Draft

BC Hydro Rate Design Workshop

SUMMARY 18 NOVEMBER 2014 9:00 A.M. TO 3:00 P.M. BCUC Hearing Room Vancouver

TYPE OF MEETING	RDA Workshop No. 6 – Transmission Extension Policy
FACILITATOR	Anne Wilson, BCH
PARTICIPANTS	ARC Resources Ltd., Association of Major Power Consumers of British Columbia (AMPC), , B.C. Ministry of Energy and Mines (MEM), British Columbia Old Age Pensioners Organization (BCOAPO), British Columbia Sustainable Energy Association and Sierra Club B.C. Chapter (BCSEA), BCUC staff, Canadian Association of Petroleum Producers, Canadian Office & Professional Employees Union Local 378 (COPE 378), City of New Westminster (New Westminster), Clean Energy Association of British Columbia, Commercial Energy Consumers Association of British Columbia (CEC), Encana Corporation, First Nations Energy & Mining Council, FortisBC Inc. (FortisBC), KGHM International, Linda Dong Associates, Manitoba Hydro, Marayne Consulting Inc., Midgard Consulting, Mining Association of British Columbia (MABC), Municipality of Whistler, Seabridge Gold Inc. (Seabridge), Sinclar Group Forest Products Ltd., Teck Resources Limited, TransLink, University of British Columbia, Valard, Vancouver Airport Authority
BC HYDRO ATTENDEES	Gordon Doyle, Sam Jones, Frank Lin, Justin Miedema, Craig Godsoe, Bryan Hobkirk, Anne Wilson, Jeff Christian (Lawson Lundell)
AGENDA	1. Introduction including review of draft agenda 2. Background, Legal Context and Bonbright Criteria 3. Overview of TS 6 4. Sources Informing Review of TS 6 5. Utility Contribution Options 6. Security Options 7. 150 MV.A Threshold Options 8. Transition Rule Options 9. Other Issues – Line Transfers and Queue Management 10. Next Steps

MEETING MINUTES

ABBREVIATIONS

AESO.......Alberta Electric System Operator	IPP.........Independent Power Producer
AUC.........Alberta Utilities Commission	IRP.........BC Hydro’s 2013 Integrated Resource Plan
BCH ....BC Hydro	kV......... Kilovolt
BCUC......BC Utilities Commission	kW.........Kilowatt
BTE..........Basic Transmission Extension	MV.A ....Megavolt Amperes
CFO.........Chief Financial Officer	MW.........Megawatt
COS..........Cost of Service	NTL........Northwest Transmission Line
CP............Coincident Peak	OEB........Ontario Energy Board
CPCN...... Certificate of Public Convenience and ....Necessity	RDA........Rate Design Application
DCAT......Dawson Creek/Chetwynd Area Transmission ....Project	TS 6 ....Tariff Supplement No. 6
ESA.........Electricity Supply Agreement	UCA.........Utilities Commission Act
IEPR.......Industrial Electricity Policy Review	

1. *Introduction*

Anne Wilson opened the meeting by reviewing the agenda set out at slide 2 of the Workshop No. 6 slide deck.

2. *Presentation: Background, Legal Context and Bonbright Criteria*

Gordon Doyle highlighted the jurisdictional issue posed by section 3 of Direction No. 7, which is that the BCUC cannot unilaterally change TS 6 under its UCA rate setting powers. BCH proposes that TS 6 be reviewed through a section 5 UCA inquiry process whereby the BCUC would review TS 6 as part of the 2015 RDA, make recommendations in a report to the B.C. Government, and the B.C. Government would be the decision-maker. As part of this discussion, Gord raised the phasing of the 2015 RDA, first discussed at Workshop No. 1, with BCH proposing that TS 6 be part of a later module or phase consistent with some participant statements at Workshop No. 1 in May 2014.
Gord also reviewed the Bonbright criteria used to assess TS 6 and options, and indicated that in BC Hydro’s opinion

fairness (allocation between existing customers and new customers), efficiency (incenting customers to request the most economical connection facilities), and rate and bill stability are the most important criteria in the context of TS 6 and Transmission extension policy.

	FEEDBACK	RESPONSE
1.	**COPE 378** Another way to deal with the BCUC jurisdictional issue is to request that the B.C. Government amend section 3 of Direction No. 7.	COPE 378's suggested approach was raised in 2009 in respect of Direction No. 7's predecessor, Special Heritage Direction No. HC2, as part of the BCUC's review of Transmission service rates and was not acted on. BCH has been in discussions with MEM. Use of the section 5 UCA process accords with the recent task force's draft report concerning its review of the BCUC, and permits the B.C. Government to be the final decision maker as TS 6 has economic development implications.
2.	**COPE 378** COPE 378 encourages BCH to file Transmission extension/TS 6 proposals as part of the main 2015 RDA as there is a relationship between the pricing of electricity for industrial users and Transmission extension policy.	
3.	**AMPC** There is a relationship between Transmission extension policy and rates, but having Transmission extension/TS 6 proposals be part of a later 2015 RDA module does not necessarily sever this link. AMPC is not against having Transmission extension/TS 6 proposals as a later RDA module.	
4.	**BCUC staff** BCH should consider providing a broader rationale for whatever Transmission extension policy it proposes. Transmission extension policy is typically driven by government policies which may be in addition to the Bonbright criteria. It would be helpful if BCH asked the B.C. Government to be clear on its policies. A good example is the 150 MV.A threshold – its removal may encourage larger customers to proceed but this may also have ratepayer impacts particularly if the larger customers are 'energy hogs'. BCH should also consider what has changed since 1991 when TS 6 was adopted.	
5.	**COPE 378** COPE 378 agrees with the BCUC staff comment. One perspective put forward in the IEPR review process was that the B.C. Government should bear the costs of its electricity policies in certain contexts as opposed to imposing such costs on ratepayers. In COPE 378's view, what has changed since 1991 is the large difference in energy costs between embedded Heritage hydro costs and new energy sources. The addition of new customers is not a net benefit to BCH or its existing customers.	

6.	**AMPC** AMPC agrees with the BCUC staff comment, but TS 6 and options should be assessed using the Bonbright criteria – the Bonbright criteria are as relevant to Transmission extension policy as to other rate design issues.	
7.	**New Westminster** Has BCH reviewed IPP interconnection agreements to inform its review of TS 6?	BCH will review IPP interconnection agreements as part of the overall review of TS 6. For purposes of this workshop, BCH used jurisdictional assessment, other BCH tariffs such as the NTL tariff and Distribution extension, the BCUC's DCAT CPCN proceeding submissions and decision, and the IEPR review as the basis for its proposed options.

3. Presentation: Overview of TS 6

Sam Jones and Frank Lin gave an overview of TS 6, emphasizing the three parts of a connection between a customer's facility and the BCH grid: (1) customer transmission line; (2) BTE; and (3) System Reinforcement. Slide 11 shows the customer transmission line to the right and System Reinforcement to the left. Differentiating System Reinforcements from extensions was the focus of the presentation.

Also discussed were how BCH's contribution to System Reinforcement costs is determined; security requirements; and the 150 MV.A threshold.

	FEEDBACK	RESPONSE
1.	**AMPC** When it comes time to examine possible TS 6 amendments, it would be helpful if BCH clarified the language around: BCH offset, BCH contribution, customer contribution, radial vs. non-radial, extension, customer extension, etc.	Agreed. For purposes of this workshop, BCH uses the terms 'utility contribution' (this is consistent with its Distribution extension terms found in sections 1 and 8 of the *Electric Tariff*) and 'customer payment', referring in each case to what the applicable party contributes to the incremental costs of connecting and serving the new customer.
2.	**AMPC** It would be helpful for the utility contribution discussion purposes if on slide 11 we clearly differentiate between the right side – customer transmission line and BTE; left side – System Reinforcement, and then discuss as between utility and new customer who is responsible.	
3.	**AMPC** Regarding the last item on slide 15 (bolded), if a gas-fired generation solution was proposed at the end of a radial line as an alternative to System Reinforcement transmission, would the new customer be required to make a payment that included the gas-fired generator?	TS 6 as currently worded contemplates transmission solutions as reflected in the definitions of "Facilities", "System Reinforcement", "Basic Transmission Extension", etc.[1] Regardless, BCH recognized the possibility of gas-fired generation alternatives to System Reinforcements in the DCAT CPCN proceeding. Any gas-fired generation alternative would be subject to the *Clean Energy Act*'s 93% clean or renewable energy objective.

[1] Note to readers: a copy of TS 6 is posted to BC Hydro's 2015 RDA website (http://www.bchydro.com/about/planning_regulatory/2015-rate-design/resources.html) under 'Resources'.

4.	**BCSEA** When BCH talks about new customer responsibility re: customer transmission line, does BCH mean responsible for costs or for constructing the line? Re: slide 19 and more broadly, are we talking about actual examples or theoretical?	Costs – under TS 6, the customer is responsible for all costs associated with the customer transmission line in all cases. As set out on slide 13, the customer is also responsible for constructing the customer transmission line where "reasonable, practical and economic". Both. One option going forward is to treat extensions to clusters (multiple customers are forecasted to connect) differently – in BCH's view, it is more clear cut that the new customer should pay for the customer transmission line/BTE where it is a single new customer. This cluster option requires forecasting.
5.	**AMPC** While forecasting is difficult and the results are almost always wrong, it is imperative for Transmission extension policy that BCH forecast new customer load and rate impacts.	Agreed.
6.	**COPE 378** The business practices queue management document BCH circulated references First Nation consultation. One of the costs of transmission interconnections is First Nation consultation and accommodation, correct?	Yes.
7.	**COPE 378** The impact of costs of incremental energy needs must be taken into account. Is this still an issue that is open for comment and debate as part of the RDA stakeholder engagement process?	Yes; however, as we will see with the jurisdictional assessment, no other jurisdiction BC Hydro is aware of takes into account generation costs when deciding on the utility contribution/new customer payment allocation in the transmission extension policy context.
8.	**AMPC** Please confirm that the TS 6 utility contribution formula has never resulted in a customer payment for System Reinforcements.	Confirmed.
9.	**BCOAPO** What is the rationale for the 7.4 years revenue and the one-half annual depreciation in the TS 6 utility contribution formula?	Both result from 1991 and BCH's records from that time do not indicate the rationale. Both aspects are being reviewed and may change.
10.	**AMPC** The reference to 13.5% discount rate/rate of return in the TS 6 utility contribution formula is strange; it may be that there was an unusual definition of shareholder's equity at the time TS 6 was developed in 1991.	BCH will review the 13.5% discount rate, which is materially different from the Distribution extension current 8% nominal discount rate which was based on BCH's Weighted Average Cost of Capital in 2007.
11.	**BCUC staff** We do not recall return on equity being material in the development of TS 6 in 1990 through the negotiated process.	
12.	**BCOAPO** Why would BCH build transmission facilities with a higher capacity than required at the time of the build?	BCH does this as a result of its load forecasts which show future growth in areas such as South Peace. In addition, as noted by AMPC, it is difficult to expand transmission in small increments, and there are economies of scale.

13.	**COPE 378** The problem is that there is no overarching analysis of how BCH builds transmission for the future; there appears to be a 'build it, and they will come' mentality as exemplified by NTL.	BCH does not agree with the statement. The 2013 IRP[2] contains clustering and transmission analysis in Chapters 3, 4 and 6.
14.	**BCUC staff** When BCH uses the term 'peak load' in this context, does that refer to CP?	Yes, in the context of transmission.
15.	**New Westminster** Peak may not meet contract demand as set out in customer ESAs.	While typically ESA contract demand is set somewhat above peak demand, for purposes of Transmission extension-related studies BCH assumes peak and contract demand are the same.
16.	**BCUC staff** Is there a provision in ESAs to increase demand?	Yes, a customer can increase demand within contract confines, e.g., contacted demand is 10 MV.A, actual demand is 8 MV.A, customer can increase demand up to 10 MV.A.

4. ***Presentation: Sources Informing Review of TS 6***

Justin Miedema referenced the four sources that to date have informed BCH's review of TS 6: (1) other BCH tariffs such as the NTL tariff and Distribution extension; (2) the DCAT CPCN proceeding submissions and decision; (3) the IEPR review; and (4) BCH's jurisdictional assessment.

	FEEDBACK	RESPONSE
1.	**MABC** Is TS 6 broken? For example, have there been any real examples of stranded asset risk? A refinement of TS 6 should be an option, e.g., reviewing the security provisions, which in the mining industry's view are onerous.	Both the BCUC in the DCAT CPCN proceeding and the IEPR called for a public review of TS 6. To date, BCH has not had to use security; the forecasted revenues have shown up. Agreed that this is one option (variation on status quo).
2.	**BCUC staff** Is the NTL tariff cost sharing the same as TS 6?	No. NTL is an extension and under TS 6, NTL cost would be 100% customer, with the first customer paying the entire cost and recourse being the 5 year pioneer period in consideration of subsequent customers that connect. It was decided that for NTL tariff purposes, each new customer cost would be allocated based on load/total capacity of NTL/NTL capital cost, and not revenue.
3.	**BCOAPO** What % of NTL capacity is now subscribed?	***Revised Response*** Of NTL's 375 MW of capacity, the load subscription is about 15% and the IPP subscription is about 75%.
4.	**BCSEA** Are existing ratepayers at risk to the extent NTL is not fully subscribed? Have recent announcements of NTL capital cost increases impacted mine industry interest in subscribing?	Yes. However, a number of mine customers have expressed interest and are in the interconnection study process. NTL capital cost increases could impact mine project economics but BCH understands that these increases have not in and of themselves caused mine project proponents to not want to request service.

[2] A copy of the 2013 IRP can be accessed at https://www.bchydro.com/energy-in-bc/meeting_demand_growth/irp/document_centre/reports/november-2013-irp.html.

5.	**COPE 378** Regarding first customer paying problem, has BCH investigated an option of the first new customer having the nominal right to collect revenue from subsequent customers through a wheeling charge?	Not to date; however, BCH is reviewing its current 5 year pioneer period as part of the TS 6 review. If the first mine customer owns the transmission line and charges a wheeling fee as suggested by the COPE 378 option, it is a "public utility" as defined by section 1 of the UCA. This would result in complications as mine customer would be regulated (e.g., the rate charged, etc.) or a section 22 UCA Ministerial exemption would be required for each new mine customer.
6.	**CEC** Is there a problem with the 5 year pioneer period?	The 5 year period applies to BTE and System Reinforcement components. Customer transmission lines transferred to BCH are eligible for refunds as long as there is a Net Book Value of the original asset. BCH has limited experience with the pioneer aspect of TS 6 as BCH has not actually had to apply it.
7.	**BCOAPO** On slide 24, where does the $200 per kW figure come from regarding BCH's maximum contribution in General Service Distribution context?	The figure originates from BCH's COS – what portion is Distribution-relate, what portion of Distribution is demand, what portion is capital, and out of that BCH present values over a 20 year period to arrive at the $200 per kW figure. BCH's maximum contribution is set out in section 8.3 of the *Electric Tariff* and will be considered at the Distribution extension workshop scheduled for 16 December 2014.
8.	**AMPC** Regarding the AESO model, please confirm that System Reinforcements (referred to as Network Upgrades) are rolled into rates and the utility contribution is with respect to the customer extension side of things.	Confirmed.
9.	**AMPC** AMPC understands AESO's 60% of extension/connection costs being covered by utility results from forecasts. It should be noted that for AESO, the corresponding utility coverage figure for System Reinforcements is 100%.	Slide 27 of the presentation slide deck confirms AESO looked at 215 historical projects for determining the 60% figure. If System Reinforcement or a component of System Reinforcement is only for the benefit of one customer those costs could be classified as customer-related. In general most System Reinforcement costs are non-customer and the utility pays.
10.	**BCUC staff** It is important to understand why utilities are doing what they are doing in these jurisdictional references.	***Revised Response*** Agreed, but it is difficult and time consuming to glean a clear expression of policy rationales for extension policies. One method is to review regulatory decisions. For example, BCH understands from a 2012 AUC decision that AESO put forward three primary policy extension objectives (provide effective price signals; maintain intergenerational equity; be based on cost causation) and five secondary objectives which seem to have originated from the Bonbright criteria. The AUC found that AESO emphasized inter-generational equity as a transmission extension policy objective.[3] However, regulatory decisions are not generally available for some utilities such as SaskPower, and may not capture government policy underpinnings.

[3] AUC, Decision 2012-362, *Alberta System Operator: 2012 Construction Contribution Policy*, 28 December 2012, pages 4-5 and 7-8 (http://www.aeso.ca/downloads/Decision_2012-362_AESO_2012_Construction_Contribution_Policy_(2012-12-28).pdf).

11.	**BCSEA** Is there a criterion for measuring the success of other jurisdictional models?	BCH chose jurisdictions based on the criteria set out in slide 26, including to provide a range of options for discussion. BCH uses the Bonbright criteria to assess each option. BCH is not aware of any other published metrics to evaluate 'success'.
12.	**BCUC staff** There may be important differences between AESO' transmission system configuration and BCH's, like BCH's need for regional forecasts vs. AESO's industrial make-up (oil and gas), which may make the AESO system more interconnected.	Agreed that geographic and industrial customer make up differences need to be considered. AESO does have a different industrial customer make-up and a very different market structure.
13.	**MABC/AMPC** MABC stated that AESO is an 'energy only' market[4] and so generation is not an issue. AMPC noted that prior to the Alberta 'energy-only' market, generation costs were not considered part of utility contribution/customer payment allocation for extensions except where generation was an alternative to transmission.	
14.	**BCSEA** Does BCH know what % of customer extension costs SaskPower picks up?	SaskPower's contribution to customer extensions occurs when actual construction costs exceed the fixed $/km, with customer paying up to the fixed $/km. Note that SaskPower builds the customer extension. BCH understands from SaskPower that the fixed $/km is dated and that actual construction costs have been greater than forecast, so likely SaskPower is picking up a large portion of customer extension costs.
15.	**BCUC staff** BCUC staff understand that BCH is examining the SaskPower model for its simplicity. Is the fixed $/km charge a way of addressing comments that the BCH queue process takes too long?	The SaskPower model is simpler than TS 6/BCH queue process, but would entail more risk to BCH and its existing ratepayers. Geographic differences are important. Saskatchewan is flat; transferring one overall fixed $/km as the basis for utility contribution toward customer extensions to BCH would be difficult given the terrain of BCH's service area. In addition, under the SaskPower model the utility builds the customer extension – adopting this model would be a significant departure from TS 6, where the customer builds its extension.
16.	**KGHM International** The SaskPower model is attractive from a new mine customer perspective. It looks like the utility covers all System Reinforcement costs, and there is no need to get into a queue to know how much a new customer must pay.	Confirmed that under the SaskPower model, System Reinforcements (referred to as Network Upgrades) get rolled into rates. There is no customer payment toward System Reinforcements.

[4] Alberta currently operates a wholesale power market that sets a price for electricity in each and every hour of the year, and this market is commonly referred to as a 'power pool'. This market is operated by AESO, which was established by the Alberta *Electric Utilities Act*. The large majority of power produced and consumed within Alberta notionally (financially) flows through this pool, and the hourly price determines the revenue for generators, as well as the cost for consumers.

17.	**Midgard Consulting** Does the SaskPower contribution toward customer extensions include modifications to substations or is it purely transmission lines?	***Revised Response*** BCH committed to following up on this question. SaskPower advises that the SaskPower contribution toward customer extensions does not include modifications to transmission customer-owned substations.
18.	**COPE 378** Do either the Hydro Quebec or Hydro One revenue tests include energy?	No. No generation costs are included in either the Hydro Quebec or the Hydro One revenue tests.
19.	**BCUC staff** The Hydro One model where System Reinforcement costs are covered by the utility but there is a safety valve for the utility to apply to the regulator is something for BCH to consider.	Agreed, as will be discussed in respect of the 150 MV.A threshold options later in the presentation.
20.	**BCOAPO** Is the Hydro One safety valve applicable to generation costs?	No. Hydro One can only apply to its regulator (OEB) to have the new customer pay toward transmission costs.[5] BCH understands that Hydro One has not to date used the safety valve and applied to its regulator.
21.	**BCUC staff** One aspect of the Hydro One model – judging how risky a customer is – could be problematic as it may slow things down due to debate.	Appendix 4 of the OEB Transmission System Code sets out how customer financial risk is to be classified.
22.	**AMPC** In regard to Hydro Quebec's 50 MW threshold, if service to the new customer is approved by the Quebec government is the utility contribution to the customer extension based only on $378/kW? What happens with respect to System Reinforcements (referred to as Network Upgrades)?	***Revised Response*** Yes. BCH confirmed with Hydro Quebec that no generation costs are charged to Hydro Quebec customers greater than 50 MW. BCH understands that Hydro Quebec collects security for Network Upgrades/System Reinforcement but does not require a customer payment toward the Network Upgrades/System Reinforcement. Hydro Quebec told BCH that it cannot recall any defaults re: security, and security is released as soon as the customer project enters service.

[5] The wording from OEB's Transmission System Code (http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/Transmission_System_Code.pdf) pertaining to this matter is as follows:

"6.3.5 A transmitter (Utility) shall not require any customer to make a capital contribution for the construction of or modifications to the transmitter's *network facilities* that may be required to accommodate a new or modified connection. If exceptional circumstances exist so as to reasonably require a customer to make a capital contribution for network construction or modifications, the transmitter or any other interested person may apply to the Board for direction. A transmitter:

(a) shall notify the customer as soon as possible of the transmitter's intention to apply to the Board for direction under this section 6.3.5; and

(b) shall not, without the prior written consent of the customer, refuse to commence or diligently pursue construction of or modifications to its network facilities pending direction from the Board under this section 6.3.5 provided that the customer has provided a security deposit to the transmitter in accordance with section 6.3.10. Where the customer requests that the transmitter not commence with construction pending direction from the Board, the transmitter shall promptly return to the customer any outstanding security deposit related to the construction". [Emphasis added].

The term "network facilities" is defined in section 2 of the OEB Transmission System Code to mean "those facilities, other than connection facilities, *that form part of a transmission system that are shared by all users, comprised of network stations and the transmission lines connecting them* [emphasis added].

23.	**BCSEA** None of the jurisdictions reviewed seem to require a new customer payment toward System Reinforcements. Did BCH look further afield?	BCH used E3's jurisdictional survey submitted in the IEPR process, which looked at a number of U.S, and Canadian utilities – refer to slide 25.
24.	**AMPC** Based on prior work which looked further afield, it is correct that most utilities do not require a new customer payment toward System Reinforcements; System Reinforcement costs are usually rolled into rate base.	

5. *Presentation: Utility Contribution Options*

Sam Jones described 10 utility contribution options BCH has developed.

Note to readers – in light of stakeholder feedback at Workshop No. 6 and for purposes of assisting with written feedback, BCH groups the utility contribution options into four general categories as follows. In each case, a Hydro One safety valve approach could be considered:

Category 1 – Status quo, with cluster extension option variation set out on slide 19 as a subset of Category 1.

Category 2 – Customer pays for System Reinforcement with utility contribution; customer pays for customer transmission line/BTE. Category 2 includes options 1-4 and is based on DCAT CPCN proceeding comments. BCH believes one of these options should be brought forward for further analysis and favours option 3 for this purpose as it is closest to BCH's Distribution extension policy.

Category 3 – Utility pays for System Reinforcements; Customer pays for customer transmission line/BTE. This is the Manitoba Hydro model (option 10). BCH believes option 10 should be brought forward for further analysis because: it is simple; it is similar to the outcome of applying TS 6 (rate and bill stability) but more transparent; and is fair, at least in the context of a single customer extension. A cluster extension variation could be included as a subset.

Category 4 – Utility pays for System Reinforcement; Customer pays for customer transmission line/BTE with a utility contribution. Category 4 includes options 5, 6, 7, 8 and 9. One issue to consider with Category 3 is that in most cases (SaskPower – option 8; Hydro Quebec – option 9) the utility builds and owns the customer transmission line/BTE. BCH believes option 9 (Hydro Quebec) should be brought forward for further analysis due to simplicity, similar market structure/utility transmission system; however, Hydro Quebec build and owns the customer transmission line. BCH also believes that the Hydro One model (option 7) should be brought forward as it gives the customer the option of building and owning the customer transmission line, the customer building and transferring ownership of the line to the utility, or the utility building and owning the line, and then having a true up of costs.

	FEEDBACK	RESPONSE
1.	**COPE 378** With regard to option #1, why did BCH look at a 5-10 year estimated life of the customer facility?	Some brownfield mines have a 7 year life or so.
2.	**Midgard Consulting** With regard to the "using the F16-F20 rates announced in the 10 year plan" column of the options #1-#4 slides, what did BCH assume for the last 5 years of the 10 year plan?	BCH used the rates caps set out in section 9 of Direction No. 7 for F2017, F2018 and F2019; assumptions for F2020 and F2021; and flat rates for the remainder of the period for purposes of these slides. BCH will include inflation or placeholder assumptions next time it analyzes these options.

3.	**AMPC/MABC** Please confirm that options #1-#4, which have no utility contribution to customer transmission line/BTE and which require customer payment for System Reinforcements, do not have jurisdictional support.	Confirmed. BCH developed options 1-#4 in response to arguments put forward in the DCAT CPCN proceeding. Note that given utility contribution formula, currently TS 6 has had the same effect as the Manitoba Hydro model (option 10), which is that utility pays for System Reinforcements and customer pays for customer transmission line/BTE.
4.	**BCSEA** Regarding slides 41/42, what is the project cost data? Is there an issue of the accuracy of customer project-related revenue projections?	It is a back-casting mix of actual customer project costs and customer projects not yet in service. Yes. This was discussed at the 15 October 2014 information session concerning transmission load interconnection process/timelines/requirements. Option #6 was suggested by a participant at this information session.
5.	**BCUC staff** Why is BCH not proposing to bring forward option #8 (SaskPower model)? Its main positive value is its simplicity.	BCH believes the Manitoba Hydro model (option #10) also has simplicity as a virtue, and better balances existing customer/new customer interests. As discussed, option #8 would be difficult to transfer to BCH's service area and has more risk to BCH than the current TS 6. Nevertheless, BCH is open to input, and in particular whether option #8 has a high value to BCH's industrial customers.
6.	**AMPC** It is premature to reject any options. We are discussing tariff mechanics and formulae when we should be looking at over-arching policy objectives (e.g., how to balance rate impacts with intergenerational equity). We need to discuss transmission extension policy objectives. There may be a need to amend the 'next steps' to include a time to debate objectives. AMPC agrees that transmission extension policy should form a later RDA module on the basis that there needs be an objectives discussion.	
7.	**BCUC staff** We agree with AMPC's comment. We do not know the basis for preferring one option over another, because we do not know BCH's objectives.	BCH does not agree that some options cannot be rejected now based on the information provided, e.g., option #8. Nevertheless, BCH hears that stakeholders desire an opportunity to have input into transmission extension objectives. For feedback purposes it would be useful if stakeholders could indicate if by objectives they mean objectives beyond the eight Bonbright criteria, or if what is meant is how BCH weighs the Bonbright criteria in the context of transmission extension policy. BCH will consider amending the 'next steps' to include a time to debate objectives after reviewing feedback.
8.	**BCUC staff** If industrials are going to be charged for System Reinforcements, should a similar policy be in place for residential and commercial customers where they are driving costs – an example being Interior to Lower Mainland Transmission reinforcement project.	

6. *Presentation: Security Options*

Frank Lin reviewed the existing TS 6-related security requirements, and outlined four options. Key issues are: should security be required and if so, for what amount and when should security be released?

	FEEDBACK	RESPONSE
1.	**AMPC** Stranded asset risk appears to be low for System Reinforcements. In contrast, there may be a rationale for requiring security if the utility contributes to customer radial extensions.	Agreed that stranded asset risk is low on System Reinforcements; over the last decade, BCH has not had to draw on posted security. Timing is really the issue; the customer may not be ready.
2.	**BCUC staff** Is paying back out of the revenue really a problem?	Most customers get security back within a 5 year period. BCH is exploring an option of releasing security more quickly; however, BCH understands the customer issue to be not so much how long the security is kept but rather the posting of a Letter of Credit up front.

7. *Presentation: 150 MV.A Threshold Options*

Frank Lin provided background on the 150 MV.A threshold – customers with new or incremental load exceeding 150 MV.A must pay for bulk transmission (500 kV and over) and generation costs. Frank outlined four options, and stated that BCH favours a Hydro One safety valve approach (no numeric threshold).

	FEEDBACK	RESPONSE
1.	**AMPC** It is AMPC's understanding that the Hydro Quebec 50 MW threshold is not comparable to the 150 MV.A threshold as in the case of Hydro Quebec, if new customer load is over 50 MW and approved for service, new customer is not charged bulk transmission and/or generation costs.	AMPC is correct in its understanding of the Hydro Quebec 50 MW threshold.
2.	**BCUC staff** Is there a risk with the current threshold that a new customer will argue that given they have made payment toward bulk transmission/generation, they should not be subject to future rate increases? This may also apply to options where new customers pay for System Reinforcements.	Given the hypothetical nature of the question and the lack of a factual context, BCH prefers not to speculate on whether the BCUC would accept such an argument.
3.	**MABC** In the case of Hydro One, is the safety valve application to the regulator or to government? Is BCH looking at a safety valve option where the application is to the government?	To the regulator. Yes, BCH is open to this. The safety valve option BCH has considered so far is the Hydro One model of making application to the regulator.
4.	**COPE 378** Applying to the regulator is more transparent.	

5.	**AMPC** Option 3 – the safety valve approach – should be advanced. The details of whether the application is made to government or the regulator can be worked out later. The point is that there should not be an arbitrary size threshold.	BCH agrees that if BCH proposes a utility contribution model where the utility pays for System Reinforcement, it is prudent for BCH to have a safety valve. BCH favours the Hydro One safety valve approach over option #1 (status quo), option #2 (size threshold, but with customer only responsible for incremental amount) and Option #4 (no safety valve).
6.	**BCUC staff** Option #2 looks like it could be complicated.	Agreed.
7.	**BCUC staff** Forecasts of future load and System Reinforcement costs should factor into the use of any safety valve. Would the cost be the full cost or the cost of advancing transmission infrastructure?	Note that BCH's industrial load forecast is different than the residential load forecast in that it is partly a bottom's up forecast informed by specific customer connection requests. In BCH's view we are mainly talking about the advancement of transmission infrastructure costs. There seems to be no jurisdictional support for the inclusion of generation costs.
8.	**FortisBC** The adoption of an economic test to evaluate whether a proposed customer project provides a net benefit to BCH ratepayers could obviate the need for a threshold.	***Revised Response*** BCH assumes FortisBC is referencing the economic test it advanced in the IEPR process. FortisBC's economic test would compare transmission-related revenues from a proposed industrial customer project against a threshold target regardless of customer project size. The threshold target would be based on a predefined level over the 'current average cost of transmission'. If the proposed transmission-related revenues exceed this threshold then the project would be rolled into rates. If the proposed revenues fall below the threshold then a customer payment would be required to address the shortfall.[6] It is not clear to BCH how this economic test protects existing ratepayers against a major load. In any event, BCH assumes that the FortisBC economic test would apply to customer extensions and not System Reinforcements as there is no 'average transmission cost' for System Reinforcements. If so, FortisBC's economic test seems similar to AESO's contribution to customer extension approach.
9.	**Seabridge** BCH needs to liaise with the B.C. Government regarding what the Province is trying to do with transmission extension policy – is it trying to attract industry? If so, the current threshold is a cost barrier that does not appear to be found in other jurisdictions and sends a signal that new loads are not supported in B.C.	

6 http://www.empr.gov.bc.ca/EPD/Documents/IEPR%20Submission-Fortis%20BC.pdf.

8. *Presentation: Transition Rule Options*

Frank Lin stated that this is a priority area for the reasons set out in slide 61 and set out BCH's strawman proposal for grandfathering new customers in the queue.

	FEEDBACK	RESPONSE
1.	**AMPC** Many transitions give the customer the option of choosing between the new arrangement and the old arrangement. AMPC agrees with that aspect of the BCH strawman that signals there has to be some skin in the game to take advantage of grandfathering.	
2.	**MABC** BCH should look at a menu-type approach where a new customer can choose which aspects of the old tariff and which aspects of the new tariff should apply to it. It should not be an 'all or nothing approach'.	***Revised Response*** BCH does not agree that there should be a menu-type approach for a new customer to choose between aspects of the new and old tariffs. Particular terms are not developed in isolation and need to be considered in the context of other terms of the contract. By allowing customers to cherry-pick individual aspects of each contract there may be unintended consequences to BCH and other rate payers. In addition, a menu-type approach effectively means individual tariffs for individual customers.
3.	**BCOAPO** Did BCH look at the posting of security as the trigger for grandfathering?	Yes, but this seemed to BCH to be too late in the process for grandfathering as customers have already made business decision.
4.	**COPE 378** In terms of equity, there should be a notice of change; e.g., effective date for new tariff, notice of scope of change.	Agreed.
5.	**BCUC staff** During the transition period, would BCH have two tariffs?	Yes.

9. *Other Issues: Line Transfers and Queue Management*

Sam Jones canvassed the main issue with the current line transfer provisions, which is that only the new customer has the option to transfer the customer transmission line to BCH; BCH cannot require or decline a line transfer. Sam outlined two high-level options to address this.

Sam also stepped through the draft Queue Management Business Practice document.

	FEEDBACK	RESPONSE
1.	**BCSEA** Option 2 is ambiguous as currently worded. Under Option 2, would BCH have the option to acquire the customer transmission line even if the customer does not want to transfer it? Does Option 2 also include BCH having the option of taking or rejecting the customer transmission line if the customer wants to transfer it?	Yes. Yes.

2.	**BCOAPO** So as part of Option 2 BCH could decline a transfer?	Yes.
3.	**BCUC staff** This issue is tied to other options for TS 6, particularly utility contribution options.	Yes.
4.	**COPE 378** On slide 65, what is meant by First Nation consultation?	BCH is an agent of the Crown. BCH would assess the adequacy of the customer's consultation with First Nations and what other government agency permitting is required.
5.	**CEC** What obligations does BCH assume if there is a customer transmission line transfer?	BCH must operate and maintain the transferred line. BCH assumes all the same obligations it has with regard to the lines that it builds, owns and operates from inception.
6.	**MABC** MABC is of the view that there are existing BCH capacity issues when it comes to queue management. Will BCH be looking at its own resources to tackle this?	Yes.
7.	**CEC** Is there a particular part of the Queue Management Business Practice document/existing queue process that BCH would like comments on? CEC thinks BCH should look at an option that does not require a queue system. CEC is prepared to discuss this option.	Queue management is not working that well when there are a number of customers requesting in the same area. A Manitoba Hydro contribution model would not require a queue. A queue is required if the new customer is paying for and BCH is making an offsetting contribution toward System Reinforcements. BCH asks that CEC submit details on its option as part of the written comment process following this workshop.
8.	**Midgard Consulting** An overview of the particular area to determine if it is transmission constrained or not could assist with the queue process.	BCH reviews system constraints as part of each Transmission extension-related study. The load size will determine if there is a constraint and how to resolve it.

10. *Closing Comments: Next Steps*

Anne Wilson thanked everyone for making the time to participate in the workshop and reviewed the ways that feedback can be submitted to BCH and the proposed timelines set out in the 'next steps' slide 71. Meeting adjourned at 3:00 p.m.