Summary Notes

BC Hydro Transmission Service Rate Design Workshop

October 17, 2018

Calgary – Fairmont Hotel

Type of Meeting	Transmission Service Rate Design Workshop – Customers			
Agenda	Welcome and Agenda Workshop Objectives and Opening Remarks 1. Rate Primer 2. RS 1823 – Pricing Principles 3. Market Reference Priced Rates 4. Load Attraction Rate 5. Load Retention Rate Closing and Next Steps The workshop session was facilitated by David Keir.			
Abbreviations	AESO	Alberta Electric System Operator	LRMC	Long Run Marginal Cost
	BCH	BC Hydro	MW	Megawatt
	BCUC	BC Utilities Commission	MWh	Megawatt Hour
	CBL	Customer Baseline Load	OATT	Open Access Transmission Tariff
	DSM	Demand Side Management	PTP	Point-to-Point
	ESA	Electric Service Agreement	RDA	Rate Design Application
	F20XX	Fiscal 20XX	RS	Rate Schedule
	HLH	High Load Hours	RTP	Real Time Pricing
	HQ	Hydro Quebec	TS	Tariff Supplement
	kV	Kilovolt	TSR	Transmission Service Rate(s)

Meeting Minutes

Welcome and Introductions –David Keir

David started the workshop by welcoming everyone attending, followed by a round of introductions. David went over the objectives for the day – he reviewed the agenda for the workshop and the objective to obtain feedback on 2 existing and 3 new transmission service rates. He recognized the experience in the room and advised that feedback matters – feedback is valuable and important to help inform BCH's rate proposals. David explained the process to provide feedback (verbal questions and comments at today's workshop) and written feedback (feedback form and/or written submission to be provided at end of workshop or sent back to BCH by October 24th, 2018).

Meeting Minutes

Opening Remarks

David provided background and context for the rates workshop. He explained the key pressures which are impacting BC Hydro's business and resource-dependent large industrial sectors. David emphasized BCH's strategic focus is on providing customers with affordable rates. Key initiatives to achieve this include surplus energy optimization and industry diversification. He provided context on how BCH is working to provide such opportunities, including through the provision of innovative industrial rates. He reaffirmed that the workshop is part of a consultative and collaborative engagement with existing and new industrial customers and impacted stakeholders. The purpose is to get feedback on BCH's rate proposals with the objective to advance innovative rate options to the Commission that make sense and benefit all customers.

1. Agenda Item 1 Transmission Rates Primer

David provided on overview of BCH's portfolio of transmission service rates and tariffs for electricity supply. He identified the key billing determinants for rate-making (energy charge and demand charge) and cost-of-service principles used to determine these charges. He explained the distinction between firm and non-firm service. He described the system conditions that contribute to surplus energy and framed the opportunity for increasing domestic electricity sales as an alternative to export market sales during a period of surplus. David set out the core rate-making principles which are foundational to BCH's rate proposals and sought feedback on these principles. He advised that all rate proposals are subject to review and approval by BCH's regulator, the BCUC.

	Feedback	BC Hydro Response
1.	**Kellen Foreman, Encana** **Question -** What is the government view on rate making in BC? Will there be government oversight on the various new rates that we will be reviewing and how do these rates tie in with the Site C project?	Government is working with BCH to identify cost savings, efficiencies, new revenue streams and other changes to keep electricity rates low and predictable over the long-term. The mandate is rate affordability. Any rate proposal needs to be justified on its own merits before our regulator - the BCUC has jurisdiction under the Utilities Commission Act to set rates.
2.	**Etienne Snyman, Hut8 Mining** **Question -** Wanted clarification on the proposed characteristics of non-firm service. Could BCH provide some level of firmness / back-up for non-firm service such that a customer does not get curtailed more than a certain number of times per year? **Question -** Should there be / is there a financial consideration related to interruption? For instance, if market prices are high and BCH is pushing power to high price markets like California to take advantage of that price point, BCH can interrupt customers to ensure you can serve load to those export markets?	Advised that non-firm service is provided to the extent BCH has available energy and capacity. There are no current or proposed minimum or maximum levels of interruption for non-firm service … the trigger for interruption is based on service availability. The question of whether the rate design should reflect a physical constraint (i.e., generation or wires) vs. a financial / economic opportunity is something we need to review and consider. For existing non-firm services, volumes are low so the scenario you describe is not something that's

	Feedback	BC Hydro Response
		come up.
3.	**Kellen Foreman, Encana** **Comment -** If you want our business in BC, then provide us with power and don't sell it to California. **Question -** Asked whether there were statistics on how much interruption there has been in the last year?	Acknowledged. As the monopoly provider of electricity in our service territory, BCH has to be mindful of its obligation to serve domestic loads. Reviewed interruption history in the context of existing rates for non-firm interruptible service: • RS1853; RS 1880; RS 1891; RS 1892 • Low energy volumes Subject to check, non-firm service has not been interrupted in the past 10 years. We can say with certainty that RS 1892 Freshet Rate service was not interrupted over the 3 year pilot term.
4.	**Jeff Sutherland, Teck Coal Limited** **Comment -** Our ESA Contract Demand allows me to take power from BCH to a certain maximum over my Contract Demand; however, as soon as we exceed this limit we get a notice from BCH. There is a very small range that allows for increased load over the contract demand. Teck mines are connected on to the 1L274 line; this line is constrained in the summer.	Acknowledged that there are capacity constraints on the 138kV transmission line (1L274) that serves Teck's mines. Local line constraints are dependent on connected loads and seasonal temperature (i.e., thermal operating constraints) vs capacity of the area system/network.
5.	**Etienne Snyman, Hut8 Mining** **Comment -** In Alberta, they have a demand opportunity service. If an existing customer anticipates an increase in load over their contract capacity, then the customer can have a study done in advance of this anticipated load increase to confirm if the transmission system is capable of serving the incremental load. This study is valid for a year. *David asked Etienne to clarify if the study is based on generation capacity or wires capacity:* It's wires capacity. For example, if you have a firm contract capacity of 20 MW and you self-generate 30 MW, the AESO does a study to make sure the transmission system can serve the full 50 MW of load if your generator goes down. It takes a few weeks or a month to do the study - which is fairly quick, given that it is not a typical interconnection application.	Noted.

	Feedback	BC Hydro Response
6.	**Kevin Stolz, Encana** **Question -** Are you looking at incremental energy at the site level or transmission aggregated (transmission) connected level? It's difficult to do site specific because we don't want to give up any capacity that we may not be utilizing at the time. The capacity could be used at the aggregate level. I think there is merit to look at capacity utilization at the transmission system connected level.	The rate proposal is specific to load increases at a site-specific level (i.e., at which sites you can use more). The proposed rate designs are not intended to impact any rights you might have to system capacity – the intent is to drive load increases which we think, in the scenario you describe, would increase your capacity utilization.
7.	**Edmond De Palezieux, Conoco Phillips** **Comment -** For new loads, the big disincentive is the cost of interconnection and how long it takes. Comparing BC to Alberta, even with some issues, the overall process in Alberta is much better. BCH should consider this.	Noted. We recognize that interconnection cost and schedule is important for prospective new loads, together with the costs and service requirements for electricity supply. BCH is advancing infrastructure investment in the South Peace region to provide certainty to customers that system capacity will be available to serve new loads.. Under existing interconnection tariffs, new customers would typically provide security – not cash – for this system upgrade.

2. Agenda Item 2 RS 1823 (Stepped Rate) – Default Rate for Transmission Customers

David gave an overview of the RS 1823 Stepped Rate, including background on RS 1823 energy pricing principles and the 2015 RDA decision. He explained the illustrative rate impacts of re-pricing RS 1823 Tier 1 and Tier 2 Energy Charges if the Tier 2 rate is set to reflect a lower LRMC value. He described BCH's RS 1823 energy pricing principles proposal for F2020 and asked the audience to consider the question – "do you support maintaining 'status quo' RS 1823 pricing principles for F2020 (i.e., increase demand and energy charges uniformly by the general rate increase for F2020)"? Comments and observations followed.

	Feedback	BC Hydro Response
1.	**Etienne Snyman, Hut8 Mining**	
	Question - Do you see the benefits of the stepped rate loads? Are most customers paying the full Tier 2 rate or are a lot of customers avoiding buying Tier 2 energy?	Provided background on RS1823. Rate design principles are based on negotiated settlement and government policy: • 90/10 split between Tier 1 and Tier 2 • Energy baseline (CBL) to reflect normal annual energy use • 90% * T1 rate + 10% * T2 rate = 100% of old flat rate (RS1821) • Revenue and bill neutral with old flat rate at 100% of CBL consumption RS 1823 has two different charges for energy charge A (flat rate) and energy charge B (stepped rate). You need an energy baseline (energy CBL) to be on the stepped rate. About 80% of customers are on the stepped rate and 20% are on the flat rate. The tier 2 rate (currently $95/MWh) has been a very effective price signal. Customers have invested hundreds of millions of dollars in conservation and demand side measures, operational changes and generation to reduce load. For F2018, the split for stepped rate customer volumes is about 96% for Tier 1 and 4% for Tier 2.
	Question - Is the stepped rate also available for new facilities?	New facilities are served on the flat rate until they have a normal operating history (minimum of 12 months) from which an Energy CBL can be determined. An Energy CBL is required for stepped rate pricing.
2.	**Edmond De Palezieux, Conoco Phillips**	
	Question - For a customer with phased growth say over 10 years, when would a customer CBL be determined?	The customer could remain on the flat rate during growth phases – until load has normalized. Or a CBL could be established between phases and each subsequent phase can be considered for CBL adjustment (i.e., TS 74 has a provision for Plant Capacity Increase). The advantage of having a CBL sooner is to realize the value of efficiency investments made at the plant via Tier 1 energy purchases.
	Question - To resolve the LRMC issue could BCH increase the Tier 1 & Tier 2 split to say 98% Tier 1 and 2% Tier 2?	The rate making principles previously discussed, including the 90/10 split, are set out in Direction 7.

	Question - What is the reason for the low LRMC?	BCH repriced Tier 2 in F2017, to the lower bound/ range of LRMC @ $89.20/MWh. The price was escalated by general rate increases for F2018 and F2019. We're proposing this status quo approach to continue for F2020. We're also asking government to amend the direction that requires us to set Tier 2 to reflect LRMC. Lower LRMC is predicated on a number of factors.
3.	**Kevin Stolz, Encana** **Question -** On the potential change to Tier 2, which one do you think is the reality of the 3 options $60, $70 or $80 repricing of Tier 2?	It is too early to say – the LRMC modeling is still in progress.
4.	**Edmond De Palezieux, Conoco Phillips** **Question -** Is this (i.e., the tiered pricing discussion) an existing customer vs a new customer debate?	Not directly. New customers are initially served on the flat rate which is not impacted by any changes to the tiered prices. However, any customer (existing or new) who has made investments in conservation and efficiency – with the intent to lower energy costs via access to a lower Tier 1 rate – would be impacted under stepped rate billing.
5.	**Etienne Snyman, Hut8 Mining** **Comment -** If you're BCH and you want to attract new customers, you don't want them to be efficient - you want them to use more power. You are in it for the long term; you can make good margins and drive more consumption. Might as well stay on RS1823A. **Question -** Has BCH considered providing tools to customers to help manage demand costs? What drives investment in generation and transmission infrastructure is the peak system load. **Question -** In what 15 minutes was there a peak load in the province? In Alberta, there are ~ 250 peak hours/year used to drive demand charges. If you can help customers to reduce load during peak times, this frees up capacity and reduces the need for additional investment.	Acknowledged. RS 1823 demand charges are in HLH only. Industrial load tends to have a very flat profile because loads are running on a continuous 24/7 basis. System peaks are based on residential and commercial customer loads, which are higher during the winter and at certain peak periods (typically 4pm – 8pm). We don't have a specific rate or program to incent demand reduction during peak times. The scenario you have described is consistent with the intent of rates for industrial load curtailment used in other jurisdictions such as HQ.

6.	**Edmond De Palezieux, Conoco Phillips** **Comment -** Big opportunity is getting more efficiency from existing load and everyone wins. Curtailing load isn't the answer, but attracting load to the province is key. The opportunity is getting more load in the province and using existing capacity more efficiently.	Acknowledged.

3. Agenda Item 3 Market Reference Priced Rates (Seasonal) – RS 1892 Freshet Rate Pilot

David provided an overview of the Freshet Rate pilot and the system conditions that drive an energy surplus during the freshet period of May-July. He presented information regarding system conditions, market pricing and baseline determination. He explained how the Freshet Rate design overlays non-firm freshet service with firm RS 1823 service and how incremental energy is determined and priced. He provided a summary of results for years 1-3 of the pilot and reviewed the rate economics (gross and net benefits). David walked participants through questions specific to the Freshet Rate on Slide 37 and asked for comments and feedback.

	Feedback	BC Hydro Response
1.	**Kevin Stolz, Encana** **Question -** Does any customer that would be wheeling power into the province or out of the province pay the $3 charge, same as freshet?	There is no ability for load customers to wheel power in/out of the province. Retail access is not allowed in BC. The tariff that sets wheeling rates for power transmission through the BCH system is called the Open Access Transmission Tariff (OATT). The OATT has charges for firm and non-firm point-to-point (PTP) service. To be clear, there is no ability for a load customer in BC to use the OATT to acquire power from outside BC to serve their own load. Under the Freshet Rate there's a flat fee (currently $3/MWh) on the volume of net energy purchases. We call it a wheeling rate as a proxy for delivery, but it's really a negotiated risk adjustment factor.
2.	**Edmond De Palezieux, Conoco Phillips** **Comment –** Slide 37: The pilot has proved to be a good idea – proof of concept is there.	Acknowledged.

	Feedback	BC Hydro Response
3.	**Kellen Foreman, Encana**	
	Question - Why does market rate go down in April; is there a faster melt and more hydro in the US? Prices appear to be lower in April than July – why?	Hydrology is variable in the Pacific Northwest and every year is different. In BCH's view, past hydrology consistently supports the use of the May – July period. Market prices are also variable – sometimes April can be higher than July. The past few years have seen warmer temperatures in July which have triggered air conditioning loads and market price spikes in California.
	Question - What operational considerations do you see at customer sites to be able to increase loads in summer months like July (i.e., it's holiday season, and you have to consider operational considerations – staffing, etc.)?	Yes, there are operational considerations. Some customers have flexibility to turn down load when market prices are high. Some choose to run through higher priced market periods if they have pre-sold orders.
4.	**Kevin Stolz, Encana**	
	Question - Is the transfer of freshet baselines automatic? What if the customer did not want it or will operate differently?	We're proposing an automatic transfer of freshet baselines with the site. If the new site owner wants to run the plant differently (i.e., higher, lower, or a different use) they can apply for a baseline that reflects their unique operations. The BCUC has to approve the change. There is customer choice.
5.	**Etienne Snyman, Hut8 Mining**	
	Question - For attracting new load, if you're a new customer with no prior load history, would you consider a proxy baseline based on forecast/expected load? Perhaps with a true-up mechanism?	Customers need to have at least 12 months of operating history to participate. We have not considered using a forecast baseline based on an assumed operating profile for freshet.
	Comment - Prefer both option with existing customer, you would have the baseline and if you're a new customer be baseline based on engineering studies inferred instead of having the customer on RS1823A for 12 months.	Under the annual rate option, a possible alternative is for new customers to use the 5MW minimum size criteria (or higher amount) as their firm service baseline such that any load above that would be considered non-firm.
6.	**Garth Haugen, Shell Canada**	
	Comment - Another option, for new customers, they would need to sign up for two years; 1st year is assumed baseline and next year the baseline is readjusted so the baseline is established in the 2nd year.	Acknowledged.

4. Agenda Item 3 Market Reference Priced Rates (Annual) RS XX Incremental Energy Rate

David provided background and context for BCH prior "Real Time Pricing" (RTP) Rate from 1996/97. RTP was an annual rate option available to all transmission customers which priced load above an established baseline at market-referenced prices. He provided a high-level explanation of how the RTP rate worked. He highlighted similarities and differences with the Freshet Rate. David further explained the proposed principles for an annual market priced rate (non-firm service) that would overlay with the RS 1823 Stepped Rate (firm service). David then presented a 'strawman' rate design to facilitate a discussion re: the proposed elements and criteria of the Incremental Energy Rate. Refer to Slides 42 and 43 in the presentation.

	Feedback	BC Hydro Response
1.	**Etienne Snyman, Hut8 Mining** **Question -** Regarding an interruptibility notice, what does Powerex say in terms of value to them (i.e., whether it's one or two hours' notice in terms of export market opportunities they can participate in)?	We need to consider what's appropriate notice of interruption for customers so they can safely curtail to baseline. We've confirmed that our largest customers generally have the capability to curtail with 1-2 hours' notice. Because we don't have direct load control at the site, we need to consider the use of penalties to provide a 'stick' if customers don't reduce to baseline.
2.	**Jeff Sutherland, Teck Coal Limited** **Questions –** 1) Question on the strawman design is on DSM adjustment – we have annual verification of DSM, but if you do it (baselines) monthly, how do we make adjustments for DSM energy savings that are subject to annual verification, if the verification doesn't occur until after the fact? 2) Can we have the adjustment done monthly as the DSM projects come on line?	We need to work through the baseline adjustment methodology for DSM. If the project is already operating in your baseline month/year, no further adjustment is required. For RS1823 CBL purposes, we verify savings on an annual basis and make the CBL adjustment retroactively. We may need to consider a forward-looking adjustment to monthly baselines under the Incremental Energy Rate. For Freshet, we take the current annual savings value and determine an average hourly DSM value for baseline adjustment (i.e., no DSM shape, just a flat hourly value). BCH is not proposing to make monthly adjustments – the concept is annual adjustment (to monthly baselines) based on customer submissions and BCH agreement. Commission approval would also be required. Our current thinking is that there would be no automatic adjustments (i.e., customers would need to ask for them). Baselines are complex - we have to get them right; DSM is an important adjustment consideration. Other major events such as non-recurring downtime and force majeure also need

	Feedback	BC Hydro Response
		to be considered.
3.	**Etienne Snyman, Hut8 Mining**	
	Question - What's the risk of interruption and would BCH be willing to cap it (i.e., cap on hours of interruption)?	The provision of non-firm service is based on the availability of energy and capacity. A cap on interruption is more akin to load curtailment rate provisions regarding the number of hours that a customer makes capacity available to BCH for curtailment (i.e., curtailment of firm service load). Customer would take market price risk for incremental load under the proposed rate. A new customer could manage market price risk by electing to take a fixed volume of load under standard firm service rates and the balance under the non-firm market rate. So there's an inherent hybrid option on the table (minus load curtailment provisions with interruption caps).
	Comment - Would hate to spend millions of dollars on a facility only to have power available 50% of the time – stranded asset with no power supply. Investors need to know how reliable the service is as they tick boxes for their investments. Need to manage risks of market exposure and potential interruption. Market prices we saw this past July and August were scary. Maybe we can get there with some hybrid option?	Acknowledged.
	Comment - Consider capping the number of interruptible hours. Anywhere in the range of 100 - 200 hours would be reasonable.	Acknowledged.
4.	**Edmond De Palezieux, Conoco Phillips**	
	Question - Based on prior TSR workshops it seemed the intent of the Freshet Rate was to incent existing customers to use more power during the May to July timeframe?	Agreed, that is the primary driver.
	Question - If you move to an annual option the question could be more how do we drive toward attracting new customers to BC and if there is a rate that could do this it would be worth considering. Have you looked at the Pacific North West or Alberta to see what they are offering to determine if this new annual rate would be competitive? If BCH hasn't done this then maybe do this to make sure you are competitive and if you are not then there is a reason to tweak the rate to be more effective and attractive.	The proposed annual rate uses day ahead Mid-C market reference pricing for incremental load. The potential to blend firm service (at a flat tariff rate) and non-firm service (at a market rate) would provide new customers with the ability to risk-manage energy pricing for some or all of their new load above 5 MW. Customers would have a choice as to how much market price risk they are willing to take vs. de-regulated jurisdictions such as Alberta where the customer would be exposed to energy market (power pool) price risk for their

	Feedback	BC Hydro Response
		entire load.

5. Agenda Item 4 Load Attraction Rate		
David provided a high-level overview of the rationale, principles and objectives for a Load Attraction Rate. He advised that regulated utilities in other jurisdictions offer load attraction and retention rates. He emphasized that our current environment provides opportunities to attract new loads and diversify the industrial customer base. David explained potential pricing, availability, term, caps, risk mitigation and performance, evaluation and reporting criteria. The emphasis for review and discussion was on availability criteria and principles of fairness / undue discrimination / free ridership as between new and existing customers in the same industry.		
	Feedback	**BC Hydro Response**
1.	**Etienne Snyman, Hut8 Mining** **Comment –** Slide 51: A combination of the load attraction rate and non-firm rate would be a better option. RS 1823 “as is” and what it’s projected to be in year 6 is not appealing. Consider a combination of the fixed discount to RS 1823 to provide 5 years of stable competitive pricing for base load, but then transition to Mid-C market prices in year 6 rather than RS1823. This would better support a business case and payback on capital. **Example:** If we are looking at building a data centre, we would compare this rate vs. rates in other jurisdictions. The concern with Mid-C market rates is the July/August price spikes and the risk that trend might persist. So the market-priced rate on its own doesn’t look good for the first 3, 4, or 5 years. With a fixed term discount, we can count on stable, lower pricing in the first few years to recover investment capital. Afterwards, even though we would be fully exposed to market prices, we would be in a better position to accept the risk of short-term high prices with a view that, on balance, we’d be able to get cost competitive prices over the year.	Acknowledged.
2.	**Kellen Foreman, Encana** **Question -** Are you committed to a 5 year term? Could it be 10?	The proposed term is illustrative for discussion purposes. The length of the term does impact the discount. For example, there could be a deeper discount for a shorter term or a shallower discount for a longer term.

	Feedback	BC Hydro Response
3.	**Edmond De Palezieux, Conoco Phillips** **Comment -** It's a good idea and a good rate. With incremental costs to connect (capex), offering the rate discount could be an incentive to grid connect. **Comment -** Regarding eligibility for discounted rates, if splitting benefits, then it is good for existing customers. If this is successful, then everyone wins.	Acknowledged. Confirmed this is the 'greater good' argument (i.e., to the extent that incremental revenues reduce pressure on rates, general rate increases would be lower than they might otherwise be).
4.	**Garth Haugen, Shell Canada** **Comment -** We've seen examples in our industry where some companies decided to hold back when they could be expanding / building in BC; the economics are important.	Acknowledged.
5.	**Kevin Stolz, Encana** **Comment -** You're making your competitor better off than you are since you were there first. If we compare Canada and the US, the US is more competitive. We need to be careful that this rate doesn't have unintended consequences. It's not fair for an existing operator to pay higher rates for being first.	Acknowledged.
6.	**Etienne Snyman, Hut8 Mining** **Comment -** For existing clients who are expanding and want the benefit, you might need them to prove that they would not do the expansion in the absence of the discount.	Acknowledged.
7.	**Edmond De Palezieux, Conoco Phillips** **Comment –** Slide 57 regarding the discount term – it has to start whenever you get connected. In certain areas, it can 3-5 years to get connected.	Acknowledged.
8.	**Kevin Stolz, Encana** **Question -** What is the time frame for surplus? Should we plan for this timeframe?	This depends on a number of variables.
9.	**Kellen Foreman, Encana** **Comment -** Customers with new load could take more than one year to ramp up production, so we can't maximize the discount benefit (i.e., if load ramp-up is slow or delayed).	Acknowledged.

	Feedback	BC Hydro Response
10.	**Edmond De Palezieux, Conoco Phillips** **Question -** When is the sign-up period for this rate; when would it be available?	If we file in the next 3 to 6 months and get approval within 6-12 months, then the rate could be in effect by this time next year. We are considering a 3 year sign-up period. The fixed discount term would start at load energization.

6. Agenda Item 5 Load Retention Rate

David provided an overview of the Load Retention Rate from BCH 1996 Industrial Service Application (which was incorporated into BCH RTP Rate – RS 1848). He discussed eligibility criteria, CBL adjustment considerations and special conditions for load retention. He reviewed Hydro Quebec's load retention rate eligibility criteria and pricing. He asked participants to review and consider the questions on Slide 63.

	Feedback	BC Hydro Response
1.	**Etienne Snyman, Hut8 Mining** **Question -** Is this for load conversion (i.e., choosing grid over gas)?	It's not targeted at load conversion specifically. For upstream gas facilities with gas power alternatives, a 10% discount might not be the right number.
2.	**Kellen Foreman, Encana** **Question -** Gas prices continue to be low; would BCH consider adjustment of the discount indexed to gas prices?	Commodity-indexed pricing was part of the Power for Jobs Act in 1997. Commodity prices are also used to trigger bill deferral under BCH's Mining Deferral Program. However, the current rate design does not consider commodity-indexed pricing.
3.	**Etienne Snyman, Hut8 Mining** **Question/Comment -** Should we be asset specific? You can have ten facilities across the world, with one in BC that's not doing well, even though, overall, your company is healthy. Also, when it comes to a discussion around capital spent on interconnection, would that apply for retrofit as well (i.e., data centre taking over an abandoned paper mill)? When all the infrastructure has been paid for, you get the same economic benefit in the region.	Acknowledged.

Closing and Next Steps
David thanked everyone for their attendance and participation in the workshop and provided a timeline for next steps. • Deadline for submission of feedback forms is October 24, 2018. • Summary notes (minutes) of the session will be circulated to participants for review and comment. • Next rate design workshop will be in Vancouver only (target date November 19, 2018).