REQUESTOR NAME	**BCOAPO**
INFORMATION REQUEST ROUND:	**# 1**
TO:	**FORTISBC INC. (FBC)**
DATE:	**March 29, 2018**
CASE NO:	**1598939**
APPLICATION NAME	**2017 Cost of Service Analysis and Rate Design Application**

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?

1.1.1 If yes, which ones?

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

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

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.

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?

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.

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.

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?

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

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

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).

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?

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?

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?

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?

5.2.1 If yes, what is it?

5.2.2 If not, why not?

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?

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"?

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

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)?

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

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

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?

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

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?

8.2.1 If not, why not?

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

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?

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.

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.

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?

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?

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.

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.

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?

12.1.1 If no, why not?

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

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

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

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"?

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 <u>currently</u> taken under Rate 31?

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.

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?

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

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

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.

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.

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.

14.1.1 If not, why not?

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.

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.

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?

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.

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

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.

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.

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

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.

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?

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

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

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.

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?

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

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.

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.

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.

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.

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?

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?

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.

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?

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?

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.

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?

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

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

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.

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?

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?

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.

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

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?

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

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?

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.

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?

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

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).

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?

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?

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?

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.

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?

32.3.1 If not, why not?

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

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.

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

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

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?

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.

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

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.

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

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.

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?

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)

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?

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?

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?

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?

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.

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)?

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

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.

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".

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 $).

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

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

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

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.

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.

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.

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

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?

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

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?

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?

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

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

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.

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

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?

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?

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?

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.

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.

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.

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?

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.

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?

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?

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.

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?

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?

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.

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?

52.1.1 If not, why not?

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.

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

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.

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?

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)?

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?

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?

55.3.1 If not, why not?

55.4 Do the historical values for the hourly cost of market purchases support the proposed 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)..

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

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

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

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"?

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

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"?

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?

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?

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.

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"?

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

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?

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

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

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.

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?

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.

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.

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?

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?

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)?

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)?

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".

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.

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.

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?

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?

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?

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

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?

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

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