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May 8, 2018

British Columbia Public Interest Advocacy Centre
Suite 208 – 1090 West Pender Street
Vancouver, B.C.
V6E 2N7

Attention: Ms. Leigha Worth, Executive Director

Dear Ms. Worth:

Re: FortisBC Inc. (FBC)

Project No. 1598939

2017 Cost of Service Analysis and Rate Design Application (the Application)

Response to the British Columbia Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre *et al.* (BCOAPO) Information Request (IR) No. 1

On December 22, 2017, FBC filed the Application referenced above. In accordance with the British Columbia Utilities Commission Exhibit A-6 amending the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCOAPO IR No. 1.

If further information is required, please contact Corey Sinclair at (250) 469-8038.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachment

cc (email only): Commission Secretary
Registered Parties

1.0 Reference: Exhibit B-1, pages 16-17

Preamble: At page 16 FBC sets out the fundamental principles adopted by FortisBC for rate design in the development of the Application.

At page 17 FortisBC states that while it does not generally apply the principles in any priority, it does consider that the principle of cost causation represents an important foundation upon which cost allocation and rate design should rest.

1.1 Apart from cost causation (per Principle 2), are any of the other eight principles considered in the development of the Cost of Service Analysis methodology?

Response:

Please refer to the response to BCUC IR 1.3.1.

1.1.1 If yes, which ones?

Response:

Please refer to the response to BCUC IR 1.3.1

1.1.2 If yes, please indicate where such considerations influenced the choice of the COSA methodology.

Response:

The COSA model is based on the principle of cost causation, given the nature of cost of service analysis. However, FBC has considered and tried to strike a balance among all rate design principles and considerations to reach to its rate design proposals. Please refer to the responses to BCUC IRs 1.3.1 and 1.2.1.1.

1.2 Please indicate what metrics/measures FortisBC uses to determine the extent to a particular rate design satisfies each of the eight principles.

Response:

Please refer to the response to BCUC IRs 1.47.1 and 1.47.2.

1.3 If FortisBC has not established such metric/measures, please indicate what metrics/measures would be appropriate to use in determining the extent to which a particular rate design satisfies each of the eight principles.

Response:

Please refer to the response to BCUC IRs 1.47.1 and 1.47.2.

2.0 Reference: Exhibit B-1, page 29, lines 19-20

Preamble: At lines 19-20 FBC makes reference to "fixed costs"

2.1 Please clarify what FBC means by "fixed costs". For example, is the reference to the customer-related costs as identified in the COSA?

Response:

FBC considers that fixed costs are those that do not vary with the level of consumption, which includes customer-related costs such as billing and customer service, and costs related to the utility infrastructure that are demand-related, and are typically associated with the demand charges for those rate classes that have them.

3.0 Reference: Exhibit B-1, page 29, lines 24-28

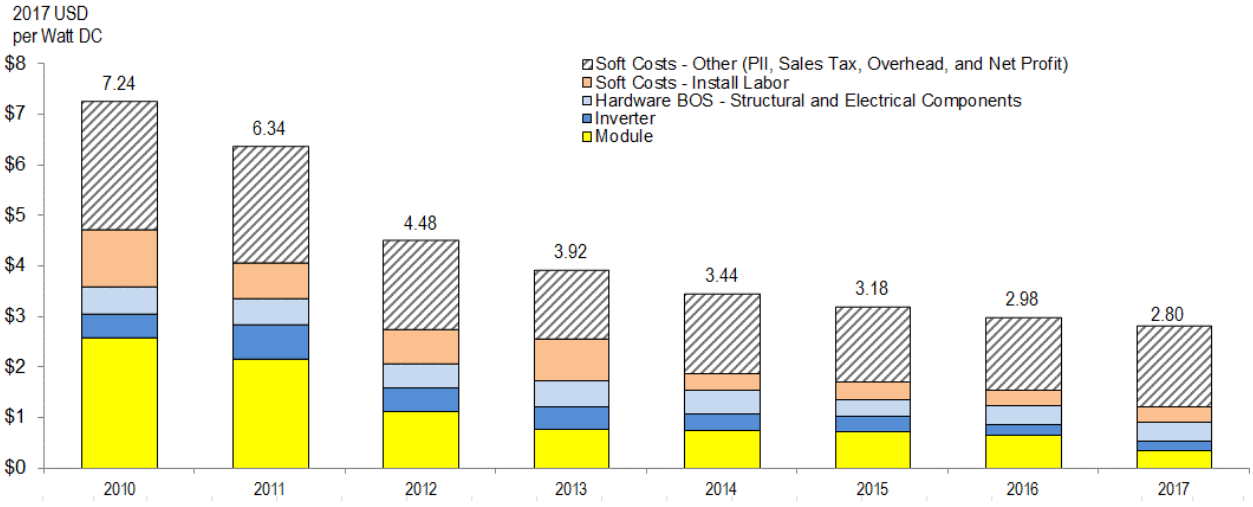
Preamble: At lines 24-28 FBC makes reference to "increasingly affordable distributed generation technologies" and "electric storage technologies"

3.1 Please provide additional details regarding the increasing affordability of distributed generation technologies and, in doing so, please comment on the current and future relative economics of these technologies for different rate classes when compared to the rates currently charged.

Response:

Distributed generation technologies include sources of on-site generation that can be owned and operated by customers to meet some or all of their own power needs rather than using power provided by their local electric utility. In the residential sector, common distributed generation systems include solar photovoltaic (PV) panels and small wind turbines. In the commercial and industrial sectors, distributed generation can include resources such as combined heat and power systems, solar PV, wind, biomass and hydropower.

Growth in the use of solar PV has gained attention in recent years as the costs for this resource have declined more significantly over time than for other resources, primarily due to the reduction in costs for solar panel modules. Therefore, FBC has focused on solar PV in responding to this question. It is estimated that the median installed prices of residential US solar PV panels decreased by 61 percent from 2010 to 2017. The following figure shows the average installed price for residential solar PV panel installations in the US since 2010.[1]



[1] https://www.nrel.gov/docs/fy17osti/68925.pdf, page 23. Excludes any tax credits available in certain jurisdictions.

There was a similar percentage decline in terms of commercial solar PV installation costs, but costs are lower overall than residential solar PV due to economies of scale associated with larger commercial solar PV systems. The 2017 commercial solar PV average cost is about $1.85 per Watt (US$2017).[2]

BC Hydro recently estimated the current cost of residential rooftop solar PV in BC to be about $3.6 per Watt ($Cdn).[3] Based on the assumptions of the cost of $14,500 for 4 kW of installed panels with annual generation of 1,200 kWh per year per kW installed, this yields a levelized price of $0.24 per kWh[4]. This cost is higher than rates currently charged by FBC to its residential and commercial customers. For example, as shown in Table 6-10 of the Application, FBC's current residential energy rate is about $0.101 per kWh for Tier 1 and about $0.156 per kWh for Tier 2. Table 6-13 shows the current small commercial energy rate is about $0.102 per kWh.

There are numerous projections for future solar PV costs available from various sources which show varying levels of cost decline. One recent forecast by the International Renewable Energy Agency (IRENA) predicts a 60 percent reduction in costs over the next ten years.[5] Cost reductions will vary by country and region due to differences in the delivered cost of the various solar PV components and local skilled labour costs, both of which will affect the total installed cost of a solar PV system. Assuming a 60 percent reduction in the estimated current BC residential solar PV cost of $0.24 per kWh, the cost in ten years would be about $0.10 per kWh ($0.24 per kWh less 60 percent of $0.24 per kWh). Assuming that FBC's rates charged to residential and commercial customers increase over time, it is possible that rooftop solar will be less expensive than at least some of FBC's residential and commercial rates, on a dollar per kWh basis, within ten years.

3.2 Please provide additional details regarding the referenced "electric storage technologies" and, in doing so, comment on their economics given FBC's current rate designs for its different rate classes.

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[2] https://www.nrel.gov/docs/fy17osti/68925.pdf, page 31.

[3] http://www.bcuc.com/Documents/wp-content/10/00700_A-9_Site-C-Inquiry_Deloitte-LLP-Independent-Report-No2.pdf, page 77.

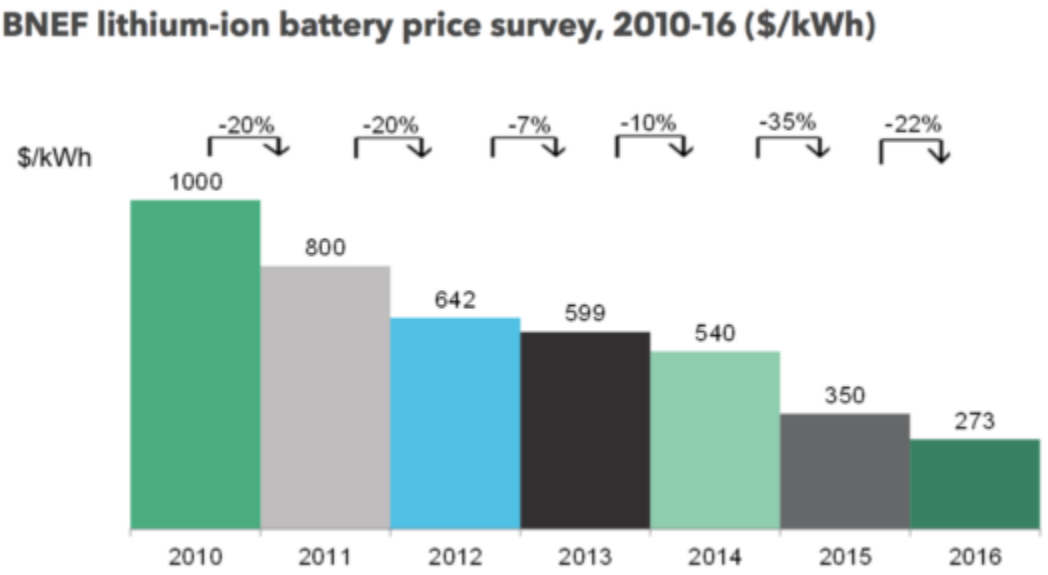
[4] On a Net Present value basis assuming a 6% discount rate and 25 year lifespan.

[5] https://www.pv-magazine.com/2017/10/23/solar-costs-will-fall-60-over-next-decade-to-fuel-pv-adoption-says-irena-head/

Response:

'Electric storage technologies' refers to small-scale storage systems that residential or commercial customers could install in their homes or businesses to store power during low usage or off-peak times and provide power during higher usage or on-peak times. This is in contrast to larger scale storage systems that could be used by larger industrial users or utilities. These smaller scale systems can allow users to avoid higher on-peak rates that may be charged by utilities, provide some or all of their own generated power when required and provide backup power when supply from the utility is disrupted during a power outage. In sunnier parts of the US, lithium-ion battery storage systems have been combined with solar PV systems rather than as stand-alone systems.

Like solar PV, the cost of lithium-ion batteries has also decreased significantly in recent years. The average price of a lithium-ion battery pack is down to $209 per kWh and the prices are forecast to fall below $100 per kWh by 2025, according to Bloomberg New Energy Finance (BNEF).[6]



The cost per kWh to a customer using an electric storage technology is more difficult to quantify than with other resource options. This is because energy storage can provide both energy and capacity as well as other benefits, which may vary among users. For example, the value of having backup energy storage in the event of a power outage will likely differ for a residential as opposed to a commercial customer.

[6] https://cleantechnica.com/2017/12/11/batteries-keep-getting-cheaper/

Comparisons to FBC's residential and commercial electricity rates are also difficult with energy storage since FBC's rates are largely energy-based, rather than capacity-based, while energy storage is more of a capacity resource, even though it may be combined with an energy resource like solar PV. Therefore, it may be more appropriate to compare energy storage costs to FBC's TOU rates. As shown in Table 8-3 of the Application, FBC's current TOU rates for on-peak periods range from about $0.052 per kWh to about $0.244 per kWh, depending on the rate class.

A recent report by the National Renewable Energy Laboratory (NREL) shows that combining a solar PV system with an energy storage system approximately doubles the cost for the combined system from about $16 thousand for a 5.6 kW solar PV system to almost $30 thousand for a combined 5.6 kW solar PV and 3 kW/6 kWh lithium-ion battery system[7]. Using a simplified approach, by doubling the unit energy cost of $0.24 per kWh for the solar PV system from the response to BCOAPO IR 1.3.1, one could assume $0.48 per kWh for a combined solar PV and energy storage system. If the costs for solar PV and battery storage decrease by say 50 percent over the next decade, then the estimated cost for the combined solar PV and battery storage system could be in the order of $0.24 per kWh ($0.48 per kWh less 50 percent of $0.48 per kWh = $0.24 per kWh). Assuming increases in the FBC TOU rates over time, it is possible that battery storage combined with solar PV may be close to being cost-competitive with FBC's TOU rates by the end of the next decade.

[7] https://www.nrel.gov/docs/fy17osti/67474.pdf?utm_source=New%20Report%20Shines%20Light%20on%20Installed%20Costs%20and%20Deployment%20Barriers%20for%20Residential%20Solar%20PV%20with%20Energy%20Storage&utm_medium=email&utm_content=nrel&utm_campaign=NewsRelease , page vii.

4.0 Reference: Exhibit B-1, page 31, lines 28-37

Exhibit B-1, page 32, lines 3-16 and page 33, lines 1-2

Preamble: The Application states: "FBC recommends a minimum fixed cost recovery of 55% of customer-related unit costs and 65% of fixed infrastructure related unit costs" (page 31)

The Application states that these changes "will help to mitigate the transfer of costs between customers on both an inter-class and intra-class basis".

4.1 Does the "65% recovery of fixed infrastructure unit costs" refer to the percentage of demand-related costs (per the COSA) to be recovered through the demand charge? If not, what is 65% referring to?

Response:

Yes, the 65 percent recovery refers to the percentage of demand-related costs (per the COSA) to be recovered through the demand charge.

4.2 Is the "65% recovery of fixed infrastructure unit costs" objective applicable at all to Residential and Small Commercial rate classes?

Response:

The 65 percent metric cannot be applied directly to the Residential and Small Commercial classes since these classes do not include a demand charge in their rate structure.

4.2.1 If yes, how is applicable given there is no demand charge for these classes?

Response:

Not applicable. Please refer to the response to BCOAPO IR 1.4.2.

4.3 Please explain how the recommended approach to fixed cost recovery will help to mitigate the transfer of costs between customers on an inter-class basis (per page 32, lines 13-16).

Response:

Historically, a redistribution of the revenue collected from the various billing components within a rate would only have had bill impacts within the rate class. However, within the context of increasing distributed generation discussed in the Application, this will no longer be the case. Where a customer class such as Residential or Commercial recovers most of the fixed costs of service through an energy rate, the ability to avoid energy charges as a result of meeting load with customer-owned generation can result in two ways that costs will be being borne by other rate classes. First, given that FBC has a deferral account that recovers revenue shortfalls from all customers, costs would shift to all other classes. Second, in a future COSA, where customers take little energy and reduce their peak demand, they would have no allocated costs for T&D (demand-related parts) and the Company would collect existing T&D costs from all other classes. With regard to power supply these customers would also pay a reduced contribution towards the fixed costs for resources. An approach of increasing the fixed cost recovery percentages in the rates does not completely eliminate this risk, but it does mitigate it to some extent.

4.4 At page 33, the Application states that these changes will be revenue neutral for the utility overall. Will they also be revenue neutral on an individual rate class basis?

Response:

Yes. The changes are designed to be revenue neutral within each class.

4.4.1 If not, which classes will they not be revenue neutral and, in each case, what will be the impact on the overall revenue recovered from the rate class?

Response:

Not applicable. Please refer to the response to BCOAPO IR 1.4.4.

5.0 Reference: Exhibit B-1, page 36, lines 14-22

Exhibit B-1, Appendix E, July 2017 Presentation Slide 9 (Residential Rates, Guiding Principles)

Preamble: One of the guiding principles cited is that 95% of customers should have bill increases no greater than 10% as compared to existing rates.

5.1 Does the 10% refer to the change in bill from: i) just rate design, ii) rate design plus rate (i.e., R/C ratio) re-balancing or iii) rate design, plus rate rebalancing plus the overall general rate increase?

Response:

In the context of the referenced July 2017 presentation, the 10 per cent criterion considers annual customer bill impacts solely related to the change in rate structure. This principle was accepted by the Commission in the initial establishment of the RCR (BCUC Order G-3-12). However, in making the recommendation that the RCR be phased out, the Company considered that there may be additional increases to rates as a result of an annual revenue requirements adjustment.

5.2 If the 10% does not refer to part (ii) or (iii) above, does FBC consider there to be a maximum bill increase for the combined effect of rate design plus rate rebalancing changes?

Response:

As stated in the previous response, the specific criterion only considers rate structure-related impact, which is consistent with the manner in which it was applied in the 2011 RIB Application. It would also be valid to take the view that a general principle of avoiding rate shock should consider all factors such as rate design rebalancing and revenue requirement increases. Only the annual bill changes due to the rate structure proposals are included in the Application scenario analyses, but the potential for additional increases to rates as a result of an annual revenue requirements adjustment factored into the proposal to phase out the RCR in four annual steps.

5.2.1 If yes, what is it?

Response:

Please refer to the response to BCOAPO IR 1.5.2.

5.2.2 If not, why not?

Response:

Please refer to the response to BCOAPO IR 1.5.2.

5.3 Is the 10% bill increase criterial applicable regarding less of the level of the general rate increase that would be implemented in the same year?

Response:

Please refer to the response to BCOAPO IR 1.5.2.

6.0 Reference: Exhibit B-1, page 36, lines 14-22

Exhibit B-1, Appendix E, July 2017 Presentation Slide 26 (Optional Time of Use)

Preamble: Second bullet under Notes states: "No demonstrable cost basis for TOU at this time".

6.1 What is the basis for the note that there is "no demonstrable cost basis for TOU at this time"?

Response:

The presentation in Appendix E was from the public consultation discussions related to rate alternatives. The discussion during the sessions focused on the difficulty in justifying a wide gap in TOU prices for the on-peak and off-peak hours that would be similar to those in the current TOU rates. Slides 27 to 29 of the presentation demonstrate potential rates developed by FBC that reflected the current load and cost structure faced by the Company which feature a smaller price differential and adjusted periods.

FBC did not, at any point in the consultations, indicate that there were no possible justifications for TOU rates, only that the expectation was that the rate differentials would likely be narrower. At the time, FBC was attempting to gain information on the potential for customer interest in TOU given the likely pricing.

6.2 Please reconcile this comment with FBC's proposal to re-introduce Residential TOU rates on an optional basis.

Response:

Please refer to the response to BCOAPO IR 1.6.1.

7.0 Reference: Exhibit B-1, page 36, lines 14-22

Exhibit B-1, Appendix E, October 2017 Presentation Slide 18 (What is a COSA?)

Exhibit B-1, page 16, line 14

Preamble: Third Bullet in Presentation Slide 18 states: "Meets Rate Design Principles of fairness and appropriate price signals"

7.1 Does the reference to "appropriate price signals" refer to Rate Design Principle #3 (Price signals that encourage efficient use and discourage inefficient use)?

Response:

The cost of service allocation model primarily relates to Bonbright principle number two; that is, fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates). As stated on slide 20 of the same slide deck, rate design in its simplest form is determination of the most appropriate rate to charge customer groups that recovers the cost of serving them. The reference to "appropriate price signals" reflects the fact that under FBC's cost allocation methodology, peak load is a major allocator and therefore customer classes with a higher level of efficiency (those with a better load factor) are allocated a smaller portion of the costs compared to low efficiency customer classes. Irrespective of the rate structure option chosen, the rates for the majority of customer groups are derived from the COSA model and therefore it can be said that the COSA model provides some price signal for efficient use of the system at a customer class level.

A more central aspect of providing "appropriate price signals" relates to the choice of rate structure options and how the rate design can encourage efficient use and discourage inefficient use within a rate class.

7.1.1 If yes, please explain how the COSA contributes to meeting this principle.

Response:

Please refer to the response to BCOAPO IR 1.7.1

7.1.2 If no, what "appropriate price signals" are being referred to?

Response:

Please refer to the response to BCOAPO IR 1.7.1.

8.0 Reference: Exhibit B-1, page 36, lines 14-22

Exhibit B-1, Appendix E, October 2017 Presentation Slide 37 (Revenue to Cost Ratio)

Exhibit B-1, page 16

Preamble: The first bullet on Slide 37 states: "If a customer group's R/C ratio is within a range around unity, their rates are assumed to be fair and reasonable from a cost allocation perspective"

8.1 Does the reference to "fair and reasonable from a cost allocation perspective" mean that the rates are assumed to align with Rate Design Principle 2?

Response:

Yes. This was also confirmed by BCUC's independent consultant in FEI's rate design proceeding, as provided below:

"Regulators typically accept rates within a range as constituting full recovery since it is recognized that cost allocation studies are not precise. Hence, unless the level of cost recovery is outside the specified range of reasonableness, differential rate increase would not be considered equitable since small deviations from 100% are as likely to be the results of the imprecision of the methodology as they are to be the results of true cost difference."[8]

8.1.1 If not, how does the comment regarding "fair and reasonable" relate to the Rate Design Principles set out at page 16?

Response:

Please refer to the response to BCOAPO IR 1.8.1.

[8] Elenchus; "Review of FortisBC Energy Inc. Rate design Methodology for the 2016 Rate Design Application", p.34

8.2 Are there circumstances where a Revenue to Cost ratio outside of the adopted "range" would be appropriate based on considerations involving the other Rate Design Principles –either on a short-term or a long-term basis?

Response:

FBC believes that the Revenue to Cost (RC) ratio and the adopted range of reasonableness is a guide to inform the rate design and rebalancing proposals. Although an RC ratio for a rate schedule outside the range of reasonableness indicates under or over recovery of the cost of service and that rebalancing may be required, it may be appropriate to accept this result based on other rate design principles and considerations both on short-term and long-term bases. This is because rate design is a complex balancing process as it frequently requires the application of multiple, and sometimes conflicting, principles and the consideration of viewpoints from various stakeholders. In addition, different rate design principles may have varying levels of importance in different contexts. FBC, therefore, believes that a utility should apply its experience and judgment to consider and balance the most relevant principles in a given context when identifying rate design issues and proposing rate design solutions. Rate design should strive to strike a balance among competing rate design principles based on characteristics of customers in each rate schedule.

8.2.1 If not, why not?

Response:

Please refer to the response to BCOAPO IR 1.8.2.

8.2.2 If not, doesn't this result in Principle 2 having priority over Principles 3 through 8?

Response:

Please refer to the response to BCOAPO IR 1.8.2.

9.0 Reference: Exhibit B-1, page 43, lines 5-10

Preamble: At page 43 the Application states: "FBC has examined customers with Net Metering systems and other partial requirements customers (that is, a self-generating customer that does not rely on FBC for its full requirements at all times) in isolation to better understand any differences …. This is further discussed in Section 3.6".

9.1 Section 3.6 only discusses the Net Metering Program. Where in the application has FBC examined the requirements of other self-generating customers that don't rely on FBC for their full requirements at all times?

Response:

FBC has provided additional discussion relating to customers served on the standby rate, RS 37, at Section 5.1.1.2.1 of the Application.

9.1.1 If not provided elsewhere in the Application, please discuss the requirements and usage of the FBC system by these customers and the degree to which the rates charged to these customers do or do not recover the costs they impose on the FBC system.

Response:

Please refer to the response to BCOAPO IR 1.9.1.

10.0 Reference: Exhibit B-1, page 43 (lines 24-26)

10.1 Is the $1.4 M in RS 37 revenues based solely on the revenues from the RS37 energy charges or does it also include revenues from;

- The RS 37 Notification Fee and/or
- The RS 31 Wires Charge attributable to the Stand-by Billing Demand.

Response:

The Company consulted with EES to provide the following response.

The $1.4 million in revenues includes the revenue from the Notification Fee and the Stand-by Billing Demand charges.

10.2 If not included in the $1.4 M, are the RS31 Wires Charge revenues attributable to the Stand-by Billing Demand included in the RS 31 revenues for purposes of determining the class' R/C ratio?

Response:

The Company consulted with EES to provide the following response.

Not applicable since these charges are included. Please refer to the response to BCOAPO IR 1.10.1.

11.0 Reference: Exhibit B-1, page 44 (lines 9-10)

11.1 At page 44, the Application states that the energy and demand associated with the RS 37 sales are also left out of the RS 31 class amounts and total system amounts. Does this mean that the Stand-by Billing Demand (as used in the application of the RS 31 rates) is also left out of the RS 31 demand amounts for purposes of the COSA?

Response:

The Company consulted with EES to provide the following response.

Yes, these amounts are excluded for purposes of the COSA. Although the Stand-by Billing Demand is charged under the RS 31 rate schedule, it is driven directly from the customers' participation in RS 37.

11.1.1 If no, please explain how the Stand-by Billing Demand (SBBD) is factored into the RS 31 demand amount used in the COSA.

Response:

The Company consulted with EES to provide the following response.

Not applicable. Please refer to the response to BCOAPO IR 1.11.1.

11.1.2 If yes, please explain why this is appropriate as the system benefits from self-generation are already reflected in the determination of the SBBD as a percentage of the Stand-by Demand Limit.

Response:

The Company consulted with EES to provide the following response.

Both the load and the revenues associated with stand-by demands are excluded because the stand-by rates were not set on the basis of the COSA. As shown in the response to BCUC

1 IR1.12.3, the COSA would allocate too small of a share of costs to the full load of the RS37
2 customer and not enough costs based on the stand-by load.

3

12.0 Reference: Exhibit B-1, page 44 (lines 10-11)

Exhibit B-1, Appendix A, page 22

Preamble: Page 44 of the Application states: "Other customers are better off having standby sales because even at a reduced rate, the sales are contributing to fixed costs of the system".

Page 22 of Appendix A states that: "Without standby service the customer would reduce its service to the portion just taken under Rate 31 and would forgo standby service"

12.1 Will FBC's commitment to provide RS 37 service impact the "fixed costs" the Company incurs for purpose of Power Supply?

Response:

The Company consulted with EES to provide the following response.

No, the provision of the RS 37 service to customers does not impact the fixed costs associated with Power Supply.

12.1.1 If no, why not?

Response:

The Company consulted with EES to provide the following response.

FBC meets its aggregate gross load from its portfolio of resources, and changing a customer from one rate class to another (in this case from RS 31 to RS 37), with no change to volume or timing of purchases, will have no impact on FBC's overall power supply costs.

12.2 Will FBC's commitment to provide RS 37 service impact "Wires" capability that FBC must maintain to supply the affected customers?

Response:

The Company consulted with EES to provide the following response.

FBC maintains infrastructure as required to serve the full load of all connected customers regardless of whether or not service incorporates RS 37.

12.2.1 If no, why not since Stand-by sales can create demand in excess of the customer's RS 31 contract demand.

Response:

Not applicable. Please refer to the response to BCOAPO 1.12.2.

12.3 If the response to either parts (1) or (2) is yes, why are 100% of RS 37 revenues considered a "revenue offset"?

Response:

The Company consulted with EES to provide the following response.

FBC does not believe there are significant incremental fixed costs associated with providing RS 37 service and, as such, has not attempted to make cost allocations to this service. This means that 100% of the RS37 revenues should be credited against the overall revenue requirements so that the fixed cost mitigation benefits are spread amongst all rate classes whose rates are paying for the largely-fixed cost nature of the system. Please refer also to the response to ICG 1.4.1.

12.4 If the response to either parts (1) or (2) is yes, why shouldn't Stand-by Service demand amounts be included in the COSA (either fully or a portion there) and be allocated a portion of "fixed costs"?

Response:

Please refer to the response to BCOAPO IR 1.12.3.

12.5 With respect to the statement on page 22 of Appendix A, what is the basis for the assertion that, without standby service, the customer's load would be just that currently taken under Rate 31?

Response:

The Company consulted with EES to provide the following response.

If FBC did not have a standby rate, the standby customer, under the current regulatory regime, would be provided service on RS 31 on a net-of-load basis. EES did not state "currently" in its report. However, in the absence of RS 37 a contract demand would be established that denotes a minimum level of RS 31 that FBC would be required to serve and energy supplied to the customer would be at the RS 31 rate and would be far less than if the customer took full supply from FBC. The prospective contract demand is undetermined. This discussion is not particularly relevant to the current COSA since FBC does have standby service and the current service characteristics are accurately reflected in the model.

13.0 Reference: Exhibit B-1, page 46, lines 9-11

Exhibit B-2, COSA Model, Rate Base Tab

13.1 Please confirm that, since all Distribution cost accounts are not classified/allocated on the same basis, the basis on which accumulated depreciation is (explicitly or implicitly) attributed to each of the Distribution cost accounts (accounts 360-373) will impact the COSA results as it will affect the way accumulated depreciation and the resulting rate base is classified/allocated.

Response:

The Company consulted with EES to provide the following response.

Confirmed.

13.2 Please confirm that the COSA effectively splits the total accumulated depreciation functionalized as Distribution between the Distribution cost accounts (accounts 360-373) based on the gross book value of each account?

Response:

The Company consulted with EES to provide the following response.

Confirmed.

13.2.1 If not confirmed, how is accumulated depreciation (either explicitly or implicitly) attributed to each of the Distribution cost accounts (360-373)?

Response:

Please refer to the response to BCOAPO IR 1.13.2.

13.3 Please provide the estimated depreciation rate (or accounting service life) for the assets in each of the Distribution cost accounts (360-373).

Response:

The depreciation rates shown below have been approved by BCUC Order G-202-15 and implemented as of January 1, 2016.

DISTRIBUTION COST ACCOUNT	ACCOUNT DESCRIPTION	DEPRECIATION RATE
360.00	LAND RIGHTS - RIGHT OF WAY	0.0%
360.10	LAND RIGHTS - CLEARING	1.2%
362.00	SUBSTATION EQUIPMENT	2.6%
364.00	POLES, TOWERS AND FIXTURES	2.7%
365.00	CONDUCTORS AND DEVICES	2.9%
368.00	LINE TRANSFORMERS	2.7%
369.00	SERVICES	0.5%
370.00	METERS	6.7%
370.10	AMI METERS	5.0%
371.00	INSTALLATIONS ON CUSTOMER PREMISES	0.0%
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	4.7%

Note: Depreciation rate is inclusive of net salvage.

13.4 Please confirm that the age profile (i.e., the average years in-service) of the assets recorded in each of the Distribution cost accounts will vary.

Response:

Confirmed.

13.5 Please confirm that, to the extent that: i) depreciation rates vary across the Distribution cost accounts and ii) the age profile of the assets in each of the Distribution cost accounts varies – the use of the gross book value in each Distribution cost account as the allocator will not result in an accurate attribution of accumulated depreciation to each cost account.

Response:

The Company consulted with EES to provide the following response.

Confirmed. However, any inaccuracy resulting from the allocation method should not result in significant impacts on any of the customer classes.

14.0 Reference: Exhibit B-1, page 46, lines 15-20

Preamble: The Application states that the Allowance for Working Capital is functionalized on the same basis as all operating and maintenance costs.

14.1 The Application notes that O&M and purchased power costs are the primary bill paid by the utility. Please confirm that the allocation base used for the Allowance for Working Capital includes Purchased Power costs.

Response:

The Company consulted with EES to provide the following response.

Confirmed.

14.1.1 If not, why not?

Response:

The Company consulted with EES to provide the following response.

Not applicable. Please refer to the response to BCOAPO IR 1.14.1.

15.0 Reference: Exhibit B-1, page 46, lines 20-22

Preamble: The Application states that the adjustment for capital additions is similar to working capital.

15.1 Please outline what the "adjustment for capital additions" represents and how it is determined.

Response:

The adjustment for capital additions is an adjustment to the mid-year plant in service/rate base, based on the monthly profile of capital expenditures, to ensure that rate base reflects the weighted average capital expenditures for the year. The adjustment is calculated as the difference between the weighted monthly average and the simple average of capital expenditures. If capital expenditures are heavier in the first half of the year, then the weighted average of expenditures will be greater than the simple average, resulting in a positive adjustment to the mid-year value.

15.2 Based on the response to part (1) please explain why the adjustment for capital additions is similar to working capital such that overall operating and maintenance costs was considered to be an appropriate allocation base.

Response:

The Company consulted with EES to provide the following response.

Because this item reflects an adjustment related to the timing of expenditures during the year, it was treated the same as working capital. This was the method used in the approved COSA for 2009.

16.0 Reference: Exhibit B-1, page 46 (line 23) to page 47 (line 2)

Exhibit B-2, COSA Model, C&A by Cust Tab

16.1 Please provide the analysis/reference supporting the functionalization and classification of deferred DSM costs?

Response:

Please refer to the response to BCUC IR 1.27.1.

16.2 With respect to the derivation of the Labor Ratios used to functionalize various Other Rate Base Items:

16.2.1 Are the FTE values used total FTEs or do they exclude those associated with capitalized activities? Please explain the basis for the choice.

Response:

The Company consulted with EES to provide the following response.

The FTE values used reflect the total FTEs for the Company. Total FTEs was the basis because it represented the approach used and approved in the 2009 COSA and it was the most readily available information.

16.2.2 Please explain how the total FTEs for T&D are split between Transmission and Distribution.

Response:

The Company consulted with EES to provide the following response.

The data available for FTEs did not include a split between the transmission and distribution function because staff perform activities related to both functions. Data was available in the

2009 COSA with a resulting split of 30% for transmission and 70% for distribution. That split was applied to the total T&D FTEs.

16.3 Please explain the difference between Adjustment for Capital Additions (Row 108) and Plant Acquisition Adjustment & Deferred (Row 126) and why they are functionalized on different bases.

Response:

The Plant Acquisition Adjustment represents the premium paid on plants 2, 3 and 4 over the net book value of the plants, as prescribed by the BCUC Uniform System of Accounts for Electric Utilities, Account #114. Commission Order G-37-84 approved the Plant Acquisition Adjustment in the amount of $11.9 million and the amortization rate of 1.6 percent.

Further, EES provides the following response.

The Plant Acquisition Adjustment is not based on the timing of capital expenditures, as is the case for the Adjustment for Capital Additions. Because the Plant Acquisition Adjustment is related to the value of assets, it was treated the same as gross plant. This was the method used in the approved COSA for 2009. Any change in the classification method for these two items would not impact the RC ratios beyond the first decimal place.

17.0 Reference: Exhibit B-1, page 47 (lines 9-10)

Exhibit B-2, COSA Model, Rev Req Tab

17.1 Please confirm that all of the costs in accounts 535-554 are associated with the Kootenay River Plants.

Response:

The Company consulted with EES to provide the following response.

Confirmed.

17.1.1 If not, please provide a schedule that breaks out, by account, the values for each source of production/power supply.

Response:

The Company consulted with EES to provide the following response.

Not applicable. Please refer to the response to BCOAPO IR 1.17.1.

18.0 Reference: Exhibit B-1, page 47 (lines 21-24)

Exhibit B-2, COSA Model, Rev Req Tab

18.1 Please confirm that, since all Distribution cost accounts are not classified/allocated on the same basis, the basis on which depreciation is (explicitly or implicitly) attributed to each of the Distribution cost accounts (accounts 360-373) will impact the COSA results as it will affect the way depreciation is classified/allocated.

Response:

The Company consulted with EES to provide the following response.

Confirmed.

18.2 Please confirm that the COSA effectively splits the depreciation functionalized as Distribution between the Distribution cost accounts (accounts 360-373) based on the gross book value of each account?

Response:

The Company consulted with EES to provide the following response.

Confirmed.

18.2.1 If not confirmed, how is depreciation (either explicitly or implicitly) attributed to each of the Distribution cost accounts (360-373)?

Response:

The Company consulted with EES to provide the following response.

Not applicable. Please refer to the response to BCOAPO IR 1.18.2.

18.3 Please provide the estimated depreciation rate (or accounting service life) for the assets in each of the Distribution cost accounts (360-373).

Response:

Please refer to the response to BCOAPO IR 1.13.3.

18.4 Please confirm that, to the extent depreciation rates vary across the Distribution cost accounts the use of the gross book value in each Distribution cost account as the allocator will not result in an accurate attribution of accumulated depreciation to each cost account.

Response:

Please refer to the response to BCOAPO IR 1.13.5.

19.0 Reference: Exhibit B-1, page 48 (lines 3-6)
Exhibit B1, Appendix A, page 31
Exhibit B-2, COSA Model, Rev Req Tab

19.1 Do Waneta and Brilliant account for all of the $1.865 M in Contract Revenue (Row 245) such that it is appropriate to functionalize all of it as Generation?

Response:

In addition to Waneta and Brilliant, the $1.865 million in Contract Revenue is also comprised of revenue from services that FBC provides to FBC's parent company, Fortis Pacific Holdings Inc., to service the Waneta Expansion, Brilliant Expansion, and Arrow Lakes Hydro facilities. As a result, it is appropriate to classify it all on the same basis as Generation.

19.2 What was FBC's forecast 2017 revenue from Late Payment Charges and where are they accounted for in the COSA?

Response:

Historically, FBC has not forecast late payment charges as part of its revenue requirement. Late payment charges received are included as part of the flow-through, and refunded to all customers in the subsequent year's revenue requirements.

19.2.1 Does FBC track Late Payment Charge revenues by rate class? If yes, please provide a breakdown of the actual historical revenues by class for 2014-2016.

Response:

FBC does not track Late Payment Charges by rate class, but they are classified as either Residential or Commercial. The table below shows the breakdown for 2014 – 2016.

LPC Revenue breakdown

	2014	2015	2016
Residential $	$ 818,085	$ 743,649	$ 654,591
Commercial $	$ 241,724	$ 187,621	$ 156,176
Total	$ 1,059,809	$ 931,270	$ 810,767

1

2

20.0 Reference: Exhibit B-1, page 49

Exhibit B-2, COSA Model, Rate Base Tab

20.1 Please provide the actual demand/energy split for BC Hydro purchases for each of the most recent four years available.

Response:

Table 1 below shows the dollar and percentage split between energy and capacity purchases under FBC's Power Purchase Agreement with BC Hydro from 2014 to 2017.

Table 1

BC Hydro PPA Purchases	2014	2015	2016	2017
Energy ($000)	24,705	22,527	23,185	29,819
Capacity ($000)	10,525	10,414	10,310	10,688
Total ($000)	35,230	32,941	33,496	40,507
Energy (%)	70%	68%	69%	74%
Capacity (%)	30%	32%	31%	26%
Total (%)	100%	100%	100%	100%

21.0 Reference: Exhibit B-1, page 51 (lines 1-3)

Exhibit B-2, COSA Model, Rate Base Tab

21.1 The Application states that DSM costs are classified as 72% power supply energy, 17% power supply demand and 12 percent transmission and distribution demand. However, in the COSA, 4.27% of the costs are classified as distribution customer. Please reconcile.

Response:

The statement in the Application should state that costs are classified as 12 percent transmission and distribution, not 12 percent transmission and distribution demand. The 12 percent is further split between transmission and distribution classification components on the basis of the transmission and distribution gross plant. The resulting breakdown of the 12 percent is 3.6 percent transmission demand, 3.9 percent distribution demand and 4.3 percent distribution customer. A replacement page will be filed as part of an Errata, filed concurrently with these IR responses

22.0 Reference: Exhibit B-1, page 51 (lines 5-11)

Exhibit B-2, COSA Model, Rev Req Tab

22.1 It is noted that System Control costs (account 556) are classified as 100% demand. Please explain why this is the case and why it would not be more appropriate to classify a portion of these costs as energy-related.

Response:

The Company consulted with EES to provide the following response.

Having System Control costs classified as 100% demand is the same method that was accepted in the 2009 COSA and reflects standard COSA practice. When system control is offered as an ancillary service product in standard OATT tariffs, it is typically billed on the basis of peak demand rather than energy. Changing the approach to reflect both demand and energy would have very little impact on the results as the account makes up less than 1 percent of the total revenue requirements.

23.0 Reference: Exhibit B-1, Appendix A, page 12

SaskPower's 2017 Cost of Service Methodology Review

http://www.saskpower.com/accounts-and-services/power-rates/2017-cost-of-service-methodology-review/

23.1 Why didn't EES draw on the information available from the Cost of Service Methodology Review initiated by SaskPower in February 2017 which provided (publically) information regarding its current cost of service methodology?

Response:

The Company consulted with EES to provide the following response.

The EES Methodology Review was undertaken prior to the release of the SaskPower report. The EES Methodology Review was one of the first steps undertaken in the 2017 COSA process to determine whether or not any changes in methodology should be considered.

The regulatory process in Saskatchewan appears to be somewhat different than in British Columbia. SaskPower does not undergo a full regulatory process but instead has a Rate Review Panel that advises the Government on rate applications. The Review of Cost Allocation and Rate Design Methodologies was conducted on behalf of SaskPower and was not a regulatory decision, nor was it issued on behalf of the Review Panel. The cost of service methodology review performed by EES was based on regulated utilities and regulatory decisions regarding those utilities related to the Cost of Service Allocation filing (or negotiated settlement in some cases).

24.0 Reference: Exhibit B-1, Appendix A, page 12

Manitoba Hydro's 2016 Cost of Service Methodology Review

http://www.pub.gov.mb.ca/v1/proceedings-decisions/appl-previous/mh-coss/index.html

24.1 Why doesn't the EES Jurisdictional Review reflect the results of the Manitoba Public Utilities Board's 2016 Review of Manitoba Hydro's Cost of Service Methodology?

Response:

The Company consulted with EES to provide the following response.

EES started with the jurisdictional review completed by BC Hydro in its 2015 RDA Application and then looked to see if any of the jurisdictions had newer rate decisions. In searching for any updates for Manitoba Hydro we did not come across the 2016 Review, perhaps because we were looking for rate design applications. Note that the 2016 Review is not reflected in Manitoba Hydro rates at this time. The newly approved COSA methodology is intended for use in the next rate design application.

24.2 Please confirm that the Board's December 2016 Order 164/16 changes the results reported for Manitoba Hydro in Tables 2, 4, 5 and 6.

Response:

The Company consulted with EES to provide the following response.

Confirmed. In Table 2 the approved generation classification method for Manitoba Hydro should be on the basis of the load factor method. While this differs from FBC's approach, it does support a split between demand and energy. In Table 4 the method should be changed to 100% demand-related. This differs from the FBC approach but in EES's view, FBC should not change its approach based on this one finding. In Table 5 the customer care costs should be changed to 100 percent customer-related, which supports the FBC approach. In Table 6 the method should be that DSM is treated the same as power supply costs. This is relatively consistent with the FBC approach.

25.0 Reference: Exhibit B-1, Appendix A, page 18

Exhibit B-2, COSA Model, Load Tab

Preamble: It is noted that for the Lighting class, each "customer" could have a number of connections to FBC's system (e.g., municipalities with street lights).

25.1 Does the Lighting class include all unmetered loads (including traffic lights, telephone booth, etc.)? If not, what types of unmetered loads are not included in Lighting and where are they included?

Response:

No, the Lighting class does not include all unmetered loads. The Lighting class includes only unmetered lighting loads. Unmetered non-lighting loads (traffic lights, telephone booths, cable boxes, etc.) are billed on General Service rates.

25.2 Do the Lighting customer counts set out in the Load Tab represent the number of Lighting customers or the number of Lighting connections to FBC's system?

Response:

The Lighting customer counts represent the number of active lighting customers.

25.3 It is noted per the Load Tab that only the Wholesale Primary class has more than one delivery point per customer. Please confirm that for all other classes, each "customer" only has one connection to the FBC system and only one FBC-owned meter.

Response:

Confirmed.

26.0 Reference: Exhibit B-1, Appendix A, pages 18 and 74

26.1 Was the 2016 data used for developing the allocation factors "weather normalized" or was just the actual metered data used?

Response:

The Company consulted with EES to provide the following response.

The load data was not weather normalized. The data sources were actual billing data and a sample of hourly consumption data for each customer class, as described in pages 72-77 of Appendix C of the Cost of Service Study – Load Analysis.

26.1.1 If the "hourly" data was weather normalized please describe how this was done?

Response:

The Company consulted with EES to provide the following response.

Not applicable. Please refer to the response to BCOAPO IR 1.26.1.

26.1.2 If not, please provide information regarding the actual 2016 weather (e.g. heating degree days etc.) versus FortisBC considers "weather normal".

Response:

Heating Degree Days (HDD) for 2016 were 3032, while normal weather for 2016 was 3293, meaning that 2016 was warmer than normal.

26.2 For which rate classes was the hourly load data based on a sample of customers as opposed to all customers in the rate class for purposes of establishing the various types of peak demand required by the COSA?

Response:

The Company consulted with EES to provide the following response.

A sample of hourly data was used for developing COSA peak coincidence and load factor assumptions for the following rate classes:

- Residential
- Small Commercial
- Commercial
- Large Commercial Primary
- Irrigation

For other rate classes, hourly data for all customers was used. In addition, metered peak demand data was used for classes that bill on the basis of demand.

27.0 Reference: Exhibit B-1, Appendix A, page 24

27.1 Please explain more fully how not separating out the transmission component of Rate 3808 yields a "net result equivalent to the approach FBC would like to achieve for classification" when generation and transmission are classified on different bases.

Response:

The Company consulted with EES to provide the following response.

One way of looking at the transmission component of Rate 3808 would be to consider it as transmission rather than power supply. In that case it would be treated as 100% demand-related and allocated on the basis of the 2CP demand allocator. If the transmission component of Rate 3808 is classified as 100% demand-related for BC Hydro, it would be included in the demand charge for Rate 3808. Because the demand charges from the Rate 3808 purchase are also allocated on the basis of the 2 CP demand allocator, there would be no difference in the amounts allocated to customer classes in either case.

An alternate way of looking at the transmission component of Rate 3808 is to assume that it is part of a delivered price of power supply. Much like purchases from the market, transmission must be procured to deliver the market purchases and that cost is typically included in the delivered price of market power.

In either case, the transmission component is specific to power supply and would not be appropriate to include as a transmission-related cost when setting the transmission requirement used for setting wholesale transmission tariffs. The BC Hydro transmission used to transmit BC Hydro power to FBC cannot be used by parties other than FBC.

28.0 Reference: Exhibit B-1, Appendix A, page 28

Preamble: At page 28 the total costs for purchased power are "compared" to the direct costs associated with FBC-owned generation.

28.1 What are the total costs (including depreciation, return and income taxes) from the revenue requirement that can be associated with FBC-owned generation?

Response:

The Company consulted with EES to provide the following response.

The table shows the total direct costs associated with the FBC-owned generation. It does not include any assigned indirect costs associated for general plant or Administration & General expenses.

	FBC Resource Expense
O&M	$13,555,250
Depreciation	$4,507,000
Return	$15,716,433
Taxes	$1,954,533
Total	$35,733,215*

*Minor difference due to rounding.

29.0 Reference: Exhibit B-1, Appendix A, pages 31-32

29.1 What is the basis for determining whether "CP" or "NCP" is the most appropriate allocator for a category of demand-related costs?

Response:

The Company consulted with EES to provide the following response.

It is standard practice to use CP for production and transmission facilities and NCP for distribution facilities. Generally, facilities that are built or planned for based on the system peak were allocated on the basis of CP while those that were built or planned for based on localized peaks were allocated on the basis of NCP. Also please refer to the responses to BCUC IRs 1.18.2 and 1.18.2.1.

30.0 Reference: Exhibit B-1, Appendix A, pages 32 and 35-36

30.1 Please provide a schedule that sets out the actual data used to create Figure 1.

Response:

The Company consulted with EES to provide the following response.

Please see the following table setting out the actual data used to create Figure 1:

	2012 MW	2013 MW	2014 MW	2015 MW	2016 MW	2017 MW Forecast
January	737	639	624	604	625	671
February	598	547	684	556	583	636
March	534	517	579	541	514	545
April	497	464	470	447	438	466
May	434	453	415	428	412	432
June	409	449	450	555	594	634
July	551	579	596	597	579	617
August	540	556	601	581	590	623
September	431	487	415	410	416	437
October	489	490	459	488	459	491
November	571	599	642	624	531	571
December	613	699	671	610	712	761

30.2 Based on the data for 2012-2017, are January and December always the two winter months with the highest system peak?

Response:

The Company consulted with EES to provide the following response.

No. January and December were the two highest months in 2012, 2013 and 2016, as well as in the 2017 forecast, but they were not the two highest months in 2014 and 2015.

30.2.1 If not, please explain why peaks in these two months were summed to generate the "winter" contribution to the 2 CP allocation factor?

Response:

The Company consulted with EES to provide the following response.

The months of January and December were the two months with the highest loads for the majority of years in the historic period and for the 2017 forecast. January and December also reflected the months used in the method approved for the 2009 COSA.

30.3 Based on the data for 2012-2017, are July and August always the two summer months with the highest system peak?

Response:

The Company consulted with EES to provide the following response.

No. July and August were the highest summer peaks in 2012 through 2015. In 2016 and for the 2017 forecast June and August were the two highest summer peaks.

30.3.1 If not, please explain why peaks in these two months were summed to generate the "summer" contribution to the 2 CP allocation factor?

Response:

The Company consulted with EES to provide the following response.

The months of July and August were the two months with the highest loads for most years in the historic period. July and August also reflected the months used in the method approved for the 2009 COSA. To provide consistency, those two months were used rather than June and August, which were the highest forecast months for 2017. If FBC continues to see a change in the timing of the summer peaks it will re-examine the appropriate peaks to use in the future.

31.0 Reference: Exhibit B-1, Appendix A, pages 31-36

Exhibit B-2, COSA Model, C&A by Cust Tab

Preamble: Pages 32-36 discuss various tests used to determine whether the CP allocator used should be based on more than just one "peak" value (i.e., 1 CP versus a CP factor that considers more than just the highest peak). However, there is no similar discussion regarding the basis for the NCP allocator.

31.1 Please confirm that the NCP, NCPP and NCPS value used are all based on the single highest non-coincident peak for the year.

Response:

The Company consulted with EES to provide the following response.

Confirmed.

31.2 Does the OEB (or any other regulator) use NCP values for allocation that are based on more than just the single highest no-coincident peak for the each class?

Response:

The Company consulted with EES to provide the following response.

Yes. While in the experience of EES a 1 NCP allocator is the standard approach, Hydro-Quebec and Avista both use a 12 NCP allocator for demand-related distribution costs rather than a 1 NCP allocator.

31.2.1 If so, please indicate who they are and on what basis they determine which NCP allocator should be used.

Response:

The Company consulted with EES to provide the following response.

The utilities that use a non-standard NCP allocator are Hydro-Quebec and Avista. While the 12 NCP allocator was approved in these two cases, EES does not know the reasons this approach was adopted for these two utilities.

31.2.2 Please apply the same approach to the FBC load data and indicate what the result would be (i.e., in terms of the appropriate NCP factor to use).

Response:

The Company consulted with EES to provide the following response.

The following table shows the results of the 1 NCP allocation factor compared to the 12 NCP allocation factor. EES believes the 1 NCP is the appropriate allocator to use for FBC as that most closely aligns with cost causation and the demand-related driver for distribution planning.

	1 NCP Class kW	1 NCP % of Total	12 NCP Class kW	12 NCP % of Total
Total	854,376	100.0%	7,662,207	100.0%
Residential	407,445	47.7%	3,374,909	44.0%
Small Commercial 20	71,243	8.3%	735,746	9.6%
Commercial 21/22	132,301	15.5%	1,330,739	17.4%
Large Comm Primary 30/32	65,409	7.7%	661,624	8.6%
Large Comm Transmission 31	18,660	2.2%	208,863	2.7%
Lighting	3,860	0.5%	27,544	0.4%
Irrigation	9,504	1.1%	53,073	0.7%
Wholesale Primary 40	115,136	13.5%	1,059,125	13.8%
Wholesale Transmission 41	30,817	3.6%	210,584	2.7%

31.3 It is noted that in the COSA model the NCP value for Residential is determined by adding the NCP values for Residential w/o Net Metering and Residential with Net Metering.

31.3.1 For each month of the year, do the NCP values for these two sub-classes occur at the same time?

Response:

The Company consulted with EES to provide the following response.

Not necessarily. The nature of the NCP calculation is that it does not include peaks that occur at the same time. Therefore, it is appropriate to add the NCP amounts for the two classes together whether or not they occur at the same time.

31.3.2 If not, why is it appropriate to simply add the NCP values for eh two sub-classes to obtain the NCP value for the total Residential class? Won't this approach overestimate the NCP value for the Residential class?

Response:

Please refer to the response to BCOAPO IR 1.31.3.1.

32.0 Reference: Exhibit B-1, Appendix A, page 31

Exhibit B-1, Appendix a, pages 58 & 61

32.1 The Application states (page 31) that the poles and conductors are split 80% to NCPP and 20% to NCPS based on "industry experience". Please clarify what is meant by industry experience – is this FBC's experience with its own system configuration or EES's experience with the electricity industry in general?

Response:

The Company consulted with EES to provide the following response.

This is based on EES's experience with the electric industry in general.

32.2 Given that FBC know the length of conductor installed by conductor type and the replacement costs (see page 61), please indicate the following:

- The total kilometers of conductor at secondary and primary voltages
- The total breakdown of the total replacement costs as between primary and secondary conductor.

Response:

The total kilometers of conductors at primary voltages is 16,070 km and the total replacement cost of primary conductor is $67,341,135, as indicated on Page 61 of Appendix B of the EES COSA Report (Exhibit B-1, Appendix A).

The total kilometers and total replacement cost of secondary conductors are unknown.

32.3 Would it be reasonable to apply the proportions determined above to split the cost of poles, towers and fixtures between primary and secondary?

Response:

The Company consulted with EES to provide the following response.

Given that the total kilometers and total replacement cost of secondary conductors are unknown, FBC cannot provide the requested proportions; therefore, EES cannot apply those proportions to split the costs of poles, towers and fixtures.

32.3.1 If not, why not?

Response:

Not applicable. Please refer to the response to BCOAPO IR 1.32.3.

32.3.2 If not, what approach could be applied using the data on page 58?

Response:

Not applicable. Please refer to the response to BCOAPO IR 1.32.3.

33.0 Reference: Exhibit B-1, Appendix A, page 37

Exhibit B-2, COSA Model, Rate Base and Rev Req Tabs

33.1 It is noted that the CUSTM allocation factor is applied to Services (account 369) as well as Meters but the factor is just based on the relative cost of meters for each rate class. Please explain why this is appropriate.

Response:

The Company consulted with EES to provide the following response.

While the cost of a service line differs from the cost of a meter, there is a correlation between the two. FBC does not have the information available to provide the typical service line cost by customer class. For that reason, the weighting associated with meters was used when allocating service lines. In general, the cost for a service line is larger for larger customers, as is the case for meters, Service lines are more situation dependent, however, and the cost of a typical new service line is more difficult to estimate than the cost of a new meter for each class.

33.1.1 What is the current cost of a typical service installation for each rate class?

Response:

Please refer to the response to BCOAPO IR 1.33.1. FBC does not have the information necessary to determine the current cost of a service installation by rate class. FBC does not track service installations based on specific customer classes, but instead based on service characteristics.

33.2 Please provide the analysis that supports the values use in the COSA for CUSTW.

Response:

The Company consulted with EES to provide the following response.

The CUSTW weighting factors used for 2017 are the same values used in the approved COSA for 2009. FBC staff working in the areas of customer service and billing were consulted to determine whether any changes had occurred in their departments that would impact the results of the weighting factors. Based on those discussions, FBC determined it was not necessary to change the 2009 weighting factors for use in the 2017 COSA.

33.2.1 It is noted that the CUSTW allocation factor is applied to Meter Reading, Customer Billing and Customer Assistance. Does the analysis incorporate all of these activities in its determination of the relative costs per customer?

Response:

The Company consulted with EES to provide the following response.

Yes, all of these activities were considered in developing the weighting factors.

34.0 Reference: Exhibit B-1, Appendix A, page 44

34.1 Please provide a schedule that summarizes – by function - the costs allocated to the Wholesale Primary class under the COSA vs. the allocated costs assuming they were served at Transmission Voltage.

Response:

Please refer to the response to BCUC IR 1.56.7.

34.2 Please provide the derivation of the "discounts" for the wires charge and the energy charge.

Response:

Please refer to the response to BCUC IR 1.56.7.

34.2.1 If the discounts for both are the same in percentage terms, please explain why this is appropriate since the energy charge also recovers a power supply costs classified as energy-related.

Response:

The Company consulted with EES to provide the following response.

Not applicable as the percent discounts are not the same.

34.3 If one or more wholesale customers did "opt" for the rate, how would the foregone revenues be treated in the COSA?

Response:

Please refer to the response to BCUC IR 1.56.10.

35.0 Reference: Exhibit B-1, Appendix A, pages 44-45

35.1 Please provide the analysis supporting the derivation of the line extension credits set out in Table 13.

Response:

The Company consulted with EES to provide the following response.

The following tables show the results of the analysis used in setting the line extension credits. The calculations can be found in the Extension tab of the COSA model.

	Distribution Wire Demand-Related Rate Base ($)	Distribution Transformation Demand-Related Rate Base ($)	Distribution Meters Customer-Related Rate Base ($)	Distribution Services Customer-Related Rate Base ($)	Less Accumulated Depreciation ($)	Less CIAC ($)
Residential	394,914,018	99,533,469	21,273,886	5,816,687	(133,296,646)	(83,753,696)
Small Commercial	53,006,152	13,450,985	7,727,344	2,112,804	(19,500,345)	(11,257,072)
Commercial	35,964,482	9,590,004	1,348,805	368,789	(12,081,975)	(7,716,404)
Large Commercial	12,898,160	0	196,149	53,631	(1,449,702)	(2,910,250)
Lighting	5,010,711	1,255,663	0	0	(1,601,583)	(1,061,451)
Irrigation	5,104,474	1,309,919	201,522	55,100	(1,705,003)	(1,086,524)
Total	506,897,996	125,140,038	30,747,707	8,407,011		
Combined Commercial	88,970,634	23,040,988	9,076,150	2,481,593	(31,582,320)	(18,973,476)

	Net Allocated Base ($)	Number of Customers	Resulting Credit per Customer ($)	Average Billing kW per Customer	Resulting Credit per kVA ($)
Residential	304,487,718	115,595	2,634	8	344
Small Commercial	45,539,868	13,956	3,263	7	440
Commercial	27,473,701	1,561	17,601	101	174
Large Commercial	8,787,987	46	191,043	1,577	121
Lighting	3,603,339	1,590	2,266	4	642
Irrigation	3,879,487	1,095	3,543	13	265
Combined Commercial	73,013,569	15,517	4,705	17	279

35.2 Shouldn't the credits be adjusted to account for the fact that the R/C ratios for the various rate classes do not equal 100%, as cost-recovery under current rates is not equivalent to the costs derived from the COSA?

Response:

The Company consulted with EES to provide the following response.

While FBC uses a range of reasonableness in determining the rate increases and rebalancing among customer classes, FBC has not used a range of reasonableness in setting the line extension credits. The approach in setting the line extension credit is that the costs per customer paid for by the utility should not be higher than the costs per customer already embedded in the COSA. The approach is intended to avoid an increase in costs for any given class resulting from growth from that particular class, and hold customers harmless from growth on the system. If adjustments are made to reflect a range of reasonableness, the resulting extension credits may not hold other customers harmless.

36.0 Reference: Exhibit B-1, Appendix A, page 46

Preamble: The Application identities $33.1 M of the transmission rate base that is viewed as being associated with generation integration.

36.1 Please confirm that BC Hydro classified a portion its transmission costs as Generation Related Transmission Assets for purposes of its COSA (BCUC Order 47-16, Appendix A, page 15)

Response:

The Company consulted with EES to provide the following response.

Confirmed.

36.2 Is FBC or EES aware of any other electric utilities that functionalize a portion of their transmission costs as generation for purposes of their COSA?

Response:

The Company consulted with EES to provide the following response.

Yes, it is standard practice to functionalize generation integration lines and step-up transformers to generation. Sometimes this is done within the COSA and sometimes the assets are placed in generation accounts to begin with.

36.3 Why didn't FBC functionalize these costs (both the $33.1 M in rate base and related expenses) as generation for purpose its COSA?

Response:

The Company consulted with EES to provide the following response.

The FBC COSA followed the FERC accounts when functionalizing costs. Regardless of whether the costs were functionalized as generation or transmission, they would be classified as

100 percent demand-related and allocated on the basis of the 2 CP demand allocator. In either case, the amount allocated to each customer class would be the same.

36.4 What would be the impact on the COSA results (i.e., the R/C ratios by rate class) if these costs were functionalized as generation and, then, classified and allocated in the same manner as the costs associated with the Kootenay River plants?

Response:

The Company consulted with EES to provide the following response.

EES does not believe it would be appropriate to classify these costs in the same manner as the Kootenay River Plants. However, if the costs had been treated as requested, the following results would apply.

	R/C Ratio As Filed	R/C Ratio per IR 36.4
Residential	98.4%	98.5%
Small Commercial 20	102.2%	102.1%
Commercial 21/22	104.7%	104.6%
Large Comm Primary 30/32	104.0%	103.8%
Large Comm Transmission 31	107.0%	107.0%
Lighting	92.2%	91.8%
Irrigation	97.2%	96.7%
Wholesale Primary 40	96.7%	96.7%
Wholesale Transmission 41	103.9%	104.1%

The resulting changes are relatively minor. They would not have moved any of the classes outside the proposed range of reasonableness and would not have changed the proposed rates.

37.0 Reference: Exhibit B-1, Appendix A, pages 47-48

37.1 What were the 2016 revenues that FBC received from third-parties for each of the Ancillary Services?

Response:

The following table shows the 2016 revenue that FBC received for each of the Ancillary Services

Rate Schedules	2016 Revenue ($000)
103 (Scheduling, System Control and Dispatch Service)	$ 185
104 (Reactive Supply and Voltage Control)	$ 192
105 (Regulation and Frequency Response)	$ -
106 (Energy Imbalance Service)	$ -
107 (Operating Reserve – Spinning)	$ -
108 (Operating Reserve – Supplemental)	$ -
109 (Loss Compensation)	$ -

38.0 Reference: Exhibit B-1, page 58 (lines 7-11)

38.1 Please provide a schedule that sets out the number of customers currently billed on each of RS 03 and RS 03A along with their associated annual energy sales.

Response:

FBC no longer has customers billed on RS03 (the flat rate applicable to RCR Control Group customers) and has applied in this Application to cancel this rate schedule.

RS03A (the flat rate applicable to qualified farm customers), has customers billed on either a bi-monthly or monthly basis in the following numbers:

	Bi-Monthly	Monthly	Total
Number of Customers (Dec. 2017)	453	57	510
Total kWh (2017)	9,746,620	1,497,929	11,244,549

39.0 Reference: Exhibit B-1, page 60 (lines 18-28)

39.1 Please clarify the basis for the 10% comparison to existing rate as used for purposes of the RIB (lines 18-23). In this case, how were "existing rates" defined and is the resulting change that which would occur strictly as a result of the change in rate design (i.e., excludes any year over year changes that would result from general rate increases or rate rebalancing)?

Response:

Please refer to the responses to BCOAPO IRs 1.5.1, 1.5.2 and 1.5.3.

39.2 Please, similarly, clarify the calculation basis for the 3.6% maximum bill impact associated with FBC's proposal.

Response:

This statement is simply a reference to the potential annual bill increases shown in Table 6-10.

40.0 Reference: Exhibit B-1, page 63 (lines 7-16)

40.1 Based on the referenced analysis regarding the cost of service analysis of "gas" versus "no-gas" customers please provide a schedule the sets out: i) the total demand-related costs allocated to each group, ii) the total energy-related costs allocated to each group, iii) the kWh usage for each group and iv) the average cents/kWh of the demand plus energy-related cost for each group.

Response:

The Company consulted with EES to provide the following response.

The following table provides a summary of the cost of service results for the gas vs. no gas comparison. FBC does not have information related to its customers' access to gas as part of customer information associated with accounts. Therefore, in order to respond to this question, the Company has relied upon the sample data used to answer COSA-related questions in the BCUC RIB Rate Report to Government process that concluded in 2017. This information is based on the 2009 COSA, not the 2017 COSA as filed in this application.

Forecast Year: 2009	Residential With Gas Access	Residential No Gas Access
Billing Determinants		
Total Demand (kW)	3,079,968	133,534
Total Energy (kWh)	1,170,202,564	51,472,306
Average Monthly Customers	93,083	3,331
Avg kWh/Customer	12,572	15,454
Avg monthly load factor	52.0%	52.8%
Allocated Functional Cost		
Production Demand (PD)	$10,788,962	$471,217
Production Energy (PE)	$30,907,380	$1,350,619
Transmission Demand (TD)	$22,266,556	$853,015
Distribution Demand (DD)	$13,769,813	$560,308
Distribution Customer (DC)	$32,097,872	$1,158,768
Totals/Unit Costs		
Customer-Related Costs	$32,097,872	$1,158,768
$/Customer/Month	$28.74	$28.99
Demand-Related Costs	$46,825,331	$1,884,540
$/kW	$15.20	$14.11
Energy-Related Costs	$30,907,380	$1,350,619
$/kWh	$0.0264	$0.0262

Forecast Year: 2009	Residential With Gas Access	Residential No Gas Access
Combined Demand & Energy	$77,732,712	$3,235,159
Demand & Energy $/kWh	$0.0664	$0.0629
Total Costs	$109,830,584	$4,393,928
Total Average Cost per kWh	**$0.0939**	**$0.0854**
Revenues	$101,398,429	$4,557,353
Average Revenue per kWh	$0.0867	$0.0885
Adjusted R/C Ratio	92.9%	104.3%

1
2

41.0 Reference: Exhibit B-1, page 63 (lines 24-28)

41.1 Please explain the basis for the statement that: "where a customer that has access to natural gas chooses, for environmental reasons, to used electricity for its lower GHG emission impact, they would be faced with a higher rate should a no-gas rate be implemented".

Response:

Two customers may be similar in all respects, except that one has access to natural gas and the other does not. Customer #1 does not have access to gas, and customer #2 does have access to gas but chooses to heat with electricity. One of the potential reasons for such a choice by customer #2 is an environmental concern.

If a lower rate was made available to customer #1 strictly on the basis of access to gas by community, and customer #2 must pay a higher rate despite being otherwise similar to customer #1, an issue of fairness may arise.

42.0 Reference: Exhibit B-1, page 65 (lines 14-17)

FortisBC's 2016 LTERP, page 127

42.1 Please express the $96/MWh LRMC value associated with FBC's preferred portfolio per its 2016 LTERP on a comparable basis to the 2017 RCR (i.e., adjusted for losses for delivery to a residential customer and in real 2017 $).

Response:

Neither the 2017 RCR Tier 2 rate of $156.17 nor the RS 03 rate of $117.49 per MWh is set with reference to the LRMC.

The LRMC of $96 per MW (2015$)[9] adjusted for inflation is $99 per MW (2017$)[10]. In determining the LRMC for the LTERP, FBC used the Gross Load forecast for modeling load requirements within the LTERP resource portfolio effectively stating the LRMC at the Point of Interconnection. Therefore, the LRMC from a customer perspective, assuming a losses rate of 8.3%, is $108 per MW (2017$)[11].

FBC's LRMC of $96 per MW (2015$) reflects the marginal cost of power, but does not include any capital costs associated with marginal transmission and distribution infrastructure[12]. The gross load forecast is an aggregation of all load classes. It is not possible to accurately separate out the marginal costs associated with the residential class or any other particular customer class. Therefore, comparison to the RS 03 rate of $117.49 per MWh with marginal transmission and distribution costs cannot be done accurately. The LRMC of $96 per MW (2015$) associated with FBC's preferred portfolio A4 is pending Commission approval.

42.2 Does FBC have an estimate as to the marginal transmission and distribution costs for serving a residential customer?

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[9] The LRMC of Portfolio A4 is $95.52 per MWh (2015$), but is commonly presented as $96 per MWh (2015$) using standard rounding rules. FBC 2016 LTERP, Response to BCUC IR 2.76.2. Ex. B-1-1, filed September 15, 2017.

[10] $95.52 per MWh*(1 + 1.8%)*(1 + 2.1%) = $99.28 per MWh. Based on annual inflation rates of 1.8% and 2.1% for the years 2016 and 2017, respectfully. Source: Consumer Price Index (CPI) of British Columbia. Produced by BC Stats, January 2018.

[11] LRMC (2017$) * 1/(1-Loss percentage) = $99.28 per MWh * 1/(1-8.3%) = $108.27 per MWh.

[12] The LRMC does include infrastructure costs associated with connecting any new resources to FBC's system; in other words, all costs up to the point of interconnection.

Response:

No, FBC does not have an estimate as to the marginal transmission and distribution costs for serving a residential customer.

FBC does use a Deferred Capital Expenditure (DCE) value of $79.85 per kW-Year for DSM purposes[13]. The DCE factor is used to estimate the "avoided" transmission and distribution (T&D) costs i.e. benefits, due to the implementation of demand side management (DSM) programs. In this context, the DCE factor is a high-level system-wide estimate for the marginal costs of transmission and distribution, but does not separate out a value for the residential or any other customer class.

42.2.1 If yes, please provide the $.kW value in real 2017 $, adjusted for losses for delivery to a residential customer.

Response:

Please refer to the response to BCOAPO IR 1.42.2.

42.2.2 Please convert this to a cents/kWh value based on the Residential rate class' load factor.

Response:

Please refer to the response to BCOAPO IR 1.42.2.

[13] FBC 2017 DSM Application. Appendix C: Deferred Capital Expenditure Study (EES Consulting). Ex B-1, filed August 8, 2016.

42.3 Please compare the long-run marginal cost of supplying a Residential customer (both with and without marginal transmission and distribution costs) to the 2017 Tier 2 rate and the 2017 energy rate under RS 03A.

Response:

Please refer to the response to BCOAPO IR 1.42.1.

43.0 Reference: Exhibit B-1, page 67 (lines 20-28)

Preamble: The Application states that (under the equivalent RCR) the differential between the Tier 1 and Tier 2 remains the same as it is today. However the differential between the Tier 1 and Tier 2 rates under the equivalent RCR is not the same as the differential under the Current RCR in either absolute or percentage terms.

43.1 Please explain how the Tier 1 and Tier 2 rates under the Equivalent RCR were established and in what way the differential is the same as under the current RCR.

Response:

Please refer to the response to BCUC IR 1.40.1.

44.0 Reference: Exhibit B-1, page 67, Table 6-5 and page 69, Table 6-7

44.1 Please explain why the Tier 1 and Tier 2 energy rates for the Equivalent RCR in Table 6-5 and not the same as the Tier 1 and Tier 2 energy rates in Year 5 in Table 6-7.

Response:

Please refer to the response to BCUC IR 1.40.1.

44.2 Please provide a schedule (similar to Table 6-6) of implementing the Year 5 rates (per Table 6-7) in one year.

Response:

Please refer to the response to BCUC IR 1.46.1.

45.0 Reference: Exhibit B-1, page 70 (lines 8-15)

FBC's September 2016 RIB Rate Report to the BCUC, page 12

Preamble: The Application states: "Since FBC has no data that indicates that low income customers have consumption that varies from customers in general, it follows that similar bill impacts will occur within the low income groups as well". Page 12 of FBC's RIB Rate Report noted that "Attempts to classify respondents as low-income using the LICO standard proved to be problematic and were discontinued".

45.1 Does FBC have any data that indicates low income customers have consumption that is similar to Residential customers in general?

Response:

Please refer to the response to BCUC IR 1.44.2.

45.1.1 If yes please provide and indicate the source of the data.

Response:

Please refer to the response to BCUC IR 1.44.2.

45.1.2 If not, would it be more accurate to say that FBC does not know whether similar impacts will occur with the low-income group as well? If not, why not?

Response:

Please refer to the response to BCUC IR 1.44.2.

46.0 Reference: Exhibit B-1, page 71 (lines 17-21) and page 72 (lines 1-2**)**

Exhibit B-1, Appendix A, pages 74-75

Preamble: The Application states that "there is no cost basis for the current levels of the Tier 1 and Tier 2 rates that form the RCR, nor for any particular threshold and tiered pricing".

The Application also states that "the lack of a cost basis for the existing RCR is the primary driver behind the Company's proposal to return the default residential rate to a flat structure.

46.1 Was there a "cost-basis" for the RCR when it was originally introduced?

Response:

The RCR was originally only cost-based in the sense that it was revenue neutral to the flat rate that existed at the time. However, there was not a cost basis for the individual RCR rate components. Please refer to the response to BCUC IR 1.35.2 for a discussion of the circumstances surrounding the original implementation of the RCR.

46.1.1 If no, why was it proposed by FortisBC and do similar circumstances continue to support maintaining the RCR?

Response:

Please refer to the response to BCUC IR 1.35.2.

46.1.2 If yes, what was it and how have circumstances changed such that there currently is no "cost basis".

Response:

Not applicable. The response to BCOAPO IR 1.46.1 indicated there was no cost basis for the individual RCR rate components.

46.2 Using the available Residential load data per Appendix A please undertake the following:

i. For each month, prepare a graph that plots the average monthly usage of each customer against the customer's 2 CP load factor – calculated as the customer's average hourly use divided by the customer's average use in the four hours that make up the 2 CP factor.

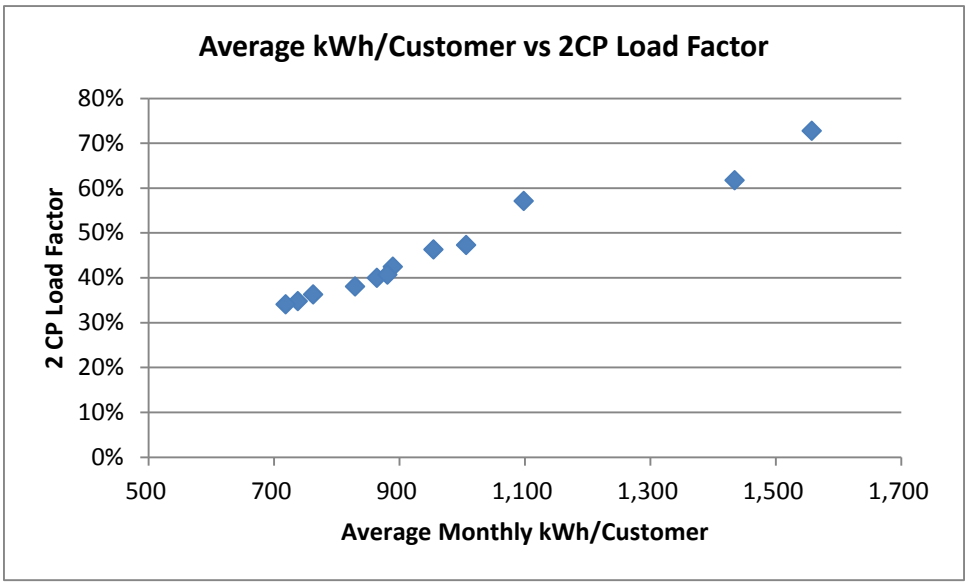
ii. For each month, prepare a graph that plots the average monthly usage of each customer against the customer's NCP load factor – calculated as the customer's average hourly use divided by the customer's usage in the one hour that defined the NCP value for the Residential class overall.

iii. For each month, prepare a graph that plots the average monthly usage of each customer against the customer' individual load factor – calculated as the customer's average hourly use divided by the individual customer's peak demand.

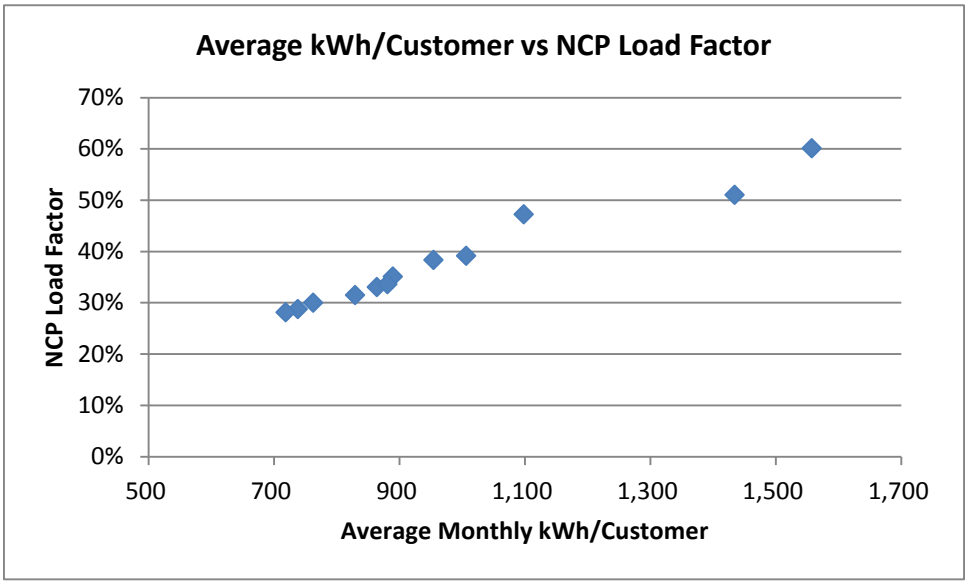
Response:

The Company consulted with EES to provide the following response.

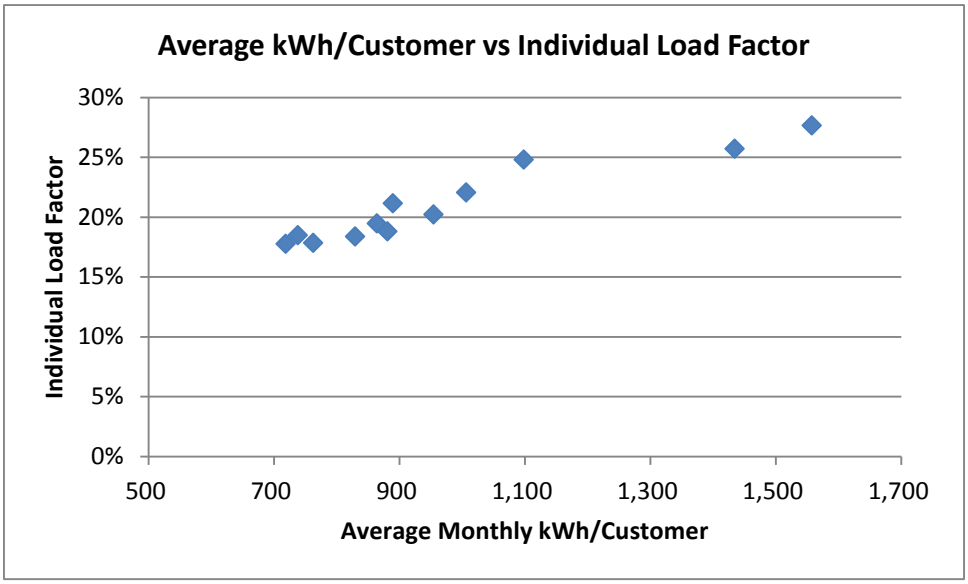
The following graphs are based on average use per customer by month for the residential class. FBC does not have the requested information for each customer.


Average kWh/Customer vs 2CP Load Factor
2 CP Load Factor
80%
70%
60%
50%
40%
30%
20%
10%
0%
500
700
900
1,100
1,300
1,500
1,700
Average Monthly kWh/Customer

1


Average kWh/Customer vs NCP Load Factor
NCP Load Factor
70%
60%
50%
40%
30%
20%
10%
0%
500
700
900
1,100
1,300
1,500
1,700
Average Monthly kWh/Customer

2



46.3 Based on the results from part (2), can one conclude that the load factor changes with monthly usage?

Response:

The Company consulted with EES to provide the following response.

Based on the graphs, the conclusion is that load factors change with monthly usage. The graphs show that a higher usage per month is correlated with a higher load factor. This is consistent with FBC expectations as often higher usage levels result from customers that use their appliances on a more constant basis rather than just using them sporadically.

46.4 If the response to pat (3) is yes and given that for Residential customers demand-related charges are recovered through the energy rate, does this provide a cost-based justification for tiered pricing?

Response:

The Company consulted with EES to provide the following response.

Yes, but it supports declining block rates rather than the current inclining block rates. The correlation shows that higher use is correlated with a higher load factor. A higher load factor is generally correlated with a lower cost per kWh. This would lead one to believe that a customer with higher use would be less costly to serve. Based on these results, the cost per kWh for the second tier would be lower than the cost per kWh for the first tier, reflecting a declining block rate rather than an inclining block rate.

Further, there is no obvious break point as the correlation between the average use per month and the load factor is rather continuous over the range of average use per month.

Accordingly, the data requested does not support the current RCR rate structure and does not assist in setting an appropriate threshold for tiered pricing.

46.4.1 If yes, what would appear to be an appropriate the break point if there were to be two Tiers and would the rate for the second Tier be higher or lower than the rate for the first Tier?

Response:

Please refer to the response to BCOAPO IR 1.46.4.

47.0 Reference: Exhibit B-1, page 74 (lines 1-4)

47.1 Please clarify the statement at lines 3-4. Does the statement mean that 8.7% of the customers will see a bill impact greater than 10% and that for these customers the average impact is $41?

Response:

Yes, that is what the statement at lines 3-4 means.

48.0 Reference: Exhibit B-1, page 77 (lines 1-17)

48.1 Please confirm that under RS 21 the demand charge only applies to demand over 40 kW.

Response:

Confirmed.

48.2 It would appear that one reason for a higher Tier 1 energy rate could be that it compensates for the fact there is no demand charge levied on the first 40 kW. Please comment.

Response:

This is correct. The revenues associated with RS 21 as used in the COSA are based on billing determinants that incorporate the nature of the rate (with the first 40 kW attracting no demand charge revenue); however, the costs are allocated on the full demand of the class. Therefore, the higher Tier 1 energy charges balance the lack of a demand charge of the first 40 kW.

48.3 At line 15 the Application makes reference to the "conservation objective". Please explain what is meant by the "conservation objective". In particular, please comment on: i) whether conservation objective is the same or different from Rate Design Principle #2 (Exhibit B-1, page 16) and ii) whether the intent of Rate Design Principle #2 is to encourage less use or to encourage more efficient use from an economic perspective.

Response:

FBC assumes that the question refers to rate design principle #3 (not principle #2, which is about the fair apportionment of costs among customers).

As described below, FBC distinguishes rate design principle #3 from "conservation objectives" which is taken into account in the Application as part of the government policy considerations.

Bonbright describes the term "efficiency" as follows:

> Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use: (a) in the control of the total amounts of service supplied by the company; (b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service) … Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns. [Underline added]

Further, in the *Clean Energy Act* (CEA), when discussed in the context of rate design, the term energy conservation is differentiated from energy efficiency (CEA, Section 3 (1), (b), iv):

> the use of rates, including rates to encourage
>
> (A) energy conservation or efficiency,
>
> (B) the use of energy during periods of lower demand,
>
> (C) the reduction of the energy demand the authority must serve, or
>
> (D) the development and use of electricity from clean or renewable resources; [Underline added]

Correspondingly, energy efficiency is not necessarily always aligned with "conservation objectives". In other words, energy conservation (less electricity use) may or may not result in more efficient use of the system. Therefore, rate design principle #3, which is mainly intended to provide appropriate price signals to customers for efficient use of the electric system, may or may not lead to increased electricity conservation (for example under TOU rates, a customer can improve system efficiency by shifting its consumption from on-peak period to off-peak period while maintaining its consumption level).

49.0 Reference: Exhibit B-1, page 78

49.1 With respect to Table 6-15, does the demand charge under the proposed tariff apply to all kW or just demand over 40 kW?

Response:

The demand charge under the proposed tariff will apply to demand over 40 kW. FBC is not proposing to change the demand billing structure of the rate. This provision of the demand charge was kept in order to provide better comparability to RS 20 for commercial customers that are close to the minimum load required for RS 21.

49.2 If it applies to only demand over 40 kW, please explain why this is appropriate when the energy rate has been flattened to a single rate.

Response:

Please refer to the response to BCOAPO IR 1.49.1.

50.0 Reference: Exhibit B-1, pages 78-80

50.1 Are the proposed rates set out in Table 6-15 revenue neutral inclusive of the proposed change in the transformation discount?

Response:

The Company consulted with EES to provide the following response.

Yes.

50.1.1 If not, what would be the impact on the RS 21 revenues and the RS 21 R/C ratio of the change in the transformation discount?

Response:

The Company consulted with EES to provide the following response.

Not applicable. Please refer to the response to BCOAPO IR 1.50.1.

50.1.2 If not, please provide a revised set of proposed rates that are revenue neutral when the change in the transformation discount is also taken into account.

Response:

The Company consulted with EES to provide the following response.

Not applicable. Please refer to the response to BCOAPO IR 1.50.1.

51.0 Reference: Exhibit B-1, page 80

51.1 Are the proposed rates set out in Table 6-18 revenue neutral inclusive of the proposed change in the transformation discount?

Response:

The Company consulted with EES to provide the following response.

Yes.

51.1.1 If not, what would be the impact on the RS 30 revenues and the RS 30 R/C ratio of the change in the transformation discount?

Response:

Not applicable. Please refer to the response to BCOAPO IR 1.51.1.

51.1.2 If not, please provide a revised set of proposed rates that are revenue neutral when the change in the transformation discount is also taken into account.

Response:

Not applicable. Please refer to the response to BCOAPO IR 1.51.1.

52.0 Reference: Exhibit B-1, page 85

52.1 If Irrigation customers were permitted opt-in to the optional Commercial TOU rate for a portion of the year would Residential customers also be permitted to opt-in to the proposed optional Residential TOU rate for only portions of the year?

Response:

FBC has only committed to review the possibility and potential impact of allowing the irrigation customers the ability to be "part-time" TOU customers, and, it may be that their unique load profile may lend itself to this possibility. There are no plans to offer the same provision to residential customers.

52.1.1 If not, why not?

Response:

Please refer to the response to BCOAPO IR 1.52.1.

53.0 Reference: Exhibit B-1, page 87 (lines 4-11)

Preamble: The Application notes that no changes are being proposed to the RS 40 demand charges because in aggregate (i.e., wires and power supply combined) the recovery of fixed costs is at an acceptable level.

53.1 Please confirm that that the billing determinant for the Wires Charge is not the necessarily the same as the billing determinant for the Power Supply Charge in a given month and may be higher.

Response:

Confirmed.

53.2 How was this difference in billing determinants taken into account when deciding that there should be no increase to the Wires Charge?

Response:

The different billing determinants were taken into account when calculating the separate unit costs for the power supply costs and the demand-related transmission and distribution (wires) costs. While this had an impact on the unit costs, the difference in billing determinants by itself did not drive the decision to retain the existing wires demand charge. In comparing the fixed cost recovery of current rates compared to total fixed unit costs, as shown in Table 3-2, the wires charge was short of the 65% fixed cost recovery target but the combined customer and demand charges did meet that target.

54.0 Reference: Exhibit B-1, pages 98-99

54.1 Please explain what the proposed rate of $0.00031/kW of Reserve Capacity per hour noted on page 98 (line 23) is in reference to and reconcile with the proposed hourly rate of $0.00023/kW set out on page 99.

Response:

The $0.00031 per kW figure is a preliminary value that was missed during an update. The $0.00023 per kW is correct. A replacement page will be filed as part of an Errata, filed concurrently with these IR responses. Please refer also to the response to BCUC IR 1.68.5.

55.0 Reference: Exhibit B-1, pages 108 (lines 2-4) and 110 (lines 18-20)

Exhibit B-1, Appendix A, pages 40-41

Preamble: The Application states (page 108): "TOU rates are generally intended to incent customers to shift the time of consumption in a manner that allows the utility to reduce costs or generate incremental revenue such that a rate benefit will accrue to all customers"

"The Application states (page 110): "The goal in developing TOU periods is to capture periods that consistently have higher levels of usage while at the same time ….and will not result in shifting the peak period for the utility"

55.1 Please confirm that based on the intent of TOU rates (per page 18) the rates should incent customers to shift from higher cost to lower cost periods. If not confirmed, why not?

Response:

The Company consulted with EES to provide the following response.

Confirmed.

55.2 Given the intent of TOU rates, why isn't the appropriate goal in developing TOU period to capture periods where the costs are higher to serve customers (as opposed to periods where loads are higher)?

Response:

The Company consulted with EES to provide the following response.

There is alignment between loads and costs, with peak demand driving the need for capacity resources. The first step in developing the TOU rates was to focus on when loads are higher and then look at the capacity-driven power supply costs that correspond to the TOU on-peak period.

55.2.1 Furthermore, if the intent is that all customers overall will benefit from individual customers shifting their time of consumption, then is the appropriate focus the incremental costs of serving customers when choosing time periods? If not, why not?

Response:

The Company consulted with EES to provide the following response.

The focus of the TOU rates is to incent customers to shift usage away from the on-peak period. The cost of serving customers at different times of the day is the focus of the TOU pricing. As specific incremental costs for each hour of the year were not available, hourly loads were used in setting the TOU periods rather than hourly costs. Because the peak demands are the driving factor for the capacity-related costs associated with power supply, the TOU periods were designed to capture the periods in which the peak demand occurs.

55.3 Rather than using relative load levels over the hours of the day, did EES/FBC consider using relative cost, such as the hourly cost of market purchases to determine the peak, mid-peak and off-peak hours?

Response:

The Company consulted with EES to provide the following response.

EES/FBC did consider using market price cost differentials but found that the cost differentials were not as large as expected. Because FBC is not purchasing power in the wholesale market for most of its power supply needs, market prices were not the most appropriate basis for price differentials. Further, market prices are reported on the basis of on-peak and off-peak hours only. This would not adequately reflect the cost differentials between FBC's different sources of power supply.

55.3.1 If not, why not?

Response:

Please refer to the response to BCOAPO IR 1.55.3.

55.4 Do the historical values for the hourly cost of market purchases support the proposed TOU periods?

Response:

The Company consulted with EES to provide the following response.

No. Market prices are not reported on an hourly basis and use only a standardized on-peak/off-peak definition. This does not support the development of both on-peak and mid-peak periods. The standard off-peak period is similar to that used by FBC in setting the TOU periods.

56.0 Reference: Exhibit B-1, page 113, lines 3-29

Exhibit B-1, Appendix A, pages 29 and 42-43

Preamble: The Application states (page 113): "power supply costs for 2016 were split into several categories to cover capacity-related costs, energy purchases and baseload costs". The Application then goes on to describe how there costs were assigned to the TOU periods.

56.1 Please provide a schedule similar to Table 7 (Appendix A, page 29) based on the 2016 Power Supply costs used to determine the TOU cost differentials. As part of the response: i) please add a column that indicates the split between peak capacity cost and energy costs for each power supply source and ii) indicate which power supply sources are considered "owned resources" per Table 8-8 (page 113)..

Response:

To clarify, while 2016 data was used to develop TOU periods, the Application is incorrect in stating that 2016 costs were used in the TOU analysis. The 2017 forecast power supply costs were used, consistent with what was used for the COSA. FBC will file a replacement page as part of the Errata to the Application, being filed concurrent with these IR responses.

The following table shows which resources (similar to Table 7) were used to develop the TOU cost differentials (as shown in Table 8-8):

Resource	On-Peak	Mid-Peak
BCH 3808 Purchases	$12.9 million (demand charges)	$36.0 million (energy charges)
Waneta Expansion	$38.3 million (capacity purchase)	
Net Market Purchases		$6.1 million (energy purchases)
Kootenay River Plants	$4.9 million (capacity-related portion)	
Total	**$56.1 million**	**$42.1 million**

"Owned resources" consists of the output from FBC's four owned dams on the Kootenay River. All other costs, including long-term contracted resources from Brilliant, were included as baseload and applied to all hours.

56.2 Please describe how the split between peak capacity and energy costs was determined for each power supply source.

Response:

The demand charges for BCH 3808 purchases, the charges for the Waneta Expansion project (which is a capacity only resource), and a portion of costs for the Kootenay River Plants classified as demand-related in the COSA, were considered capacity-related costs and used to develop the on-peak cost differential. The energy charges for the BCH 3808 purchase and the net market purchases were considered variable energy charges and were used to develop the mid-peak cost differential. All other power supply costs were considered baseload costs, including the energy-related portion of FBC-owned generation and purchases under the Brilliant Power Purchase Agreement.

Note that splitting the power supply costs into the capacity-related costs, energy purchases and baseload costs categories for developing TOU rates is different than how power supply costs were classified between demand and energy categories for purposes of the COSA allocations. Because the TOU analysis used capacity-related costs over many hours, rather than just the peak hour, there was no need to recognize both the energy and capacity associated with various resources as was done for the COSA.

56.3 Please provide a schedule that sets out for 2016 the amount of energy supplied in each TOU period by power supply source.

Response:

Please refer to the response to BCOAPO IR 1.56.1, where corrections to the Application, also applicable to this response, are noted.

FBC cannot produce the requested schedule as FBC cannot allocate what energy is used in each hour as the energy resources are aggregated through FBC's storage accounts under the Canal Plant Agreement, and it cannot be determined with accuracy which energy resource was used in each hour. However, for comparison purposes, the energy resource included in the mid-peak and on-peak resources provided 967 GWh out of the total 1,092 GWh shown in Table 8-8

of the Application. This is comprised of 750 GWh of BC Hydro 3808 plus 217 GWh of market purchases. The baseload resources, including energy from FBC owned generation and purchases under the Brilliant Power Purchase Agreement, therefore provide the equivalent to all the energy in the off-peak hours, plus 125 GWh of energy in the mid-peak and on-peak hours.

Furthermore, all energy resources except for BC Hydro 3808 purchases and market purchases are fully subscribed, so any incremental energy purchases will need to be sourced from either the BC Hydro PPA or from the market, regardless of the time they occurred.

56.4 For 2016 was the off-peak period energy demand met entirely by FBC-owned resources?

Response:

Yes. Please refer to the response to BCOAPO IR 1.56.3.

56.4.1 If not, why is the how the cost differential between the mid-peak and off-peak periods set at the average cost of "energy purchases beyond output from owned resources"?

Response:

Not applicable. Please refer to the response to BCOAPO IR 1.56.3.

56.5 For 2016, were energy purchases beyond output from owned resources required to meet domestic load requirements in all mid-peak hours?

Response:

Yes. Please also refer to the response to BCOAPO IR 1.56.3.

56.5.1 If not, why is the how the cost differential between the mid-peak and off-peak periods set at the average cost of "energy purchases beyond output from owned resources"?

Response:

Not applicable. Please refer to the response to BCOAPO IR 1.56.5.

56.6 For 2016, if additional load had materialized in the off-peak period, how would the increase in energy requirements have been met? In particular, would FBC-owned resources been capable of producing the additional energy required or were they already fully dispatched?

Response:

The FBC-owned resources and purchases from the Brilliant Power Purchase Agreement are fully dispatched and additional energy would be needed from other sources if total annual energy is increased. In that case, FBC would need to meet additional off-peak use from either the PPA with BC Hydro or through market purchases. If there had been a shift of power from one period to another, there would have been no need for additional purchases.

56.7 For 2016, if load had been shifted from the mid-peak to the off-peak hours, would the energy supplied from FBC's different power supply sources have changed? If yes, how?

Response:

No. As discussed in the response to BCOAPO IR 1.56.3, FBC's allocation of energy resources is very complex on an hourly basis, and all resources, except for purchases from BC Hydro 3808 and the market, are fully subscribed. Shifting energy from the mid-peak to off-peak hours

would therefore not change the composition of FBC's energy resources, only the timing of the use of these resources, and potentially the capacity resources used in each hour.

Shifting usage from the on-peak and mid-peak hours may result in some short-term capacity savings under the BC Hydro PPA and/or Waneta Expansion. However, the real savings potential for a TOU rate would be as follows: if sufficient consumption were to be shifted away from the peak with certainty, it may, over the long-term, result in a reduction in power purchase expenses and at some point, result in deferred investment into new generation requirements that would otherwise be required to meet growing peak demand. At the current time, however, FBC is not anticipating the addition of new generation resources over the planning horizon.

57.0 Reference: Exhibit B, page 108

Exhibit B-1, page 114, lines 4-17

Exhibit B-1, Appendix A, pages 43

Preamble: The Application describes (page 114) how elasticity factors were applied to the load in each TOU period and how the TOU rates were adjusted to account for the change (reduction) in overall use and the reduced power supply costs.

The Application states (page 108): "TOU rates are generally intended to incent customers to shift the time of consumption in a manner that allows the utility to reduce costs or generate incremental revenue such that a rate benefit will accrue to all customers"

57.1 The Application states that the TOU rates needed to be slightly higher to account for the overall reduction in energy use but that a reduction in power supply costs was also incorporated. Please provide the analysis that supports these adjustments.

Response:

Please refer to the response to BCUC IR 1.88.9.

57.2 Overall were the total power supply costs per kWh and the resulting TOU rates higher or lower than what would have resulted if no adjustments had been made for "elasticity"?

Response:

The Company consulted with EES to provide the following response.

If no adjustments had been made for elasticity, energy use and total power supply costs would be higher, but TOU rates per kWh and power supply costs per kWh would be lower.

57.2.1 If higher, please explain how this is consistent with the intent of TOU rates as set out on page 118.

Response:

The Company consulted with EES to provide the following response.

The intent of the TOU rates is to incent customers to shift kWh usage and/or reduce kWh usage, thereby reducing power supply costs. On a total basis, costs for power supply would be lower if customers respond to the TOU rates as expected. This is consistent with the goal of the rates.

58.0 Reference: Exhibit B-1, page 114, lines 4-17

Exhibit B-1, Appendix A, pages 43

Preamble: The Application describes (page 114) how elasticity factors were applied to the load in each TOU period and how the TOU rates were then adjusted to account for the change (reduction) in overall use and the reduced power supply costs.

58.1 Please confirm that the adjustments outlined on page 114 were based on the assumption that all customers were facing TOU rates?

Response:

The Company consulted with EES to provide the following response.

Confirmed.

58.2 Please reconcile this approach with FBC's plan to make TOU rates "optional" for all rate classes.

Response:

The Company consulted with EES to provide the following response.

The approach was intended to provide rates that were revenue neutral to standard rates on an overall basis, not for specific customers. FBC had no way to know how many or which customers would opt for TOU rates. Therefore, the rates were set as if all customers were on the TOU rate.

58.3 Please confirm that the elasticity factors used were based on those developed using just Residential rate class data.

Response:

The Company consulted with EES to provide the following response.

Confirmed.

58.4 Based on information available to FBC and EES please comment on whether or not the elasticity factors for other rate classes are similar to those for the Residential rate class.

Response:

The Company consulted with EES to provide the following response.

We would expect elasticity factors for smaller customers to be similar to those measured for residential customers, with greater differences for larger customers. EES did not do a full review of elasticity factors used by other utilities but used judgment in assuming the FBC-specific elasticity factors for residential customers would be more appropriate than non-residential elasticity factors from other utilities. The uncertainties associated with the participation rates and load response from the proposed TOU rates were among the reasons FBC proposed that TOU rates be optional.

58.5 The Block 2 and Block 1 RIB rate elasticity factors were applied to the peak period and mid/off-peak period usage respectively. What evidence does FBC or EES have that the elasticity factors derived for the RIB rate blocks are appropriate for purposes of its TOU impact analysis?

Response:

The Company consulted with EES to provide the following response.

EES does not have any specific evidence that TOU elasticity factors would be the same as RIB elasticity factors. This could only be assessed after the TOU rates are in place for a year or more. The RIB elasticity factors were the best information available and EES considers that customers' response to higher rates would be similar regardless of whether they are for RIB or TOU rates.

58.6 Please confirm that the elasticity estimates used were all "own-price" elasticities and how, if at all, their use accounts for the influence TOU rates will have on customers "shifting" use between TOU periods.

Response:

The Company consulted with EES to provide the following response.

We have not differentiated price elasticities from "own-price" elasticities. It is assumed that customers will react to the prices in each of the TOU periods independently from one another, for purposes of applying the elasticity factors. We would expect the response to include load reduction in the on-peak period, with some of the load reduction shifted to other periods and some of it not shifted to other periods.

59.0 Reference: Exhibit B-1, page 108, lines 2-13

Exhibit B-1, pages 114-115

Preamble: FBC plans on re-introducing Residential TOU rates on an optional basis.

59.1 Please confirm that, depending upon their TOU period usage pattern, some individual Residential customers would see a reduction in their monthly electricity bills without changing their usage pattern.

Response:

The Company consulted with EES to provide the following response.

Confirmed for some customers that opt for the residential TOU rates.

59.2 Given the proposed "optionality" of Residential TOU rates, is it not likely that customers seeing such a potential benefit would "opt" for TOU rates?

Response:

The Company consulted with EES to provide the following response.

It is expected that customers with more than average off-peak consumption will be more likely to opt for TOU rates. However, the potential for paying the higher on-peak rates may be a deterrent to opting in for any customer, regardless of their usage. Also since customers opting for TOU must remain on the rate for one year, there may a deterrent to selecting the option in the loss of flexibility to change their load profile without savings being eroded.

59.3 How does FBC plan on accounting for/recovery the lost revenue that is likely to occur as a result of customer "selectively" choosing TOU rates based on this benefit?

Response:

The Company consulted with EES to provide the following response.

FBC cannot state definitively that there will "likely" be a loss of revenue that will accompany the reintroduction of the TOU rates for residential customers. There may even be an increase in revenue if TOU customers were not able to maintain their load profile as planned. However, in the case that there is a loss of revenue, under FBC's current regulatory treatment, it would be recovered from all customers through the flow-through deferral account (or through the revenue requirements application if the TOU revenue variances had been captured in the revenue forecast). This is no different from the treatment afforded to the existing TOU rates for all other customer classes, or that was the case for the previous set of residential TOU rates that were offered by the Company.

59.3.1 If it is to be recovered from all customers (or just the Residential class), how is this consistent with the intent that "a rate benefit will accrue to all customers" from offering TOU rates (per page 108)?

Response:

The Company consulted with EES to provide the following response.

TOU rates are set to be revenue neutral for each class independent of one another, and both lost revenues and reduced power costs expected as a result of reduced consumption are already built into the TOU rate design. Any lost revenues resulting from customers switching to TOU rates without reducing consumption would be treated the same as any other revenue variance, as discussed in the response to BCOAPO IR 1.59.3.

59.3.2 How will this revenue loss be accounted for in the COSA (i.e. will it reduce the overall R/C ratio for the Residential rate class)?

Response:

The Company consulted with EES to provide the following response.

FBC has not determined whether or not it will include TOU customers as a separate class in future COSAs and therefore cannot comment about the impact of revenue losses on the residential class in future COSAs.

60.0 Reference: Exhibit B-1, page 121

Exhibit B-1, Appendix G, Section 2.5

Preamble: A security deposit is required if a customer cannot establish or maintain credit to the satisfaction of FortisBC.

60.1 Please outline how a customer establishes/maintains credit "to the satisfaction of FortisBC".

Response:

With respect to existing customers, assessing whether credit has been maintained or established is done by reviewing the timeliness of payments in the most recent 12 consecutive months, and the specifics of that particular customer's situation. For customers new to FBC (and therefore without recent payment history) a credit check is used to establish creditworthiness.

61.0 Reference: Exhibit B-1, page 121

Exhibit B-1, Appendix G, Section 3.3.4

Preamble: Section 3.3.4 indicates that, unless the Service Agreement or Rate Schedule specifies otherwise, FBC can terminate service for any reason.

61.1 This provision appears to be open-ended. Please describe the reasons for which FBC would terminate service and explain why they are not delineated in the General Terms and Conditions.

Response:

The "Termination by FortisBC" clause was included to align with the same clause contained in FEI's GT&Cs (Section 8.5 Termination by FortisBC Energy). Keeping in mind that it is FBC's primary objective to maintain service to customers, termination of service is considered by FBC to be a last resort. The termination clause, if necessary to invoke, allows FBC to protect the interests of all customers from harm in cases where suspension or termination of service is warranted for reasons not already identified in the proposed Section 10 (Continuity of Service). The intent of Section 3.3.4 is to be sufficiently broad to include all possible or potential eventualities that might warrant terminating service. As such, FBC does not consider it practical to provide a list of reasons which might limit the applicability of the termination clause in cases where termination of service is necessary and warranted.

For more information, please refer to the response to BCUC IR 1.105.1.

62.0 Reference: Exhibit B-1, page 122

Exhibit B-1, Appendix G, Section 8.2.4

62.1 Under what circumstances will a customer be charged for historical billing information.

Response:

Currently, FBC customers have two options to access general historical bill information. Customers may access their historical account consumption/energy usage via the "Account Online" system on the FBC website dating back to January 1, 2012, or they may call the FBC Customer Service Contact Centre and request this information from a customer service representative. With respect to residential customers' access to historical information on usage through Advanced Metering Infrastructure (AMI) data for a TOU period, customers can call the FBC Customer Service Contact Centre and request this information from a customer service representative. FBC is in the process of enhancing its website "Account Online" system to allow customers self-service access to their AMI data, which is expected to be available by the end of the year.

The only circumstance where FBC may consider charging customers for historical billing information is when the request is extraordinarily demanding and requires FBC to secure additional customer service resources at additional costs in order to fulfill the request. FBC foresees this to be required on very rare occurrences.

62.2 Can a Residential customer with an AMI meter receive historical information on usage by TOU period and, if so, would there be a charge?

Response:

Please refer to the response to BCOAPO IR 1.62.1.

63.0 Reference: Exhibit B-1, page 124-126

Exhibit B-1, Appendix D

63.1 What year's costs are used in Appendix D to derive the proposed Standard Charges?

Response:

Unless otherwise stated, all the Standard Charges in Appendix D are based on 2017 costs.

63.2 For each of the proposed Standard Charges are the labour, vehicle and material requirements used to derive the charge the same as those used in the 2009 COSA and RDA?

Response:

With the exception of the Account Setup Charge and the Returned Payment Service Charge, the derivations of the existing Standard Charges have been updated to reflect the current labour, vehicle and material costs. All other assumptions (for example: employee time, materials used, etc.) used to derive the proposed Standard Charges remain the same as those used in the 2009 COSA.

The Account Setup Charge and Returned Payment Service Charge were calculated using actual 2016 costs incurred to provide those services to customers, in line with the derivations of the same FEI Standard Charges.

Please also refer to the responses to BCUC IRs 1.109.1 and 1.109.2.

63.2.1 If not, please identify the differences and explain the reasons for any change.

Response:

Please refer to the response to BCOAPO IR 1.63.2.

63.3 With respect to Section 17.1 (Appendix D, page 1), is the 2.5 hours the total time for both of the 2 Crew required or the time for each crew person?

Response:

The crew labour on page 1 of Appendix D is made up of the following components, totaling 4 hours:

- "1.5 hours site time": This is 1.5 hours of time on site per Power Line Technician. In total the Standard Charge includes 3 hours of site time (1.5 hours for each PLT).
- "1.0 hours travel time": This is 0.5 hours per PLT, reflecting travel time to the site, doubled to 1.0 to reflect the involvement of two PLTs.

In total 4 hours of Crew Labour is included in the Standard Charge, consistent with the derivation provided in FBC's 2009 COSA and RDA.

63.4 Based on the response to part (3), please explain how the requirement for 4 crew hours in total was established.

Response:

Please refer to the response to BCOAPO IR 1.63.3.