops (**"Workshops"**) with BC Hydro's transmission service customers. The Workshops were conducted as part of BC Hydro's engagement activity for their 2015 Rate Design Application ("**2015 RDA"**). The purpose of the Workshops was to inform customers about rate design scope items identified by BC Hydro, collect customer comments and feedback on these scope items, and report on the results. Magnolia's primary deliverables are described in more detail below:

1. Magnolia was responsible to source and book the host facilities for the Workshops, prepare marketing collateral for customer invitations, provide graphics support for presentation materials, and prepare and print materials for customer rate binders.

2. Phoebe Yong, Principal of Magnolia, was responsible to attend each Workshop in person and take detailed notes.

3. Magnolia was responsible to collect, review, synthesize and report on the consolidated results of customer feedback, both written and verbal, for the purpose of preparing this Engagement Summary Report ("**Report"**).

DISCLAIMER

The information contained in this Report is intended only for the person(s) to whom it is transmitted at BC Hydro. Any reproduction, in whole or in part, requires the prior written consent of Magnolia or BC Hydro. However, Magnolia has prepared this Report with the understanding that it may be made available by BC Hydro to participant customers, for public review and/or be filed as evidence with the British Columbia Utilities Commission ("**BCUC"**). In any of these circumstances, Magnolia's requirement for prior written consent is waived. Magnolia has removed any reference of comments and feedback to specific individuals or corporate entities. This information is confidential. Individual customer comments were provided under the explicit assurance from BC Hydro that they would be consolidated for reporting purposes. Accordingly, copies of customer feedback forms provided in Appendix E should also be treated as confidential information. This Report incorporates information that includes engineering principles and technical discussions related to rate design and electricity generation, supply, planning, transmission system interconnection and customer use. While Magnolia has attempted to describe this information as accurately as possible, Magnolia shall be held harmless from any potential misrepresentation. No warranty of accuracy is expressed or implied. BC Hydro certifies that it has reviewed and approved this report prior to its release.

EXECUTIVE SUMMARY

This Report provides a consolidated summary of comments and feedback obtained from BC Hydro's Transmission Service Rate (**"TSR"**) customers as part of BC Hydro's engagement activity for the 2015 Rate Design Application. Magnolia hopes that the information contained in this Report will be useful to BC Hydro as part of the industrial rate design process.

This Executive Summary provides an overview of BC Hydro's customer engagement process, feedback received, and reporting of results. Please note that the information presented in this Summary assumes the reader has a high-level understanding of the subject matter. For readers less familiar with the material, please refer to the introduction of each section in the body of the Report, starting with Part A, where a short description of each BC Hydro scope topic is provided.

CUSTOMER ENGAGEMENT WORKSHOPS

A total of six half-day Customer Engagement Workshops were conducted by BC Hydro between 22 May 2014 and 2 June 2014. Summary details are provided below:

- Workshops were held at hotel conference rooms in the following locations: Prince George; Quesnel; Kamloops; Vancouver; Calgary; and Nanaimo. There was no charge to attend.
- Each session was 3 hours in length, starting at 9am and ending at 12 noon. A 7th Engagement Session was originally scheduled for Fort St. John, but was cancelled due to lack of numbers.
- A total of 170 customer representatives from BC Hydro's existing transmission service customer accounts were invited to attend. The customer list was selected by BC Hydro's Key Account Management group.
- Customer invitations were sent via email by BC Hydro staff approximately 2-3 weeks prior to the date of the first Workshop. Follow-up email invites were sent at regular intervals leading up to the start of the Workshops.
- In total, each customer received no less than four email invitations to attend the Workshop of their choice. Refer to Appendix A for a copy of the initial email invitation and follow-up invites.
- BC Hydro Key Account Managers also placed phone calls to key customers to advise them of the forthcoming Engagement Sessions and encourage their attendance.
- A total of 96 customer representatives and consultant delegates attended the Workshops. Refer to Table 1 below. Two members of staff from the British Columbia Utilities Commission attended the Vancouver Workshop.
- Various BC Hydro Key Account Managers and support staff attended Workshops with customers from their account portfolios. BC Hydro staff is not included in the attendee numbers.

Table 1: Number of Customer Attendees by Workshop Location

WORKSHOP LOCATION	NO. OF CUSTOMER ATTENDEES
Prince George	17
Quesnel	15
Kamloops	10
Vancouver	19
Calgary	23
Nanaimo	12
TOTAL	96

CUSTOMER FEEDBACK

Customer comments and feedback was requested by BC Hydro at each Workshop on two main topics: (1) BC Hydro's Transmission Voltage Service - Supply Rates; and (2) BC Hydro's Transmission System Interconnection - Tariffs and Process. Refer to Appendix B for a copy of BC Hydro's presentation materials on these topics. Customers provided both verbal and written feedback. The summary below describes how this feedback was collected and reported.

Verbal Feedback

Verbal feedback was collected by Magnolia during the Workshops. Magnolia then extracted a consolidated set of verbal comments and grouped each comment by scope item. Verbal comments are provided in the body of this report as feedback summary tables.

Written Feedback

Written feedback was collected by BC Hydro using a standard feedback form distributed to customers at each Workshop. Written feedback was provided in two ways: (1) a check-box to record customer opinions/preferences for each scope item identified by BC Hydro; and (2) sections provided for additional comments. Customer feedback forms have been separately provided, as they are confidential. Magnolia's workshop minutes have also been separately provided to Hydro. Written comments have been consolidated, grouped by scope item as described above, and reported in feedback summary tables.

To record opinions/preferences, customers were asked to indicate via check-box their agreement with each scope item identified by BC Hydro using the following descriptions: (a) Strongly agree; (b) Agree; (c) Disagree; or (d) N/A. There are a total of 40 respondents who submitted feedback forms. Not all attendees submitted forms. The summary results of customer opinions/preferences for each scope item are shown as bar graphs in the corresponding sections of this Report. Table 2 below provides an overview of customer preferences by scope category. Refer to Appendix D for a consolidated summary of customer opinions/preferences.

Table 2: Overview of Customer Preference by Proposed Scope Category

Topics of Interest	Total Preference (Strongly Agree / Agree)	% of Respondents
Residential Rates	3	8%
Commercial Rates	6	15%
Transmission Supply Rates	38	95%
Transmission System Interconnection	25	63%
Distribution Extension Policy*	11	28%
Other	0	0%

**Although Distribution Extension Policy was identified as a proposed scope item on the feedback form, no presentation materials were provided by BC Hydro on this topic.*

Customers were given the opportunity to provide formal written comments to BC Hydro by June 30th 2014. This date was provided as a "soft deadline" for the purpose of ensuring that comments were received in a timely manner to support BC Hydro's rate design efforts. However, BC Hydro indicated that formal written comments could also be submitted at any time during the process. Note that any formal written comments provided directly to BC Hydro.

RESULTS

Major themes of customer feedback are summarized below for each primary scope topic. Part A Feedback themes refer to Transmission Service Supply Rates. Part B Feedback themes refer to Transmission System Interconnection Tariff (TS6) and Interconnection Process. The theme is expressed using a headline. Supporting detail is provided in the explanatory paragraph under each headline. A selection of representative customer comments, extracted from the summary tables of verbal and written feedback, has also been provided. To identify major themes, Magnolia reviewed the consolidated summary of verbal and written feedback to identify a main view or perspective that appeared to have general support. Results are summarized starting on Page 5.

Note that the identified themes reflect Magnolia's interpretation of the feedback only. Themes should not be interpreted to reflect a consensus view, as some customers expressed support for opposing ideas and concepts. Magnolia assigned no preference to comments based on perceptions of customer size, importance or industry type. That is, each customer comment was given equal weight. Magnolia notes that "silent" support or dissent, such as nodding in agreement during the Workshops, has not been identified.

Refer to the feedback summary tables in Parts A – C of the Report for a detailed summary of customer comments.

PART A: FEEDBACK THEMES

The RS 1823 Stepped Rate is working; retain T1/T2 price indexing; review demand charges:

BC Hydro's RS 1823 Stepped Rate tariff is working well. It is achieving the goal of encouraging energy conservation and incremental self-generation. Pricing of the Tier 2 Rate should retain a marginal cost linkage and be set higher to encourage additional conservation. Pricing of the Tier 1 Rate should be set lower to maintain the benefits of prior conservation investments. There is support for the continued indexing of Tier 1 and Tier 2 prices to general rate increases. The 90% of CBL level acts to artificially limit conservation. There is strong support for the definition and pricing of the demand charge to be reviewed. Suggestions include: cost-of-service recovery of the demand charge; changing the peak demand calculation period from 30min to 1hr; and demand aggregation for coincidental peak management across multiple customer sites.

Representative Customer Feedback:

- *"Overall, the RS 1823 structure works well; keeping T2 and T1 indexing to general rate increases reinforces conservation efforts and provides for better rate forecasting."*
- *"Speaking as an owner's representative, I want (BC Hydro) to have a rate structure that offers the lowest overall cost; Speaking as an energy manager, a higher T2 rate provides a quicker payback and makes my investment in conservation projects more attractive."*
- *"The current (RS 1823) tariff structure for peak demand calculation is very strict; one hour demand calculation, versus 30 min, would be better …"*

There is limited support for TOU rates; interest is from a small sub-sector of customers:

The majority of customers indicated that TOU rates would not work for their business since they operate a continuous manufacturing process that does not support load-shifting. Customers who did express interest in TOU indicated that capital investment in "storage" may be required. Power Smart incentives were proposed as a potential approach. Some customers were not opposed to others participating, provided there is an appropriate cost-reflective price signal, transparency and level playing field. There is uncertainty about the time, duration and value of load shifting to BC Hydro that may impact TOU pricing. Some customers expressed strong views that TOU rate design efforts would be a poor use of BC Hydro's time and resources, given the limited ability for most customers to participate and the uncertain benefits to BC Hydro.

Representative Customer Feedback:

- *"TOU seems like a large-scale undertaking to target a small amount of load response; seems unnecessary at this point in time. However, a better understanding of how TOU could be utilized in future, and its effect, may be of value."*
- *"It would be helpful for customers to give BC Hydro some idea of whether we can shift a certain amount (of) load; how long it can be done for, how much it would cost to do it."*

- *"A Power smart approach for capacity similar to DSM (i.e., programs and capital incentives) would work as we often have problems with upfront costs."*

There is moderate support for interruptible service; existing standby rates work well:

Many customers said that they need firm service to operate their plants and would not use an interruptible service. However, customers were generally not opposed to making an interruptible service available to customers who can accept the risk of lower reliability. This support was conditional on helping to "keep rates lower over the long term". Some customers expressed concerns about long-term resource planning impacts and how an interruptible rate would work in practice. Customers generally agreed that interruptible pricing should be less than for firm service and be based on identified cost reduction or market opportunity benefits to BC Hydro. Cost reduction benefits should consider system needs and regional needs. Separate cost-of-service analysis may be required. Customers indicated that additional review is required to determine operating details such as notice, duration, term and risk. Overall, there is a stronger preference for an interruptible contract versus an interruptible rate. The 2008 load curtailment program was identified as an example of a workable contract mechanism. In relation to existing standby rates, customers with self-generation taking service under the RS 1880 tariff expressed satisfaction that the rate works well and the pricing is appropriate.

Representative Customer Feedback:

- *"We need reliability, so would not be willing to move to interruptible. But if implementing interruptible rates would help keep rates lower over the long term, then we would support."*
- *"Firm, reliable power is standard service from BC Hydro and pricing is relatively low; this (interruptible service) might create unknown problems with resource planning – I am concerned with this scenario."*
- *"Using load to support the grid could provide BC Hydro (with) a significant number of tools to optimize power delivery without costly infrastructure expenditure. Customers can provide value to BC Hydro and could be compensated fairly for that value."*

There is limited interest in retail access or market-based pricing:

This scope item did not generate much interest or discussion. There was general uncertainty about how a rate might work. There was no identified interest in direct market access. Customers who did provide feedback were generally supportive of incorporating a market-based pricing element into a TOU rate, interruptible rate or contract, or to encourage the more efficient utilization of customer-based generation. In terms of pricing, interested customers commented that the assumption of market price and currency exchange risk would be fair and that BC Hydro should charge a delivery fee in exchange for assurance of firm supply.

Representative Customer Feedback:

- *"Load should be given the opportunity to participate in external market sales during peak pricing periods … load can be dropped in BC to be available for sales into a high priced market."*

- *"This is a cost-shifting exercise. Customers need to have an easy process that is clear and transparent. A rate that flows through market price plus reasonable currency risk and transportation charges would be reasonable; user would forecast market delivery, plus other charges, then make a business decision to a term length."*
- *"Consider inclusion of policy elements that provide secure energy/capacity supply … ok for industry to take market price risk, but not operating supply risk; provide firm delivery via a wheeling fee/demand charge from BC Hydro."*

There is marginal support for continued RS 1827 exemption:

A majority of customers do not support continued exemption from the RS 1823 Stepped Rate under the RS 1827 tariff. Some customers indicated that, since the RS 1827 tariff only applies to a small subset of customers, there is little value to review. Customers presently on the RS 1827 tariff generally held a neutral view; they were uncertain as to the historic rationale for exemption and no analysis had been performed to consider the prospective impacts of a move to the Stepped Rate.

Representative Customer Feedback:

- *"Do not support exemption."*
- *Not required for review – only a few exempt customers.*
- *"Moving from exempt to stepped rate has pros and cons; not sure without analysis which is best."*

There is conditional support for a potential surplus rate; primary concern is fairness:

Very few customers provided feedback on a potential surplus rate for incremental load. Customers who did comment suggested that a potential rate should incorporate a short-term view only and be voluntary, to allow the customer to make an economic decision to respond. The market economics of a surplus rate were understood. However, concerns were identified with respect to the potential contradiction with conservation initiatives and the potential for limited uptake which might create an unfair competitive advantage between participants and non-participants.

Representative Customer Feedback:

- *"You could sell excess capacity and energy at a discount, but this contradicts your conservation initiatives."*
- *"There may be some special application available, but it should be only short term while BC Hydro is in excess. It should also not create an unfair competitive advantage to one customer. The principle of treating all customers equally would be tested with exempt/surplus rates."*

PART B: FEEDBACK THEMES

There is moderate support for existing TS6 (with updates); no consensus on 150 MVA threshold:

There was lengthy discussion about Tariff Supplement 6 (TS6). The relatively small sub-set of customers who have used TS6 to connect new loads generally expressed support for the existing tariff, with some minor updating of definitions, and consideration of system reinforcement costs caused by generators. Customers in the process of connecting new loads expressed concern about any potential tariff policy change that might result in a change from security/bonding to a cash contribution. Customers who had not previously used TS6 generally opined that the maximum offset calculation should be reviewed using some "blend" of principles such as fairness, economic impact, public policy and consideration of "tipping point" costs that might be allocated to a single applicant where there is regional growth. Customers had stronger, and often opposing, views on the 150 MVA threshold: some felt the threshold was appropriate; some had concerns about load staging and project sizing; some felt the threshold was arbitrary and a disincentive to large industrial investment.

Representative Customer Feedback:

- *"Support the current TS6 and ESA process; am concerned about potential $ injection if TS6 changes from security to cash as this reflects a different policy perspective."*
- *"TS6 constrains growth in BC. It creates a bias against investment decisions for large loads > 150 MVA."*
- *"Keep 150 MVA threshold; support some allocation of costs to customer for connection of new large loads; do not pass major generation and transmission system upgrade costs for large loads to smaller TSR customers."*
- *"BC Hydro should consider a cost allocation formula/contribution for generators that drive a proportionate investment in system reinforcement."*
- *Balance needed between spreading costs around, promoting economic growth and profits available to new projects if they don't pay enough for (BC Hydro system) infrastructure."*

The interconnection study process takes too long; limited views on "business practices":

Customers expressed clear, strong views on the interconnection study process. The near-consensus view (with one exception) is that the study process takes too long. Also, the rules are unclear, and there is no effective prioritization of projects that are "shovel ready". Customers expressed concern that the queue management process is prone to abuse, with no consequences for applications that prevent the timely review of firm projects. Customer suggestions for resolution include: a principles and process audit; additional BC Hydro study resources; a streamlined process for small customer-based generation; a direct contracting option with a 3rd party to conduct study work; and use of a Contract Demand fee to mitigate

under-utilization of available capacity. A limited number of customers provided comments on whether "non-tariff" commercial agreements should be incorporated into the TS6 tariff, and whether study timelines should be a prescribed tariff process. These items were presented by BC Hydro as "business practices".

Representative Customer Feedback:

- *"Interconnection process should be audited to speed up the process; 1-3 years just for studies is too long for some projects. If a customer has completed all the 'pre-work' for studies, they should move ahead of somebody in the queue who is not as advanced."*
- *"Interconnection process should be optimized to reduce long delays, costly repetition, and expensive rework. Find ways to streamline the process; studies can be conducted by contractor experts is one way."*
- *"Consider charging a fee for Contract demand (per MVA). This would make people think more carefully about how much power they really need and mitigate over-estimation of contract demand. Getting real money from real people is a good way to affirm serious projects; however, senior management might view as potential discouragement …"*

PART C: FEEDBACK THEMES

Customers want rate options; overall goal should be fairness and cost-reflective rates:

Customers provided additional questions and comments on a range of topics, in addition to rates, as highlighted below. Customers generally expressed a clear understanding of BC Hydro's regulatory and policy environment. Please refer to Part C of this report for a summary of customer comments. Please also refer to the Minutes in Appendix C.

- Desire for rate alternatives
- Cost-of-service allocations
- Policy and political considerations
- Regulated rate-making
- Power Smart incentives
- Mandatory Reliability Standards
- LNG customer treatment
- Distribution tariff issues
- Biomass energy pricing
- VAR support incentives
- Peace Region Electricity Supply (PRES) design considerations
- Commentary on Northwest Transmission Line (NTL)

REPORT STRUCTURE

This Report is structured into three main parts as set out below. Part A and Part B correspond to the format of the presentation materials reviewed with customers during each Workshop. Customer comments and feedback have been reported in the same order as the scope items were presented. This reporting order aligns with the format of the feedback forms and the Workshop minutes. Part C is designed as a general "catch-all" category to report all comments and feedback received on other topics. Detailed reference materials are located in the Appendices.

1. **Part A: Transmission Voltage Service - Supply Rates**
   - 1.1. RS 1823 Stepped Rate
   - 1.2. Time of Use Rates
   - 1.3. Standby & Interruptible Rates
   - 1.4. Retail/Market Access Rates
   - 1.5. Exempt/Surplus/Other Rates

2. **Part B: Transmission System Interconnection - Tariffs and Process**
   - 1.1 Tariff Supplement No. 6
   - 1.2 Load Interconnection Process & Queue Management

3. **Part C: General Comments and Feedback**

Appendices:

Appendix A: Workshop Email Invitations

Appendix B: Workshop Presentation Materials & Rate Sheets

Appendix C: Customer Opinions/Preferences Summary *(These reside with BC Hydro as printed forms)*

1. PART A: Transmission Voltage Service – Supply Rates

Introduction

BC Hydro provides transmission voltage service to customers that take electricity directly from the transmission system at voltages > 60,000 volts. BC Hydro is a regulated utility. Electrical service is provided under a portfolio of rates and tariffs approved by the British Columbia Utilities Commission.

As part of BC Hydro's 2015 Rate Design Application, transmission service customers were engaged to provide comments and feedback on BC Hydro's existing portfolio of transmission supply rates. Customers were also asked to provide feedback on other potential supply rate options.

These rate options were identified in Recommendations #9 – 13 from the November 2013 Industrial Electricity Policy Review (IEPR) Taskforce Report as shown in Table 3 below and endorsed by the provincial government for review. Customer feedback on transmission service supply rates described in Part A of this report is part of the rate design review process recommended by government.

Table 3: IEPR Taskforce Recommendations & Government Response

	Taskforce Recommendations	Government Response
9	Continue using postage stamp rates	Government will continue to use postage stamp rates
10	End use rates which have no impact on ratepayers could be considered, those which impact ratepayers and are directed by government should be paid for by taxpayers and not ratepayers	A rate design review process will be launched to examine ways to provide industrial customers with more options to reduce electricity costs
11	BC Hydro should develop a revised retail access program	A rate design review process will be launched to examine ways to provide industrial customers with more options to reduce electricity costs
12	Government need not act on the BCUC's 2009 TSR report until BC Hydro's surplus has diminished and the effect of other recommendations in this report can be seen	Government accepts this recommendation
13	BC Hydro should work with industrial customers and the Commission to develop options that take advantage of industrial power consumption flexibility, such as time of use and interruptible rates	A rate design review process will be launched to examine ways to provide industrial customers with more options to reduce electricity costs. BC Hydro will implement a voluntary load curtailment program with industrial customers starting in 2015

1.1 RS 1823 STEPPED RATE

Background

The RS 1823 Stepped Rate (RS 1823) is BC Hydro's default rate for transmission service. It has been in effect since April 2006. It was approved by the British Columbia Utilities Commission in 2005 following a Negotiated Settlement Agreement process. RS 1823 is a two-step inclining block conservation rate which separates the pricing of the customer's annual energy consumption into two steps, relative to a historic customer baseline load (the CBL). This stepped rate approach has customers purchase the first 90% of annual energy use at a lower price (the Tier 1 Rate) and the balance at a higher price (the Tier 2 Rate). The intent of the higher-priced Tier 2 energy block is to encourage energy conservation, efficiency, and incremental self-generation.

BC Hydro's Proposed Scope Items

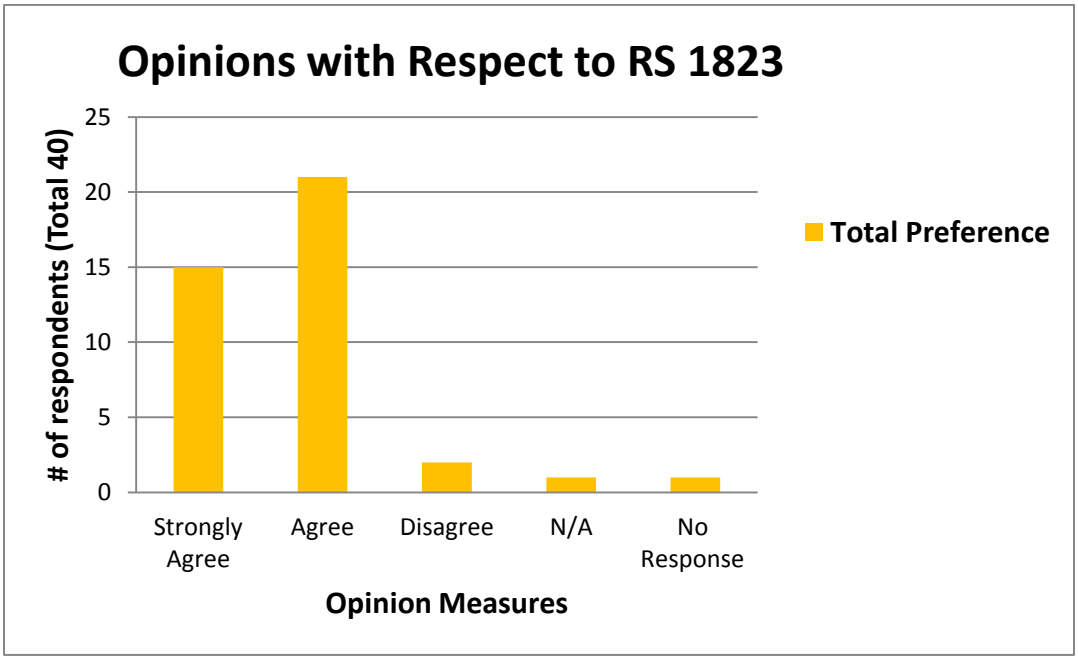
With respect to RS 1823, the following scope items were proposed by BC Hydro for customer feedback:

- Review RS 1823 energy pricing principles
- Review revenue and bill neutrality definition
- Review demand charges – COS allocation, TOU period refinements

Customer Preferences

A total of 40 respondents submitted feedback and indicated their preferences for proposed RS 1823 scope items. There is strong support for BC Hydro's scope. Results are shown in Table 4 below.

Table 4: Customer Preferences for RS 1823 Scope Items



Customer Feedback Summary

The feedback summary tables below show all of the written and verbal comments provided by customers on proposed RS 1823 scope items. Feedback is separated into comments on "RS 1823 energy" and "RS 1823 demand" as follows:

- Table 5a: Written Feedback for RS 1823 energy
- Table 5b: Verbal Feedback for RS 1823 energy
- Table 6a: Written Feedback for RS 1823 demand
- Table 6b: Verbal Feedback for RS 1823 demand

Written comments are taken from customer feedback forms submitted to BC Hydro. Verbal comments are taken from Workshop minutes prepared by Magnolia. Since comments were made on a confidential basis, no attribution to individuals or corporate entities is provided. Major themes were synthesized by Magnolia from these summary comments.

*Overall sentiment of feedback in both verbal and written collected have also been denoted with a gradient to the left of each table to illustrate the range of topics being expressed.

**To illustrate the opposing feedback, an arrow has been placed next to the corresponding feedback tables where applicable.

Change Desired	Table 5a: Written Feedback for RS 1823 Energy
	T2 needs to be adjusted continuously, or else T1 will equal T2 in the future.
	RS1823 T1 and T2 billing creates an artificial ceiling on conservation at 10%. Reductions below 90% (of CBL) will result in a customer being penalized for conserving. Any changes should consider options for further conservation without penalizing those who conserve.
	T2 price should not be capped in order to provide continued incentive to conserve; RS1823 rate design concepts still relevant; practice may require review.
	T2 Rates should be applied monthly; Concerned that T2 rates based on future costs could lose touch with current (actual) costs.
	Fundamentally, rate increases will trigger how T1 and T2 increases impact customers. This topic should allow for customers who are able to generate an easy way to do so with an appropriate rate. If T2 goes up, it makes self-gen more desirable.
	Rate increases need to go through a strict financial review to determine the impacts (on tiered rates).
	Keep T2 in step with T1 or else rate of return for energy savings projects decrease.
	T2 rate should be representative of marginal cost; the impact of energy conservation is linked to T2.
	Any future changes to rates should be explained and reasons provided.
	Good incentive to use less power; review and strengthen.
	Overall, RS1823 structure works well; keeping T2 and T1 indexing to general rate increases reinforces conservation efforts; provides for better rate forecasting.
Little or No Change	*RS1823 is working well.*
	RS1823 is not broken.
	Leave RS1823 as is.

	Table 5b: Verbal Feedback for RS 1823 Energy
Overall costs review	*Oil and gas have not fared as well (in terms of T2 reductions) compared to forestry.*
T2 Focus	*The Tier 2 Rate used to have an LRMC reference point ($73.60/MWh), but now the addition of the general rate increase makes the T2 price-setting arbitrary.*
	Revenue has to match your costs; the T2 rate should be based on what the estimate of the cost increases would be for BCH reduction programs.
	Speaking as an owner's representative, I want you to have a rate structure that offers the lowest overall cost; Speaking as an energy manager, a higher T2 rate provides a quicker payback and makes my investment in conservation projects more attractive.
	Tier 2 (under the "old way") did represent marginal cost as it was based on a prior power call.
	If government agrees with "green mandate" policies, then that would determine the long run marginal reference price (i.e., reference price based on clean/green/ renewable definition).
	The higher order driver for Tier 2 should be conservation.
	Agree that Tier 2 price drives energy saving projects.
	If you drop or fix the T2 rates, you erode the incentive to conserve energy.
	Fixed Tier 2 price is a disincentive.
	Setting a T2 price cap is not effective as you're setting an arbitrary cap that has no limit, so for us the liability exists. We believe your actions need to be dictated by the costs.
T1 Focus	*We are part of a select group of large users that is price-exposed to Tier 1 and getting too close to the edge of the cliff; Tier 1 price increases would be economically damaging for some customers.*
	If Tier 2 is supposed to promote conservation, and if you're managing your CBL to get down from 100% to 90% and only pay T1, then it doesn't seem fair that the benefit of that conservation is eroded where Tier 2 is fixed and only Tier 1 goes up, so I'm penalized; the uniform increase will solve that.
	With T2 fixed, Tier 1 would gradually catch up to Tier 2 (with general rate increases); as a result there would a big increase in power costs (for customers at Tier 1).
	If Tier 1 escalates faster than T2, there will be a point where the T1 price gets too close to the T2 price; this will reduce the conservation incentive.
	As long as the T1/T2 split remains at 90/10, escalating Tier 2 at the same rate as Tier 1 isn't a big issue. The relative price gap will be maintained.
T1 and T2	*Uniform rate increases provides simplicity and predictability and maintains a conservation differential between Tier 1 & 2; therefore there is value in that it offers uniformity and clarity.*

	Table 6a: Written Feedback for RS 1823 Demand
Change to demand charges	*Multiple opportunities for revenue shifting with demand charges.*
	BC Hydro is currently under-charging on demand.
	Review mechanisms for demand charges could be beneficial.
	Consider more narrow windows on RS1823 demand charge as alternative to TOU rate.

	Table 6b: Verbal Feedback for RS 1823 Demand
Demand charges	*Demand pricing should be driven from where the true costs come from. For instance, if demand pricing is motivated by generation capacity and peak and super-peak hours actually reflect higher system loads, then these peaks should be used to set demand pricing; nothing artificial.*
	Demand isn't driven by your industrial customers - most industrials are 16hr x 7 days or 24hr x 7 days base load; other customers cause the peaks.
	Generation capacity is more of a system based view and regional capacity refers to lines and substations; so where you are trying to get incremental power in a region where there are constraints, it would be better if BC Hydro had programs or tariffs that supported the reduction of demand; historic focus has been on energy only.
	Need clarification on revenue recovery by rate class and specifically for transmission class; For example, BC Hydro seems to be over-recovering on energy charges and under-recovering on demand charges.
	The method by which peak demand is calculated; it's extremely sensitive and difficult to manage the risk. Is there any flexibility around the edges to help manage the risk?
	Agree that peak demand pricing is very sensitive; (we) don't have large loads, but have unpredictable and dynamic load - peak demand is hard to control.
	Current tariff structure (for peak demand calculation) is very strict; One hour demand calculation (versus 30min) would be better for mining industry; also provide leeway for peak demand "mistakes".
Demand recovery	*Consider using aggregation principle (per stepped rate energy) for management of coincidental peak demand - for customers with multiple locations via demand aggregation.*

1.2 TIME OF USE (TOU) RATES

Background

The purpose of a TOU rate is to encourage customers to shift load from periods of peak system use to periods of lower use. A benefit is achieved if the customer response means that the utility can avoid more expensive investments in generation and transmission capacity or take advantage of market opportunities. TOU rate designs charge higher prices during on-peak periods and lower prices during off-peak periods. BC Hydro currently uses the terms Heavy Load Hours (HLH) and Light Load Hours (LLH) to refer to on-peak and off-peak periods in rates. BC Hydro has two approved TOU rate schedules, as described below.

- **RS 1825 –TOU Rate:** This is a voluntary TOU rate with a three-year fixed term. The rate is available to all transmission customers. It was approved in April 2006. The RS 1825 design provides energy price signals on an hourly (time of day) basis and seasonal basis through pricing modifications to the Tier 2 Rate. The rate concept is to shift load from HLH to LLH during the winter months of November to February, and to shift load from winter months to all other months of the year. No customers have used RS 1825. BC Hydro explained in the Workshops that the primary reasons for non-use were complexity, thin margins and term risk.

- **RS 1852 – Modified Transmission Demand Rate:** This is a voluntary TOU rate. The rate is available to all transmission customers. It was approved in September 2000. Participating customers continue to take service under RS 1823 for energy, but RS 1852 is used for demand billing. The RS 1852 tariff is designed to reduce demand charges by shifting load from on-peak periods into off-peak periods. The RS 1852 on-peak period has been defined as two 4hr blocks (6am – 10am and 4pm – 8pm). BC Hydro's standard on-peak period is a continuous 16hr block, from 6am – 10pm. BC Hydro explained that limited uptake of the rate is due to complexity, uncertain benefits, and customer load curtailment and production recovery capability.

BC Hydro's Proposed Scope Items

The IEPR Taskforce Report recommended that BC Hydro work with industrial customers to develop TOU rate options that take advantage of industrial customer flexibility. With respect to TOU Rates, the following scope items were proposed by BC Hydro for review:

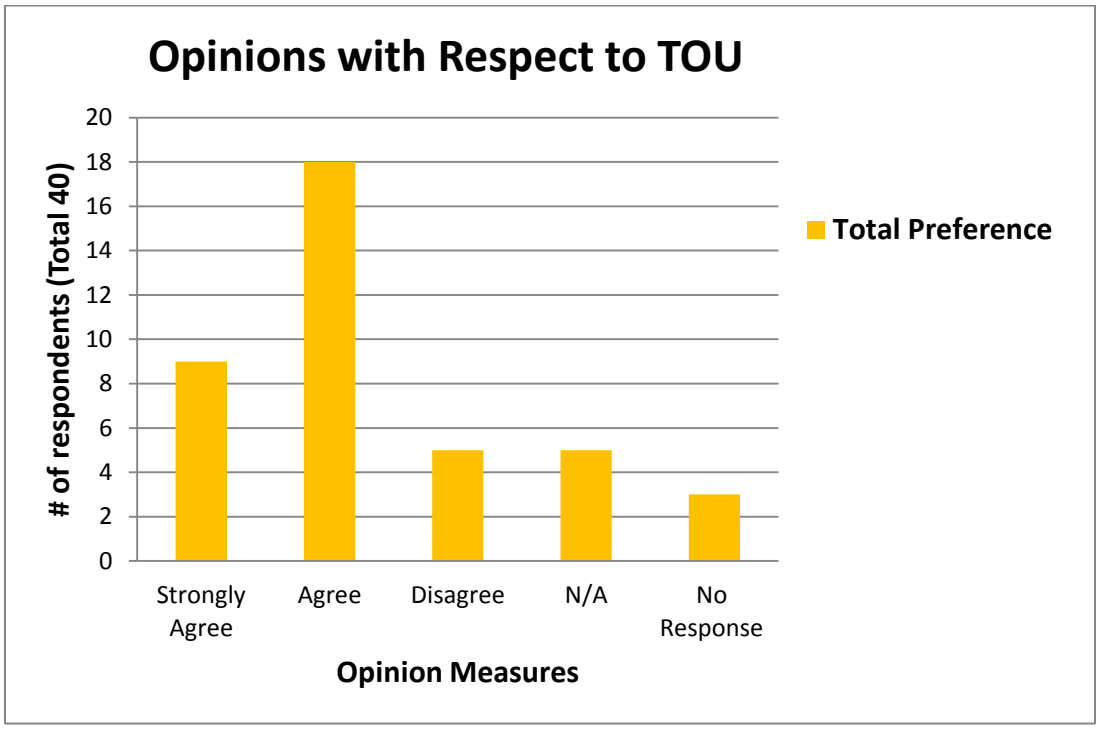
- TOU scope to be partially informed by TSR 3yr Evaluation
- Better definition of desired capacity products
- Better understanding of customer capabilities and ratepayer impacts

In the Workshops, BC Hydro also asked customers for feedback on approved TOU rates (i.e., RS 1825 and RS 1852), in addition to the scope items listed above.

Customer Preferences

A total of 40 respondents submitted feedback forms and indicated their preferences for proposed TOU scope items. There is strong support for BC Hydro's scope. The results are shown in Table 7 below.

Table 7: Customer Preferences for TOU Scope Items



Customer Feedback Summary

The feedback summary tables below show all of the written and verbal comments provided by customers on proposed TOU scope items. Feedback is separated into comments on "TOU Design" and "General TOU Comments" as follows:

- Table 8a: Written Feedback for TOU Design
- Table 8b: Verbal Feedback for TOU Design
- Table 9a: Written Feedback for General TOU Comments
- Table 9b: Verbal Feedback for General TOU Comments

Written comments are taken from customer feedback forms submitted to BC Hydro. Verbal comments are taken from Workshop minutes prepared by Magnolia. Since comments were made on a confidential basis, no attribution to individuals or corporate entities is provided. Major themes were synthesized by Magnolia from these summary comments.

*Overall sentiment of feedback in both verbal and written collected have also been denoted with a gradient to the left of each table to illustrate the range of topics being expressed.

**To illustrate the opposing feedback, an arrow has been placed next to the corresponding feedback tables where applicable.

TOU Changes

Table 8a: Written Feedback for TOU Design
Current TOU is not attractive if only 1 customer signed up; TOU time blocks need to be set by overall demand.
BC Hydro should look at layered rates; TOU on top of base amount.
Need aggressive TOU rate schedule to better match load with capacity.
TOU rate should have more flexibility in terms of time of day; BC Hydro should provide financial incentives to allow customers to optimize their facilities to participate – such as additional storage.
TOU rates might work well for a lot of smaller industrial customers working with labour unions to move production hours out of peak; could introduce incentive/improvement possibilities to keep industry competitive.
TOU is not really an option unless there is a strong enough price signal.
HLH span/period at present is too large; may not reflect actual load profile of system.
For O&G, not much we can do on a daily basis; loads can't be interrupted and accelerated. A seasonal rate might work, since summer loads are lower.

Little Consideration

Flexibility Desired

Table 8b: Verbal Feedback for TOU Design
Our mills (mines) have significant critical loads running 24/7 so we can't take interruptions; we want firm, reliable power to run operations safely and effectively. We run one continuous process, including removing, moving and crushing rock. However, we may be able to do something with the timing of our conveying loads, but these are not large loads and we still need to keep the stock piles full.
Some mines may have some flexibility (with conveying loads); a sister mill in Alberta has been doing it and getting good at it; they align load shifting capability with market price signals when prices spike; relatively short notice would be ok (ie. maybe only one hour); but we would also need to invest in storage capacity.
There is some small opportunity to look at load shifting options; we are open to the concept, but there are not huge MW in a sawmill.
Consider having multiple (rate) products; use Tiered approach - layers depending on products.

Shifts in Load Options

It would helpful for customers to give BC Hydro some idea of whether we can shift a certain amount (of) load; how long it can be done for, how much it would cost to do it.

No Interest in TOU

Better understanding of TOU needed

Table 9a: Written Feedback for General TOU Comments
TOU is a poor use of time and resources. No current TOU customers; potentially lots of work for no gain.
For TOU … need to clearly hear up-front if customer is interested / can respond before spending time and effort through RDA.
Do not see a TOU opportunity for my site; may be appropriate at other (customer) sites?
Have not considered TOU in any detail; we (sawmill industry) would have limited ability to take advantage.
We are a 24/7 production operation (mine) with no ability to utilize TOU optimization.
Have limited ability to control load under TOU system; better clarity around options would be worthwhile.
TOU seems like a large-scale undertaking to target a small amount of load response; seems unnecessary at this point in time. However, a better understanding of how TOU could be utilized in future, and its effect, may be of value.
Due to nature of operations, the majority of customers cannot use this rate structure; suggest using an incentive approach to influence change rather than rate structure.
TOU complexity is a concern; many industries unable to swing load to react.
TOU would benefit only a small sub-sector of industrial class.
Canvas industry to ascertain TOU capabilities within sectors/specific plants; use to provide basis for further discussions around support programs and incentives.
TOU is of no interest to the mining sector.

No Interest

TOU Flexibility Considerations

Table 9b: Verbal Feedback for General TOU Comments
Not interested in TOU; mining is 24x7 operation; no ability to shift load or curtail.
Demand charge is used to pay for transmission infrastructure.
Although you may not need it (capacity) now, you need to ensure that capability exists for the future.
A Power smart approach for capacity similar to DSM (i.e., programs and capital incentives) would work as we often have problems with upfront costs.
Contract terms need to be specific and clear with everyone; need to have level playing field. Transparency is best.
Look at other jurisdictions for good examples of uptake with TOU.
Any TOU cost savings that accrue to BCH needs to be shared by all.
Alberta and Ontario meet base load with coal and nuclear, therefore incentive for defined TOU is reduced, whereas with water based generation resources, utility has more flexibility to meet load from available resources.
We have flexible loads for TOU (paper company).

1.3 STANDBY & INTERRUPTIBLE RATES

Background

Whereas most of BC Hydro's rates and tariffs are based on firm electricity service, standby and interruptible rates reflect non-firm electricity service. Similar to TOU rates, the pricing of standby and interruptible rates is often based on the avoided costs of generation or transmission capacity. Although both standby and interruptible rates fall into the same non-firm service category, the pricing may be different. This is due to different reasons for their use, as explained below.

Standby rates are generally used by customers who take additional electricity during emergency, maintenance or plant upset conditions. Interruptible rates are generally used by customers willing to take less electricity under certain circumstances. For example, a customer might choose to accept a less reliable service, such as a higher risk of outages, in exchange for a lower electricity price. A customer may also be able to provide specific types of capacity resources that can be achieved through demand reductions rather than capacity additions. BC Hydro explained that some types of capacity resources can be more effectively acquired using a contract mechanism, rather than a rate structure.

BC Hydro has two approved rate schedules for standby service, as described below. BC Hydro does not presently have an interruptible rate schedule for non-firm service. BC Hydro had a Load Curtailment Program with contract terms that ran from 2008 and 2013. The Program has since expired.

- **RS 1880 –Standby & Maintenance Supply:** This is a non-firm service for transmission customers with self-generation who wish to take additional energy and capacity from BC Hydro when all, or part, of their generating plant is curtailed. RS 1880 service is typically requested when the customer has planned downtime for generator repairs or maintenance, or during unplanned events when there is a sudden disruption to the generation system. RS 1880 service is only provided if BC Hydro has available energy and capacity. RS 1880 has an energy charge, but no demand charge. RS 1880 energy is priced at the RS 1823 Tier 2 Rate. There is no demand charge for capacity required above an established reference demand during each period of use.

- **RS 1853 – Independent Power Producer Station Service:** This is a non-firm service for Independent Power Producers. An IPP is a BC Hydro generator customer, not a load customer, who normally generates electricity for delivery and sale into the BC Hydro system. When an IPP is operating, it generates electricity for its own plant electrical requirements such as lighting, fans, compressors and fuel handling requirements. These electrical requirements are commonly known as "station service". When generating facilities are shutdown, or need to be re-started, the IPP takes electricity from BC Hydro for station service. RS 1853 service is only provided if BC Hydro has available energy and capacity. RS 1853 has an energy charge but no demand charge.

BC Hydro's Proposed Scope Items

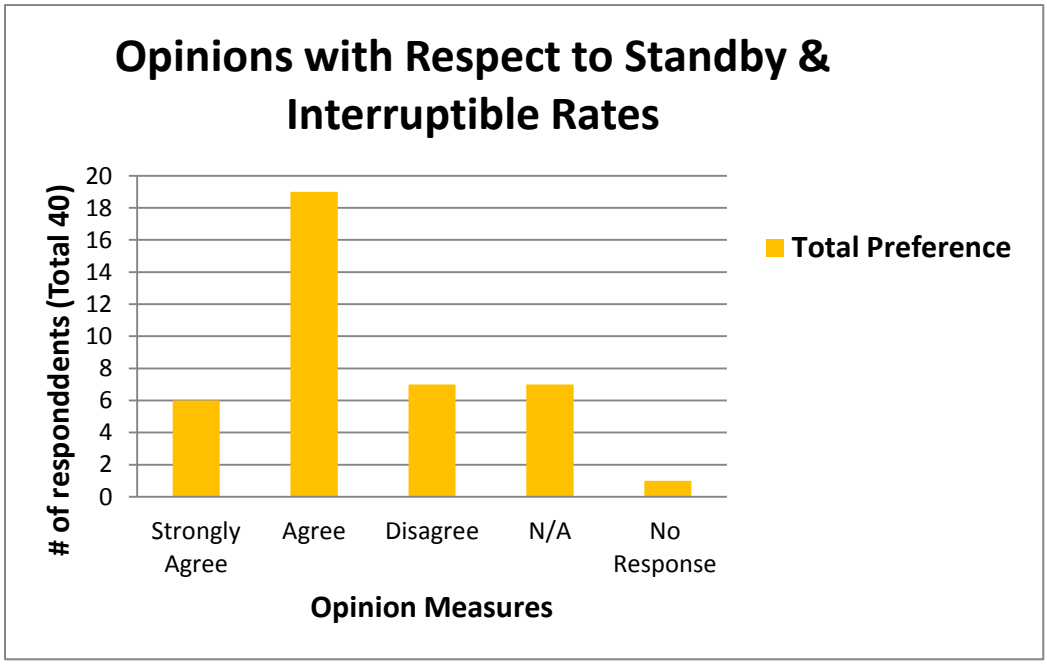
The IEPR Taskforce Report recommended that BC Hydro work with industrial customers to develop interruptible rate options that take advantage of industrial customer flexibility. With respect to standby and interruptible rates, the following scope items were proposed by BC Hydro for review:

- Consider eligibility: entire TSR class
- Review of pricing principles for RS 1880, RS 1853 and capacity/delivery charge
- Consider service characteristics – firm vs non-firm, direct control vs voluntary, term, notice period and number of interruptions

Customer Preferences

A total of 40 respondents submitted feedback forms and indicated their preferences for proposed TOU scope items. There is strong support for BC Hydro's scope. The results are shown in Table 10 below.

Table 10: Customer Preferences for Standby & Interruptible Scope Items



Customer Feedback Summary

The feedback summary tables below show all of the written and verbal comments provided by customers on proposed Standby and Interruptible Rate scope items. Feedback is separated into comments on "Standby Rates" and "Interruptible Service" as follows:

- Table 11a: Written Feedback for Standby Rates
- Table 11b: Verbal Feedback for Standby Rates
- Table 12a: Written Feedback for Interruptible Service
- Table 12b: Verbal Feedback for Interruptible Service

Written comments are taken from customer feedback forms submitted to BC Hydro. Verbal comments are taken from Workshop minutes prepared by Magnolia. Since comments were made on a confidential

basis, no attribution to individuals or corporate entities is provided. Major themes were synthesized by Magnolia from these summary comments.

*Overall sentiment of feedback in both verbal and written collected have also been denoted with a gradient to the left of each table to illustrate the range of topics being expressed.

**To illustrate the opposing feedback, an arrow has been placed next to the corresponding feedback tables where applicable.

Table 11a: Written Feedback for Standby Rates
Existing RS1880/1853 charges are fair; higher cost of "standby" capacity is consistent with other industries.
For RS1880/RS1853; unsure of prior history; may not warrant changing; not applicable to our site.

	Table 11b: Verbal Feedback for Standby Rates
Further discussion	*If pulp storages are big enough to allow you to run and make-up the shortfall, this (RS1852 rate) could be beneficial.*
	Of 17 customers that have self-generation, majority of them are tied to an EPA. May be arbitrage in play to buy cheap market power if no EPA under modified RS 1880 (i.e., if pricing was linked to market prices); but limited with current pricing and EPA in place.
	Do not believe that tinkering with this option would yield much result.
	We like RS1880 - works well for us (pulp & paper company with self-generation).
	We take advantage of RS1880 when needed (i.e., when our generation is down); understand the rate and the price is appropriate, especially when we don't use it that much; feel it's fair.
Works well as is	*RS1880 works fine for us (pulp mill); want to clarify that it doesn't count for CBL purposes.*

Flexibility desired

No changes needed

Table 12a: Written Feedback for Interruptible Service
Bring back 2008 load curtailment program; consider demand contracts for maximum flexibility.
Better to go to contract side for interruptible as each customer has differing ability to interrupt.
For interruptible rates, if a plant can be flexible and move production outside of peak hours, they should get better rates.
Consider a variable rate based on the amount of interruptible load available at the requested time.
The price signal is key; realistically, this would not happen (for sawmill) unless advance notice could be given so that shifting and manpower could be allocated accordingly.
We need reliability (sawmill), so would not be willing to move to interruptible; if implementing interruptible rates would help keep rates lower over the long term, then we would support.
Need controls around contract demand setting; CBL linkage to prevent abuse where the interruption still allows full productivity. Example: 100 MVA contract; 50 MVA for production; 50 MVA available for interruption.
Would like to see potential cost savings and interruption frequency / duration / risk.
Using load to support the grid could provide BC Hydro (with) a significant number of tools to optimize power delivery without costly infrastructure expenditure. Customers can provide value to BC Hydro and could be compensated fairly for that value.
Not interested, we need reliable power to run.
This area is lower priority; BC Hydro is serving customers adequately under current rate forms.
Not of interest to mining sector; no changes required to existing rates.

	Table 12b: Verbal Feedback for Interruptible Service
Open to further discussion	*Would need clarity on what "non-firm service" means and how I might be interrupted.*
	It might be good to have an option to purchase a block of power at a "flat market price".
	For gas plant; would require a minimum notice period for curtailment of ½ hour.
	Re: 2008 Load Curtailment Program (electrochemical plant) - the terms worked for all; just roll-out same customer terms as before and you can implement in no time.
	BC Hydro should offer interruptible rates to all TSR customers; rather than invest huge sums of money into system for N-1 service; Customer can elect to go interruptible provided that interruptible service is cost-reflective (i.e., lower cost than firm service); from fairness perspective, get lower priced power for less reliable service; prevents BCH from making large investments in capital which get rolled into rate-base (and drive higher rates).
	Perform a separate Cost of Service study around interruptible rates.
	Managing the discounts for non-firm service using market-based pricing should be on the energy side, not the demand side.
	The term or time that you require the interruptible service needs to be managed properly; BCH needs to manage system planning and reinforcement requirements.
	(Interruptible service concept) has some annual validity since BCH can store water. BCH can play in thermal market; it is a good scenario for BCH.
	In constrained areas, the customer might be inclined to favor an interruptible rate where the pricing is lower than firm service; this would help improve the competitive position of his business; but in a non-constrained area, the value to BCH may be less; how would this be managed?
	2008 Load curtailment program was similar to buying insurance.
	Better to have (interruptible rate) that is not just applicable to large generator customers; would need to see discount for service and how it is calculated.
	Confirmed that mechanical pulp mills would apply to have interruptible rates for refiner loads.
	Pricing (for interruptible rates) that is based on long run marginal rates should be considered.
	Hard to imagine BCH could make the price reduction attractive enough to make it worthwhile.
	Firm, reliable power is standard service from BC Hydro and pricing is relatively low; this (interruptible service) might create unknown problems with resource planning - I am concerned with this scenario.
No interest	*Theory sounds great but as a customer who wants firm reliable power from the BC Hydro grid, and pricing has been relatively low compared to other parts of the world, we want resource plans that reflect long term planning; this theory doesn't work for us.*

1.4 RETAIL / MARKET ACCESS RATES

Background

BC Hydro previously had a Retail Access Program. It was created in response to Policy Action 14 from the provincial government's 2002 Energy Plan. The Retail Access Program was approved in April 2006 in conjunction with the RS 1823 Stepped Rate Negotiated Settlement Agreement. The Program concept was that the RS 1823 Tier 2 price would provide an incentive for transmission rate customers to purchase from IPPs, or to self-generate, if they could do so less expensively than BC Hydro's cost of new supply. No customers used the Retail Access Program. The Program was suspended with the approval of the British Columbia Utilities Commission in 2012. It was cancelled in 2014 under section 14 of government Direction No. 7.

BC Hydro has an Open Access Transmission Tariff (OATT). The OATT is mainly used by generators and power marketing companies to purchase space on BC Hydro's transmission system for moving electricity from point to point (PTP). PTP transmission can be purchased on a firm and non-firm basis. Section 14 of government Direction No. 7 has removed any "obligation for BC Hydro to offer unbundled transmission services" for domestic loads under the OATT. This means that there is no retail alternative to BC Hydro supply.

BC Hydro's Proposed Scope Items

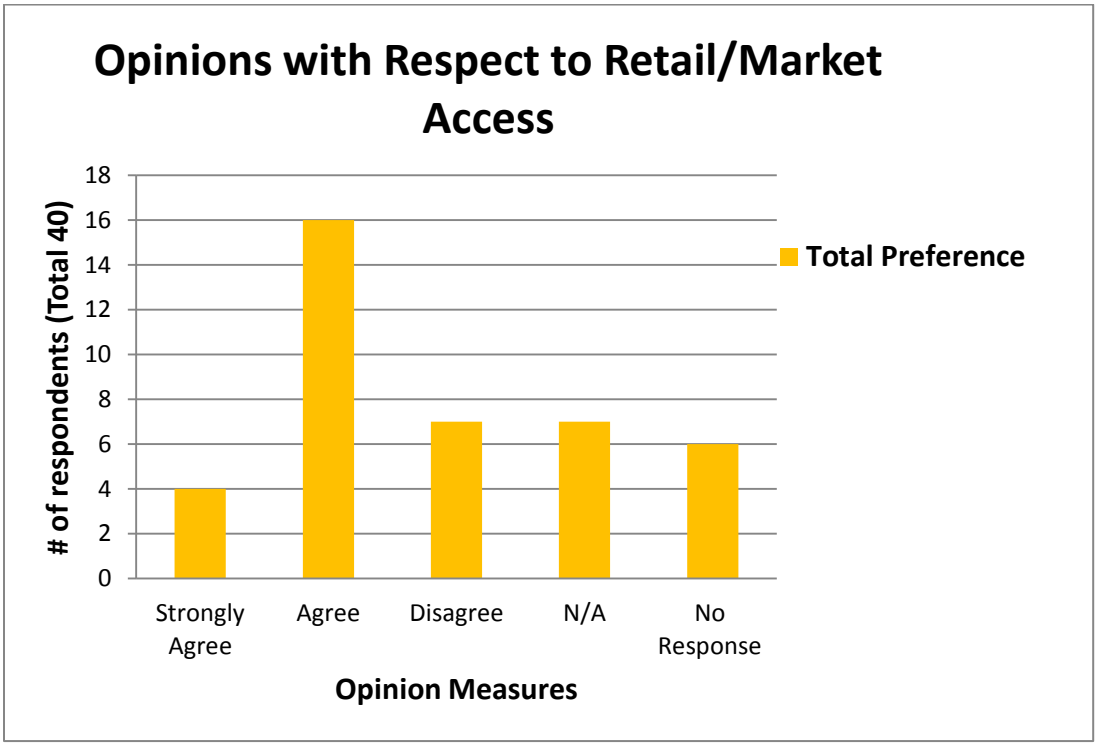
Recommendation # 11 from the IEPR Taskforce Report was for BC Hydro to develop a revised retail access program. In the Workshops, BC Hydro explained that the RDA is a rate design hearing, not a market access hearing. BC Hydro expressed a preference for any market-based pricing element to be incorporated into rates for regulated electricity service, rather than provide physical market access. BC Hydro asked customers for feedback on this approach. With respect to retail / market access rates, the following scope items were proposed by BC Hydro for review:

- Market-based pricing simulation only?
- Market pricing references for energy, capacity, carbon?
- Integrate market based pricing mechanism with other rates
- Eligibility, term, risk
- Participant vs. non-participant impacts
- Service characteristics: firm vs. non-firm supply
- Utility cost/benefit analysis

Customer Preferences

A total of 40 respondents submitted feedback forms and indicated their preferences for proposed retail / market access scope items. There is strong support for BC Hydro's scope. The results are shown in Table 13 below.

Table 13: Customer Preferences for Retail / Market Access Scope Items



Customer Feedback Summary

The feedback summary tables below show all of the written and verbal comments provided by customers on proposed Retail / Market Access scope items:

- Table 14a: Written Feedback for Retail / Market Access Rates
- Table 14b: Verbal Feedback for Retail / Market Access Rates

Written comments are taken from customer feedback forms submitted to BC Hydro. Verbal comments are taken from Workshop minutes prepared by Magnolia. Since comments were made on a confidential basis, no attribution to individuals or corporate entities is provided. Major themes were synthesized by Magnolia from these summary comments.

*Overall sentiment of feedback in both verbal and written collected have also been denoted with a gradient to the left of each table to illustrate the range of topics being expressed.

**To illustrate the opposing feedback, an arrow has been placed next to the corresponding feedback tables where applicable.

	Table 14a: Written Feedback for Retail / Market Access Rates
More discussion needed	*What happens when the long-term reservoir levels drop as long-term ice melts and runs through the system; Do we still have enough capacity? OR, with so much over-capacity, should be have a moratorium on building further IPP and BCH generation facilities? What do we need?*
	Would require extensive discussions to establish rates.
	Review use of Burrard (Thermal) for peaking capacity.
	This is a cost-shifting exercise; customers need to have an easy process that is clear and transparent; a rate that flows through market price plus reasonable currency risk and transportation charges would be reasonable; user would forecast market delivery, plus other charges, then make a business decision to a term length.
	Yes, integrate market-based pricing mechanism with other rates.
	Consider inclusion of policy elements that provide secure energy/capacity supply with market access for variable % of total demand; ok for industry to take market price risk but not operating supply risk. Provide firm delivery via a wheeling fee/demand charge from BC Hydro.
	Maintain alignment of T2 rates with market rates.
	This will provide some accountability for BC Hydro to provide competitive power. If BC hydro power is competitive over market on all spectrums it is unlikely that retail access would be necessary or would be used if provided. Inter facility transfers within one company should be facilitated if CBG is not being fully utilized. Load should be given the opportunity to participate in external sales during super peak pricing if physically possible (i.e., if BC Hydro is too constrained to provide power for sales to very high priced markets). Load can be dropped in BC to be available for sales into a high priced market.
Maintain existing structure	*Not likely we would go to market.*
	Not sure if there is sufficient customer interest for retail access.

Table 14b: Verbal Feedback for Retail / Market Access Rates
Market pricing is fine if it flows through Hydro.

1.5 EXEMPT / SURPLUS / OTHER RATES

Background – Exempt Rates

BC Hydro's approved Rate Schedule 1827 (RS 1827) provides a small number of customers with an exemption from tiered energy pricing under the RS 1823 Stepped Rate. RS 1827 has a flat energy charge that is identical to the cancelled RS 1821 energy charge and RS 1823 Energy Charge Part A. Demand charges under RS 1827 are the same as under RS 1823.

Eligibility for exemption requires approval from the British Columbia Utilities Commission. The original rationale for exemption is set out in Section 8 of the TSR Negotiated Settlement Agreement (TSR NSA). All parties to the TSR NSA agreed that the Commission should have the discretion to address the issue of exemptions. Refer to excerpt below:

> *" … In accepting the Commission's Recommendation #15 in the Heritage Inquiry Report and Recommendations, the Government response described these customers as 'effectively distributors who sell the electricity they purchase onwards to end-use customers' …."*

Background – Surplus Rates

BC Hydro explained in the Workshops that the system is presently experiencing an energy surplus. Surplus energy is sold into power markets by Powerex, BC Hydro's trading arm, at market prices. When market prices are low, the value of surplus energy is reduced. The concept of a surplus rate is to extract the equivalent market (or higher) value for a volume of surplus energy by making it available to customers at a reduced rate. BC Hydro asked for customer feedback on whether surplus energy rates should be made available for incremental customer loads. BC Hydro advised that surplus energy rates would not apply to existing customer loads. BC Hydro also asked for feedback on any other prospective rates that might be of interest.

BC Hydro's Proposed Scope Items

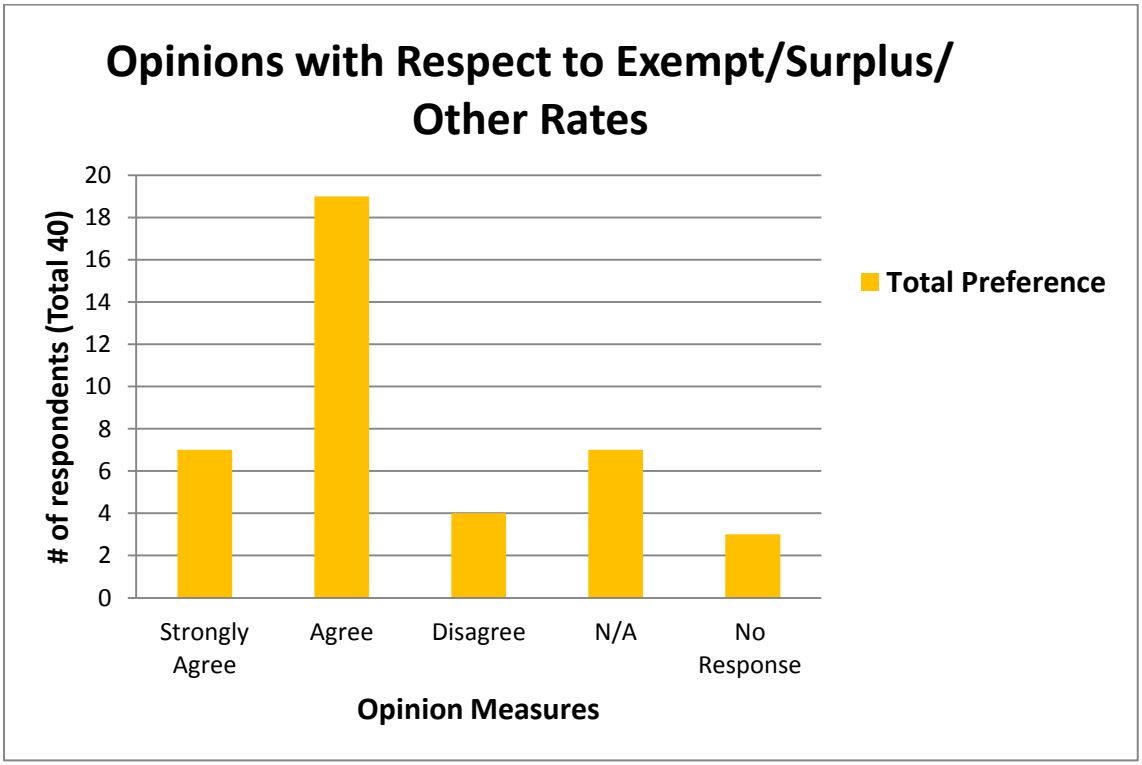
With respect to Exempt / Surplus / Other rates, the following scope items were proposed by BC Hydro for review:

- Is the rationale for exemption still appropriate?
- Should specific rates be designed to reflect specific operating circumstances and times (i.e., energy surplus)?

Customer Preferences

A total of 40 respondents submitted feedback forms and indicated their preferences for proposed Exempt / Surplus / Other rate scope items. There is strong support for BC Hydro's scope. The results are shown in Table 15 below.

Table 15: Customer Preferences for Exempt / Surplus / Other Scope Items



Customer Feedback Summary

The feedback summary tables below show all of the written and verbal comments provided by customers on proposed Exempt / Surplus / Other rate scope items:

- Table 16a: Written Feedback for Exempt / Surplus / Other Rates
- Table 16b: Verbal Feedback for Exempt / Surplus / Other Rates

Written comments are taken from customer feedback forms submitted to BC Hydro. Verbal comments are taken from Workshop minutes prepared by Magnolia. Since comments were made on a confidential basis, no attribution to individuals or corporate entities is provided. Major themes were synthesized by Magnolia from these summary comments.
*Overall sentiment of feedback in both verbal and written collected have also been denoted with a gradient to the left of each table to illustrate the range of topics being expressed.

**To illustrate the opposing feedback, an arrow has been placed next to the corresponding feedback tables where applicable.

Do not support

Support

Table 16a: Written Feedback for Exempt / Surplus / Other Rates
Do not support exemption.
Do not support exemption.
Do not support exemption.
Moving from exempt to stepped rate has pros and cons; not sure without analysis which is best.
Eliminate exemption.
OK to review exempt rates, but need to understand potential impacts.
Support re-consideration of exempt rates.
Ensure that "flow-through" organizations (that take power from exempt customers) have incentives in place for DSM vs flat rates.
Need to have better understanding re: how stepped rate would be beneficial in order to provide input; need to understand how rate deals with slow incremental growth.
Surplus rates are of short-term interest as there is the possibility of significant discounts based on current market (surplus) conditions for incremental loads.
Surplus: There may be some special application available, but it should be only short term while BC hydro is in excess. It should also not create an unfair competitive advantage to one customer. Principle of treating all customers equally would be tested with exempt/surplus rates.
Don't see need to review (exempt rates).
Not required for review – only few existing customers.
For exemption: unsure of past history; may not desire changes.

Table 16b: Verbal Feedback for Exempt / Surplus / Other Rates
You could sell excess capacity and energy at a discount; but this contradicts your conservation initiatives.
If you priced surplus power at market, there is self-efficiency; customer can make the decision to respond.

1. PART B: Transmission System Interconnection – Tariffs and Process

Background:

BC Hydro's transmission system interconnection tariff is called Tariff Supplement No. 6 (TS6) – the Facilities Agreement. This tariff was approved in 1991. It has not been modified, or formally reviewed, since then. For the purpose of giving the reader a high-level overview of TS6, the summary below is adapted from BC Hydro's Workshop presentation materials. Please also refer to Appendix B.

- The customer is responsible to design, build, own and operate the: (a) transmission line to connect with the BC Hydro transmission system; (b) substation that transforms the electricity voltage to customer plant specifications; (c) electrical distribution system that delivers electricity to the plant; and (d) the plant itself.

- BC Hydro is responsible to design, build, own and operate additions and alterations to the transmission system, such as transmission lines and substations. This is referred to as "system reinforcement". BC Hydro is also responsible for the Basic Transmission Extension, which is the physical connection between the BC Hydro system and the customer's transmission line.

- The customer pays for the cost of the Basic Transmission Extension. The customer also pays for mandatory system studies, conducted by BC Hydro, that determine the point of interconnection and identify the required system reinforcement upgrades, costs and timing.

- Costs of system reinforcement are allocated between the new customer and the utility in accordance with a contribution formula and a 150 MVA load threshold. System reinforcement costs allocated to the customer require a capital contribution. System reinforcement costs allocated to the utility are "rolled-in" to rates for recovery from all ratepayers.

- The new customer must provide security/bonding using an acceptable financial instrument for the entire portion of system reinforcement costs allocated to the utility. This is to mitigate any financial risk that the utility takes, on behalf of ratepayers, when it spends money. Annual revenue received from the customer is used to reduce the security.

- For new loads > 150 MVA in size, the customer may also be responsible for the costs of additions and alterations to BC Hydro's generation plant and 500kV transmission system. For loads < 150 MVA, these additional cost obligations do not apply.

2.1 Transmission System Interconnection Tariff (TS6)

BC Hydro's Proposed Scope

With respect to the Transmission System Interconnection Tariff (TS6), the following scope item was proposed by BC Hydro for review.

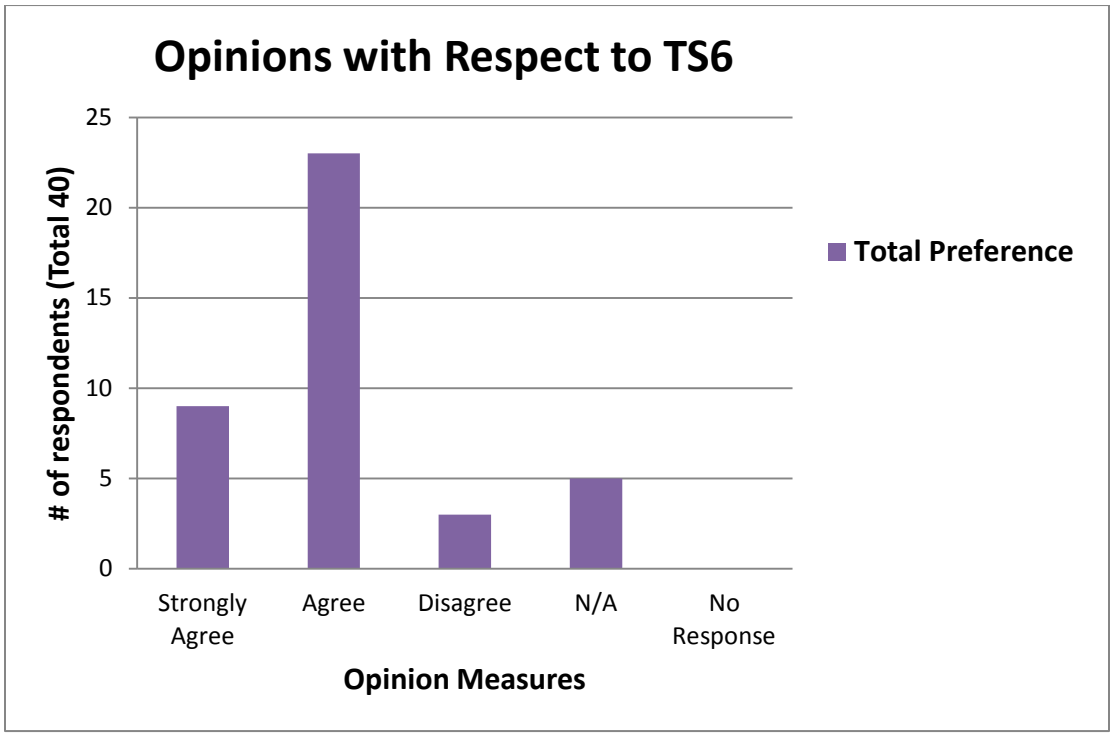
- Tariff Supplement 6 - and Tariff Supplement 5

Note that Tariff Supplement 5 is the Electricity Supply Agreement. Although TS5 is included in the scope item, customer feedback was provided almost entirely for TS6.

Customer Preferences

A total of 40 respondents submitted feedback forms and indicated their preferences for the proposed review of TS6. There is strong support. The results are shown in Table 17 below.

Table 17: Customer Preferences for TS6 and TS5



BC Hydro's Proposed Scope – TS6 Details

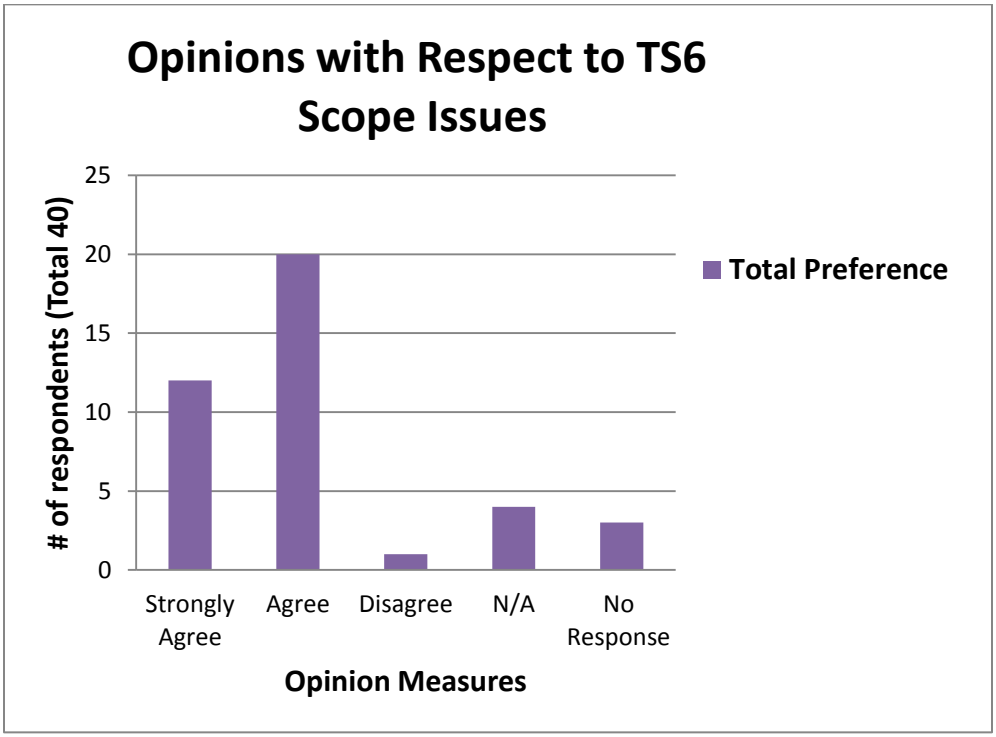
For TS6, BC Hydro proposed additional scope detail for review. These are the TS6 scope items on which BC Hydro sought substantive customer feedback:

- TSR customer eligibility criteria
- Definition of eligible "system costs" for allocation
- Methodology/formula to allocate system costs
- Examination of 150 MVA threshold
- Treatment of "system reinforcement" vs "system extension"
- Treatment of single loads, phased loads, regional load clusters
- Treatment of load customers with self-generation
- Commercial agreements / terms & conditions

Customer Preferences

A total of 40 respondents submitted feedback forms and indicated their preferences for these proposed scope items. There is strong support. The results are shown in Table 20 below.

Table 20: Customer Preferences for TS6 Detailed Scope Items



Customer Feedback Summary

The feedback summary tables below show all of the written and verbal comments provided by customers on proposed TS6 scope items:

- Table 21a: Written Feedback for TS6
- Table 22b: Verbal Feedback for TS6

Written comments are taken from customer feedback forms submitted to BC Hydro. Verbal comments are taken from Workshop minutes prepared by Magnolia. Since comments were made on a confidential basis, no attribution to individuals or corporate entities is provided. Major themes were synthesized by Magnolia from these summary comments.

*Overall sentiment of feedback in both verbal and written collected have also been denoted with a gradient to the left of each table to illustrate the range of topics being expressed.

**To illustrate the opposing feedback, an arrow has been placed next to the corresponding feedback tables where applicable.

	Table 21a: Written Feedback for TS6
Threshold discussion	*Keep 150 MVA threshold; support some allocation of costs to customer for connection of new large loads; do not pass major generation and transmission system upgrade costs for large loads to smaller TSR customers.*
	Support current TS6 and ESA process; concerned about potential $ injection if TS6 changes (from security to cash) as this reflects a different policy perspective.
	Support separation of TS6 from supply rate stream.
	New customer should make a contribution for a portion of up-front costs.
	Need to define better guidelines re: which loads are eligible for 150 MVA threshold. Plants that "phase-in" should be dealt with as entire load.
	TS6 constrains growth in BC; it creates a bias against investment decisions for large loads > 150 MVA.
	Existing tariff document could be "updated", but is still light years ahead of Alberta; Non-tariff documents should not be included in tariff - keep as stand-alone process.
	Need to understand potential risks for expansion if SR costs are migrated in full to the customer as opposed to current LOC policy.
	Need more clarity (on tariff application) for customers with EPA/LDA agreements.
	Agree that a well-designed contribution policy would not require an arbitrary threshold, but in practice believe this would be hard to achieve; hurdles to progress in the queue seem reasonable.
	Balance needed between spreading costs around, promoting economic growth and profits available to new projects if they don't pay enough for (system) infrastructure.
	TS6 is not in current business scope for us.
	150 MVA threshold is arbitrary; should all security have a pro-rated capacity component?
	Need (weighted) blend of principles and economic impacts to determine connection cost allocation; consider impact of regional industrial development to avoid "tipping point" cost for any one applicant.
	There are public policy issues at play; issue of "fairness" mixed with commercial self-interest of load/gen customers; no right answers.
	Interconnection: TS6 ok as is; only issue is time taken to have study done – need quicker studies; non-tariff documents OK as is.
	Was 150MVA an arbitrary choice? (then review); if based on customer demand (then not necessary to review).
Room for improvements	*Maximum offset calculation should be reviewed to ensure it is applicable; the 150 MVA threshold may prevent right sizing of projects.*
	System reinforcement vs system extension: This has worked and should be evaluated for performance; there may be room for optimization.

	Table 21b: Verbal Feedback for TS6
Imbalance of loads to clarify and review	*It's not appropriate for BC Hydro to have 150 MVA just sitting there waiting for someone to trigger an upgrade. In theory, the concept that the new customer should pay is good, but where the limit lies can be debated.*
	Existing customers with good history that have posted security for cost of reinforcement is fair; prefer to pay security versus cash.
	There is a disproportionate impact on the system for the cost of wind integration and peak generation.
	Load creep needs to be recognized.
	DCAT was specific to load customers; didn't have allocation for wind power. BC Hydro should consider a cost allocation formula/contribution for generators that drive a proportionate investment in system reinforcement.
	Re: size threshold for Transmission service: Unless you have a big load, no one is going to incur the cost to build their own substation just to take T service.
	Recommend BCH label "basic transmission extension" to something more meaningful or reflective of what it really is: (ie. line tap or substation line position); Current definition is confusing.
	One piece we want BCH to consider is how customers can provide services to reduce the cost of transmission.
	Re: NTL vs TS6 Application: Wanted clarification re: whether a new mining customer connecting to the NTL system would pay cash (under TS37) or provide security (under TS6) for a new switching station. In other words, does a new switching station get designated as an NTL asset or fall under the general TS6 definition of system reinforcement? This determines whether we pay cash or provide security.
	150 MVA threshold is not a bad thing especially if you look at it from LNG perspective (Magnolia note: context was avoiding ratepayer cost burden caused by large LNG loads).
	150 MVA threshold appears to be designed to discourage large loads; not really relevant to solid wood industry where typical sawmill loads are in 5 – 10 MVA range.
	Re: option for BCH to build customer T line: Customer can build cheaper and faster than BC Hydro.
	For load interconnection, if other customers connect to the line that you paid for, pioneer rights apply; need to be mindful of that and follow-up with BC Hydro.
	We needed to apply for a load increase for 2 MW sawmill expansion; had nearly completed the work, then realized we should probably call BC Hydro to request ESA increase; there never used to be an issue for capacity.
No changes needed	*If you have a well-designed policy, feel that you probably don't need a threshold. However, most customer loads under 150 MVA, so it has not been an issue.*
	Don't have a problem with current formula application for "decent" sized mine; this is reasonable; mining industry views bonding (security) as important to ensure skin in the game.

2.2 Interconnection Process & Queue Management

Background

BC Hydro's Interconnection and Queue Management Process is not a prescribed part of TS6. The process includes application forms, commercial agreements, technical requirements and business practices.. Technical requirements are set out in BC Hydro's Guide and Requirements for Service at 69kV – 287kV. Business practices are designed to manage the load interconnection "queue".

The load interconnection queue is based on a 'first come, first serve' principle. Ultimately, the queue position determines the allocation of potential system upgrade costs between customers.

No formal documentation on BC Hydro's business practices for queue management was provided for customer feedback. Review in the Workshops featured an overview slide and an illustrative timeline for system study work (1-3 years) and system construction and commissioning (1-4 years). Refer to slides 20 and 21 of the Transmission System Interconnection slide-deck in Appendix B.

BC Hydro's Proposed Scope

BC Hydro characterized non-tariff scope items for customer review as follows:

- Interconnection Process and Queue Management
- Related terms and conditions/commercial agreements
  - System Impact Study and Facilities Study Agreement
  - Credit Support Agreement
  - Transmission Line Ownership Transfer Agreement

Customer Preferences

A total of 40 respondents submitted feedback forms and indicated their preferences for these proposed non-tariff scope items. There is strong support. The results are shown in Tables 22 and 23 below.

Table 22: Customer Preferences for Interconnection Process and Queue Management

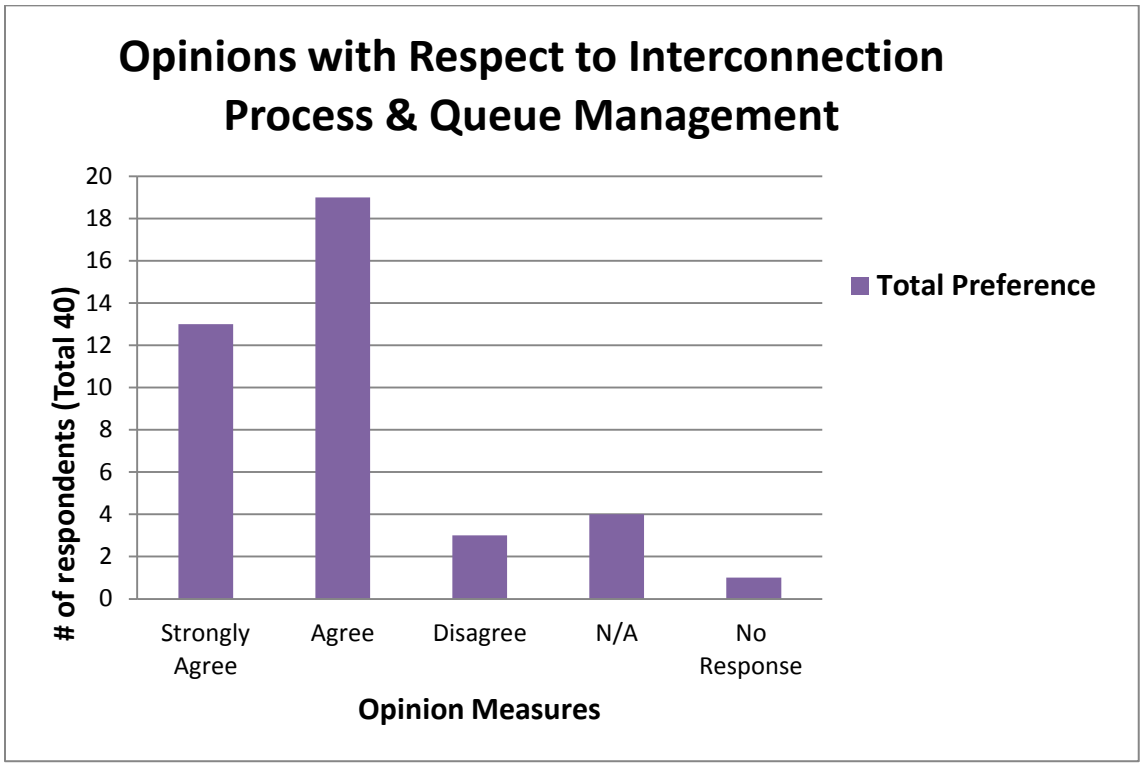
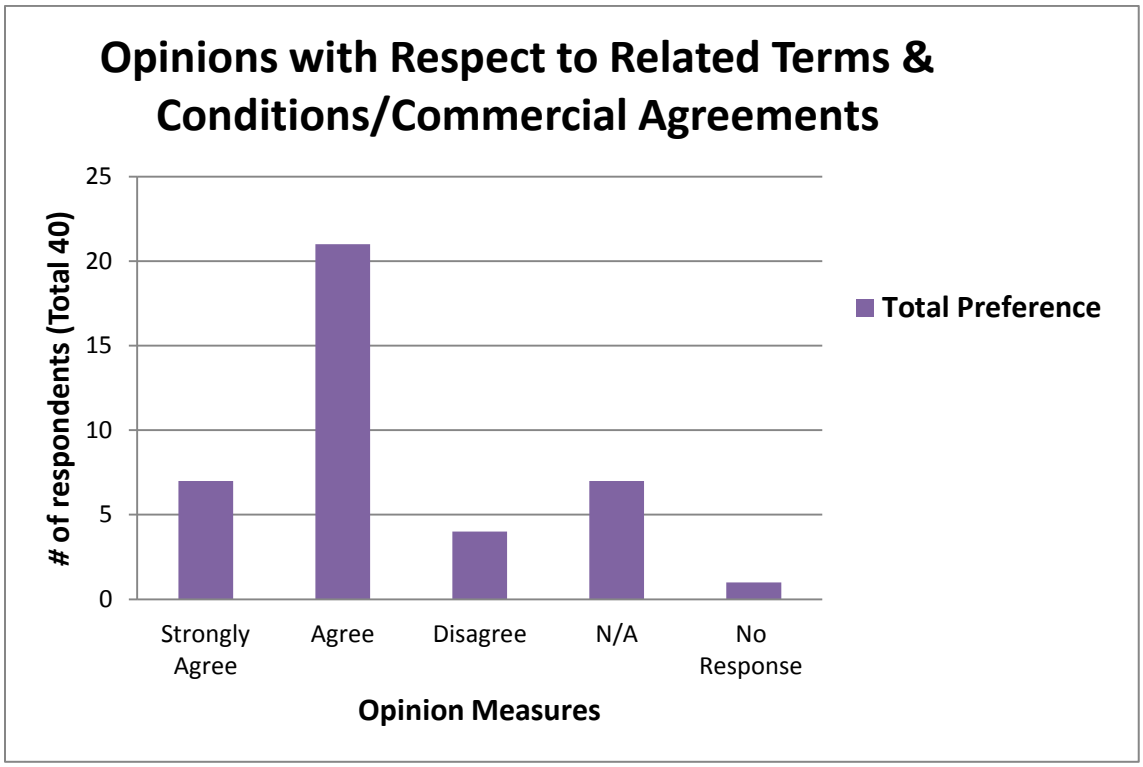


Table 23: Customer Preferences for Related Terms and Conditions



Customer Feedback Summary

The feedback summary tables below show all of the written and verbal comments provided by customers on proposed Interconnection Process and Queue Management scope items:

- Table 24a: Written Feedback for Interconnection Process
- Table 24b: Verbal Feedback for Interconnection Process

Written comments are taken from customer feedback forms submitted to BC Hydro. Verbal comments are taken from Workshop minutes prepared by Magnolia. Since comments were made on a confidential basis, no attribution to individuals or corporate entities is provided. Major themes were synthesized by Magnolia from these summary comments.

*Overall sentiment of feedback in both verbal and written collected have also been denoted with a gradient to the left of each table to illustrate the range of topics being expressed.

**To illustrate the opposing feedback, an arrow has been placed next to the corresponding feedback tables where applicable.

	Table 24a: Written Feedback for Interconnection Process
Need to streamline	*Interconnection process should be audited to speed up the process; 1-3 years just for studies is too long for some projects; If a customer has completed all the "pre-work" for studies, they should move ahead of somebody in the queue who is not as advanced.*
	Interconnection process takes too long and is prone to abuse; no consequences for "applications" that prevent timely review of real projects.
	Shorten and simplify the review process and consultation period by BC Hydro.
	Needs to be a streamlined way for 2-5 MW self-generation loads to be connected; current process is too complicated. Conduct a principles review of the entire process; look at the intent of what this is trying to accomplish; get a practical understanding of what customers are trying to do.
	Timeline is far too long; BC Hydro should provide more resources to speed up process.
	Need to streamline process and shorten timelines.
	Interconnection process is too long.
	Interconnection process is too long; rules are unclear.
	Need to have an expedited process available.
	Illustrative example: 3 types of customer-based generation: (1) Offset site load with gen; (2) Offset site load + occasional export; (3) pure export.
	2-7 years is too long for connection; no need to bring in non-tariff agreements – working OK as is; look at overall process with view to prioritizing customers who are "shovel ready"; set (additional) size thresholds to encourage nimbleness.
	Non-tariff documents should be part of tariff; they are important commercial items for load/gen customers to understand early in the process.
	TS6 ok as is; only issue is time taken to have study done – need quicker studies; non-tariff documents OK as is.
	Interconnection process should be optimized to reduce long delays, costly repetition, and expensive rework; Find ways to streamline the process; studies can be conducted by contractor experts is one way.
More adaptation and accessibility	*Studies: BCH has monopoly on studies; can charge whatever they want; limits/rules need to be imposed.*
	Project development stage should impact queue placement.

	Table 24b: Verbal Feedback for Interconnection Process
Focus on Principles	*Suggest you focus on principles first before diving into process itself; confirm intent of the process at high-level; confirm policy framework; then do process audit to see if process is aligned with principle and policy framework. End goal would be to have more streamlined and transparent process that customers can understand.*
	BC Hydro needs to publish business practices and circulate for feedback.
	It may be a long process, but due to close relationship with KAM, it's worked well for us. Been advised the queue for the process takes a long time; so get your request in early.
	From mining perspective, not a difficult process, especially if you know where on the system you want to connect.
	For new mining projects, critical to know if power is available and at what cost; need this information as part of feasibility study and financing; if have to wait 1-3 years to determine, it's too long and could kill project before it gets started.
	Critical path to build new customer facilities is so much faster than BC Hydro timeline to do studies.
	Consider charging a fee for Contract demand (per MVA). This would make people think more carefully about how much power they really need and mitigate over-estimation of contract demand. Getting real money from real people is a good way to affirm serious projects; however, senior management might view as potential discouragement to mining projects.
	The interconnection process schedule is reasonably well-aligned with the approval process for environmental permitting of a mine.
	Seven years period (for studies and system reinforcement construction) is not realistic - the reality of building plants does not take as long as this.
	Shorten study time.
	If you change the load interconnection process to be like the OATT, you would have a prescribed process in place.
	Interconnection process is too long and complex.
	Process stuff (i.e., non-tariff agreements) should be included; currently the process is too long.
	Should be option to skip system impact study; go straight to facilities study.
Focus on Process	*Customer gave example re: how they paid a deposit intended for generator study cost; bid was unsuccessful; when they asked for balance of deposit money back, BC Hydro provided detailed report to account for money spent 'to the nickel'. Customer doubtful re: accuracy of cost details provided. Make actual cost reconciliation process more transparent.*

2. PART C: General Comments and Feedback

Customer Feedback Summary

During the Workshops, customers provided general comments and feedback on a wide range of topics that were not formally identified as scope items for engagement. The feedback summary tables below show all of the additional written and verbal comments provided by customers:

- Table 25a: Written Feedback - General Comments
- Table 25b: Verbal Feedback – General Comments

Written comments are taken from customer feedback forms submitted to BC Hydro. Verbal comments are taken from Workshop minutes prepared by Magnolia. Since comments were made on a confidential basis, no attribution to individuals or corporate entities is provided.

No major themes were prepared by Magnolia from these summary comments as they are not directly related to BC Hydro's engagement scope.

*For general feedback that includes a range of opinions, a solid color code is used to the left of each table

More discussion on structure and option of rate	**Table 25a: Written Feedback – General Comments**
	Customers need/want rate options.
	Overall goal should be cost-reflective rates; customers can then use their operational flexibility and risk appetite to take advantage of cost-reflective rates and optimize between their operations and BC Hydro's cost structure.
	Rates and components should be cost-reflective so that when customers respond to price signals it generates savings for the customer and BC Hydro.
	This workshop approach is a good forum for dealing with distribution tariff issues.
	Cost of Service allocation needs re-balancing; likely over time to make more fair.
	Distribution extension policy is also important.
	Incentives should be provided for customers who make VARS available to the grid (i.e., for leading power factor).
	Forest industry is still burning bush piles (of fibre) so energy price (for biomass) is still too low; need rate signals to better utilize this energy source (for power generation).
	Our plants are not very large loads (5 -10 MVA); we prefer good decisions to help smaller and medium size TSR customers; would value more "nimbleness" in system for new load connections.
	The BC Hydro system is well-suited to the standard (default) rate structure, whether stepped or flat; our EPA further entrenches us into this structure; we have little opportunity to take advantage of TOU or interruptible rates.
	Why was Red Chris paid $52M for their transmission line transfer, when TS6 says $1?

	Table 25b: Verbal Feedback – General Comments
General concerns on politics, MRS administration and rate applications for various industries	*Politics come into play when you look at how BC residential customers are paying less for power; will politics be a driving force for this RDA?*
	For Peace Region Electricity Supply (PRES) project, BC Hydro should consider installation of system substations at strategic locations to serve multiple customer loads, rather than just 230kV loop.
	The regulated approach (to rate-making) in BC works well, compared to unregulated markets where power prices have tended to rise.
	Mandatory Reliability Standards (MRS) have quite onerous administration and paperwork; no customer expertise - would be nice for BCH to manage this on our behalf, as was done without incident for decades prior to MRS.
	MRS, although we understand it's out of scope – review documentation to determine if new customer actually needs MRS.
	Should be postage stamp rate application for LNG too - why discriminate?
	We like being a load customer with reserved rights to electricity on the system via electricity supply agreement - this is beneficial; also like access to Power Smart incentives and program funding; works well with TSR; want this to continue.