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January 11, 2023

British Columbia Public Interest Advocacy Centre
Suite 803 470 Granville Street
Vancouver, B.C.
V6C 1V5

Attention: Ms. Leigha Worth, Executive Director

Dear Ms. Worth:

Re: FortisBC Inc. (FBC)

Application for Approval of a Large Commercial Interruptible Rate (Application)

Response to the British Columbia Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Council of Senior Citizens' Organizations of BC, Disability Alliance BC, and the Tenant Resource and Advisory Centre *et al.* (BCOAPO) Information Request (IR) No. 2

On July 6, 2022, FBC filed the Application referenced above. In accordance with the further regulatory timetable established in British Columbia Utilities Commission Order G-331-22 for the review of the Application, FBC respectfully submits the attached response to BCOAPO IR No. 2.

For convenience and efficiency, if FBC has provided an internet address for referenced reports instead of attaching the documents to its IR responses, FBC intends for the referenced documents to form part of its IR responses and the evidentiary record in this proceeding.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

35.0 Reference: Exhibit B-3, BCUC 1.1

Exhibit B-6, CEC 11.1

Exhibit B-5, BCSEA 5.1

Preamble: The response to BCUC 1.1 states:

"The following tables represent the best information available to FBC and may not include some requests that were made prior to FBC tracking the requests in a more formal fashion. Requests have been included regardless of their current implementation status (e.g. discontinued, in progress, complete)".

The response to CEC 11.1 refers to BCUC 1.1 for information on customers already in FBC's interconnection queues for large commercial customers. However, this information is not specifically provided.

35.1 Please provide a revised version of Table 1 that includes the following information (i.e., additional columns) for each request:

- Implementation Status (e.g. discontinued, currently in progress/in the interconnection queue, complete and customer connected)
- Whether or not there was a determination made regarding the availability of system capacity to serve the customer's request under existing system planning criteria. In an additional column indicate for: i) those circumstances where such a determination was not/has not been made – why not and ii) those circumstances where such a determination was made – what was the result.

Response:

Please see below a revised version of Table 1 from BCUC IR1 1.1, with columns H through J added.

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Revised Table 1

A	B	C	D	E	F	G	H	I	J
Request	Request Received	Industry	Requested Load	Existing or New Customer	Anticipated Rate Schedule	Region	Status[1]	Determination Made	Result[2]
1	2017	Horticulture	10-50 MW	New	RS 31	Okanagan	Discontinued	No	
2	2017	Horticulture	1-5 MW	New	RS 30	Okanagan	Connected	Yes	Full
3	2018	Crypto / Data Center	50+ MW	New	RS 31	Boundary	Connected	Yes	Partial
4	2018	Renewable Gas	10-50 MW	New	RS 31	West Kootenay	In progress	Yes	Full
5	2018	Horticulture	5-10 MW	New	RS 30	Boundary	Connected	Yes	Full
6	2018	Horticulture	1-5 MW	New	RS 31	Similkameen	Connected	Yes	Full
7	2018	Horticulture	1-5 MW	New	RS 30	Okanagan	Connected	Yes	Full
8	2019	Horticulture	5-10 MW	New	RS 30	Okanagan	Discontinued	No	
9	2019	Horticulture	5-10 MW	New	RS 31	Okanagan	In progress	Yes	Full
10	2019	Horticulture	1-5 MW	Existing	RS 30	Kootenay	Connected	Yes	Full
11	2019	Horticulture	1-5 MW	New	RS 30	Similkameen	Preliminary	No	
12	2019	Horticulture	1-5 MW	New	RS 30	West Kootenay	Discontinued	No	
13	2020	Crypto / Data Center	10-50 MW	New	RS 31	West Kootenay	Preliminary	No	
14	2021	Renewable Gas	50+ MW	New	RS 31	West Kootenay	Preliminary	No	
15	2021	Crypto / Data Center	50+ MW	New	RS 31	TBD	Preliminary	No	
16	2021	Crypto / Data Center	50+ MW	Existing	RS 31	TBD	Preliminary	No	
17	2021	Crypto / Data Center	50+ MW	Existing	RS 31	Okanagan	In progress	Yes	Partial
18	2021	Crypto / Data Center	10-50 MW	New	RS 31	TBD	Preliminary	No	
19	2021	Other	5-10 MW	New	RS 31	Okanagan	Preliminary	No	
20	2021	Crypto / Data Center	5-10 MW	New	RS 31	West Kootenay	Discontinued	Yes	Partial
21	2021	Other	5-10 MW	Existing	RS 31	West Kootenay	Preliminary	No	
22	2021	Solar	5-10 MW	New	RS 31	Okanagan	In progress	Yes	Full

A	B	C	D	E	F	G	H	I	J
Request	**Request Received**	**Industry**	**Requested Load**	**Existing or New Customer**	**Anticipated Rate Schedule**	**Region**	**Status[1]**	**Determination Made**	**Result[2]**
23	2021	Crypto / Data Center	1-5 MW	New	RS 30	West Kootenay	Preliminary	No	
24	2021	Horticulture	1-5 MW	New	RS 30	Okanagan	In progress	Yes	Full
25	2022	Crypto / Data Center	50+ MW	New	RS 31	TBD	Preliminary	No	
26	2022	Crypto / Data Center	50+ MW	New	RS 31	Okanagan	Preliminary	No	
27	2022	Crypto / Data Center	50+ MW	New	RS 31	Similkameen	Preliminary	No	
28	2022	Crypto / Data Center	50+ MW	New	RS 31	Okanagan	Preliminary	No	
29	2022	Crypto / Data Center	50+ MW	New	RS 31	Okanagan	In progress	Yes	Partial
30	2022	Crypto / Data Center	50+ MW	New	RS 31	Similkameen	In progress	Yes	Partial
31	2022	Crypto / Data Center	50+ MW	New	RS 31	Similkameen	In progress	Yes	Partial
32	2022	Crypto / Data Center	50+ MW	New	RS 31	Boundary	Preliminary	No	
33	2022	Crypto / Data Center	10-50 MW	Existing	RS 31	Similkameen	Preliminary	No	
34	2022	Crypto / Data Center	10-50 MW	New	RS 31	Okanagan Valley	Preliminary	No	
35	2022	Crypto / Data Center	10-50 MW	Existing	RS 31	TBD	Preliminary	No	
36	2022	Mining	10-50 MW	New	RS 31	West Kootenay	Preliminary	No	
37	2022	Crypto / Data Center	1-5 MW	New	RS 30	TBD	Preliminary	No	
38	2022	EV Charging	1-5 MW	Existing	RS 30	Okanagan	In progress	Yes	Full
39	2022	Crypto / Data Center	1-5 MW	Existing	RS 30	Okanagan	Preliminary	No	
40	2022	Crypto / Data Center	1-5 MW	Existing	RS 30	TBD	Preliminary	No	
41	2022	Crypto / Data Center	1-5 MW	Existing	RS 30	Okanagan	In progress	Yes	Full
42	2022	Solar	1-5 MW	New	RS 30	Similkameen	Preliminary	No	

Notes to Revised Table 1:

1) Under Column H – Status:
   a. "Preliminary" indicates a request that has not yet reached the System Impact Study phase.
   b. "In Progress" indicates a request that is at the System Impact Study phase or further in the Interconnection Process.

2) Under Column J – Result:
   a. Results have only been given for requests where a determination has been made. For all other requests, a determination and result will be reached once the project is at the System Impact Study phase.
   b. "Full" indicates that the load request can be fully met based on the availability of system capacity under existing system planning criteria.
   c. "Partial" indicates that the load request can only be partially met based on the availability of system capacity under existing system planning criteria.
   d. For both "Full" and "Partial" results, FBC's assessment is based on current system conditions and is subject to change as new loads are added, including those in the Interconnection Process.

35.2 For customers currently in the interconnection queue for RS 30 or RS 31 service and now requesting RS 38 service would the request for RS 38 service be considered a "new request" and be given a different position in the interconnection queue?

Response:

FBC does not have customers currently in the interconnection queue for RS 30 or RS 31 service that are requesting RS 38 service, since RS 38 service is not currently available. Should RS 38 be approved, and a customer currently in the queue for firm service expresses an interest in taking service on an interruptible basis, the allocation of LCIR load will be made in accordance with the process outlined in the response to BCUC IR1 20.4.

35.3 Could a prospective customer currently in the interconnection queue for RS 30/31 service and now requesting service under RS 38 continue to also remain in its current queue position for RS30/31 service?

Response:

FBC anticipates that if RS 38 is approved, a customer who expresses interest in it but is also at that time in the interconnection queue for RS 30/31 would be able to remain in that RS 30/31 queue position provided they still wish to become a firm service customer once that is available to them. Once firm service is available, they must either commence firm service or lose their queue position.

36.0 Reference: Exhibit B-3, BCUC 2.2

Exhibit B-1, page 15

Preamble: The response to BCUC 2.2 states:

> "However, FBC reserves the right to manage RS 38 load such that short term power rather than day ahead power may be purchased from time to time".

36.1 Apart from the one example provided, please outline all other circumstances under which FBC would purchase power to meet RS38 load other than on a day ahead basis.

<u>Response:</u>

As stated in the response to BCUC IR1 2.2, "However, as the RS 38 rate is based on day-ahead power, purchasing power on any other basis than day-ahead creates risk of a mismatch between the price paid by FBC and the RS 38 revenue received." Therefore, if FBC is going to plan to purchase power on anything other than a day-ahead basis, it must be fairly certain that the price paid will be below the day-ahead price. This is accomplished in the negative price example given in BCUC IR1 2.2. However, as prices increase it becomes more and more uncertain that the price paid will not be higher than the day-ahead price and it becomes more and more unlikely that FBC would risk such a purchase.

However, purchases could still occur for other reasons with the power ending up being used to meet LCIR load. The only additional example where FBC envisions this happening is if based on forecast load several days out, FBC buys 50 MW of power to ensure sufficient supply to non-LCIR customers and then as time moves forward, the load forecast drops off, this power is already purchased and available to meet LCIR load. It would not make sense to purchase additional power to meet the LCIR load when this existing power was available. The price may end up being either higher or lower than the daily market price, but however that turns out to be, it is a more efficient use of the available system resources, and overall power purchase expense is lower than it would be otherwise.

36.2 As part of its annual report on LCIR-related activity would FBC be willing to provide summary information on the use of market purchases, other than day ahead, used to meet RS38 load including the costs incurred relative to applicable Mid-C prices?

<u>Response:</u>

FBC could provide this information to the extent that such market purchases were made solely for the purpose of meeting RS 38 load and would be willing to do so.

Please also refer to the response to BCOAPO IR2 36.1.

37.0 Reference: Exhibit B-3, BCUC 2.3, 9.3 and 13.1.2

Exhibit B-1, page 15

Exhibit B-6, CEC 5.1

Preamble: The response to BCUC 2.3 states:

"FBC expects to optimize the power supply portfolio considering the RS 38 load. FBC may choose to use FBC resources to meet the RS 38 load if that is the best option or FBC may choose to purchase market energy to meet the RS 38 load."

BCUC 9.3 provides a practical example of how such a situation could arise.

BCUC 13.1.2 describes various instances where the cost of power delivered to RS 38 customers may vary from the day ahead Mid-C Index.

CEC 5.1 states:

"There is also a somewhat higher risk, but still very low, related to FBC not purchasing market electricity to supply LCIR Customers. It is possible that the alternative supply arrangements could end up costing more than the market price on any given day. Averaged out over the course of a longer time period this is not expected to be the case".

37.1 Have the specific circumstance outlined in BCUC 9.3.1, where towards the end of the Canal Plant Agreement (CPA) summer storage season on July 31st FBC had a surplus of energy in storage that had to be "spilled" but at the same time had surplus capacity, ever occurred and, if so, when?

Response:

Yes, this has occurred. FBC has not conducted an analysis of how many times this has occurred over the life of the CPA but it is not an unusual occurrence. Extremely low-priced market energy is often available in May and early June and it makes sense to overbuy to have the energy available to meet July loads if July should turn out to be hot. If FBC is able to obtain this energy and July is not hot, then there will be surplus July capacity and surplus energy.

37.2 BCUC 2.3 states that FBC expects to optimize the power supply portfolio which may result in FBC choosing to use FBC resources (as opposed to market purchases) to meet RS 38 load if that is the best option. Please explain more fully why (per CEC 5.1) there is risk that the cost of the alternative (e.g., using FBC resources) could end up costing more than the market price.

37.2.1 Please outline how FBC plans to minimize this risk.

Response:

If FBC is using alternative supply arrangements, it is possible that conditions change from what FBC was expecting and FBC is forced into the market at high prices to meet load. For example, if FBC is forecasting surplus capacity and energy, and chooses to use that capacity and energy to meet LCIR load, it is possible that either FBC generation could fail or loads could be unexpectedly high such that FBC is short power and is forced to buy to cover its loads. These prices may be above the day-ahead price that would have been paid to meet LCIR load with day-ahead market purchases.

FBC considers this risk to be minimal and is part of standard utility operations where for any particular hour, many things could happen. FBC minimizes this risk through keeping prudent margins in reserve to help meet unexpected load.

37.3 As part of its annual report on LCIR-related activity would FBC be willing to provide summary information on the use of FBC resources to meet RS38 load including the costs incurred relative to applicable Mid-C prices?

Response:

Please also refer to the response to BCUC IR2 9.1.

FBC believes it is likely not possible to accurately separate out the costs sufficiently to include this information in the LCIR report. For example, FBC may not even know for sure if the strategy was economically successful or not for up to a year after the hour in question. This is since the BC Hydro PPA contract pricing is dependent on both past load as well as current load. If BC Hydro PPA energy were to be used to meet LCIR load, FBC would have to wait until the end of the PPA use year, at the end of September, to know what the true incremental cost was. Then, once that is known, FBC expects it will still be very difficult to determine cause and effect between the thousands of interactions that occur on a system basis. Any number that FBC could produce would be a rough estimate at best.

38.0 Reference: Exhibit B-3, BCUC 2.3

Preamble: The response states:

> "FBC expects to optimize the power supply portfolio considering the RS 38 load. FBC may choose to use FBC resources to meet the RS 38 load if that is the best option or FBC may choose to purchase market energy to meet the RS 38 load. <u>When the latter occurs, the FBC energy resources remain available to meet load at a later time. On a capacity basis, additional surplus capacity sales might be possible, or if all FBC capacity is being used to meet load, then the portion of market costs used to meet RS 38 loads will be recovered from the RS 38 Customer rather than from all customers as would otherwise be the case.</u> This also has the potential to result in significant savings to all non-RS 38 Customers." (emphasis added)

38.1 With respect to the first underlined part of the response, please confirm that, if market purchases are used to supply RS 38 load, the availability of FBC resources to meet FBC's other load requirements is no different than if there was no RS 38 load.

38.1.1 If not confirmed, please explain why.

<u>Response:</u>

Not confirmed since if there was no RS 38 load, it is possible that firm load might be higher. In other words, the availability of FBC resources to meet other FBC load could be higher if market power is used to meet RS 38 load.

However, assuming FBC firm load is not impacted by RS 38 load, then the statement is confirmed.

38.2 With respect to the second underlined part of the response, please confirm that, if market purchases are used to supply RS 38 load, FBC's ability to make additional surplus capacity sales is no different than if there was not RS 38 load.

38.2.1 If not confirmed, please explain why.

<u>Response:</u>

Please refer to the response to BCOAPO IR2 38.1 as the same logic applies for capacity as for energy.

38.3 With respect to the third underlined part of the response, please confirm that if there was no RS 38 load there would be no market costs incurred to meet RS 38 load and, therefore, no related cost to be recovered from any customers.

38.3.1 If not confirmed, please explain why.

Response:

Confirmed, but the point FBC was attempting to make with this part of its prior response is that buying from the market to meet RS 38 load protects the other customers from potentially high market costs as compared to a situation in which FBC just made a general market purchase to be shared by all customers. BCUC IR1 2.3 was asking about the benefits of not using FBC resources to meet RS 38 load during high price periods, so the response was required to assume the RS 38 load did exist.

38.4 Based on the foregoing responses, please explain how the circumstances described in the FBC's response to BCUC 2.3 have the "potential to result in significant savings to all non-RS 38 Customers".

Response:

The FBC statement in the response to BCUC IR1 2.3 must be read in the context of the original question, which FBC repeats here for clarity.

BCUC IR1 2.3: "Please discuss how FBC's resources could be used to the benefit of other customers if the energy is not used to serve RS 38 Customers during periods of higher Mid-C prices (e.g., the use of cheaper embedded cost power to supply other customers, buying less volume of expensive market energy in its resource stack, take advantage of high market energy prices by selling resources on the market, etc.)."

The question seemed to relate to the benefits to other FBC customers from FBC not simply blending the RS 38 load into its load resource stack all of the time, and, rather, doing so just when it is advantageous to do so.

Correspondingly, in response to the current question, the fact that FBC's approach has the "potential to result in significant savings to all non-RS 38 Customers" flows from the fact that FBC will not serve the RS 38 load as part of its existing resources unless it is beneficial to do so. The benefits from non-RS 38 Customers come in three forms:

1. Revenue from the RS 38 Customer to the extent that the $10 per MWh adder is above FBC's incremental cost to provide the power.

2. Revenue from the RS 38 Customer to the extent that FBC's cost to supply is less than the Mid-C component of the price FBC will charge the RS 38 Customer. This is the case where FBC determines that it is more cost effective to serve the RS 38 load from other resources.

3. Avoided cost of not serving RS 38 load from other resources when it is not economical to do so.

FBC agrees that if the RS 38 load was zero or the Program did not exist, then the avoided cost would not be relevant. However, in the context of a situation in which the RS 38 Program does exist and does have load, the Program design ensures that non-RS 38 Customers avoid these costs and see only the benefits.

39.0 Reference: Exhibit B-3, BCUC 3.1, 3.3, 3.4 and 3.8

Exhibit B-7, ICG 9.3

Exhibit B-4, BCOAPO 3.1 and 5.1

Preamble: The response to BCUC 3.1 states:

"The Customer would be required to follow the Interconnection Request process, commission a System Impact and Facilities study, and fund any required system reinforcement. The key point here is that any large commercial customer, whether new or existing, would face similar costs to take firm service if connecting a similar load in substantially similar circumstances."

The response to BCUC 3.3 states:

"A Customer requesting firm service under RS 30 or RS 31 would be required to fund any infrastructure additions or upgrades necessary to ensure that service under the N-1 criterion could be maintained".

The response to BCUC 3.4 states:

"Requirements specific to prospective and existing RS 30 and RS 31 Customers undertaking RS 38 service are summarized below".

The response to BCOAPO 3.1 states:

"Generally speaking, FBC will connect a Customer regardless of the distance to the nearest appropriate point of supply provided that the Customer makes the required contribution toward the required infrastructure additions or upgrades in accordance with its extension and connection policies as contained in the FBC Electric Tariff and related policy documents such as those included in the response the BCUC IR1 5.1".

The response to ICG 9.3 states:

"The AS Mawdsley Terminal project was planned to begin in 2024 and the primary driver of the project was age and condition of the ASM T1 transformer. With the addition of the new load on 11L, the project is also now required due to the growth in the Boundary and Kootenay area and to meet transmission planning criteria. However, the project cannot be accelerated and is still planned to begin in 2024. The new load was not assigned costs for this upgrade.

New point loads seeking to interconnect to the FBC system 1 will receive an estimate of cost responsibility as outlined in the Facility Connection Requirements that form part of the Industrial Electricity Interconnection process and pursuant to the required studies therein. Generally speaking, new point loads that drive infrastructure upgrades and advancement are responsible to pay for those costs prior to connection."

39.1 The purpose of the original questions (including BCOAPO 3.1) was to understand specifically what additional system facilities and associated costs could be involved (in terms of reinforcement, upgrades, etc.) under the various circumstances (including: i) a RS 38 customer seeking to be served as firm load {i.e. RS 30 or 31}, ii) a new RS 38 customer {or an existing RS 30/31 customer} seeking to add additional RS 38 load or iii) a new RS 30/31 customer) and which of these costs would be the responsibility of the customer as opposed to FBC. The response to BCUC 3.3 suggests that in circumstances (i) and (iii) the customer would be responsible for the costs of all required infrastructure improvements and FBC would have no responsibility for any of the incremental costs. Please confirm that this is the case and that this approach is applied to both BES and non-BES facilities.

39.1.1 If not confirmed, please provide a response that details the types of facilities that could require upgrading and/or reinforcement due to either a new RS 30/31 customer requiring service or a RS 38 customer seeking to be served as firm load and indicate, for each type of facility upgrade/reinforcement (BES and non-BES), whether the responsibility for funding the additional costs lies with the customer or FBC. Please also indicate any differences in either the facilities impacted or the responsibility for costs as between RS 30 and RS 31 customers.

Response:

It is confirmed that for both i), an RS 38 customer seeking to be served as firm load, and iii), a new RS 30/31 customer, the customer would be responsible for the costs of all required infrastructure improvements for both BES and non-BES facilities.

39.2 With respect to BCUC 3.4, the response states that for prospective RS 31 customers seeking RS 38 service "Customers will also be required to build a customer-owned substation and transmission line extension to their location. The equipment described above would be included in the customer-owned substation". What are the related requirements for prospective RS 30 customers seeking RS 38 service: i) will they be required to build a customer-owned line extension or fund any FBC owned line extension required, ii) will they be required to build a customer owned substation or fund any new/upgrades to FBC substations, iii) where will any necessary equipment (i.e., communications, relays, disconnecting equipment, etc.) to facilitate remote interruption by FBC be located?

Response:

A customer that would normally be served under RS 30 (a primary-connected customer with a load below 5 MVA) does not typically own the distribution substation but may be required to fund a distribution extension subject to Section 16 of the FBC Tariff, if one is required. This same situation would apply for a primary connected RS 38 Customer. While an RS 30 Customer would not be required to install equipment to facilitate remote interruption by FBC, the same customer on RS 38 would be required to do so. It is not expected that an RS 38 Customer would also fund upgrades to FBC-owned infrastructure since doing so would only be required to enable firm service.

39.3 With respect to BCUC 3.8 and ICG 9.3, do these responses mean that a new RS30/31 customer (or an RS 38 customer converting to RS 30/31 service) would not be responsible for "any incremental infrastructure additions or upgrades" that are already included in FBC's approved capital plan but would be responsible for any incremental costs if a project in the capital plan is subsequently advanced to permit the customer to receive service under RS 30/31?

Response:

The determination of cost responsibility is situation specific. For example, if an existing project that is part of a capital plan provides excess capacity and a customer request is received that uses some of that capacity but still leaves enough remaining capacity to serve expected load growth, it is unlikely that a customer contribution would be required. If, however, the load request was significant enough that it impacted the original purpose for which the capacity addition was being made, the customer could be required to make a contribution. Similarly, if advancing a planned system project resulted in incremental costs, a customer may be required to provide funding to offset the cost increase.

40.0 Reference: Exhibit B-3, BCUC 10.2 and BCUC 15.4

Preamble: The response to BCUC 10.2 states:

> "RS 31 Revenue is calculated according to the RS 31 tariff pages, based on continuous service through the month for the total energy consumed and peak demand.
>
> RS 38 Margin is the difference between total RS 38 revenues and RS 38 power purchase costs assuming that power is purchased from the market.
>
> RS 31 Margin is the difference between total RS 31 revenues and RS 31 power purchase costs assuming that power is purchased under the Power Purchase Agreement (PPA) with BC Hydro."

40.1 While the response states that the RS 31 margin is based on assuming power is purchased under the PPA the formulae used in the attached excel spreadsheet appears to assume RS 31 costs are based on the lesser of cost under the PPA or the market price for hour. Please reconcile.

Response:

In Attachment 10.2 provided in the response to BCUC IR1 10.2, RS 31 margin utilizes a power purchase cost that is the lesser of the cost under the PPA or the market price for that hour, as would be the actual practice in normal operation. As such, the response to BCUC IR1 10.2 in the description of RS 31 margin should have reflected this.

40.2 Please explain why for the March 2022 Results the PPA cost was based on the tranche 1 energy rate ($0.05096/kWh) whereas for the July 2022 Results the PPA cost was based on a blended rate ($0.0614/kWh). As part of the response, please explain how the blended rate was determined.

Response:

When the BC Hydro PPA is used to supply RS 31 load, there may or may not be incremental PPA capacity required in addition to the PPA energy depending on the time of year. In Table 3-1: March 2022 Results, referenced in BCUC IR1 10.2, only PPA energy costs of $50.96/MWh were taken into consideration in the margin calculation, because FBC has a capacity surplus in March and would likely not need to purchase additional capacity under the PPA. However, in Table 3-2: July 2022 Results, referenced in BCUC IR1 10.2, FBC used a blended PPA energy and capacity rate of $61.40/MWh in the margin calculation because FBC is generally short capacity in July and would likely need to purchase additional capacity as well as energy, under the PPA.

In order to calculate the blended rate of $61.40[1]/MWh, FBC assumed a flat average of energy and capacity charges throughout the month.

40.3 When market power is assumed to be used to supply either RS 38 or RS 31 load are there any other costs that FBC incurs apart from the Mid-C price and losses that should be accounted for in the determining the "margins" under each rate schedule (e.g., those costs noted in BCUC 15.4)?

40.3.1 If yes, what are these costs (i.e. types) and why weren't they included in the analysis?

Response:

The data presented in Tables 3-1 and 3-2, and referenced in the response to BCUC IR1 10.2, illustrates a base scenario which considers the market price, exchange rate, Mid-C Price Cap, PPA costs, amount of load switched to RS 38, and revenue associated with RS 31 and RS 38. However, as stated in the response to BCUC IR1 15.4, FBC does recognize there are other possible scenarios where transmission costs incurred by FBC to wheel market power could vary for either RS 31 or RS 38 Customers depending on the assumptions made. Assumptions that could change the analysis include the location of a customer within the service territory, source of market purchase (BC or US), and timing of required purchase (HLH or LLH). The initial analysis did not include multiple scenarios for the sake of simplicity.

40.4 When the PPA is used to supply RS 31 load are there any costs (e.g. PPA capacity costs in the March 2022 Results) that should be accounted for in determining the "margin" under that rate schedule?

40.4.1 If yes, what are the costs (i.e., types and amounts per MWh)?

Response:

Please refer to the response to BCOAPO IR2 40.2.

[1] [($50.96/MWh x 744 hours)+($8,696/MW/month)]/744 hours x (1 - 0.02) = $61.40/MWh, where -0.02 represents the current BC Hydro rate rider.

40.5 If, based on the response to the previous questions, other costs have been identified as being applicable, please provide a revised version of Tables 3-1 and 3-2.

Response:

FBC agrees that other costs could be applicable, depending on the assumptions made. Assuming costs consistent with BCUC IR1 15.4 and 15.5, then the following tables would apply. The first two tables below also assume that the customer is located in the Kootenays, whereas the last two tables assume the customer is based in the Okanagan.

Revised Table 3-1: March 2022 Results; Kootenay Location

Load Switched to RS 38 (kVA)	Mid-C Price Cap (USD)	Interrupted ?	Hours of Interruption	RS 38 Revenue	RS 31 Revenue	Monthly RS 38 Margin	Monthly RS 31 Margin	Margin Variance
5,000	50	No	0	$ 199,309	$ 254,466	$ 31,376	$ 87,285	$ 55,909
5,000	40	No	0	$ 199,309	$ 254,466	$ 31,376	$ 87,285	$ 55,909
5,000	35	No	0	$ 199,309	$ 254,466	$ 31,376	$ 87,285	$ 55,909
5,000	50	Yes	0	$ 199,309	$ 254,466	$ 31,376	$ 87,285	$ 55,909
5,000	40	Yes	16	$ 194,284	$ 254,466	$ 30,723	$ 87,285	$ 56,562
5,000	35	Yes	312	$ 108,361	$ 254,466	$ 18,181	$ 87,285	$ 69,104
10,000	50	No	0	$ 398,618	$ 508,932	$ 62,753	$ 174,571	$ 111,818
10,000	40	No	0	$ 398,618	$ 508,932	$ 62,753	$ 174,571	$ 111,818
10,000	35	No	0	$ 398,618	$ 508,932	$ 62,753	$ 174,571	$ 111,818
10,000	50	Yes	0	$ 398,618	$ 508,932	$ 62,753	$ 174,571	$ 111,818
10,000	40	Yes	16	$ 388,567	$ 508,932	$ 61,446	$ 174,571	$ 113,125
10,000	35	Yes	312	$ 216,721	$ 508,932	$ 36,363	$ 174,571	$ 138,208
20,000	50	No	0	$ 797,237	$ 1,017,864	$ 125,506	$ 349,142	$ 223,636
20,000	40	No	0	$ 797,237	$ 1,017,864	$ 125,506	$ 349,142	$ 223,636
20,000	35	No	0	$ 797,237	$ 1,017,864	$ 125,506	$ 349,142	$ 223,636
20,000	50	Yes	0	$ 797,237	$ 1,017,864	$ 125,506	$ 349,142	$ 223,636
20,000	40	Yes	16	$ 777,135	$ 1,017,864	$ 122,892	$ 349,142	$ 226,249
20,000	35	Yes	312	$ 433,443	$ 1,017,864	$ 72,726	$ 349,142	$ 276,416
50,000	50	No	0	$ 1,993,091	$ 2,544,660	$ 313,765	$ 872,854	$ 559,089
50,000	40	No	0	$ 1,993,091	$ 2,544,660	$ 313,765	$ 872,854	$ 559,089
50,000	35	No	0	$ 1,993,091	$ 2,544,660	$ 313,765	$ 872,854	$ 559,089
50,000	50	Yes	0	$ 1,993,091	$ 2,544,660	$ 313,765	$ 872,854	$ 559,089
50,000	40	Yes	16	$ 1,942,837	$ 2,544,660	$ 307,231	$ 872,854	$ 565,623
50,000	35	Yes	312	$ 1,083,606	$ 2,544,660	$ 181,815	$ 872,854	$ 691,039

1 **Revised Table 3-2: July 2022 Results; Kootenay Location**

Load Switched to RS 38 (kVA)	Mid-C Price Cap (USD)	Interrupted ?	Hours of Interruption	RS 38 Revenue	RS 31 Revenue	Monthly RS 38 Margin	Monthly RS 31 Margin	Margin Variance
5,000	50	No	0	$ 302,969	$ 254,466	$ 34,271	$ 72,938	$ 38,667
5,000	40	No	0	$ 302,969	$ 254,466	$ 34,271	$ 72,938	$ 38,667
5,000	35	No	0	$ 302,969	$ 254,466	$ 34,271	$ 72,938	$ 38,667
5,000	50	Yes	352	$ 90,610	$ 254,466	$ 16,566	$ 72,938	$ 56,372
5,000	40	Yes	512	$ 37,126	$ 254,466	$ 9,789	$ 72,938	$ 63,148
5,000	35	Yes	528	$ 32,569	$ 254,466	$ 9,154	$ 72,938	$ 63,784
10,000	50	No	0	$ 605,939	$ 508,932	$ 68,542	$ 145,875	$ 77,333
10,000	40	No	0	$ 605,939	$ 508,932	$ 68,542	$ 145,875	$ 77,333
10,000	35	No	0	$ 605,939	$ 508,932	$ 68,542	$ 145,875	$ 77,333
10,000	50	Yes	352	$ 181,220	$ 508,932	$ 33,132	$ 145,875	$ 112,744
10,000	40	Yes	512	$ 74,252	$ 508,932	$ 19,579	$ 145,875	$ 126,297
10,000	35	Yes	528	$ 65,137	$ 508,932	$ 18,308	$ 145,875	$ 127,567
20,000	50	No	0	$ 1,211,877	$ 1,017,864	$ 137,084	$ 291,751	$ 154,667
20,000	40	No	0	$ 1,211,877	$ 1,017,864	$ 137,084	$ 291,751	$ 154,667
20,000	35	No	0	$ 1,211,877	$ 1,017,864	$ 137,084	$ 291,751	$ 154,667
20,000	50	Yes	352	$ 362,439	$ 1,017,864	$ 66,263	$ 291,751	$ 225,488
20,000	40	Yes	512	$ 148,504	$ 1,017,864	$ 39,157	$ 291,751	$ 252,594
20,000	35	Yes	528	$ 130,275	$ 1,017,864	$ 36,617	$ 291,751	$ 255,134
50,000	50	No	0	$ 3,146,470	$ 2,544,660	$ 459,487	$ 729,377	$ 269,890
50,000	40	No	0	$ 3,146,470	$ 2,544,660	$ 459,487	$ 729,377	$ 269,890
50,000	35	No	0	$ 3,146,470	$ 2,544,660	$ 459,487	$ 729,377	$ 269,890
50,000	50	Yes	352	$ 963,223	$ 2,544,660	$ 222,782	$ 729,377	$ 506,595
50,000	40	Yes	512	$ 400,504	$ 2,544,660	$ 127,136	$ 729,377	$ 602,241
50,000	35	Yes	528	$ 351,930	$ 2,544,660	$ 117,785	$ 729,377	$ 611,592

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Revised Table 3-1: March 2022 Results; Okanagan Location

Load Switched to RS 38 (kVA)	Mid-C Price Cap (USD)	Interrupted ?	Hours of Interruption	RS 38 Revenue	RS 31 Revenue	Monthly RS 38 Margin	Monthly RS 31 Margin	Margin Variance
5,000	50	No	0	$ 199,309	$ 254,466	$ 22,076	$ 79,829	$ 57,752
5,000	40	No	0	$ 199,309	$ 254,466	$ 22,076	$ 79,829	$ 57,752
5,000	35	No	0	$ 199,309	$ 254,466	$ 22,076	$ 79,829	$ 57,752
5,000	50	Yes	0	$ 199,309	$ 254,466	$ 22,076	$ 79,829	$ 57,752
5,000	40	Yes	16	$ 194,284	$ 254,466	$ 21,623	$ 79,829	$ 58,206
5,000	35	Yes	312	$ 108,361	$ 254,466	$ 12,781	$ 79,829	$ 67,047
10,000	50	No	0	$ 398,618	$ 508,932	$ 44,153	$ 159,658	$ 115,505
10,000	40	No	0	$ 398,618	$ 508,932	$ 44,153	$ 159,658	$ 115,505
10,000	35	No	0	$ 398,618	$ 508,932	$ 44,153	$ 159,658	$ 115,505
10,000	50	Yes	0	$ 398,618	$ 508,932	$ 44,153	$ 159,658	$ 115,505
10,000	40	Yes	16	$ 388,567	$ 508,932	$ 43,246	$ 159,658	$ 116,412
10,000	35	Yes	312	$ 216,721	$ 508,932	$ 25,563	$ 159,658	$ 134,095
20,000	50	No	0	$ 797,237	$ 1,017,864	$ 88,306	$ 319,315	$ 231,009
20,000	40	No	0	$ 797,237	$ 1,017,864	$ 88,306	$ 319,315	$ 231,009
20,000	35	No	0	$ 797,237	$ 1,017,864	$ 88,306	$ 319,315	$ 231,009
20,000	50	Yes	0	$ 797,237	$ 1,017,864	$ 88,306	$ 319,315	$ 231,009
20,000	40	Yes	16	$ 777,135	$ 1,017,864	$ 86,492	$ 319,315	$ 232,823
20,000	35	Yes	312	$ 433,443	$ 1,017,864	$ 51,126	$ 319,315	$ 268,190
50,000	50	No	0	$ 1,993,091	$ 2,544,660	$ 220,765	$ 798,289	$ 577,524
50,000	40	No	0	$ 1,993,091	$ 2,544,660	$ 220,765	$ 798,289	$ 577,524
50,000	35	No	0	$ 1,993,091	$ 2,544,660	$ 220,765	$ 798,289	$ 577,524
50,000	50	Yes	0	$ 1,993,091	$ 2,544,660	$ 220,765	$ 798,289	$ 577,524
50,000	40	Yes	16	$ 1,942,837	$ 2,544,660	$ 216,231	$ 798,289	$ 582,058
50,000	35	Yes	312	$ 1,083,606	$ 2,544,660	$ 127,815	$ 798,289	$ 670,474

Revised Table 3-2: July 2022 Results; Okanagan Location

Load Switched to RS 38 (kVA)	Mid-C Price Cap (USD)	Interrupted ?	Hours of Interruption	RS 38 Revenue	RS 31 Revenue	Monthly RS 38 Margin	Monthly RS 31 Margin	Margin Variance
5,000	50	No	0	$ 302,969	$ 254,466	$ 24,971	$ 68,738	$ 43,767
5,000	40	No	0	$ 302,969	$ 254,466	$ 24,971	$ 68,738	$ 43,767
5,000	35	No	0	$ 302,969	$ 254,466	$ 24,971	$ 68,738	$ 43,767
5,000	50	Yes	352	$ 90,610	$ 254,466	$ 11,666	$ 68,738	$ 57,072
5,000	40	Yes	512	$ 37,126	$ 254,466	$ 6,889	$ 68,738	$ 61,848
5,000	35	Yes	528	$ 32,569	$ 254,466	$ 6,454	$ 68,738	$ 62,284
10,000	50	No	0	$ 605,939	$ 508,932	$ 49,942	$ 137,475	$ 87,533
10,000	40	No	0	$ 605,939	$ 508,932	$ 49,942	$ 137,475	$ 87,533
10,000	35	No	0	$ 605,939	$ 508,932	$ 49,942	$ 137,475	$ 87,533
10,000	50	Yes	352	$ 181,220	$ 508,932	$ 23,332	$ 137,475	$ 114,144
10,000	40	Yes	512	$ 74,252	$ 508,932	$ 13,779	$ 137,475	$ 123,697
10,000	35	Yes	528	$ 65,137	$ 508,932	$ 12,908	$ 137,475	$ 124,567
20,000	50	No	0	$ 1,211,877	$ 1,017,864	$ 99,884	$ 274,951	$ 175,067
20,000	40	No	0	$ 1,211,877	$ 1,017,864	$ 99,884	$ 274,951	$ 175,067
20,000	35	No	0	$ 1,211,877	$ 1,017,864	$ 99,884	$ 274,951	$ 175,067
20,000	50	Yes	352	$ 362,439	$ 1,017,864	$ 46,663	$ 274,951	$ 228,288
20,000	40	Yes	512	$ 148,504	$ 1,017,864	$ 27,557	$ 274,951	$ 247,394
20,000	35	Yes	528	$ 130,275	$ 1,017,864	$ 25,817	$ 274,951	$ 249,134
50,000	50	No	0	$ 3,029,694	$ 2,544,660	$ 249,711	$ 687,377	$ 437,666
50,000	40	No	0	$ 3,029,694	$ 2,544,660	$ 249,711	$ 687,377	$ 437,666
50,000	35	No	0	$ 3,029,694	$ 2,544,660	$ 249,711	$ 687,377	$ 437,666
50,000	50	Yes	352	$ 906,098	$ 2,544,660	$ 116,658	$ 687,377	$ 570,720
50,000	40	Yes	512	$ 371,261	$ 2,544,660	$ 68,893	$ 687,377	$ 618,484
50,000	35	Yes	528	$ 325,687	$ 2,544,660	$ 64,542	$ 687,377	$ 622,835

41.0 Reference: Exhibit B-3, BCUC 10.1 and 10.2

Exhibit B-4, BCOAPO 4.2

Preamble: The response to BCOAPO 4.2 states:

> "It is possible that revenues received for RS 38 service could be higher than revenues that would have been received under RS 30/31 if the Mid-C price or Mid-C Price Cap are high enough. In addition, the level of revenue is not indicative of the impact to other customers. It is the margin, or revenue net of associated costs that influences customer impact and this may also be higher for RS 38 service under item #2."

41.1 How high would the average monthly Mid-C price have to be (assuming no interruptions) in order for the monthly revenue under RS 38 to exceed that under: i) RS 31 or ii) RS 30?

Response:

Using the same calculations used to produce Table 3-1 and Table 3-2, the average monthly Mid-C price would have to be higher than $42.77 USD/MWh for the RS 38 revenue to exceed RS 31 revenue, and higher than $47.30 USD/MWh for the RS 38 revenue to exceed RS 30 revenue. These calculations also use the same assumptions described in BCOAPO IR2 40.5.

However, as stated in the response to BCUC IR1 17.2, overall revenue, whether on an individual or aggregate customer basis, is not a useful measure by which to gauge the success of the LCIR, or to evaluate the impact to other customers. This assessment must also consider the cost side of the equation, including the cost of marginal resources required to meet incremental load.

Using the same calculations used to produce Table 3-1 and Table 3-2, the average monthly Mid-C price would have to be higher than $45.22 USD/MWh for the RS 38 revenue to exceed RS 31 revenue, and higher than $49.75 USD/MWh for the RS 38 revenue to exceed RS 30 revenue. These calculations also use the same assumptions described in BCOAPO IR2 40.5 and assume the customer is located in the Kootenays.

41.2 In the last three years (October 2019 to September 2022) in how many months has the average monthly Mid-C price reached the level identified in response to IR 41.1? As part of the response, please identify the specific months and the range of Mid-C prices experienced in each.

Response:

The average monthly Mid-C price exceeded $45.22 USD/MWh in 11 of the 36 months specified in the question and exceeded $49.75 USD/MWh in 11 of those months. Please see the table below for the specific months and range of Mid-C prices experienced in each.

Year	Month	Mid-C Average Day Ahead Price	Mid-C Min Day Ahead Price	Mid-C Max Day Ahead Price	Avg > $45.22 USD/MWh (Yes/No)	Avg > $49.75 USD/MWh (Yes/No)
2021	6	$ 55.46	$ 4.13	$ 334.22	Y	Y
2021	7	$ 89.09	$ 15.62	$ 583.04	Y	Y
2021	8	$ 60.14	$ 24.43	$ 173.79	Y	Y
2021	9	$ 66.07	$ 36.63	$ 278.61	Y	Y
2021	10	$ 61.68	$ 44.13	$ 82.27	Y	Y
2021	12	$ 50.35	$ 21.08	$ 130.61	Y	Y
2022	4	$ 72.44	$ 36.17	$ 117.97	Y	Y
2022	5	$ 55.60	$ 3.99	$ 107.33	Y	Y
2022	7	$ 53.94	$ 1.59	$ 134.68	Y	Y
2022	8	$ 91.67	$ 48.30	$ 217.12	Y	Y
2022	9	$ 151.64	$ 58.16	$ 1,001.46	Y	Y

41.3 Please confirm that in the analysis supporting Tables 3-1 and 3-2 provided in Exhibit B-2, the cost of supply for RS 31 in any given hour was assumed to be equal to or less than the cost of supplying RS 38.

41.3.1 If not confirmed, please explain why.

41.3.2 If confirmed, does this mean that in hours where the RS 31 revenues exceed those for RS 38, the margin earned on RS 31 will exceed the margin earned on RS 38? Please explain.

Response:

Confirmed.

Yes, under the power purchase assumptions used in the model, a customer served under RS 31 will create an hourly margin greater than for a customer of the same size being served under RS 38. This is shown in the summary tables in the model provided in Attachment 10.2 in the response to BCUC IR1 10.2. As also noted in the summary table, the margin comparison is useful only for the case in which an existing RS 31 customer switches to RS 38. For an entirely new RS 38 customer, the margin is all incremental to FBC.

Reference: Exhibit B-3, BCUC 14.2, 14.3 and 15.9

Preamble: The response to BCUC 14.3 states:

"FBC anticipates that all market power required to serve RS 38 Customers will be wheeled to the FBC system via 71 Line".

The response to BCUC 15.9 states:

"In any event, FBC does not anticipate using BC Hydro OATT services to supply LCIR load.

41.4 Please explain why FBC anticipates that all market power required to serve RS 38 Customers will be wheeled to the FBC system via 71 Line. Is it that: i) there are no alternative paths for the US to FBC's system, ii) there are alternative paths but capacity is not available, iii) there are alternative paths but the charges for their use make them impractical to use or iv) some other reason?

Response:

71 Line transmission to the FBC system is both the most reliable and the lowest cost transmission available to FBC. Transmission may be available to wheel power through the BC Hydro system to the FBC system but the cost of doing so is much higher and is not considered in the proposed LCIR rate. Therefore, FBC does not anticipate that any power would be wheeled through the BC Hydro system to meet LCIR customer load.

42.0 Reference: Exhibit B-3, BCUC 15.1, 15.2, 15.3, 15.3.1, 15.4, 15.5 and 15.6

Exhibit B-4, BCOAPO 10.3 and 24.1

Preamble: The response to BCUC 15.2 states:

"As part of the Supplemental Information FBC provided its opinion that at a minimum, the charge (i.e., the Hourly Service Charge) should be no less than the charges that would occur under FBC's wholesale wheeling tariff if retail access service was available and being taken. This was expanded upon by the inclusion of the 26 $.00792/kilowatt-hour charge as a comparator."

The response also provided the derivation of the $0.00792/kWh as follows:

FBC Rate Schedule	Estimated Annual Cost Based on 10 MW Flat Load		Total Annual Cost
101	10 MW x 12 months x $4570 =	$	548,400
103	10 MW x 12 months x $182.202 =	$	21,864.24
104	10 MW x 8760 hours x $0.899 =	$	78,752.40
107	10 MW x 8760 hours x $10.15 x 2.5% =	$	22,228.50
108	10 MW x 8760 hours x $10.15 x 2.5% =	$	22,228.50
	Total Annual Cost =	$	693,474
Average Cost per MWh	Total Annual Cost ($693,474)/Total Annual Energy (10MW x 8760 hours) =	$	7.92

The response to BCOAPO 10.3 states:

"As described in the response to BCUC IR 1 15.2, the Hourly Service Adder is not precisely set with respect to any particular cost recovery percentage. It is an adder intended to notionally recover transmission related charges, administration, and a broader customer benefit. As such, no precise allocation of the resulting revenues is possible or appropriate".

The response to BCOAPO 24.1 states:

"FBC confirms that the market price used in the determination of the FBC contracts for block supply price is equal to that used in the determination of the LCIR Energy Charge. As described in the confidential response to BCUC IR1 15.6, FBC also incurs certain other direct costs but they are lower than the Hourly Service Adder.

42.1 In purchasing and acquiring market power to supply RS 38 load would FBC actually incur any of the charges listed in the response to BCUC 15.2?

42.1.1 If so, please identify which ones FBC would actually have to pay (in addition to the Mid-C day ahead price). As part of the response, please also indicate if the volumes subject to the charge would need to be adjusted for losses.

Response:

FBC wishes to clarify that the charges in BCUC IR1 15.2 are charges that FBC would charge to a customer taking Transmission service, not charges that FBC would pay to a third party.

42.2 The responses to BCUC 15.4 and 15.5 identify additional incremental wheeling-related charges and loss charges that FBC must pay to deliver market power to its service area. BCUC 15.5 also states that these are the only incremental direct costs that FBC is required to pay (in addition to the Mid-C day ahead price) in order to purchase/acquired market power to supply RS 38 load. Please re-confirm that this is the case.

42.2.1 If not confirmed, please describe the nature of any additional charges that FBC could be required to pay and indicate the amount for each per kWh.

Response:

Confirmed.

42.3 The response to 15.6 discusses the total costs that FBC would actually pay (in addition to the Mid-C day ahead price) to acquire and have market power delivered to its service area to supply RS 38 load in the peak and off-peak periods with and without ARWA wheeling. The range of values is considered to be confidential. BCOAPO 24.1 states that these costs are lower than the Hourly Service Charge ($0.01/kWh). Please indicate: i) whether the upper end of the range described in BCUC 15.6 is less than the $0.01/kWh (at point of delivery to the RS 38 customer), ii) whether the upper end or the range described in BCUC 15.6 is less than $0.00792/kWh (at point of delivery to the RS 38 customer and iii) whether (on average) these costs are lower than $0.00792/kWh.

Response:

In all cases, the cost is expected to be less than $0.00792/kWh. However, as identified in the response to BCUC IR1 15.5, ARWA loss compensation is returned to BC Hydro as energy and capacity. This means that the cost to FBC to compensate BC Hydro for ARWA losses is directly dependent on the FBC marginal cost at the time the power is returned to BC Hydro. FBC has estimated a reasonable marginal cost based on the BC Hydro PPA rate of about $50 per MWh.

At times the true marginal rate will be higher as these loss returns are made every hour of every day—including during peak load situations where FBC may be paying much more than $50 per MWh for power. FBC has not attempted to estimate the overall average as it is highly dependent on what Mid-C Price Caps that LCIR customers and FBC agree to.

43.0 Reference: Exhibit B-3, BCUC 18.1 and 15.4

Preamble: The response to BCUC 18.1 states:

> "The scenario that would most likely result in the maximum benefit is the addition of new RS 38 load from the addition of a Customer that is completely new to FBC. All of the revenue from this Customer would be incremental. If the Customer is being supplied at the Mid-C market price exclusively, the incremental revenue would result from the Hourly Service Adder and any margin that FBC could achieve by supplying the load from alternate resources priced less than the Mid-C market price in any hour".

43.1 Please confirm, or explain otherwise, that, in the situation described, the incremental net revenue (i.e., incremental revenue less incremental costs) would be: i) the revenue from the Hourly Service Charge less any incremental charges (e.g. those reference in BCUC 15.4) for delivering the power to FBC service area plus ii) any margin that FBC could achieve by supplying the load from alternate resources priced less than the Mid-C market price in any hour.

<u>Response:</u>

Confirmed.

44.0 Reference: Exhibit B-3, BCUC 6.3, 18.1 and 10.2

Preamble: The response to BCUC 6.3 states:

> "However, in the case where FBC is unable to attract firm load to infill existing load that has transitioned to RS 38, this contribution may fall short of that formerly provided by either RS 30 or RS 31 resulting in a net negative contribution".

The response to 18.1 states:

> "Maximum potential gain could also be achieved by increasing RS 30/31 load as a result of attracting an infill Customer to take up the capacity made available by an existing Customer moving its load to RS 38. In this case, <u>the size of the benefit would depend on whether or not the new RS 38 Customer provided more or less margin (rate revenue over associated costs)</u> than it did on RS 30/31, combined with the new RS 30/31 margin". (emphasis added)

44.1 In the response to BCUC 10.2 both the March 2022 and the July 2022 Results show that the margin for RS 31 exceeds that for RS 38 in all the cases analyzed. Under what circumstances would the new RS 38 customer provide more margin that it formerly did as an RS 31 customer as suggested in the response to BCUC 18.1?

<u>Response:</u>

The response to BCUC IR1 18.1 does not suggest that a new RS 38 Customer would provide more margin that it formerly did as an RS 31 Customer. Consideration of the response needs to include the last portion of the sentence, "…combined with the new RS 30/31 margin", in order to fully consider the total amount of margin from both customers.

45.0 Reference: Exhibit B-3, BCUC 25.1

Preamble: The Attachment set out FBC Hydro's proposed revisions to RS 38.

45.1 Revised Special Provision 3 a) states:

"If the Interruptible Customer's actual hourly consumption is greater than that customer's forecast load for that hour, FortisBC will make a reasonable effort to serve the load but is under no obligation to do so. The customer may be asked to reduce load and failure to do so may result in interruption due to lack of supply. Energy Taken, for the purposes of billing in the Energy Charge section of this rate schedule, shall be based on actual consumption. The rate charged by FBC will not be impacted by increased consumption."

In such circumstances why would it not be appropriate for FBC to apply a "surcharge" (e.g. an mark-up) to the Mid-C price applicable to all energy used in excess of the customer's forecast load or, at minimum, used in excess of the customer's forecast load plus a percentage threshold (e.g. 5%) as an means of incenting RS 38 customers provide accurate forecasts?

<u>Response:</u>

FBC attempts to enter into each hour with a prudent margin to cover minor operational issues and variances from the expected load forecast. This is sufficient to ensure the hourly load resource balance of the system in almost all hours. For the relatively few hours in each year that it is not sufficient, then FBC is likely looking at interrupting service to LCIR Customers. If an LCIR Customer is taking over their forecast amount, taking action with that customer to restore system balance would be a priority and a surcharge to the Mid-C price is not required.

45.2 Revised Special Provision 3 b) states:

"Where the Interruptible Customer's hourly consumption is less than that customer's forecast load for that hour and this is not due to a FortisBC curtailment of the Customer, Energy Taken, for the purposes of billing in the Energy Charge section of this rate schedule, shall be based on the customer forecast load for that hour. However, in recognition that power has been delivered to the FortisBC system and not consumed by the Customer, the Customer will receive a credit equal to the amount of energy it did not consume, grossed up for losses, multiplied by a rate equal to the lower of the BC Hydro RS 3808 Tranche One Energy rate and the Mid-C market-based rate being charged for that hour."

In those hours where the Interruptible customer's hourly consumption is less than that customer's forecast load for that hour will FBC actually be able to affect a corresponding reduction in either market purchases or purchases under the PPA or could there be hours where the lower consumption results in a lower use of FBC's resources?

Response:

If the LCIR Customer load is lower than forecast for an hour, system load resource balance will be maintained by a corresponding reduction in FBC entitlement usage from its own units, all other factors being equal to forecast. FBC will not be able to reduce market purchases or purchases under the PPA within the hour.

45.2.1 If the lower customer use results in a reduction in the use of FBC's resources, why is it appropriate to base the "credit" on the lower of the BC Hydro RS 3808 Tranche One Energy rate and the Mid-C market-based rate being charged for that hour?

Response:

Generally speaking, FBC considers the lower of the BC Hydro PPA Tranche One Energy rate or the Mid-C market rate as a reasonable approximation of FBC's marginal cost of energy for that hour. The credit itself reflects the fact that FBC now has additional energy to use for its own purposes. Since the LCIR Customer is fully charged for the cost of the energy purchase that it did not use, crediting the value of this energy to FBC back to the LCIR Customer ensures that the LCIR Customer only pays the amount that FBC needs to recover.

45.2.2 In such circumstances, would it be appropriate for FBC to establish a maximum amount of energy (based for example on a percentage of the customer's forecast for that hour) to which any credit would apply as a means of incenting RS 38 customers to provide accurate forecasts? If FBC does not consider this approach appropriate, please explain.

Response:

No, FBC does not believe this approach is needed or appropriate. Since the LCIR Customer pays for the energy it forecasts regardless of whether that customer uses it or not, FBC believes this should be sufficient incentive to the LCIR Customer to use the energy it forecast.

46.0 Reference: Exhibit B-3, BCUC 23.2 and BCUC 25.1 – Attachment

Exhibit B-2, Attachment 1

Preamble: The response to BCUC 23.2 references Special Condition #1 for RS 38 states: "Once RS 38 is selected, a Customer must remain on RS 38 for 12 months, after which it could make application to return to firm service following the process discussed in the response to BCUC IR1 23.1".

However, the Contract for Interruptible Service (Exhibit B-2, Attachment 1, Item #5) states: "The term of this Contract shall be for two years, commencing on the date on which Electricity Service is deemed to commence in accordance with this clause 5, and shall continue thereafter until terminated by 6 months' prior notice in writing by either party to the other".

46.1 Please reconcile the apparent inconsistency between these two provisions and indicate what if any revisions are required.

Response:

Please refer to the response to BCUC IR1 28.2.

47.0 Reference: Exhibit B-4, BCOAPO 32.1

Exhibit B-7, ICG 4.1

Exhibit B-3, BCUC 2.1

Preamble: The response to BCUC 2.1 states: "At this point in time, FBC has not made assumptions about the expected take-up rate for RS 38 and therefore has not included any forecast for costs and revenue in the revenue requirement forecasts".

47.1 Please confirm that FBC does not intend to include either the revenues or the energy costs associated with RS 38 in its forecast revenue requirement or rate derivation for 2024.

47.1.1 If not confirmed, please outline FBC's planned treatment of these items in its application for 2024 Rates.

Response:

Given that a decision in this proceeding is expected only a few months before FBC's 2024 Annual Review materials will be submitted, FBC does not anticipate including a forecast of the RS 38 revenues and energy costs in its 2024 rate proposals. However, the Flow-through deferral account will ensure that any revenues and energy costs that do arise in 2024 are captured and returned to/recovered from customers.

47.2 Please confirm that any revenues or energy costs related to RS 38 for either 2023 or 2024 will be captured in a Flow-Through Deferral Account.

Response:

Confirmed.

47.3 BCOAPO 32.1 asked how the load and revenue related to customers on the LCIR will be treated in future Fully Allocated Cost of Service Studies undertaken by FortisBC. The response referred to ICG 4.1. However, the response to ICG 4.1 does not clearly explain how RS 38 will be treated in the FACOS. Please address the following issues regarding the treatment of RS 38 in the FACOS:

- RS 30 and RS 31 are treated as separate customer classes in the current FACOS. Will RS 38 be incorporated in the FACOS as a separate rate class or included as part of RS 30 and RS 31?
- Will the total energy cost to be allocate in the FACOS include the energy costs associated with supplying RS 38 and will energy costs be allocated to RS 38 load using the same methodology as used for other rate classes?
- Will the demand allocators used to allocate the demand-related portions of generation, transmission and distribution costs exclude the load associated with RS 38?
- Will RS 38 customers be included in the customer counts used to allocate customer related costs? How will customer counts be established when a single customer contracts for both RS 38 and RS 30 or 31 and requires two meters?

Response:

FBC cannot provide the treatment of RS 38 for the purpose of a cost-of-service-analysis (COSA) with certainty at this time as it has not arrived at any recommendations that would be made to the BCUC as part of a COSA filing.

One likely scenario is that RS 38 will receive similar COSA treatment to RS 37 Standby service revenues which are treated as an offset to the revenue requirements and allocated to all customers to compensate for the use of the system paid for by all customers, including those within Rates 30 and 31. The energy and demand associated with the RS 37 standby sales are also left out of the Industrial class amounts and the total system amounts, and a similar treatment for RS 38 would be consistent with treatment of the associated revenue.

47.4 The response to ICG 4.1 states:

"For example, if the savings reduced capacity costs for allocated power supply demand costs, then this savings would be a reduction to the overall power supply demand costs and reduce that unit cost to all rates that pay that cost using the same allocation as other power supply demand is spread, in this case on the basis of demand purchases weighted by month."

Please explain how the existence of RS 38 customers/load leads to reduced capacity costs for allocated power supply demand costs.

Response:

This example was meant to illustrate how unit cost savings allocate to proportionally benefit the rate classes that pay those unit costs in rates. There may or may not be capacity savings in all cases. However, a system without interruptible loads has less capability to reduce capacity when needed and must reserve more capacity ahead of need. Having flexible capacity on the system by its very nature provides an extra tool for reducing planned capacity purchases and margins. This has potential cost savings that would reduce overall demand costs and these savings are proportionally allocated to rate classes that pay those unit costs.

48.0 Reference: Exhibit B-3, BCUC 24.1

Exhibit B-6, CEC 7.2

Preamble: The response to CEC 7.2 provides examples of situations where prior notice of an interruption may not be practical.

48.1 Please provide example of situations where prior notice of an interruption would be practical.

<u>Response:</u>

Examples of situations in which prior notice of an interruption may be practical are as follows, but in each case it will depend on the particular circumstances that actually arise.

- **Example 1**: Due to planned maintenance on a substation transformer, loading is forecasted to exceed the emergency rating of the other transformer. This issue is identified by an engineering study of the outage and the LCIR Customer is notified of the load curtailment requirement prior to the planned maintenance commencing.
- **Example 2:** Due to an extreme cold weather forecast, loading is forecasted to exceed the emergency rating of a substation transformer. This issue is identified by an engineering study and the LCIR Customer is notified of the load curtailment requirement prior to the weather event.
- **Example 3**: Due to high market prices, the LCIR Customer's Mid-C Price Cap was exceeded, and no power was purchased to serve its load. In addition, FBC determines that it will not meet the load from other resources. As no power is available a load curtailment requirement is sent for the hours for which there will be no supply.

49.0 Reference: Exhibit B-6, CEC 1.16.1.1

Preamble: The response states:

"Existing Customers transitioning to an interruptible rate may impact planned capital projects depending on their location within the system and the size of their load. This would need to be evaluated as individual Customers transition to RS 38."

49.1 Please explain more fully how existing customers transitioning to an interruptible rate may impact planned capital projects.

Response:

The key consideration in this evaluation is the extent to which a drop in forecast firm load may allow for the deferral or cancellation of capacity-related projects within a particular geographic location.

49.2 To the extent existing customers transitioning to an interruptible rate results in capital projects being cancelled or reduced in scope, will the customer concerned be responsible for any costs incurred unnecessarily? Please explain why or why not.

49.2.1 If yes, please explain how FBC will determine whether costs were incurred unnecessarily and ensure the customer is responsible for these costs.

Response:

FBC does not foresee a situation in which a customer transitioning to an interruptible rate would result in costs that would need to be recovered from that particular customer. It is more likely that a customer that reduces the firm load on the system would provide a net benefit to other customers. FBC does not view this situation as different than any other change in customer composition caused by load growth or reduction, or the routine entry or exit of customers as part of normal utility operations.

50.0 Reference: Exhibit B-5, BCSEA 10.4

Preamble: The response states:

"The Customers that are most likely to be interested in the LCIR are those whose processes can tolerate limited interruptions and are stable, flat loads. Loads of this type can include cryptocurrency mining operations, cannabis production, and hydrogen production".

50.1 Why are stable/flat loads likely to be more interested in LCIR?

Response:

FBC expects that stable/flat loads will be more interested in the LCIR since the LCIR is designed around FBC making stable/flat blocks of power available. If the LCIR Customer's load is not stable/flat, it will be very difficult for such a customer to manage its operations in a secure and economic manner. For example, if the LCIR Customer forecasts its load at the maximum it expects to require for that day, but it is going to be highly variable throughout the day, then the LCIR Customer will be paying for large amounts of power that it will not consume. This is likely to make the effective cost of power very high for such a customer. Conversely, if the LCIR Customer forecasts its load for that same day at the low side of what it expects to require, then its actual load will be much higher than forecast and since FBC has not arranged for the LCIR Customer's supply, there is a high likelihood that load will need to be curtailed.

It is FBC's expectation that these operational realities will make the LCIR rate uneconomic to potential LCIR Customers unless their load is stable/flat. Nevertheless, FBC is not limiting the program to such loads; it is the customer's choice to manage the benefits and risks of taking LCIR supply.

50.2 Please provide a schedule that, by region (similar to those used in BCUC 1.1) sets out the current number of customers and total load associated with cryptocurrency mining operations, cannabis production, and hydrogen production.

Response:

Please refer to Table 1 – Revised in FBC's response to BCOAPO IR2 35.1 for the relevant information. Specifically, Column H – "Status" specifies which load requests have been connected indicating current customers.

Note that existing large capacity customers whose load requests were made prior to 2017 (the original scope asked for in BCUC IR1 1.1) are not captured in Table 1 – Revised.

51.0 Reference: Exhibit B-5, BCSEA 12.4

Preamble: The response states:

"From an operational perspective, the 50 MVA cap has been proposed because it is a level that will not pose a problem for FBC and its Customers".

51.1 In what ways could RS 38 load requests in excess of 50 MVA pose a problem for: i) FBC or ii) FBC's customers?

Response:

A program that exceeds 50 MVA in load poses the risk that the very large amounts of energy required will be beyond the ability of FBC to supply on a regular basis while still leaving sufficient system flexibility to purchase low-cost power for the benefit of existing customers when it is available. The initial 50 MVA cap on participation will provide FBC with the experience necessary to subsequently set the program limit at a level where FBC is confident that additional load can be interconnected.

52.0 Reference: Exhibit B-1, page 14

Exhibit B-4, BCOAPO 16.4

Preamble: The Application states:

"During public engagement in relation to the LCIR, participants expressed a need for FBC to provide historical feeder performance, and that communication regarding the Mid-C pricing be made available. FBC has agreed to provide feeder data to prospective participants with the understanding that this historical data may not represent future performance".

The response to BCOAPO 16.4 states:

"This information cannot be provided as it would require FBC to perform a system study at each of the Customer locations. To determine whether a new load addition could be accommodated without system upgrades, the Customer would be required to submit a request and the appropriate studies would need to be completed by FBC".

52.1 Please provide an example as to the type of feeder data FortisBC will be providing prospective participants per the reference from Exhibit B-1.

Response:

Please refer to the response to BCOAPO IR1 18.1.

52.2 Will it include information on the current capability of individual feeders to accommodate additional firm load?

Response:

Yes. Please refer to the response to BCOAPO IR1 18.2.

52.3 If the information provided includes the current capability of individual feeders, will the provision of such information require FBC to undertake a system impact study?

52.3.1 If no system study is needed, please reconcile the ability to provide such information with FBC's response to BCOAPO 16.4.

52.3.2 If yes, what commitments is the prospective customer required to make before FBC undertakes the system impact study?

Response:

Yes, FBC would be required to perform a system study to provide the current capability of the individual feeder to accommodate the new load.

Depending on the size of the request, the customer would either follow the Interconnection Request process or the New Connect process. Please refer to the response to BCUC IR1 5.1 for details on these processes (including timing and cost) and their requirements.

53.0 Reference: Exhibit B-4, BCOAPO 7.2

Preamble: The response states:

> "Based on the 2020 Cost of Service Analysis, the Customer related costs for RS 30 and RS 31 were $1,431.02 and $353.71 per Customer per Month respectively, while the Customer Charge was $954.49 and $3,117.23 per Customer per month. FBC will review these costs as part of its next COSA".

53.1 Please confirm, or explain otherwise, that the values reported for the RS 30 and RS 31 Customer-related costs and Customer Charges are correct (i.e., for RS 30 the customer-related costs are $1,431.02 while the Customer Charge is $954.49 and for RS 31 the customer-related costs are $353.71 while he Customer Charge is $3,117.23), such that for RS 30 the Customer Charge is well below the customer related costs whereas for RS 31 the opposite is the case.

<u>Response:</u>

Confirmed.

54.0 Reference: Exhibit B-4, BCOAPO 8.2

Preamble: The response states:

> "FBC included the referenced information in anticipation that there may be concerns stemming from the application of a single Customer Charge when the Customer site has two meters and a second calculation requirement for billing. However, as noted, FBC does not expect these costs to be significant or to impact other customers. Large commercial meters are read remotely and there may be a small amount of time expended to add the second service information to the bill on a monthly basis. To the extent that there is a small cost related to this time, it is certainly less than the potential amount over-recovered by virtue of charging a second full Customer Charge. FBC has not studied this to the extent that it can place a specific value on the work involved."

54.1 The response addresses the incremental meter reading and billing costs and suggests they will be small. However, the response does not address the additional cost of the second meter itself. Would the cost of the second meter be the responsibility of the customer or would FBC provide it?

54.1.1 If provided by FBC, what is the estimated monthly cost (i.e., depreciation, financing and ROE) and are the current Customer Charges for RS 30 and RS 31 adequate to cover the cost of a second meter?

<u>Response:</u>

The cost for a second meter is the responsibility of the Customer.

55.0 Reference: Exhibit B-4, BCOAPO 9.4

Preamble: The response states:

"Please refer to the response to BCUC IR1 10.4. Load factor is not a consideration in this calculation".

Note: BCUC 10.4 shows that at an average monthly Mid-C price of $56.50 (Cdn) the monthly bill under LCIR equals that under RS 31 for a 20,000 kW load at 100% load factor and 744 hours in the month.

55.1 Please confirm that at any load factor less than 100% the two bills would not equal and, indeed, the RS 31 bill would be higher than that for the LCIR due to the demand charge component of the RS 31 rate structure.

55.1.1 If not confirmed, please explain why.

55.1.2 If confirmed, please confirm that (contrary to the response to BCOAPO 9.4) load factor is a consideration in establishing the Mid-C price at which the bills under the LCIR and RS 31 would be equivalent.

Response:

The note regarding load factor in the response to BCOAPO IR1 9.4 indicated that no consideration was given to load factor for the purpose of responding to BCUC IR1 10.4.

The tables in BCUC IR1 10.4 were provided in an effort to be responsive to the question; however, the limitations of the response were noted, given that only a single hour comparison was a practical measure. Even within the hourly scenario the comparison is limited given that the peak demand may not occur in the hour used.

Over the course of an entire month using actual load and cost information, FBC agrees that load factor will have an impact on the results.

56.0 Reference: Exhibit B-4, BCOAPO 9.5

56.1 With respect to the graph provided regarding historical on-peak Mid-C prices (October 1, 2021 – September 30, 2022), please provide a schedule that sets out the number of hours the Mid-C price exceeded:

i) $45 US

ii) $60 US

iii) $85 US and

iv) $100 US

<u>Response:</u>

Please see the table below with the number of hours where the Mid-C Day Ahead price was higher than $45, $60, $85 and $100 USD/MWh between October 1, 2021 and September 30, 2022.

Price (USD/MWh)	On-Peak Hours Above	Off-Peak Hours Above	Total Hours Above
$45	3120	1824	4944
$60	2240	1024	3264
$85	944	200	1144
$100	624	88	712

57.0 Reference: Exhibit B-4, BCOAPO 14.1

Preamble: The response states:

> "However, in general, FBC will be considering if the available resources' best use is to continue LCIR service even though the market price is above the cap. In making this determination, possible factors FBC staff may consider include, but are not limited to, whether the amount of energy in storage is too high or too low, the amount of available surplus capacity, the expected price from the sale of surplus capacity, the amount of BC Hydro PPA tranche 1 nominated energy available and <u>the LCIR Customer's preference regarding the potential to receive only partial service during a given period</u>. (emphasis added)"

57.1 At what level in the FBC organization will the decision to supply LCIR load in an hour when the market price is above the "cap" be made?

<u>Response:</u>

The decision on whether supply is available to meet LCIR load if market power is not available will be made by the Power Supply on-duty individual responsible to manage system load and resource balance. This will most often be the Power Supply Operations Manager.

57.2 Is there a risk (similar to that discussed in CEC 5.1) that alternative supply arrangements could end up costing more than the "cap" price on any given day?

57.2.1 If so, how does FBC plan to mitigate/minimize this risk?

<u>Response:</u>

As stated in the response to CEC IR1 5.1, "It is possible that the alternative supply arrangements could end up costing more than the market price on any given day. Averaged out over the course of a longer time period this is not expected to be the case."

FBC plans to mitigate/minimize this risk by heavily relying on market purchases to meet the LCIR load. In cases where FBC chooses not to do so, it will be where FBC is very confident that other resources will be more cost effective.

57.3 With respect to the emphasized part of the response, how will the Customer's preference regarding the potential to receive only partial service during a given period be known and how will it play into the decision making process?

Response:

FBC expects that if an LCIR Customer is interested in receiving partial service, the LCIR Customer will inform FBC of that preference. A preference for partial service will play into the decision-making process since if FBC only has other resources available that could provide partial service, then it is partial service or no service at all.

58.0 Reference: Exhibit B-4, BCOAPO 15.2

Exhibit B-2, Tables 3-1 and 3-2

Exhibit B-3, BCUC 10.2 - Attachment

Preamble: The response states:

> "It is not possible to state the net margin for incremental RS 30 or RS 31 Customers as FBC has not calculated the incremental cost of serving incremental load. Depending on the circumstances, the FBC system incremental cost may be higher or lower than RS 30 or RS 31 rates".

58.1 Please reconcile the statement made in the response to BCOAPO 15.2 with the fact that in Tables 3-1 and 3-2 of Exhibit B-2 FBC has calculated the net margin for RS 31 for March 2022 and July 2022.

<u>Response:</u>

The information provided in Tables 3-1 and 3-2 of Exhibit B-2 uses a set of assumptions regarding power costs in order to provide a reasonable comparison of margin under firm versus non-firm rates. The response to BCOAPO IR1 15.2 relates to actual net margin related to incremental RS 30/31 load which cannot be stated with certainty since the resources are unknown and would likely differ from those assumed in Tables 3-1 and 3-2.

59.0 Reference: Exhibit B-4, BCOAPO 16.3

Preamble: The response refers to BCUC 28.1 which states:

> "The Demand Limit is set in consultation with FBC Engineering which will determine the maximum amount of load that can be accommodated on either a firm or non-firm basis after conducting a study of the system in the area where the load is to be located. Typical elements of such a study include a power flow analysis, short circuit analysis, and a stability analysis".

59.1 In areas where incremental firm load cannot be served without FBC system upgrades/reinforcements, what type of issues could these various analyses (e.g., power flow analysis, short circuit analysis and stability analysis) potentially identify that would mean even incremental LCIR load could not be served without further investment in upgrades/ reinforcements?

Response:

RS 38 Customers are not required to make investments for upgrades or infrastructure other than those required for the interconnection and communication with FBC. The ability to take service without additional investment normally required to meet the N-1 criterion is a basic reason for the interruptible nature of the rate.

Generally speaking, the types of issues potentially identified by the various analyses that would indicate that available capacity in a particular location is limited could include equipment thermal overloads or voltage instability.

59.2 In those areas across FBC's current system where incremental firm load cannot be served without FBC system upgrades/reinforcements, what is FBC's expectation as to the likelihood of such issues actually being identified such that even incremental LCIR load could not be served?

Response:

Please refer to the response to BCOAPO IR2 59.1.

60.0 Reference: Exhibit B-4, BCOAPO 16.4 and 18.2

Preamble: The response to BCOAPO 16.4 states that FBC is unable to identify which of its current RS 30 and RS 31 customers are in locations where additional capability exists to serve firm load without performing system impact studies which would require a customer to submit a request.

The response to BCOAPO 18.2 states that customers can be provided the amount of firm capacity available on the system at the time of their request.

60.1 Is the information referred to in BCOAPO 18.2 the same information referenced in response to BCOAPO 16.4 such that the provision of the information referred to in BCOAPO 18.2 would require a system impact study?

60.1.1 If yes, who would pay for the system impact study, how long does such a study take to complete and what is the typical cost of such a study?

60.1.2 If not, what is the difference between the information identified in the two responses?

Response:

Yes, the information is the same. The information referenced in BCOAPO IR1 18.2 would be determined by undertaking a system study considering the addition of the new requested load.

Depending on the size of the request, the customer would either follow the Interconnection Request process or the New Connect process. Please refer to the response to BCUC IR1 5.1 for details on these processes including general information on timing, cost, and responsibilities.

61.0 Reference: Exhibit B-4, BCOAPO 4.2 and 19.2

Preamble: The response to BCOAPO 4.2 states:

> "It is possible that revenues received for RS 38 service could be higher than revenues that would have been received under RS 30/31 if the Mid-C price or Mid-C Price Cap are high enough. In addition, the level of revenue is not indicative of the impact to other customers. <u>It is the margin, or revenue net of associated costs that influences customer impact</u> and this may also be higher for RS 38 service under item #2." (emphasis added)

The response to BCOAPO 19.2 states:

> "The intent of "A comparison of revenues under the LCIR to foregone revenue under RS 31 and RS 30" is to provide the amount of revenue that any service provided on the LCIR would have generated under RS 30/31 given the levels of peak load and consumption of the Customers in question".

61.1 Given FBC's view that it is margin (i.e., revenue net of associated costs) that influences customer impact, is FBC willing to commit to also reporting the net margin associated with the RS 38 sales and providing comparison to the margin that "any service provided on the LCIR would have generated under RS 30/31 given the levels of peak load and consumption of the Customers in question"?

61.1.1 If not, why not?

<u>Response:</u>

FBC can provide information (including margin) specific to RS 38 but cannot provide a direct comparison to service under RS 30/31 since power purchased to meet firm load is not divisible between individual customer classes or customers.

62.0 Reference: Exhibit B-4, BCOAPO 16.4 and 20.2

Preamble: The response to BCOAPO 16.4 states that FBC is unable to identify which of its current RS 30 and RS 31 customers are in locations where additional capability exists to serve firm load without performing system impact studies which would require a customer to submit a request.

The response to BCOAPO 20.2 states:

"While FBC cannot discuss particular Customer interactions for reasons related to privacy, it can confirm that the most promising inquiries regarding non-firm service are for areas of the system that cannot accommodate the load levels discussed on a firm basis".

62.1 Is the response to BCOAPO 20.2 based on system impact studies having been undertaken for these "most promising inquiries"?

62.1.1 If not, on what is the claim that "the most promising inquiries regarding non-firm service are for areas of the system that cannot accommodate the load levels discussed on a firm basis" founded?

Response:

The response to BCOAPO IR1 20.2 is not based on a specific System Impact Study, but rather on FBC's general knowledge of the system's capacity across various regions, specifically when dealing with requests for very large loads. It is readily apparent to FBC that some of the larger, more promising inquiries cannot be accommodated on a firm basis at the load levels discussed at the requested locations.

In contrast, existing RS 30 and RS 31 Customers that are requesting additional capacity are usually asking for smaller, incremental load increases compared to the large loads discussed above. Determining whether such additional capacity is available is not immediately obvious and usually requires a System Impact Study.

62.2 Please provide an indication of what portions of FBC's service area: i) could accommodate additional firm load that has been requested, ii) could not accommodate additional load that has been requested, and iii) have not been assessed as to the ability to accommodate additional load.

Response:

Please refer to the response to BCOAPO IR2 35.1 for information on existing load requests and FBC's ability to accommodate additional firm load at the associated locations.

63.0 Reference: Exhibit B-4, BCOAPO 27.2

Preamble: The response states:

> "When a Customer originally requires an Extension of System Upgrade, FBC may contribute towards the overall cost based on the contribution amounts contained in section 16 of the FBC Electric Tariff. This capital credit or allowance is based on the net rate base for distribution poles, conductors, and transformers covered in the applicable retail rate such that the average rate base per customer is not increased as a result of new extensions. If FBC required that the customer moving from firm to non-firm service pay back 100 percent of the contribution, there would be no recognition that revenues received since the extension was put into service contributed to the costs associated with the increased rate base. FBC believes that this would be unfair to the LCIR Customer".

63.1 We wish to clarify that the original question was not asking why the customer should not be required to pay back 100% of the contribution, but rather why 100% of the revenue paid to date by the customer should be subtracted from FBC's contribution when determining the amount to be repaid.

Given the capital credit is based on "the net rate base for distribution poles, conductors, and transformers covered in the applicable retail rate", please explain why FBC would not use only the <u>portion</u> of the revenue that covers the cost of distribution poles, conductors, and transformers as an offset in determining the amount of the contribution to be repaid.

<u>Response:</u>

While there is merit in an approach that would provide a customer credit for only a portion of the revenues received, FBC considers that the additional effort required to initially determine the appropriate proportion upon which to base the refund, which would vary by rate class and over time, as unwarranted. Customers transitioning to RS 38 will still be using the FBC system and providing revenue as an offset to system costs, which is also a consideration when determining the treatment of capital credit refunds.

64.0 Reference: Exhibit B-4, BCOAPO 28.2.1

Preamble: The response states:

> "Whether or not curtailments may be phased in will depend on individual customer preferences and the specifics of the location including the service and network configuration and nature of the event prompting the interruption. FBC will work with Customers to identify opportunities to phase in interruptions, but it will not apply in all cases".

64.1 Please provide examples of the types of events are likely to permit interruptions/curtailments to be "phased-in".

Response:

An example of such a situation is as follows:

Due to an extreme cold weather forecast, loading is forecasted to exceed the emergency rating of a substation transformer by approximately 10-20 MW. This issue is identified by an engineering study and the LCIR Customer is notified of the load curtailment request prior to the weather event. Because the LCIR Customer's 20 MW interruptible load is evenly divided between two feeders, FBC will be able to continuously monitor the transformer loading and only request curtailment in blocks of 10 MW as needed.

As noted in the preamble to the question, however, individual customer preferences and other specifics are key, and as such phasing-in situations will depend on the facts as they arise.

64.2 In such circumstances, would the phase-in be applied equally to all LCIR customers in the affected area? Please explain why or why not.

Response:

FBC cannot provide information beyond what was stated in the original response. The potential to offer a phased-in approach to interruptions will depend on the size and nature of the load, even within a defined geographical location. FBC will give some level of consideration to all requests for some form of phased-in interruption, but it is difficult to assess whether or not a phase-in is applied equally to all customers in an area.

64.3 Would a phase-in be more complicated to manage, in terms of both customer communication and system operation, than a single interruption applied to all LCIR customers that are to be subject to interruption?

64.3.1 If not, why not?

Response:

It is likely that a phase-in will be more complicated than a straight on/off scenario; however, given the limited number of anticipated participants, FBC does not have concerns with the amount of effort required.

65.0 Reference: Exhibit B-3, BCUC 7.1, 9.1, 12.6 13.1, and 15.4
BCOAPO 7.1
CEC 7.2 and 7.3
FBC Electric Tariff, Rate Schedule 37

Preamble: The responses to BCUC 7.1, 9.1, 12.6, & 13.1; CEC 7.2 & 7.3 and BCOAPO 7.1 all identify/discuss various internal activities associated with administering RS 38 including customer communication related to setting price caps, load forecasts and curtailments; determining whether to supply RS 38 load when Mid-C price exceeds the price cap, determining the CMA applicability and billing.

65.1 Please describe and compare the internal FBC activities required to administer RS 37 vs. RS 38.

<u>Response:</u>

Detailed below are the internal activities required to administer RS 37 and 38 respectively. The main differences are that for an RS 37 Customer, FBC must track the status of the customer's own generation, and for an RS 38 Customer, FBC must track a customer nomination and price cap, as well as endeavor to provide notice to the customer of interruption, where practicable.

Rate Schedule 37 Administrative Tasks

- Forecast and monitor RS 37 load on a long-term and short-term basis, for both annual planning and operational purposes
- Track scheduled generation outages for RS 37 Customers
- Procure power for RS 37 load
- Manually pull meter data on a monthly basis
- Maintain custom billing model to track various elements of tariff (i.e., penalty period, hours on standby service, maintenance periods, Mid-C prices)

Rate Schedule 38 Administrative Tasks

- Forecast and monitor RS 38 load on a long-term and short-term basis, for both annual planning and operational purposes
- Track monthly nomination and price cap for RS 38 Customers
- Procure power for RS 38 load, either on a day-ahead basis or optimize resources already on hand
- Manually pull meter data on a monthly basis

- Maintain custom billing model to track various elements of tariff (i.e., clean market adder, Mid-C prices)
- Endeavor to provide notice to customers of interruption, where practicable

65.2 Please describe and compare the external transmission/wheeling costs incurred to supply power under RS 37 vs. RS 38 – assuming RS 37 is supplied from market purchases.

Response:

Some of the transmission/wheeling costs incurred to supply power are confidential in nature, and to disclose them could harm or prejudice FBC's competitive or negotiating position.

However, in terms of a comparison of wheeling costs to serve an RS 37 vs. RS 38 Customer, FBC expects that the cost of serving the RS 38 Customer would be equal to or less than the cost of serving an RS 37 Customer, assuming those customers are located in the same region, taking power during the same time. This is because FBC would not purchase additional firm transmission to serve non-firm RS 38 load whereas it could be required to serve firm RS 37 load.

65.3 Based on the foregoing responses, should the mark-up over Mid-C prices for RS 38 be higher or lower than that for RS 37?

Response:

Please refer to the response to BCUC IR2 5.4.

65.4 Is the Hourly transmission charge from the Mid-C hub to the border of $0.0040 per kWh used in the RS 37 tariff reasonably representative of the cost of delivering market power to supply RS 38 from the Mid-C hub to the border?

65.4.1 If not, why not?

Response:

Please refer to the response to BCOAPO IR2 65.2.

65.5 Would it be appropriate to use an approach for RS 38 similar to that used for RS 37 where a 10% administrative premium is applied to the Mid-C rate plus the cost of transmission to the border and the resulting rate then applied to the energy delivered inclusive of a mark-up for losses? Please explain why or why not.

Response:

Please refer to the response to BCUC IR2 5.4.

65.5.1 For the two months analyzed in Exhibit B-2 (Tables 3-1 and 3-2) what is the average cost per kWh for RS 38 priced: i) as proposed by FBC vs. ii) as describe above based on the following to scenarios:

a. No Price Cap/No Interruptions

b. A $35/MWh Price Cap with Interruptions

Response:

For part a., the average cost per kWh is equal to the RS 38 Revenue shown in Tables 3-1 and 3-2, divided by the total number of kWh delivered to the customer during the month (without losses). If "No Interruptions" is specified, the Mid-C Price Cap is irrelevant since energy is delivered regardless of the Mid-C price. In this scenario, the average cost per kWh for RS 38 in March 2022 is $0.05357 and in July 2022 is $0.08144.

For part b., a $35 Mid-C Price Cap would result in hours of interruption totaling 312 in March and 528 in July. The average cost per kWh for RS 38 for the energy actually delivered to the customer in March and July would be $0.05017 and $0.03016, respectively.