Diane Roy
Vice President, Regulatory Affairs

Gas Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

July 10, 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. 2

On December 22, 2017, FBC filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-101-18 establishing the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCOAPO IR No. 2.

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

64.0 Reference: Exhibit B-8, BCUC 1.2

Exhibit B-11, BCOAPO 50.1

Exhibit B-11, BCOAPO 51.1

Exhibit B-8, BCUC 51.1

64.1 Please provide a schedule that demonstrates that the revenues from the existing rates for RS 21 (as set out in Exhibit B-1, Table 6-15) in combination with the impact of the existing Transformation Discount ($0.53/kW) produce the same revenues as the proposed RS 21 rates (as set out in Table 6-15) in combination with the proposed Transformation Discount ($0.32./kW – per BCUC 51.1).

Response:

The Company consulted with EES to provide the following response.

The table below shows the RS 21 revenues under current and proposed rates with the transformation discount included. The total amounts are virtually the same, with a difference of less than one-hundredth of one percent. As with all rate classes, there will be some minor differences in total revenues for the class due to the fact the rate components are only carried out to two or five decimal places.

Rate Component	Rate Level	Billing Amount	Annual Charges
Current Rates			
Customer Charge	$16.48	1,561	$308,687
Demand Charge	$7.72	1,212,392	$9,359,664
Block 1 Energy Charge	$0.08663	131,745,039	$11,413,073
Block 2 Energy Charge	$0.07191	443,364,368	$31,882,332
Transformation Discount	$0.53	119,323	-$63,241
Total Annual Charges			$52,900,515
Proposed Rates			
Customer Charge	$54.00	1,561	$1,011,475
Demand Charge	$10.22	1,212,392	$12,390,643
Energy Charge	$0.06875	575,109,408	$39,538,772
Transformation Discount	$0.32	119,323	-$38,183
Total Annual Charges			$52,902,707
Difference			+$2,192
Percent Difference			+0.0041%

64.2 Please provide a schedule that demonstrates that the revenues from the existing rates for RS 30 (as set out in Exhibit B-1, Table 6-18) in combination with the impact of the existing Transformation Discount ($2.676 / kVA) produce the same revenues as the proposed RS 30 rates (as set out in Table 6-18) in combination with the proposed Transformation Discount ($5.26/kVA).

Response:

The Company consulted with EES to provide the following response.

Since there is only one customer to which the transformation discount applies, answering the question with reference to dollar impact would require the disclosure of information that is confidential to the customer. FBC therefore cannot provide a response to this request. As stated in the response to BCUC IR 1.52.2, the change related to the transformation discount leads to a very small revenue impact.

65.0 Reference: Exhibit B-8, BCUC 2.2

Preamble: The response states:

> "In addition, different rate design principles may have varying levels of importance in different contexts."
>
> and
>
> "FBC's intermediary role in the rate design process consists of applying its judgement and experience to balance the most relevant principles in a given context when identifying rate design solutions".

65.1 With respect to FBC's rate design proposals for the Residential class' default rates (as set out in Exhibit B-1, pages 57-74) what were the "most relevant" (rate design) principles that FBC considered it needed to balance?

Response:

Please refer to the responses to BCUC IRs 1.3.1, 1.3.3 and 1.4.2 where the most relevant rate design principles and considerations for FBC's residential rate proposals are discussed.

65.2 With respect to FBC's rate design proposals for the Residential class' optional TOU rates (as set out in Exhibit B-1, page 74) what were the "most relevant" (rate design) principles that FBC considered it needed to balance?

Response:

The fair apportionment of costs (cost causation – principle 2) and efficient use of the system by providing the appropriate price signals (principle 3) are the most relevant principles for optional TOU rates. Government energy policy is also an important consideration.

As an optional rate, customer understanding and acceptance is less critical than it is for the default rate option since the customers can choose between this option and the easier-to-understand default rate. Similarly, due to the optionality of this rate, the bill impact and rate shock are less important than for the default rates. This is because the customers who choose this option are usually utility and rates savvy (i.e., they are more knowledgeable regarding the rates, their consumption pattern and their monthly bill amounts). As explained in response to

BCUC IR 1.82.2.1 because there is a greater potential for variability in the usage per TOU period when compared to energy in total, the TOU rates could lead to less revenue stability than under the standard rates.

65.2.1 If these differ from those considered in the development of the default Residential rate design, please explain why.

Response:

Please refer to the response to BCOAPO IR 2.65.2.

65.3 With respect to FBC's rate design proposals for the various commercial classes RS 20, RS 21, RS 30 and RS 31 (as set out in Exhibit B-1, pages 74-82) what were the "most relevant" (rate design) principles that FBC considered it needed to balance?

Response:

FBC notes that the referenced response continues,

> Explicit prioritization of rate design principles may lead to favouring the interests of a certain customer group to the detriment of another customer group's interests, without due consideration of the specific circumstances, and is not aligned with FBC's objective of striking a balance between the competing rate design principles and considerations based on specific characteristics of customers in each rate schedule. The topic of prioritization of rate design principles is discussed further in the response to BCUC IR 1.49.4.

Please refer also to the response to BCUC IR 1.49.4 which asks the following:

> Please discuss the consideration and prioritization given to the eight rate design principles outlined on page 16 of the Application in making the rate design proposals for RS 20.

FBC believes the response to BCUC IR 1.49.4, which addresses the requested issues for RS 20, is equally applicable to RS 21, RS 30 and RS 31.

65.3.1 If these differ from those considered in the development of the default Residential rate design, please explain why.

Response:

Please refer to the response to BCOAPO IR 2.65.3.

66.0 Reference: Exhibit B-8, BCUC 3.3

Exhibit B-11, BCOAPO 48.3

Preamble: The response to BCUC 3.3 states that: "Generally speaking, inclining block rate structures may provide better price signals for energy conservation for some segments of residential customers."

In the response to BCOAPO 48.3, "FBC distinguishes rate design principle #3 from "conservation objectives" which is taken into account in the Application as part of the government policy considerations"

66.1 In FBC's current circumstances, do inclining block rate structures "provide better price signals for energy conservation", where "energy conservation" is interpreted as energy "efficiency" consistent with Bonbright principle #3?

Response:

FBC does not have any evidence to suggest that the current RIB rates lead to more efficient use of the system (lower peak) compared to a flat rate structure. It is very difficult to determine how the customer response to the higher Tier 2 rate affects the energy use in peak time. Any energy conserved due to the higher Tier 2 rate may or may not be related to the peak time. If the lower consumption is due to the energy conservation during the off-peak period, this would actually lead to a lower load factor and higher cost per kWh consumed. Further, it is difficult to distinguish between the effects of DSM programs, energy efficiency codes and standards and conservation rates on system peak. In any case, the TOU rate provides a better price signal for efficient use of the system as it distinguishes between the cost of power supply during off-peak, mid-peak and on-peak periods.

With respect to the matter of "better price signals" the RCR provides only a single threshold for the price differential and does so at an amount unrelated to any underlying system costs. It would be difficult to characterize this one-dimensional aspect of the rate as providing a pricing signal that is "better" than other options, including a flat or TOU rate structure.

67.0 Reference: Exhibit B-8, BCUC 4.4 Exhibit B-8, BCUC 27.2.1

Preamble: The response to BCUC 4.4 states that with respect to the cost recovery of DSM programs: "This cost recovery treatment mechanism (from all customers) can be considered to be in conflict with the cost causation principle; however, at the same time it is aligned with the principle of encouraging efficient use and discouraging inefficient use of the system".

The response to BCUC 4.4 also states that "Recovery of fixed costs (whether customer-related or demand-related) through fixed charges (such as basic charges or demand charges) aligns with several of the Bonbright principles such as, revenue stability and fair apportionment of costs among customers, but may be construed as running contrary to energy conservation and efficiency policies by leaving less of a price signal in the energy-based charges".

The response to BCUC 27.2.1 states "FBC looked at allocating

DSM on the basis of which class the conservation dollars were spent on; however, that approach would not reflect the long- term benefits of reduced power supply and T&D costs associated with conservation spending. Using the same basis as was used when making conservation decisions in the planning process best reflects cost-causation and is more appropriate to use for the COSA".

67.1 With respect to the response to BCUC 4.4, please explain how the cost recovery treatment for DSM programs from all customers "is aligned with the principle of encouraging efficient use and discouraging inefficient use of the system".

Response:

FBC's intended reference for the "it" in the sentence was to the DSM program itself and not the DSM cost recovery mechanism; however, it is apparent that this is unclear in the wording of the response. Some DSM investments (such as improved door and window insulation) can reduce the energy consumption during the peak periods and therefore can be described as being aligned with the principle of encouraging efficient use and discouraging inefficient use of the system.

67.2 In FBC's current circumstances, does FBC's proposal to increase the recovery of fixed costs (whether customer-related or demand-related) through fixed charges (such as basic charges or demand charges) run contrary to efficiency policies (as set expressed in Bonbright principle #3)?

Response:

The response to this question depends. For example, a higher percentage of fixed cost recovery for demand-related costs through demand ratchets can encourage large industrial customers to increase their annual load factor, which promotes efficient use of the system. On the other hand, the recovery of customer-related costs through a fixed charge may encourage customers to increase their consumption during both peak and off-peak periods. However, this increased consumption is not necessarily "inefficient" consumption in the context of Bonbright principle #3, since rates should be designed to discourage,"…wasteful use of service while promoting all justified types and amounts of use."

Nevertheless, FBC notes that the reference to the "efficiency" in the phrase "energy conservation and efficiency" was related to the common use of this phrase which is mainly focused on the conservation (energy efficiency for consumer products such as refrigerators means less use).

67.3 FBC's response to BCUC 4.4 suggests that the proposed allocation approach for DSM expenditures (i.e., to all customers) is in conflict with the principle of cost causality. However, the response to BCUC 27.2.1 suggests that it best reflects cost causality. Please reconcile.

Response:

The Company consulted with EES to provide the following response.

The response to BCUC IR 1.4.4 reflects cost causation only in the sense of where the dollars were actually spent. If you consider that residential DSM dollars were spent to benefit the residential class, then the method used in the COSA does not reflect cost causation. It was not intended to represent that the DSM allocation did not reflect cost causation in any sense.

FBC looked at DSM in a different fashion when allocating the costs in the COSA. Rather than considering that DSM was spent to benefit customers directly, DSM was considered as an alternative to power supply costs and T&D spending. This is the approach FBC used when

1 looking at the cost-effectiveness of DSM alternatives. This was therefore the basis of the cost-
2 causation used in developing the DSM treatment in the COSA.

3

68.0 Reference: Exhibit B-8, BCUC 5.1

68.1 When does FBC plan on completing its next REUS?

Response:

Please refer to the response to BCUC IR 2.112.1.

69.0 Reference: Exhibit B-8, BCUC 7.1 and 7.1.1

Preamble: The response to BCUC 7.1 states: "FBC believes rate shock, as a general concept, could be interpreted as either including general rate increases or not including them. However, throughout the Application, for clarity of analysis, only bill impacts related to the rate design and rebalancing proposals are described".

The response to BCUC 7.1.1 states: "The percentage change in the total customer bill is and should be the key consideration in bill impact assessments".

69.1 Given FBC's response to BCUC 7.1.1 that "the percentage change in the total customer bill is and should be the key consideration in bill impact assessments" why wouldn't it be more appropriate for the bill impacts presented in the Application include the estimated effect of general rate increases?

Response:

FBC has previously responded to BCOAPO IR 1.5.2 as follows,

> 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.

FBC does not have forecast rate increases for the years over which the RCR phase-out is being proposed. However, as whatever increases may occur would only serve to exacerbate the impact to negatively impacted customers, their inclusion would be supportive of the Company's proposal with respect to the residential rates, particularly in regard to a phase-out period.

70.0 Reference: Exhibit B-8, BCUC 8.4

Preamble: The response states "FBC's proposal will slightly improve economic fairness as well as rate and revenue stability."

70.1 Please explain what FBC means by "economic fairness" and how its proposal achieves this.

Response:

Economic fairness refers to revenue recovery driven by the fair apportionment of costs among customers (Principle 2), and more particularly in the referenced question (BCUC IR 1.8.4) intra-class revenue recovery issues amongst residential customers. That is, customers pay for the costs they impose on the system. Considering that most of the distribution utility costs are fixed, the increase in the Customer Charge to a minimum of 55 percent of the COSA customer related unit cost, along with an increase in the demand-related charges in certain rate schedules, will help to mitigate the intra-class transfer of cost recovery between customers. As stated in Section 6.1.5 of the Application, FBC's proposal will help to improve the intra-class fairness since low use customers, who currently benefit from the lower Customer Charge at the expense of higher consuming customers, would pay a more equitable share of the fixed costs they impose on the system.

71.0 Reference: Exhibit B-8, BCUC 10.2

Preamble: The response states: "The 2 CP used by FBC includes the two highest winter plus the two highest summer peaks"

71.1 Please confirm that the two winter/summer peaks used are not the two hours in the winter/summer with the highest peaks but rather two highest monthly peaks in the winter/summer such that the response would be better worded as "The 2 CP used by FBC includes the two highest winter months' plus the two highest summer months' peaks".

Response:

The Company consulted with EES to provide the following response.

Confirmed.

72.0 Reference: Exhibit B-8, BCUC 18.3

72.1 In using the term "customer" in regards to the application of the minimum system approach, is FBC referring to the number of customer accounts or the number of customer connections to its distribution system (recognizing that a "customer" may have more than one "connection" to the distribution system)?

Response:

The Company consulted with EES to provide the following response.

It is referring to the number of active services or connections.

72.1.1 If FBC is not actually referring to the number of "connections" please explain why.

Response:

Not applicable based on the response to BCOAPO IR 2.72.1.

73.0 Reference: Exhibit B-8, BCUC 30.2.1

73.1 Please confirm that, with respect to OEB Test #2 – as set out in Table 8 of the EES Cost of Service Report (Attachment A, page 35) – the 4 CP method referred to is based on the four highest monthly peaks.

Response:

The Company consulted with EES to provide the following response.

Confirmed.

73.2 If OEB Test #2 is applied to FBC's 2 CP Method is the percentage still greater than 83%?

Response:

The Company consulted with EES to provide the following response.

If the 2 CP results were used in place of the 4 highest peaks, the OEB Test #2 would be 83 percent in 2012 and 88 percent or higher in all other years. This would lead to a recommendation to use the 2 CP results.

74.0 Reference: Exhibit B-8, BCUC 32.1

74.1 Please confirm that the 0.038 percent difference between revenues and the revenue requirement is due to the fact rates are rounded to a set number of decimal points.

Response:

The Company consulted with EES to provide the following response.

Confirmed.

74.2 If not confirmed, what is the reason for the difference?

Response:

The Company consulted with EES to provide the following response.

Not applicable as the response to BCOAPO 2.74.1 is confirmed.

75.0 Reference: Exhibit B-8, BCUC 36.1

75.1 Please clarify what FBC means by "fairness" and whether the definition is consistent with Bonbright's principle #2 – Fair apportionment of costs among customers.

Response:

While the Application assesses both inter-class and intra-class issues, FBC's primary fairness consideration in relation to Residential customers was in terms of intra-rate schedule fairness (i.e. whether low use customers are paying their fair share as compared to high use customers within the residential rate class) in its evaluation of the financial impact of any change in rate structure to residential customers. Specifically with respect to the RCR, fairness also considers whether the rates charged to customers, which vary with the level of consumption, have a relationship to the cost of providing service that also varies with consumption level. There is no evidence to indicate that such a relationship exists. FBC confirms that this definition is consistent with Bonbright Principle #2 - Fair apportionment of costs among customers.

75.1.1 Given FBC's "definition" of fairness please explain why a flat rate (as opposed to an inclining rate) is considered a "neutral option" from a fairness perspective.

Response:

The portion of FBC's response to BCUC IR 1.36.1 that made reference to a neutral option is as follows:

> Compared to other rate structures, a flat rate is considered a neutral option for economic efficiency and fairness, as it does not encourage (like a declining block structure) or discourage (like an inclining block structure) the use of electricity.

While the main point of the quotation above is that a flat rate does not encourage or discourage the use of electricity relative to the other rate structures mentioned, the principle of fairness amongst residential customers deriving from a flat rate structure is found in the fact that the potential for intra-class cross-subsidies, such as between high and low use customers where no costs basis exists to base rates on consumption level, is diminished.

75.2 Given that a flat rate will send different price signals to customers than an inclining rate, please explain why it is considered a "neutral option for economic efficiency" when compared to an inclining rate.

Response:

The complete excerpt from FBC's response to BCUC 1.36.1 is as follows:

> Compared to other rate structures, a flat rate is considered a neutral option for economic efficiency and fairness, as it does not encourage (like a declining block structure) or discourage (like an inclining block structure) the use of electricity.

It is precisely because the inclining block rate will send different pricing signals depending on the level of consumption, while the flat rate does not, that the flat rate is considered neutral in comparison. It is a simple matter of fact that all rates will send a pricing signal since bill amounts are dependant in part on the price in the rate; however, the spread between the Tier 1 and Tier 2 rates in a RIB rate is an added element that does not exist with a flat rate. Returning to a flat rate can also be considered a neutral option relative to an inclining block structure because it will send a stronger price signal to consumption below the threshold and a lower price signal for consumption above the threshold – the two effects may be somewhat offsetting.

76.0 Reference: Exhibit B-8, BCUC 38.2 and BCUC 38.3 Exhibit B-12, BCSEA 12.2
Exhibit B-11, BCOAPO 42.1, 42.2 and 42.3
BCUC Order G-3-12, page 41

Preamble: BCUC Order G-3-12 include the following observations and directives:

"Thus, there is ambiguity between the LMRC as defined by FortisBC and the true long-run marginal cost of new supply to the customer. The Block 2 rate is a delivered rate, while the LRMC is a cost of acquisition – it only relates to the cost of procuring energy but does not include the LRMC of transporting that energy to customers through transmission and distribution networks."

"However, FortisBC is directed to provide an update of the full long- run marginal cost of acquiring energy from new resources, including the cost to transport and distribute that energy to the customer as part of the reporting to be submitted in 2014."

76.1 Based on the responses to BCOAPO 42.1 and 42.2, please provide a high level system-wide estimate of FBC's long run marginal costs (including transmission and distribution) expressed in 2017$ / MWh..

Response:

FBC's Long Run Marginal Cost (LRMC) of $96 per MWh (2015$) referenced in BCOAPO IR 1.42.1 is based on FBC's proposed preferred portfolio (A4) as described in the 2016 Long Term Electric Resource Plan (LTERP). In the LTERP decision published on June 28 2018, the BCUC did not accept FBC's proposed preferred portfolio in its entirety, specifically accepting up to the year 2024 and rejecting the years 2025 to the end of the planning horizon (G-117-18, Directive 1).

FBC does not have an established methodology for combining the LRMC of reliable power, which is a system level number, with marginal transmission and distribution costs. As stated in the DCE report, "T*&D [Transmission and Distribution] costs will only be reduced if a significant amount of load reduction is attained in an area where the utility expansion plans can be altered*".[1,2] FBC views the LRMC of power supply and the Deferred Capital Expenditures

[1] FBC 2017 DSM Application. Appendix C: Deferred Capital Expenditure Study. Page 23. Ex B-1, filed August 8, 2016.

[2] For additional discussion relating to locational aspects of conservation and network system reinforcements, please refer to:
- FBC 2016 LTERP. Response to BCOAPO IR 2.58.2.1 Series, filed as Ex-12, May 18, 2017
- FBC 2016 LTERP. Response to BCSEA IR 2.25.2, filed as Ex-13, May 18, 2017.

relating to infrastructure as two separate values expressed in different units and that apply to separate parts of the system. They cannot be readily combined and if summed together, would not be consistent with the established definition of "Long Run Marginal Cost"[3].

[3] 2016 LTERP. Appendix K – Section 1.2 Marginal Cost Definitions. Filed as Ex B-1, November 30, 2016.

77.0 Reference: Exhibit B-8, BCUC 49.4

Preamble: The response states: "In relation to RS 20, FBC has, in keeping with the overall direction toward an increased reflection of cost causation in rates, applied to increase the demand charge and reduce the energy charge."

The response also states: "At the same time as making the proposal to shift the cost recovery within the rate components, FBC views that the changes are consistent with the other principles.

77.1 Given that RS20 has no demand charges – should the first reference read "In relation to RS 20, FBC has, in keeping with the overall direction toward an increased reflection of cost causation in rates, applied to increase the customer charge and reduce the energy charge" (change underlined). If no change is required, please explain why.

Response:

Yes, the only fixed charge applicable to RS20 is the Customer Charge which is proposed to rise from $19.40 to $23.00 per month.

77.2 Please outline how the proposal to increase the demand (customer?) charge and reduce the energy charge is consistent with the other (ratemaking) principles.

Response:

The response to BCUC IR 1.49.4 also outlined the consideration given to the other principles,

> For the purpose of reviewing RS 20, as with other rates, FBC uses the principles as a means of assessing whether rate changes it may propose would tip the balance between the often competing objectives contained in the principles that cannot be justified by the impact of change.

This is consistent with the approach FBC has used in instances where an existing rate is not being considered for a structural change, and what is proposed is a redistribution of cost recovery within existing rate parameters to better align with the COSA. The Company has suggested the cost recovery shift in support of the cost causation principle and adjudged that doing so does not create an issue in light of any competing principle that would suggest that the change should not be made.

78.0 Reference: Exhibit B-8, BCUC 50.2 and BCUC 50.3

78.1 Given that the proposed RS 21 flat energy rate is less that either the current Tier 1 and Tier 2 energy rates which, in turn, are both less than FBC's current LRMC (per BCUC 38.2), please explain more fully why the flat rate maintains the price signal for energy efficiency (per BCUC 50.3) and thereby serves rate design principle 3 (per BCUC 50.2).

Response:

FBC's responses to BCUC IRs 1.50.2 and 1.50.3 were fulsome responses to the questions posed and FBC does not have additional information to add.

79.0 Reference: Exhibit B-8, BCUC 50.3, BCUC 50.4 and BCUC 50.8

Preamble: The response to BCUC 50.3 states: "Generally speaking the bill impacts of the proposed changes are modest". The response to BCUC 50.4 states: "Since the average bill impacts across the consumption strata are relatively modest, FBC does not expect to see large changes in customer behaviour from the proposed RS 21 changes".

The response to BCUC 50.8 states: "FBC does not view a phased-in approach as required since, as shown in Table 6-16 of the Application, bill impacts are moderate across the consumption strata".

79.1 Given the proposed shift in cost recovery from energy charges to demand charges, please confirm that a customer's bill impact will vary depending upon the monthly load factor.

Response:

Confirmed.

79.2 What is the range of monthly load factors for FBC's 1,370 RS 21 customers?

Response:

The Company consulted with EES to provide the following response.

The average monthly load factor for an individual RS 21 customer can range anywhere from 4 percent to 86 percent.

79.3 What is the average monthly load factor for the RS 21 customers in each consumption strata set out in Exhibit B-1, Table 6-16?

Response:

The Company consulted with EES to provide the following response.

The following table shows the average monthly load factor for RS 21 customers by consumption strata.

Annual Consumption Between			Average Monthly Load Factor
2,200,000	and	Above	66.4%
2,000,000	and	2,200,000	64.5%
1,800,000	and	2,000,000	53.3%
1,600,000	and	1,800,000	62.0%
1,400,000	and	1,600,000	49.0%
1,200,000	and	1,400,000	63.5%
1,000,000	and	1,200,000	53.1%
800,000	and	1,000,000	50.9%
600,000	and	800,000	46.1%
400,000	and	600,000	47.9%
200,000	and	400,000	41.6%
0	and	200,000	27.8%

79.4 Based on the foregoing responses, doesn't the range of bill impacts set out in Table 6-17 provide a better indication as to whether or not the bill impacts from the proposal are "moderate"?

Response:

FBC notes that Table 6-17 should contain the values included in the following table for Percent Bill Impact rather than the values shown in the Application version. FBC is filing an errata to correct this, concurrent with the filing of these IR responses.

Annual Bill Impact	# of Customers	Percent of Customers	Percent Bill Impact
Greater than 10% Increase	66	4.8	15.82
5-10% Increase	73	5.3	6.83
0-5% Increase	311	22.7	1.89
0-5% Decrease	424	30.9	-2.32
5-10% Decrease	369	26.9	-7.31
Greater than 10% Decrease	127	9.3	-11.44
Total	**1,370**	**100.0%**	**100.0%**

Both Tables 6-16 and 6-17 provide bill impacts but divide customers up on a different basis. FBC does not view one as better than the other in assessing bill impacts.

79.5 Does FBC consider the bill impacts, as set out in Table 6-17, to be "moderate"?

Response:

Referring to the corrected Table 6-17 values as shown in the response to BCOAPO IR 2.79.4, yes. While there is a relatively small number of customers with an adverse bill impact above what would be considered a rate shock level, these customers have an average load factor of less than 6 percent which indicates both that their use of the system is very inefficient and may justify an increase above what would normally be acceptable, and that their operations may benefit from additional attention from FBC staff to find opportunities for cost savings. FBC will review the accounts of the most adversely impacted customers in consideration of the rate changes.

80.0 Reference: Exhibit B-8, BCUC 68.4 and BCUC 1.2

80.1 Using the proposed change in Rate Schedule 103, please indicate how the FBC's revenues would change:

i) Assuming the BCUC accepts the interpretation of the PTP service language as set out in section 7.2.

Response:

The PTP service language discussed in Section 7.2 is only relevant to Rate Schedule 101 and 102, and will have no impact on Rate Schedule 103. Please refer to the response to BCUC IR 2.125.1.

ii) Assuming the BCUC does not accept the interpretation of the PTP service language as proposed by FBC in section 7.2.

Response:

The PTP service language discussed in Section 7.2 is only relevant to Rate Schedule 101 and 102, and will have no impact on Rate Schedule 103. Please refer to the response to BCUC IR 2.125.1.

81.0 Reference: Exhibit B-8, BCUC 75.2

Preamble: The response states: "Revenue variances from forecast are currently captured in the flow through deferral account and recovered from or refunded to customers in subsequent periods.

81.1 Please confirm that revenue variances from forecast for optional TOU Residential rate customers will be recovered from all customers and not just Residential customers.

Response:

Please refer to the response to BCUC IR 2.138.2.

82.0 Reference: Exhibit B-8, BCUC 76.10

Exhibit B-15, ICG 18.1

Exhibit B-1, Attachment H, Rate Schedule 2A

82.1 For purposes of eligibility for RS 22A and RS 33, what does FBC consider to be a "satisfactory load factor" and why is load factor a consideration for purpose of eligibility?

Response:

As outlined in section 5.1.4 of the 1997 Rate Design and New Service Options Application, where the TOU rates were first proposed, the load factor restriction is considered to be necessary for the reasons stated there:

> The proposed restriction (see TOU Tariffs, Applicable, lines 5 - 7) for customers with low load factors provides sufficient flexibility to meet the needs of participating customers while protecting the interests of non-participating customers.

In determining what constitutes an acceptable load factor the Company will assess each situation individually to determine whether allowing a customer to take or remain on TOU service adversely affects the remaining customers in the class, and whether a poor load factor contributes to the impact.

The Company cannot determine a universally applicable numerical load factor threshold that would indicate acceptability but considers that adverse impacts on non-participating customers would result if the class revenue to cost ratio dropped to the point where rebalancing would be required or the revenue loss was sufficient to cause a general rate increase.

It is highly unlikely that for rate classes with a large number of customers, that an individual customer would be denied on this basis. However, for customer classes such as Large Commercial or Wholesale, a single customer opting for TOU may have an impact.

82.2 It is noted that a similar requirement (i.e., a satisfactory load factor, as determined by FBC) exists with respect to other proposed TOU rates (e.g., RS 2A – Residential TOU). In each case, what would FBC consider to be a "satisfactory" load factor?

Response:

Please refer to the response to BCOAPO IR 2.82.1.

83.0 Reference: Exhibit B-8, BCUC 79.1.3 and BCUC 75.1

83.1 The response to BCUC 75.1 addresses variances that occur after the fact due to the actual loads and revenues for customers on the optional Residential TOU rate being different from forecast. Does FBC agree that optional Residential TOU rates can also lead to a variance in forecast revenues at the times rates are set as the revenues forecast to be received in the test year from the customers assumed to be on TOU rates can differ from the forecast revenues in the test year assuming these same customers were all on the default Residential rate.

Response:

The Company consulted with EES to provide the following response.

FBC agrees that at the times rates will be set the revenues from customers that have selected the optional TOU rate may differ from the revenues from those same customers had they stayed on the default Residential Rate.

83.1.1 If not agreed, please explain why.

Response:

Please refer to the response to BCOAPO IR 2.83.1.

83.1.2 If agreed, please indicate whether any such shortfall/surplus in forecast revenues from Residential customers choosing the optional TOU rate will be made up by increasing/decreasing the rates in the test year for I) just Residential customers or ii) all FBC customers.

Response:

Any revenue shortfalls or surpluses from Residential customers (or customers in other classes) choosing the optional TOU rate will be made up by increasing / decreasing the rates of all FBC customers. Please see the response to BCUC IR 2.138.2 for discussion of this issue.

84.0 Reference: Exhibit B-8, BCUC 79.1.8

84.1 Does "economic fairness" as used in this response have the same meaning as in the response to BCUC 8.4? If not, how does it differ?

Response:

Yes. In both instances economic fairness refers to the principle of cost causation (Principle 2).

84.2 Please explain further how offering a first year bill guarantee I) distorts the efficient price signal and ii) weakens the economic fairness qualities of TOU rates.

Response:

As noted in the response to BCUC IR 1.79.1.8, the first year bill guarantee for a customer signing up for TOU rates would mean that the customer would pay no more in their annual electricity bill under TOU rates than under the rate structure in place for the year prior to adopting TOU rates. FBC believes the customer's motivation to respond to the TOU price signals will be diminished if the customer knows that at the end of the year they will be kept whole on their annual bill. This comment applies to both the i) and ii) parts of the question. There are other distortions introduced by a bill guarantee such as the potential for masking year-to-year consumption differences that arise from weather variations or other customer behaviour changes (such as acquiring new appliances or different yearly vacation plans) unrelated to responding to TOU rates.

85.0 Reference: Exhibit B-8, BCUC 80.3.1 and BCUC 80.3.2

Exhibit B-1, pages 112-114

85.1 What is the number of hours in the on-peak, mid-peak and off-peak periods based on FBC's proposal?

Response:

The Company consulted with EES to provide the following response.

The number of hours per period are listed below. Note that these hours reflect 2016, which was a leap year. This is the year for which AMI data was available for determining the kWh split by TOU period.

- 998 On-Peak;
- 2,516 Mid-Peak; and
- 5,270 Off-Peak.

85.2 What would be the number of hours in the on-peak, mid-peak and off- peak periods if June was also included as summer month (as opposed to a shoulder month)?

Response:

The Company consulted with EES to provide the following response.

The number of hours per period with June included as a summer month are listed below. Note that these hours reflect 2016, which was a leap year.

- 1,196 On-Peak;
- 2,318 Mid-Peak; and
- 5,270 Off-Peak.

85.3 Please re-do Table 8-8 assuming June was also included as a summer month (as opposed to a shoulder month).

Response:

The Company consulted with EES to provide the following response.

The following table shows the TOU Rate Differential when June is included as a summer month.

	Annual Cost	Energy Amount	Cost Differential per kWh
On-Peak Peak Capacity Cost of Both Purchased and Owned Resources	$56 million	616 GWh On-Peak	$0.0909
Mid-Peak Energy Purchases Beyond Output from Owned Resources	$42 million	1,006 GWh Mid-Peak	$0.0259

86.0 Reference: Exhibit B-8, BCUC 88.9 Exhibit B-8, BCUC 87.3

Preamble: Attachment 88.9 does not provide the rate calculations for the rates presented in Table 8-10 which were also requested in the BCUC 88.9.

86.1 Please provide the fully functioning Excel model that sets out the calculations underlying the rates presented in Table 8-10, In doing so please include the derivation of the various adjustments described in Exhibit B-1, page 114 and BCUC 87.3 (e.g., i) the adjustments to the electricity use by period to account for the impacts of TOU rates and ii) the adjustment to account for reduced power supply costs)

Response:

Please refer to the response to BCUC IR 1.88.9.

87.0 Reference: Exhibit B-8, BCUC 87.3 Exhibit B-8, BCUC 88.6 Exhibit B-8, BCUC 93.1 Exhibit B-1, page 114

Preamble: Exhibit B-1 indicates that the TOU rates "needed to be slightly higher to maintain revenue neutrality" as a result of the application of the price elasticity assumptions to the electricity usage by period.

The Application and BCUC 87.3 indicate that the calculation of the TOU rates took into account the impact of savings in power supply that result for the changes in consumption.

87.1 Does the reference to the rates needing to be "slightly higher" take into account: i) just the effect of the change usage patterns (i.e., lower use in the on-peak period but higher use in the mid and off-peak periods with an overall reduction in total usage or ii) does it also take into account the reduction in power supply costs?

Response:

The Company consulted with EES to provide the following response.

The changes in usage patterns, (and overall reduction in consumption) and power supply impact are related. While the reduction in usage leads to higher TOU rates, the savings in power supply costs leads to lower TOU rates. After accounting for both factors, the net result is a slightly higher TOU rate. If the reduction in power supply costs had not been accounted for, the TOU rates would have been higher.

87.2 Overall, does the incorporation of price elasticity effects on usage by period and the resulting impact on power supply costs result in lower or higher TOU rates than if neither of these two considerations had been taken into account?

Response:

The Company consulted with EES to provide the following response.

If neither of those two factors had been incorporated in the analysis, the TOU rates would have been lower.

87.3 If TOU rates are higher overall, does this mean that the default rates for Residential customers will also be higher if, during the rate setting process, a portion FBC's customers are assumed to "opt" for TOU rates?

1. If not, why not?

Response:

The Company consulted with EES to provide the following response.

The TOU rates and default rates are set such that revenues are equal to one another with all customers on each respective rate. TOU rates are not set by assuming a particular participation rate, nor are default rates set by assuming a percent that would remain on default rates. The number of customer that "opt" for the TOU rates will not have an impact on the proposed rates within the rate setting process.

2. If yes, please indicate how this result is consistent with FBC's rationale for offering optional TOU rates that they "deliver benefits to customer(s) in general" (per BCUC 93.1).

Response:

Not applicable as the response to BCOAPO IR 2.87.3.1 is "no".

88.0 Reference: Exhibit B-8, BCUC 79.1.2

Exhibit B-1, page 72

88.1 The Application (page 72) states that one of reasons for moving to a flat rate is that the RCR "may create inequity amongst customers with regard to the ability to take steps to reduce consumption". Are there also differences between customers in their ability to take steps to either i) reduce usage in the on-peak period or ii) shift their usage from the on-peak to the mid-peak or off-peak periods?

Response:

FBC agrees that customers will have varying abilities to shift consumption between the pricing periods of the proposed TOU rates.

88.2 If yes, doesn't the offering of optional TOU rates potentially create inequity amongst customers, particularly if, as a result of customers opting for TOU rates, the default rates FBC offers its customers are higher than would otherwise (i.e., if no customers opted for TOU rates) be the case?

Response:

FBC does not believe that the varying abilities of customers to shift consumption as intended in the proposed TOU rates is comparable to the situation created by the RCR because, in contrast to the RCR, the TOU rates are optional. If the TOU rates achieve the intended result, i.e., the commensurate costs savings required to retain the program beyond the initial 3-year period, other customers will not see rate increases and may see decreases.

89.0 Reference: Exhibit B-8, BCUC 110.3

Exhibit B-1, Appendix D, page 10

89.1 The response to BCUC 110.3 indicates that the Equifax credit check and ID validation per transaction only relate to the setup of a new account. Appendix D indicates that the cost of these activities is $5.25 per transaction which represents roughly 40% of the total proposed charge for Account Setup or Transfer. Given the materiality of this cost and the fact it is only incurred in the case of new accounts, wouldn't it be reasonable to have a separate and lower charge for account transfers?

Response:

As noted in the response to BCUC IR 1.110.3, the $5.25 cost per transaction related to the Equifax credit check and ID validation relates only to the setup of new accounts for new customers. However, FBC believes a single charge for both an account setup or transfer is reasonable and should remain for the reasons set out in response to BCUC IR 1.110.4, and reproduced below:

1. As noted in response to BCUC IR 1.110.2, the work involved and the costs for such work for both scenarios is substantially similar;
2. Ease of understanding for customers;
3. Ease of administration for FBC;
4. Distinguishing each task for reporting purposes does not provide any benefit; and
5. It is consistent with current approved Tariffs for FBC and FEI, to charge a single charge for both the set-up of a new account and transfer of an existing account.

Please also refer to the responses to BCUC IRs 1.110.1, 1.110.2 and 1.110.4.

90.0 Reference: Exhibit B-11, BCOAPO 1.1

90.1 The initial IR focused specifically on the principles considered in the development of the COSA methodology. The response provided in the referenced information request (BCUC 3.1) addresses the role the various principles in design of rates and the proposed rate schedules. Please respond to the question as posed and indicate what role if any the other rate principles (apart from Principle #2 – cost causation) played in the development of the cost of service methodology.

Response:

BCOAPO IR 1.1.1 asked about the application of the eight Bonbright principles in the development of the Cost of Service Analysis methodology. FBC believes the COSA model is mainly focused on the fair apportionment of the utility's cost of service among various rate schedules (inter-rate class fairness). The inter-class aspect of Bonbright Principle 8 – avoidance of undue discrimination – also comes into play in the development of the COSA. Beyond Principles 2 and 8 FBC believes the other Bonbright principles are more clearly linked with rate design rather than the COSA methodology. For example, it might be argued that by using allocators such as peak demand to allocate the fair share of demand-related costs to the rate classes responsible for the costs, the COSA model also indirectly promotes the efficient use of the system; however, the efficient use of the system is better reflected in the rate design (although the rates are based on COSA, it is the rate structure and its elements that provide the context for sending the appropriate price signals to the customers). The other Bonbright principles such as bill impacts, revenue and rate stability, customer understanding and acceptance as well as other rate design considerations such as government policies are considered in the development of rate structures.

91.0 Reference: Exhibit B-11, BCOAPO 12.1 and 12.1.1 Exhibit B-11, BCOAPO 12.2
Exhibit B-11, BCOAPO 12.5
Exhibit B-1, Appendix A, page 22

Preamble: 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".

BCOPAO 12.5 indicates that in the absence of RS 37 a contract demand would be established for RS 31 and that the prospective contract demand is undetermined.

91.1 The responses to BCOAPO 12.1 and 12.1.1 suggest that a customer taking service under a combination of RS 31 and RS37 would take the same level of service overall under just RS 31 if RS 37 was not available.

91.1.1 Please confirm if the above interpretation of the responses is correct.

Response:

From BCOAPO IR 2.91.1, the interpretation that FBC is being asked to confirm is that:

> …a customer taking service under a combination of RS 31 and RS37 would take the same level of service overall under just RS 31 if RS 37 was not available.

A customer taking service under a combination of RS 31 and RS 37 would be meeting a portion of its load equal to its Contract Demand under RS 31 and generally meeting the balance of its load with self-generation. In the event that the self-generation is unavailable, energy will be supplied pursuant to RS 37.

The Contract Demand is typically going to be set at a level required by the customer to maintain basic operations.

If RS 37 were not available, it is likely that the customer would maintain the same RS 31 Contract Demand, and meet the balance of its load through self generation. However, without RS 37, when the self-generation is offline, the customer may choose to temporarily cease operations, or take replacement power under RS 31 instead. The decision to take power under RS 31 could have a significant bill impact due to the demand ratchet provisions it contains.

A customer may take the same level of service, or may reduce the level of service depending on the overall cost of the options, including the cost of shutting down the industrial process.

91.1.2 Please reconcile these responses with the referenced quotes from: i) Appendix A which suggests that if RS 37 was not available the customer would reduce its required level of service from FBC and ii) BCOPAO 12.5 which suggests that if RS 37 was not available the customer would set a level of contract demand for RS 31 that is undermined (i.e., could be higher, lower or the same).

Response:

Please refer to the clarification provided in the response to BCOAPO IR 2.91.1.1.

91.2 The responses to BCOAPO 12.1, 12.1.1 and 12.2 suggest that FBC's planning with respect to both power supply and wires infrastructure is based on customers' full loads, including load met by the customer's self-generation.

91.2.1 Please confirm if this interpretation of the responses is correct.

Response:

This is not confirmed. While planning for infrastructure does consider the full load of the customer since that is the load that the infrastructure must be able to support, planning for resource acquisition considers only the load that FBC expects to have to serve.

91.2.2 If not, please indicate how customer's use of self-generation to supply its own load and requirements for RS 37 service are factored into the planning of future requirements for power supply and wires infrastructure.

Response:

Any energy that needs to be supplied under RS37 will be acquired only on an as needed basis and does not form a part of the expected annual load. The expected RS31 load is determined as part of the load forecasting process and will include consultations with the customer through an annual survey, past load requirements and expected future load growth.

92.0 Reference: Exhibit B-11, BCOAPO 13.5

92.1 For purposes of this response, what does FBC/EES consider to be a "significant impact"?

Response:

Within the context of the referenced response, a significant impact is one that would result in a customer class' revenue to cost ratio moving outside of the range of reasonableness and prompting rebalancing.

93.0 Reference: Exhibit B-11, BCOAPO 21.1

Exhibit B-8, BCUC 27.1

93.1 Please explain more fully how classifying a portion of DSM costs as distribution-customer is consistent with the planning basis for DSM (per BCUC 27.1) and the principle of cost causation.

Response:

The Company consulted with EES to provide the following response.

When evaluating whether or not a DSM measure is cost-effective, FBC looks at the avoided cost of power supply as well as future T&D costs. However, the COSA is not based on future distribution costs but is instead based on embedded costs. The portion of DSM treated as distribution-related is treated on the same basis as all of the embedded distribution costs, which includes a customer-related component. While the DSM treatment in the COSA is not precisely the same as how it is treated when looking at the cost-effectiveness of conservation, it is intended to reflect the overall rationale for installing DSM measures.

94.0 Reference: Exhibit B-11, BCOAPO 25.2 and 25.3

Exhibit B-19, VOK 3 b)

Preamble: The response to BCOAPO 25.2 confirms that the Lighting customer counts used in the COSA represent the number of Lighting customers and not the number of lighting connections to FBC's system.

The response to BCOAPO 25.3 states that apart from the Wholesale Customer class, all other customers have only one "connection" to FBC's system.

94.1 With respect to the Lighting class, would customers include municipalities (other than those served as Wholesale customers) who have streetlights?

Response:

The Company consulted with EES to provide the following response.

Yes, it would include municipal customers with multiple street lights. Street lights (and other unmetered loads) are different than most other classes because they do not have a meter and service line specific to every light. The number of customers for street lighting may reflect an appropriate amount when looking at costs related to sending out a bill or customer service, but it is not clear that the number is appropriate in terms of a minimum system analysis. Often the results of the COSA are less reliable for the lighting class due to this issue as well as the fact that consumption is estimated rather than metered. However, the revenues associated with street lights (and other unmetered loads) are small relative to the remaining classes and as such will have little or no impact on the RC ratios for other classes.

94.1.1 In not, for such street lights, who is considered the customer?

Response:

Not applicable as the response to BCOAPO IR 2.94.1 is "yes".

94.1.2 If yes, wouldn't the street lighting service provided to such municipalities involve more than one connection to FBC's system?

Response:

The Company consulted with EES to provide the following response.

Yes, please refer to the response to BCOAPO IR 2.94.1.

94.1.3 If street lighting service to such municipalities involves more than one connection to FBC's system, why isn't each such connection considered a "customer" for purposes of the minimum system methodology and the allocation of the customer-related portion of distribution plant costs?

Response:

Please refer to the response to BCOAPO IR 2.94.1.

94.2 With respect to unmetered non-lighting loads (billed as General Service), in the situation where one telecom provider owns and requires service for multiple telephone booths, is the telecom provider considered one "customer" or is each telephone booth considered "one customer" for purposes of the COSA and, in particular, the application of the minimum system methodology and the allocation of the customer-related portion of distribution plant costs?

Response:

Please refer to the response to BCOAPO IR 2.94.1.

94.2.1 If the former please explain why such customers are only considered to have one connection.

Response:

Please refer to the response to BCOAPO IR 2.94.1.

94.3 With respect to unmetered non-lighting loads (billed as General Service), in the situation where a municipalities (other than those served as Wholesale customers) owned and required service for multiple traffic lights, is the municipality considered one "customer" or is each traffic light considered "one customer" for purposes of the COSA and, in particular, the application of the minimum system methodology and the allocation of the customer-related portion of distribution plant costs?

Response:

Please refer to the response to BCOAPO IR 2.94.1.

94.3.1 If the former please explain why such customers are only considered to have one connection.

Response:

Please refer to the response to BCOAPO IR 2.94.1.

94.4 With respect to VOK 3 b) indicates that there are (at least) four commercial customers that have multiple service points. For purposes of the minimum

system calculation is each of these service points treated as a separate "customer"?

Response:

The Company consulted with EES to provide the following response.

Yes.

95.0 Reference: Exhibit B-11, BCOAPO 31.2.2

OEB, Board Directions on Cost Allocation Methodology for Electricity Distributors (EB-2005-0317), page 60 (https://www.oeb.ca/documents/cases/EB-2005-0317/report_directions_290906.pdf)

Preamble: It is noted that the OEB also established tests for determining the appropriate NCP allocator to use for distribution costs.

95.1 The intent of the original question was to solicit what the results would be from the various tests if they were applied to FBC's NCP data. Please provide the results of the OEB's tests with respect to NCP to the FBC data.

Response:

The Company consulted with EES to provide the following response.

The peak demand used for the FERC and OEB tests is based on peak loads for the entire system, which are metered. The NCP information is estimated for use in the COSA for the 2017 test year only. Based on that test year, and using the sum of the individual NCP values, the result of the OEB Test would be a recommendation for the 12 NCP for distribution costs.

96.0 Reference: Exhibit B-11, BCOAPO 31.3

96.1 Please confirm that Residential with Net Metering and Residential w/o Net Metering are not separate customer classes but rather both sub- sets of the Residential class (similar to Residential with Gas Access and Residential w/o Gas Access being subsets of the Residential class as opposed to separate customer classes).

Response:

The Company consulted with EES to provide the following response.

The Residential with Net Metering and Residential w/o Net Metering classes are set up in the COSA so that they can be viewed as either separate customer classes or as a combined class. FBC chose not to treat them as separate rate classes when developing the proposed rates.

96.2 What would be impact on the NCP value for the Residential class if the class' NCP value was calculated not by adding the NCP values for Residential with and without Net Metering but rather by determining the NCP for the class overall?

Response:

The Company consulted with EES to provide the following response.

There would be no difference in the NCP value.

97.0 Reference: Exhibit B-11, BCOAPO 33.2 and 33.2.1

Preamble: The responses state that the CUSTW weighting factors used are the same as those used in the COSA for 2009 and that consultations with staff indicated it was not necessary to change the factors for 2017.

97.1 Please confirm that the CUSTW weighting factor is used in the allocation of meter reading costs.

Response:

The Company consulted with EES to provide the following response.

Confirmed.

97.2 Please confirm when FBC started to use AMI meter readings for customer billing purposes.

Response:

FBC began using AMI meter readings for customer billing purposes in July 2015.

97.3 Does the adoption of AMI metering and AMI meter reading alter the cost of meter reading for Residential customers relative the cost pre- AMI metering?

Response:

The Company consulted with EES to provide the following response.

The cost of meter reading went down for Residential customers as a result of AMI metering. In a few instances, specifically for the wholesale and large commercial classes, customers already had hourly meters that were read remotely and so did not see a cost reduction related to AMI metering.

97.4 Does the introduction of AMI meters and AMI meter reading for some customer classes alter the relative weighting factors for meter reading for purposes of the COSA?

Response:

The Company consulted with EES to provide the following response.

No, the level of effort is basically the same on a relative basis. Note that the CUSTW weighting factors were developed based on a variety of customer-related tasks, not just meter reading in isolation.

98.0 Reference: Exhibit B-11, BCOAPO 36.3

Exhibit B-11, BCOAPO 27.1

Preamble: The response to BCOPAO 36.3 assumes that such transmission costs would be classified a demand related and allocated on the basis of the 2 CP allocator and that the classification and allocation of all other Generation costs would remain unchanged.

The response to BCOAPO 27.1 states "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"

98.1 Given that the 3808 rates used to classify FBC's various power supply sources include transmission to the FBC system, why wouldn't it be reasonable to also apply the resulting energy/demand factors to the transmission costs associated with each power supply source?

Response:

The Company consulted with EES to provide the following response.

It would be reasonable to separate out the transmission assets that are associated with generation integration, functionalize them as production, and treat them on the same basis as power supply classification. In those cases where FBC buys delivered power, such as with the Brilliant and Waneta contracts, any transmission component is included in the contract price and would already be treated the same as generation. There are a few generation-integration assets included in FBC transmission accounts and they have all been functionalized as transmission in the COSA. This is consistent with the COSAs approved in the past. While those assets were removed from the transmission revenue requirement for purposes of wheeling rates, they were not removed for purposes of the COSA.

98.2 Alternatively, if these generation-related transmission costs are classified as demand-related and allocated on the basis of the 2 CP allocator, wouldn't it be necessary to adjust the 3808 rates used to classify FBC's other power supply sources in order to remove the transmission component of these rates?

Response:

The Company consulted with EES to provide the following response.

In setting up wholesale transmission rates FBC removed certain generation integration assets for the transmission revenue requirement because a customer needing access to FBC's transmission system would not need or have access to those assets. Similarly, the transmission provided by BC Hydro to deliver power under the 3808 contract would not be available to wholesale transmission customers and should not be included in the transmission revenue requirement.

For purposes of the COSA, it would not be appropriate to functionalize a portion of purchased power costs as transmission, if they could even be separated out, because they are not used in the same manner as FBC's own transmission facilities.

If a change was to be made to treat the transmission component of power purchases the same as generation integration assets, the appropriate change would be to treat the generation integration assets on the same basis as power supply, as discussed in the response to BCOAPO IR 2.98.2.

99.0 Reference: Exhibit B-11, BCOAPO 40.1

99.1 Please confirm that under FBC's Residential flat rate proposal the revenue to cost ratios for both segments will move closer together.

Response:

The Company consulted with EES to provide the following response.

Confirmed.

100.0 Reference: Exhibit B-11, BCOAPO 46.2

Exhibit B-8, BCUC 89.1

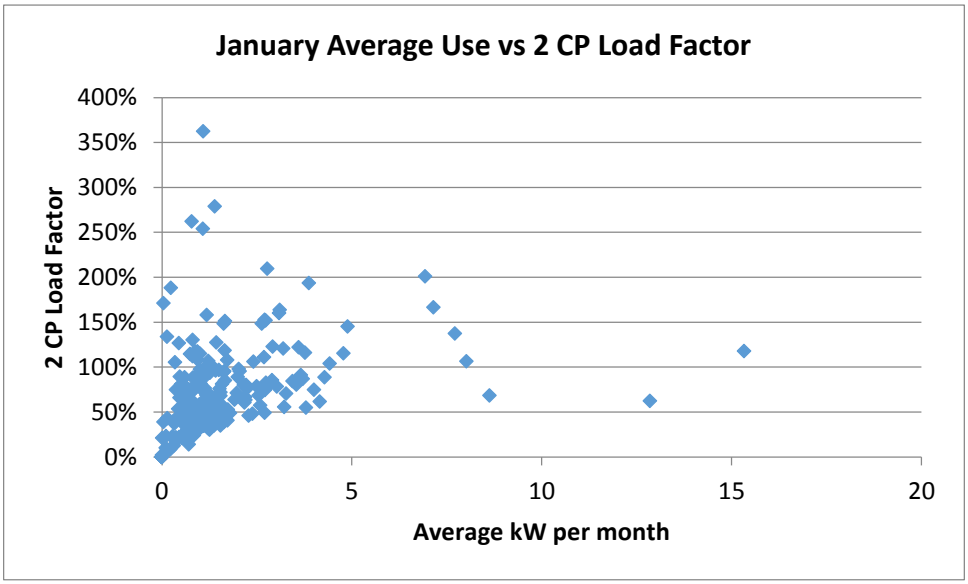
Exhibit B-1, Appendix A (EES Study) – Appendix C (Load Analysis), page 74

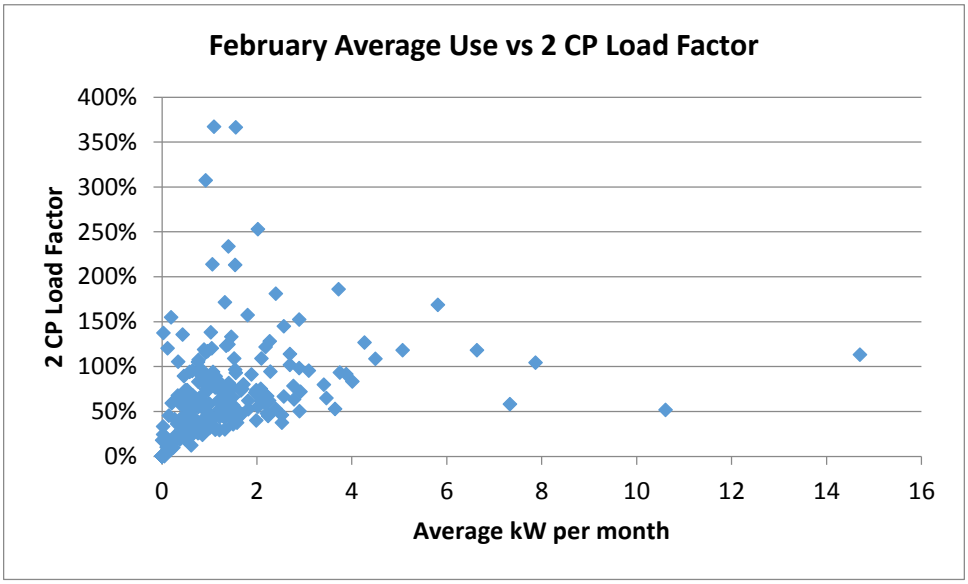
100.1 Using the sample of 233 Residential customers noted in the second and third references, please provide a response o BCOAPO 46.2 – as originally posed.

Response:

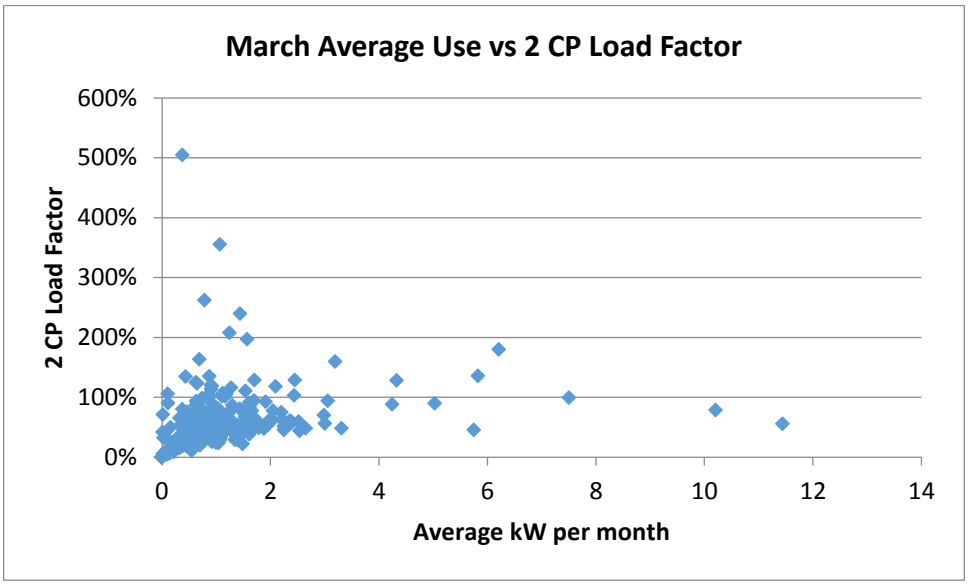
The Company consulted with EES to provide the following response.

The following graphs compare the average kW per hour to the 2 CP load factor and the NCP load factor, for each month, for the sample of residential customers. In the case of individual customers, the NCP load factor is the same as the individual load factor. On a class basis, the NCP is the sum of the individual peaks for all customers and those peaks occur in different hours. This is different than the 2 CP where it is based on the loads of customers at the same four hours of the year



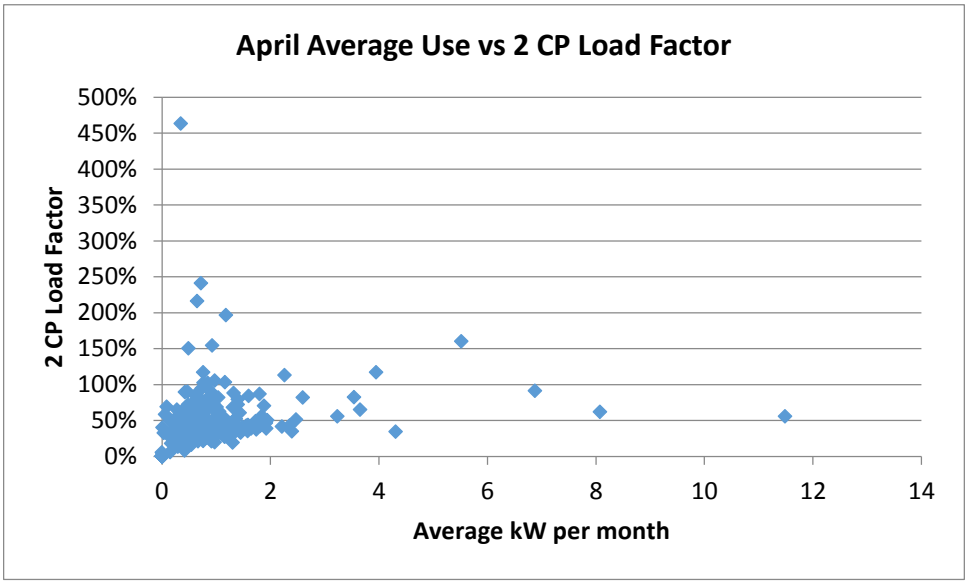

February Average Use vs 2 CP Load Factor
2 CP Load Factor
400%
350%
300%
250%
200%
150%
100%
50%
0%
0
2
4
6
8
10
12
14
16
Average kW per month

1

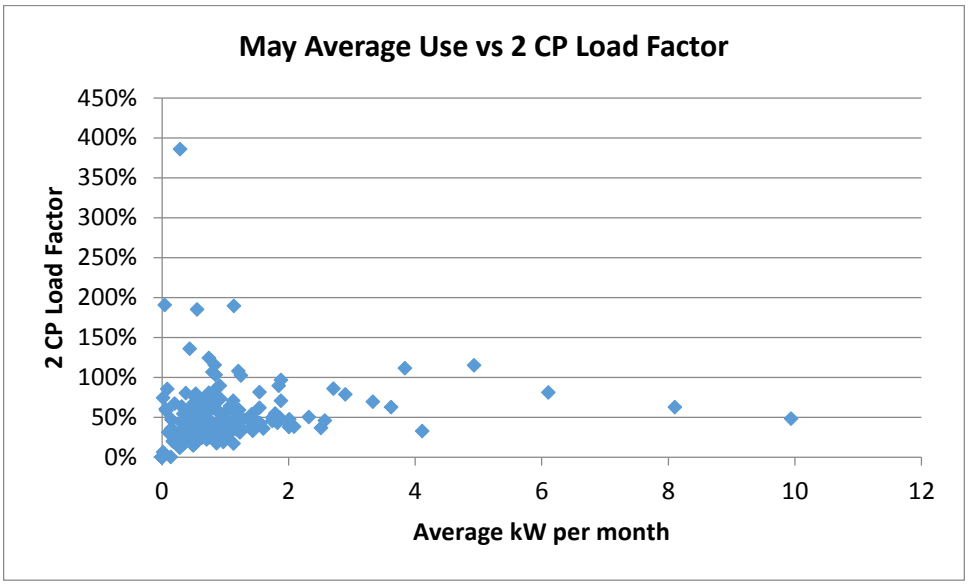

March Average Use vs 2 CP Load Factor
2 CP Load Factor
600%
500%
400%
300%
200%
100%
0%
0
2
4
6
8
10
12
14
Average kW per month

2

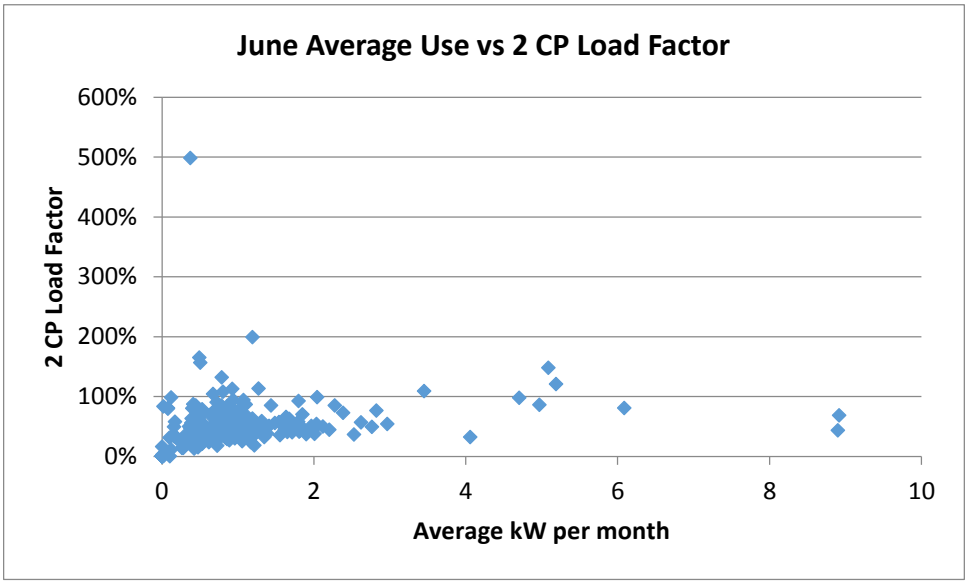
1


April Average Use vs 2 CP Load Factor
2 CP Load Factor
500%
450%
400%
350%
300%
250%
200%
150%
100%
50%
0%
0
2
4
6
8
10
12
14
Average kW per month

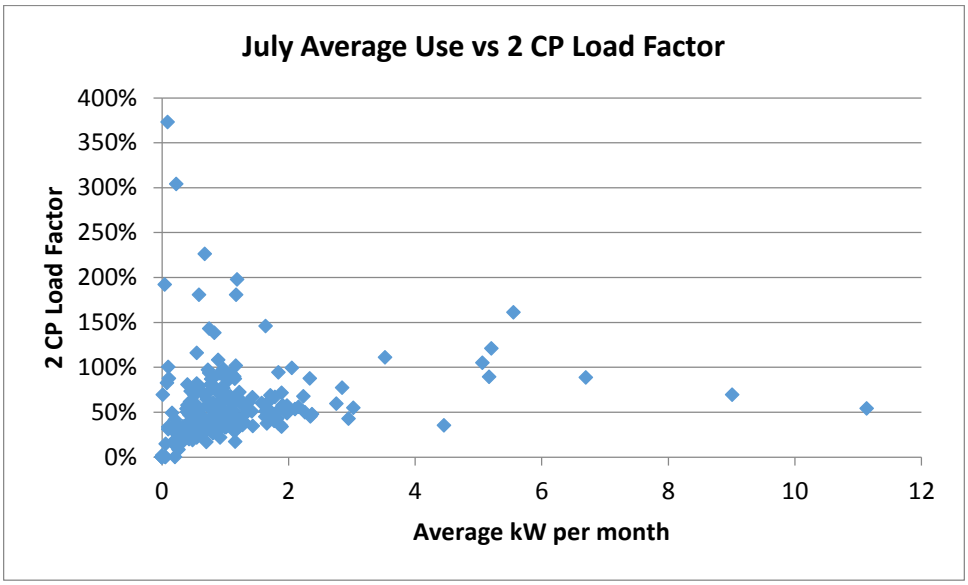
2

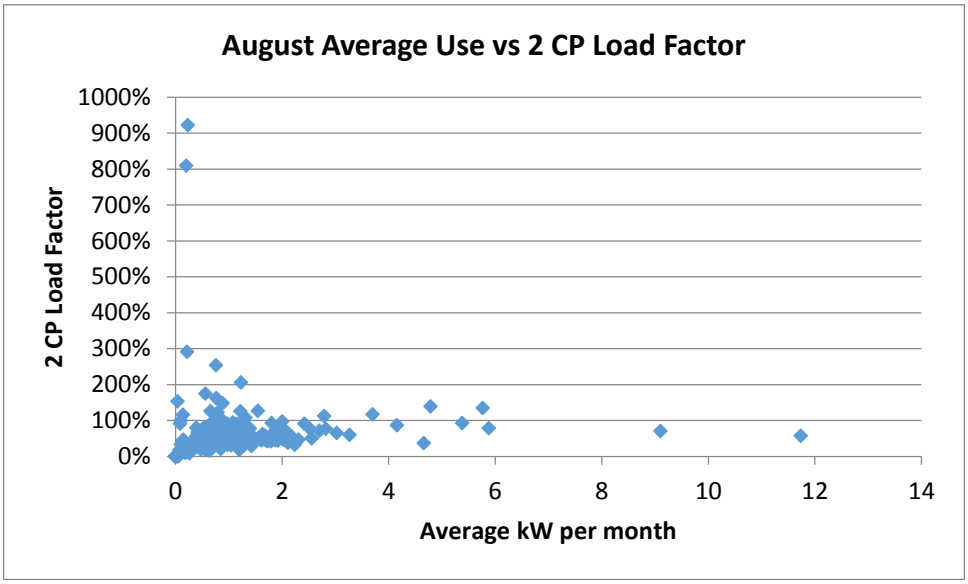

May Average Use vs 2 CP Load Factor
2 CP Load Factor
450%
400%
350%
300%
250%
200%
150%
100%
50%
0%
0
2
4
6
8
10
12
Average kW per month

1

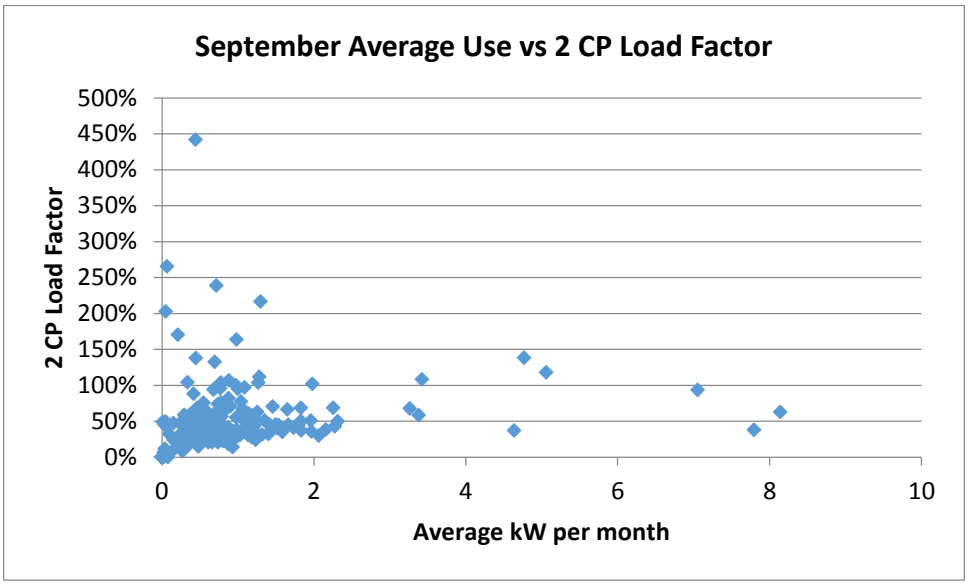

June Average Use vs 2 CP Load Factor
600%
500%
400%
300%
200%
100%
0%
2 CP Load Factor
0
2
4
6
8
10
Average kW per month

2


July Average Use vs 2 CP Load Factor
400%
350%
300%
250%
200%
150%
100%
50%
0%
2 CP Load Factor
0
2
4
6
8
10
12
Average kW per month

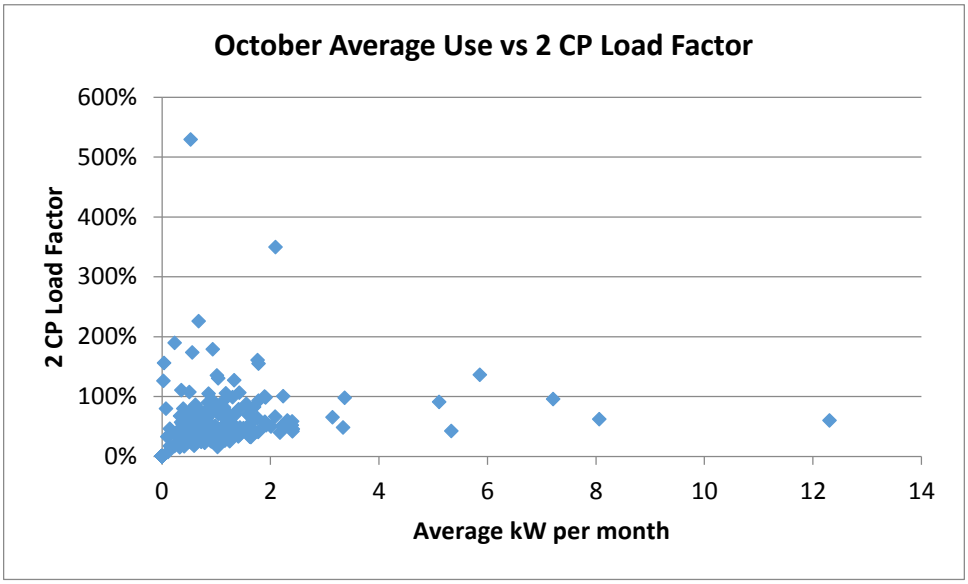

August Average Use vs 2 CP Load Factor
2 CP Load Factor
1000%
900%
800%
700%
600%
500%
400%
300%
200%
100%
0%
0
2
4
6
8
10
12
14
Average kW per month

1

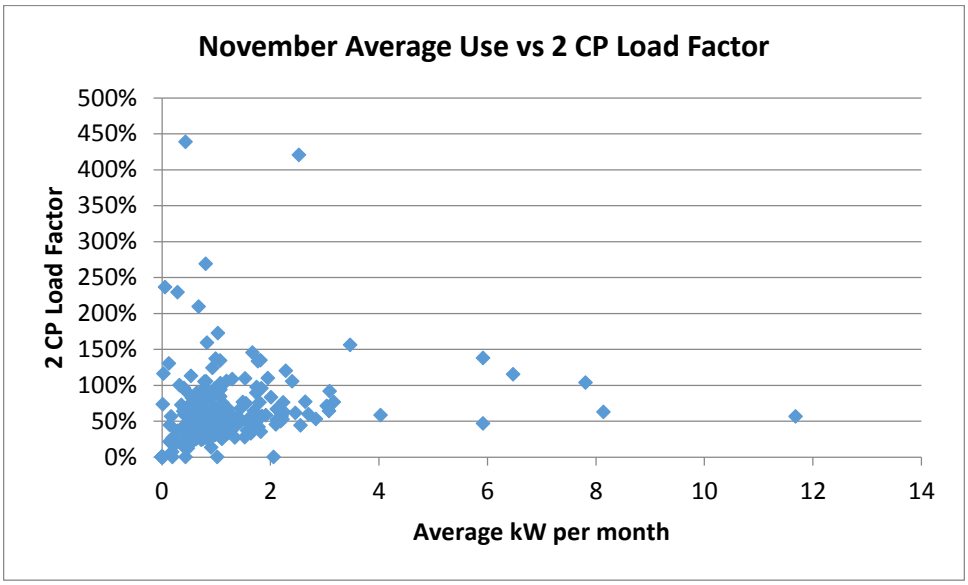

September Average Use vs 2 CP Load Factor
2 CP Load Factor
500%
450%
400%
350%
300%
250%
200%
150%
100%
50%
0%
0
2
4
6
8
10
Average kW per month

2

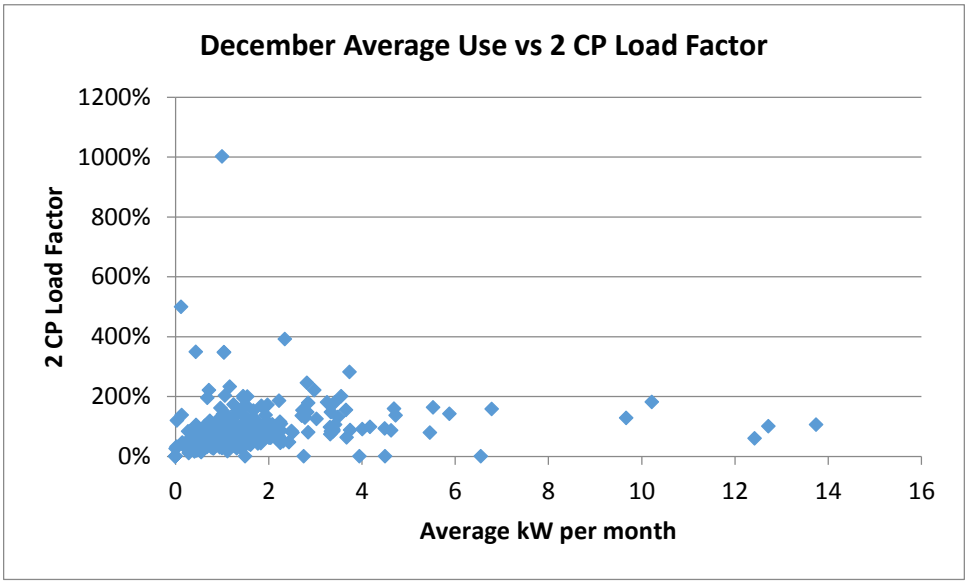
1


October Average Use vs 2 CP Load Factor
600%
500%
400%
300%
200%
100%
0%
2 CP Load Factor
0
2
4
6
8
10
12
14
Average kW per month

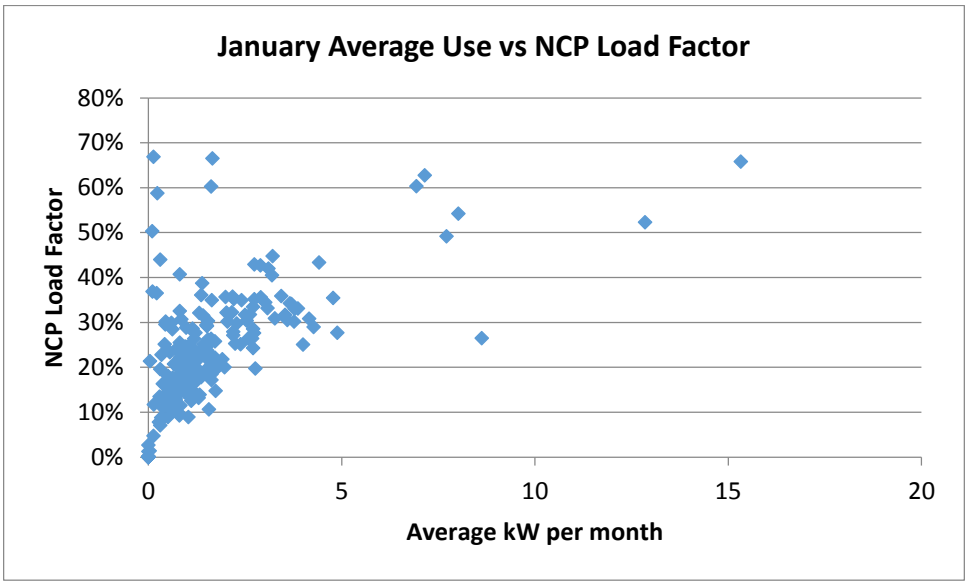
2


November Average Use vs 2 CP Load Factor
500%
450%
400%
350%
300%
250%
200%
150%
100%
50%
0%
2 CP Load Factor
0
2
4
6
8
10
12
14
Average kW per month

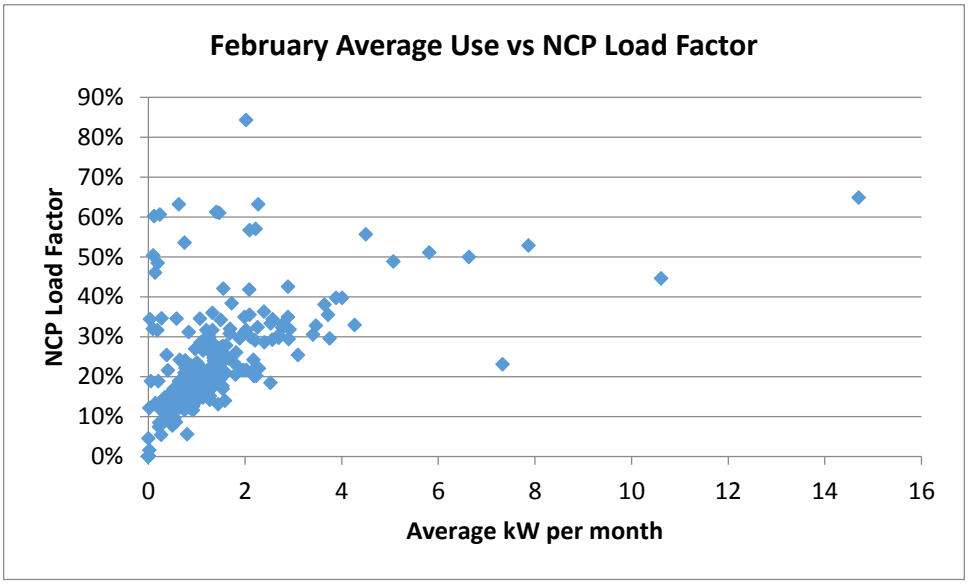
1


December Average Use vs 2 CP Load Factor
2 CP Load Factor
1200%
1000%
800%
600%
400%
200%
0%
0
2
4
6
8
10
12
14
16
Average kW per month

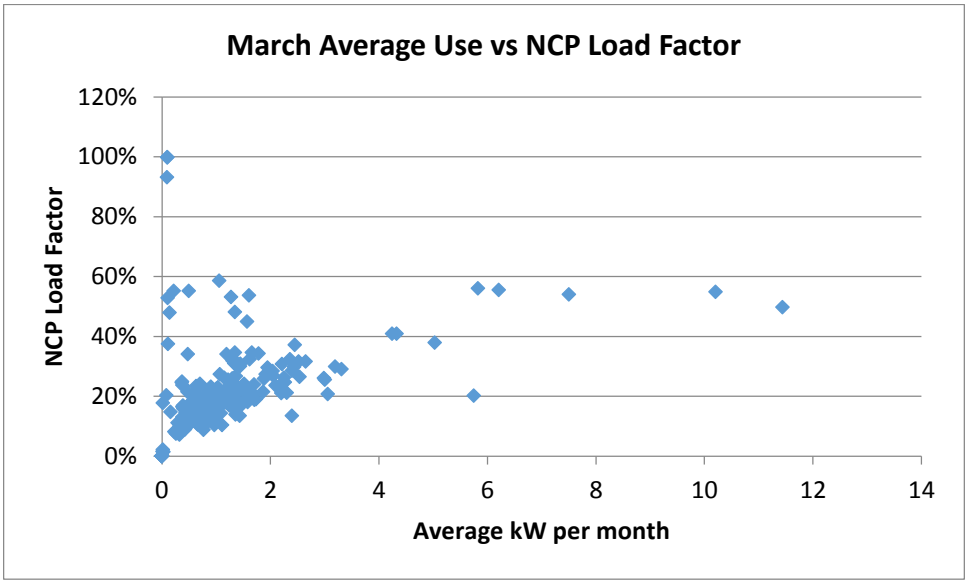
2

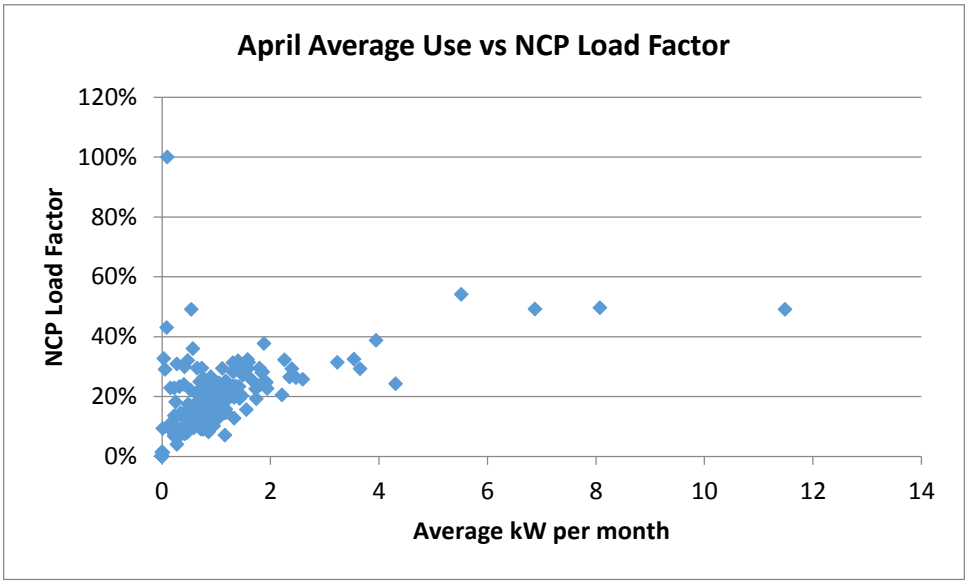

January Average Use vs NCP Load Factor
NCP Load Factor
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
5
10
15
20
Average kW per month

1

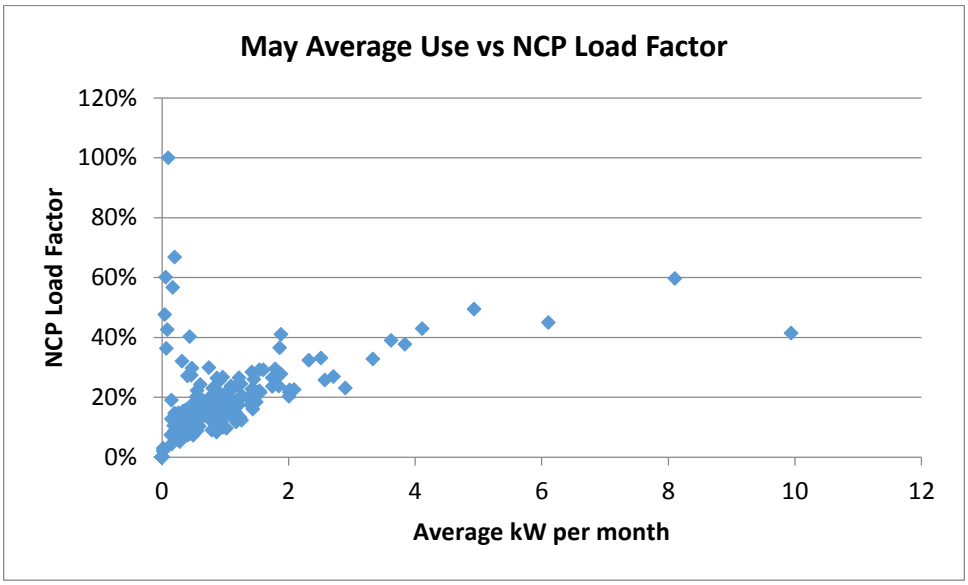

February Average Use vs NCP Load Factor
NCP Load Factor
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
2
4
6
8
10
12
14
16
Average kW per month

2


March Average Use vs NCP Load Factor
NCP Load Factor
120%
100%
80%
60%
40%
20%
0%
0
2
4
6
8
10
12
14
Average kW per month

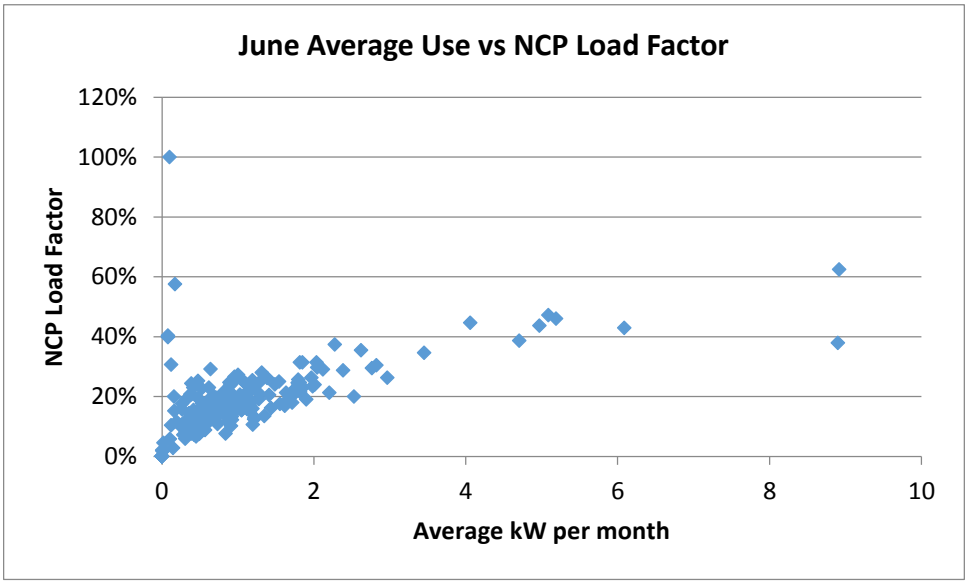

April Average Use vs NCP Load Factor
NCP Load Factor
120%
100%
80%
60%
40%
20%
0%
0
2
4
6
8
10
12
14
Average kW per month

1

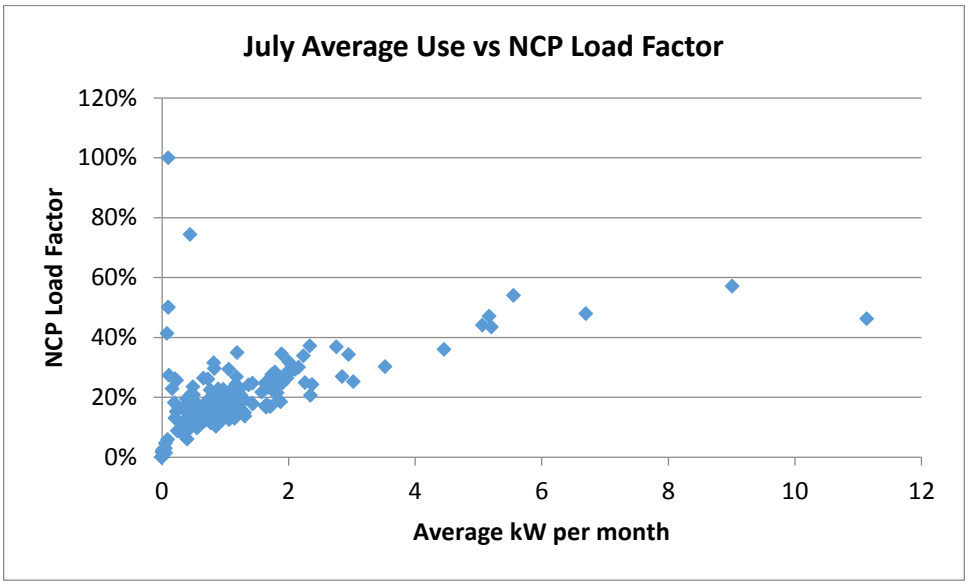

May Average Use vs NCP Load Factor
NCP Load Factor
120%
100%
80%
60%
40%
20%
0%
0
2
4
6
8
10
12
Average kW per month

2

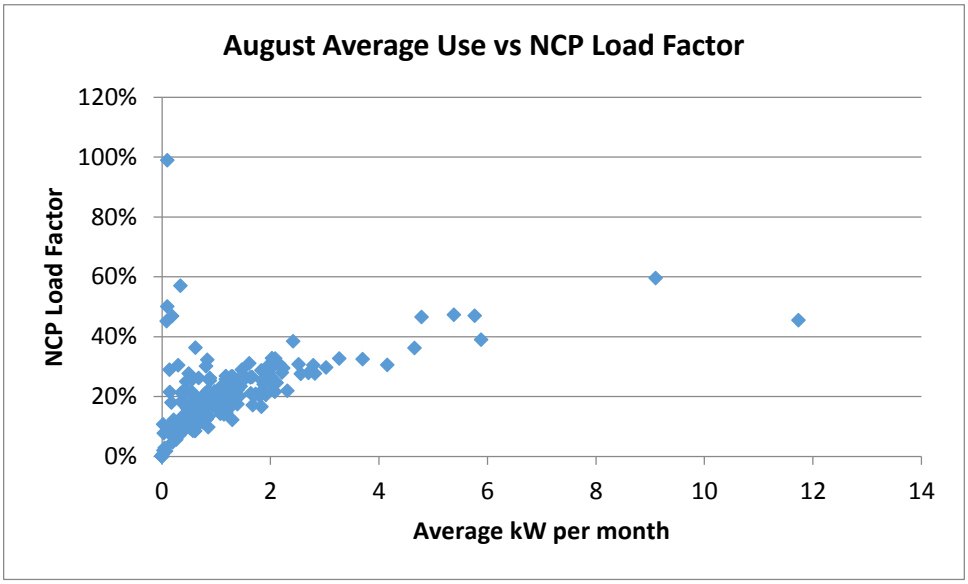
1


June Average Use vs NCP Load Factor
NCP Load Factor
120%
100%
80%
60%
40%
20%
0%
0
2
4
6
8
10
Average kW per month

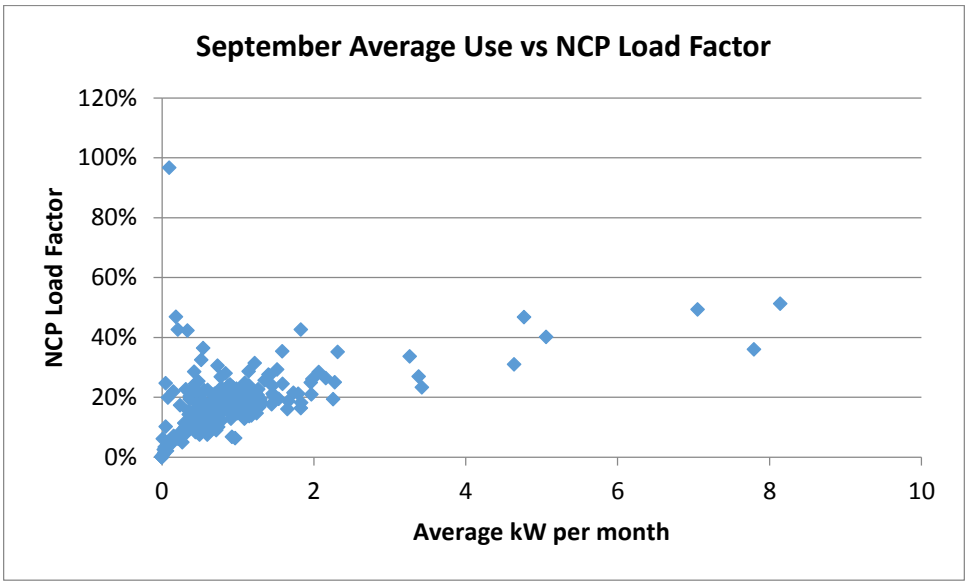
2

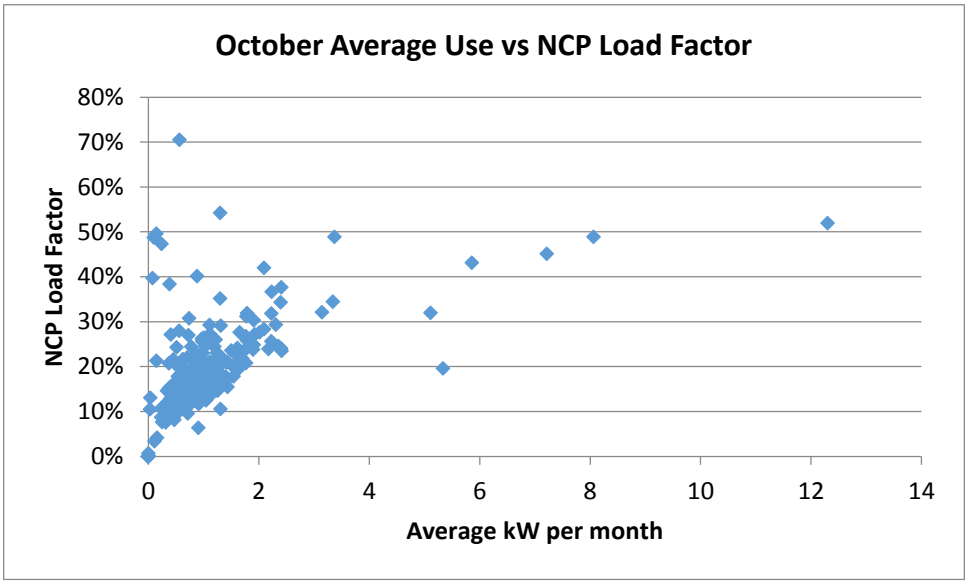

July Average Use vs NCP Load Factor
NCP Load Factor
120%
100%
80%
60%
40%
20%
0%
0
2
4
6
8
10
12
Average kW per month

1

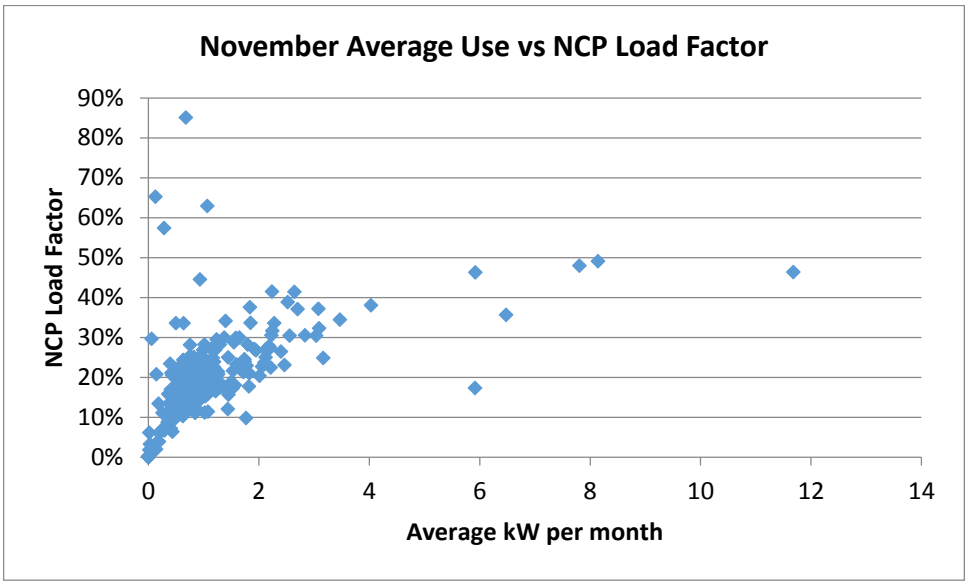

August Average Use vs NCP Load Factor
NCP Load Factor
120%
100%
80%
60%
40%
20%
0%
0
2
4
6
8
10
12
14
Average kW per month

2

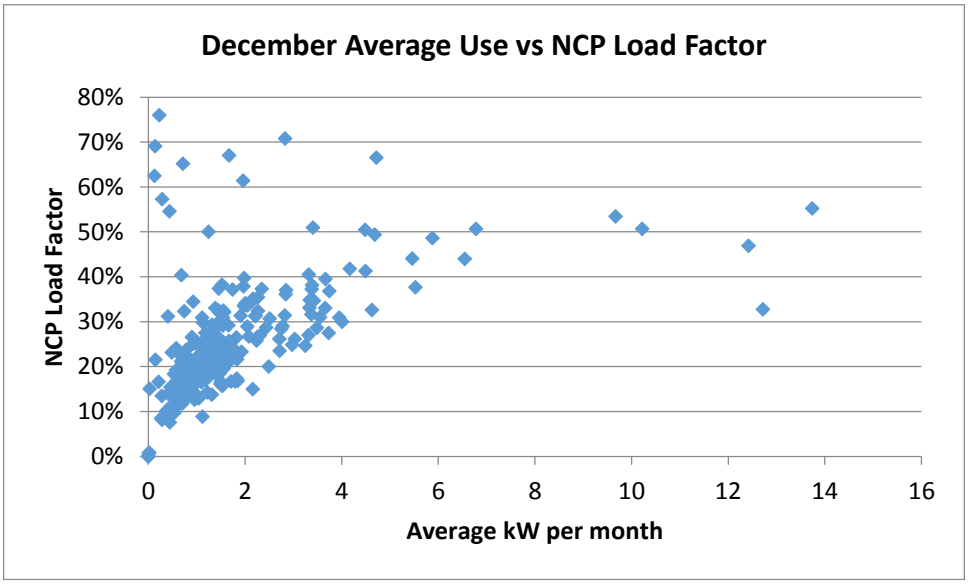

September Average Use vs NCP Load Factor
NCP Load Factor
120%
100%
80%
60%
40%
20%
0%
0
2
4
6
8
10
Average kW per month


October Average Use vs NCP Load Factor
NCP Load Factor
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
2
4
6
8
10
12
14
Average kW per month

1


November Average Use vs NCP Load Factor
NCP Load Factor
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
2
4
6
8
10
12
14
Average kW per month

2


December Average Use vs NCP Load Factor
NCP Load Factor
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
2
4
6
8
10
12
14
16
Average kW per month

1

2

101.0 Reference: Exhibit B-11, BCOAPO 49.1

Exhibit B-1, pages 76 and 78

101.1 What is the average monthly load factor for the 576 RS 21 customers with usage of less than 200,000 kWh per year

Response:

Please refer to the response to BCOAPO IR 2.79.3.

101.2 Based on this load factor what please provide a schedule that sets out the monthly bill for each of the following:

i) A RS 20 customer with a monthly energy use equivalent to 40 kW times 730 hours times the average monthly load factor calculated in part (1) using existing RS 20 rates (per Table 6-13).

Response:

The following table sets out the monthly bill (excluding taxes) for the scenarios requested in this and the next three IRs (BCOAPO IR 2.101.2 (i) through (iv)).

As shown in the response to BCOAPO IR 2.79.3, the average monthly load factor for RS 21 customers with annual consumption less than 200,000 kWh is 27.8 percent. The scenarios presented in the table use the monthly consumption of 7,972 kWh (40 kW x 730 hours x 27.8 percent) and do not include taxes or other fees.

	(i) Existing RS 20	(ii) Proposed RS 20	(iii) Existing RS 21	(iv) Proposed RS 21
Customer Charge	$19.40	$23.00	$16.48	$54.00
Energy	$812.70	$797.16	$693.04	$548.05
Energy (>8,000 kWh)	n/a	n/a	$0.00	$0.00
Demand (>40 kW)	n/a	n/a	$0.00	$0.00
Total ($)	**$832.10**	**$820.16**	**$709.52**	**$602.05**

ii) A RS 20 customer with a monthly energy use equivalent to 40 kW times 730 hours times the average monthly load factor calculated in part (1) using FBC's proposed RS 20 rates (per Table 6-13).

Response:

Please refer to the response to BCOAPO IR 2.101.2(i).

iii) A RS 21 customer with 40 kW of billing demand and a monthly energy use equivalent to 40 kW times 730 hours times the average monthly load factor calculated in part (1) using existing RS 21 rates (per Table 6-15)

Response:

Please refer to the response to BCOAPO IR 2.101.2(i).

iv) A RS 21 customer with 40 kW of billing demand and a monthly energy use equivalent to 40 kW times the average monthly load factor calculated in part (1) using FBC's proposed RS 21 rates (per Table 6-15).

Response:

Please refer to the response to BCOAPO IR 2.101.2(i).

102.0 Reference: Exhibit B-11, BCOAPO 56.1

Exhibit B-11, BCOAPO 28.1 Exhibit B-11, BCOAPO 17.1

Exhibit B-15, ICG 5.2 Exhibit B-17, KSCA 1.5.1

Exhibit B-1, Appendix A, page 29 – Table 7 Exhibit B-1, Appendix A, Schedule 3.1

FBC's Annual Review for 2018 Rates, Exhibit B-2, Table 4-2 FBC's Annual Review for 2017 Rates, Exhibit B-2-2,

Schedule 19

Preamble: BCOAPO states "the 2017 forecast power supply costs were used consistent with what was used in the COSA".

102.1 With respect to the BCH 3808 Purchases, please reconcile the difference between the total costs used in the COSA (Appendix A, Table 7 - $49.0 M) and the TOU Rate Design (BCOAPO 56.1 - $48.9 M) with the forecast/approved 2017 BCH 3808 cost of $46.968 M (per FBC's Annual Reviews for 2017 and 2018 Rates).

Response:

The Company consulted with EES to provide the following response.

The figures of $49.0 million and $48.9 million are both rounded numbers used for presentation purposes. A more precise number is $48,968,009. This cost is based on the 2017 forecast found in Schedule 19 of the Annual Review for 2017 Rates, October 5, 2016 Evidentiary Update (Exhibit B-2-2). The remaining difference is exactly $2 million and reflects the fact that when setting rates, FBC subtracts $2 million from BC Hydro expected costs to account for market opportunities throughout the year that may occur on an actual basis to displace BC Hydro power with cheaper alternatives. In all cases, the COSA and Rate Application is based on a forecast for 2017, not actual results for 2017.

102.2 With respect to Market Purchases, please reconcile the costs used in the COSA (Appendix A, Table 7 - $6.2 M) and the TOU Rate Design (BCOAPO 56.1 - $6.1 M) with the forecast/approved 2017 cost of $11.391 M (per FBC's Annual Reviews for 2017 and 2018 Rates).

Response:

The Company consulted with EES to provide the following response.

FBC assumes that the referenced number from the Annual Review for 2017 Rates is actually $11.341 million as given in Schedule 19 of that process. The $11.341 million is not just market purchases, but as given in Schedule 19, also includes Contracted Producers. The figures of $6.2 million and $6.1 million are both rounded numbers used for presentation purposes. A more precise number is $6,060,127. This cost is based on the detailed costs underlying the 2017 forecast found in Schedule 19 of the Annual Review for 2017 Rates, October 5, 2016 Evidentiary Update (Exhibit B-2-2).. In all cases, the COSA and Rate Application are based on a forecast for 2017, not actual results for 2017. Further, the $6.1 million is equal to the amount of market energy block purchases of $8.060,127 less the $2 million assumed credit to BC Hydro due to potential market purchases referred to in BCOAPO 2.102.1. For purposes of the COSA table only, $2 million was subtracted from market purchases in order to present a summary of the data.

102.3 With respect to FBC's Kootenay River plants, the responses to ICG 5.2, KSCA 1.5.1 and Table 7 indicate that the O&M costs are $16 M. However the responses to BCOAPO 17.1 and BCOAP 28.1 indicate the O&M costs are $13.6 M. Please reconcile.

Response:

The Company consulted with EES to provide the following response.

The total production O&M costs for FBC are $16 million. This includes $13.6 million related to the Kootenay River Plants and $2.4 million for System Control expenses. In some cases the $2.4 million in System Control were included in tables showing the costs for Kootenay River Plants because they were part of the production O&M rather than part of the $136.2 million included as purchased power supply costs.

103.0 Reference: Exhibit B-11, BCOAPO 56.1 and 56.2

BCOAPO 28.1

Exhibit B-13, CEC 12.1

Exhibit B-1, Appendix A, page 29, Table 7 Exhibit B-1, Appendix A, Schedule 5.3 FortisBC's 2016 LTERP, pages 74-76

Preamble: BCOAPO 56.2 states "a portion of 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"

103.1 With respect to BCOAPO 56.1 and CEC 12.1, if the demand-related costs for the Kootenay River Plants are $4.9 M and demand-related costs represent 20% of total costs this would suggest the total costs are in the order of $24 - $25 M. However, this value does not reconcile with any of the values for the Kootenay River Plants provided in the evidence (see BCOAPO 102 above and the response to BCOAPO 28.1). Please provide the derivation of the $4.9 M – the capacity – related portion of the Kootenay River Plants. In doing so please provide the total cost for the Kootenay River Plants as used in the calculation (with references to the evidence).

Response:

The Company consulted with EES to provide the following response.

The $4.9 million included for purposes of setting TOU rates represents the capacity-related portion of the fixed costs associated with the Kootenay River Plants. The total fixed costs included $4.5 million in depreciation, $17.7 million in return and $1.95 million in taxes. This results in a total of $24.2 million. The O&M costs associated with the plants included $13.6 million, of which $10.6 million is water fees. The O&M costs were considered variable costs for purposes of the TOU pricing calculations and were not included as part of the $4.9 million calculation as those costs would not be avoided if customers were to shift costs to another time period.

103.1.1 Please reconcile the total costs for the Kootenay River Plants, as used in this calculation, with the values for the Kootenay River Plant as referenced in BCOAPO 28.1.

Response:

Please refer to the response to BCOAPO IR 2.103.1.

103.2 Please explain why, for purposes of the TOU rate differentials (BCOAPO 56.1), there are no capacity costs ascribed to the Brilliant Power Purchase Agreement when: i) in Appendix A, Table 7 – 205 MW of capacity is associated with the purchase and ii) in the 2016 LTERP capacity is attributed to the purchase (Table 7 and page 76).

Response:

The Company consulted with EES to provide the following response.

The fact that resources, whether owned generation or purchases, provide both capacity and energy is reflected in the classification of costs between capacity and energy in the COSA. That approach was used to provide equity among customer classes. It is also reflected in planning for power supply needs both in the short term and long term.

TOU price differentials took a different approach. Rather than looking at how the resources are currently used, it looked at the potential to reduce costs both in the current year and in future years if customers reduce consumption overall or in different time periods. This is an incremental cost approach used only for the TOU rate design, as opposed to an average embedded cost approach used for the COSA.

The incremental cost approach used for setting the TOU price differentials reflects the fact that FBC does not have the ability to reduce the costs associated with Brilliant purchases. If customers were to reduce or shift loads away from the on-peak period, FBC would either reduce capacity purchases from the BC Hydro PPA or resell capacity from the Waneta PPA. It would not reduce or resell any power taken from the Brilliant PPA because all of the power is used to meet the energy needs of the utility and the costs associated with the Brilliant PPA are fixed.

104.0 Reference: Exhibit B-11, BCOAPO 56.1

Exhibit B-11, BCOAPO 56.3

Exhibit B-8, BCUC 86.2

104.1 Please explain why the mid-peak energy cost differential is calculated based by dividing the energy costs attributed to BCH 3808 and Net Market purchases by the total energy requirements of the on-peak and mid-peak periods (i.e., 1,622 GWh - per BCUC 86.2) as opposed to dividing the cost by the total GWh provided by these two resources (i.e., 967 GWh – per BCOAPO 56.3)

Response:

The Company consulted with EES to provide the following response.

The TOU prices differentials were designed to reflect the costs of the resources providing capacity to meet loads as opposed to the energy from the projects. For example, in the on-peak period the Waneta Expansion project provides no energy yet it allows FBC to meet its peak load requirements and therefore its cost was related to the on-peak period. The costs for the resources assigned when developing the TOU price differentials were based on the ability to dispatch resources to meet peak loads and did not reflect the energy provided in the various TOU periods.

105.0 Reference: Exhibit B-8, BCUC 81.1

Exhibit B-10, AMC 9.1

Exhibit B-11, BCOAPO 55.2.1 Exhibit B-12, BCSEA 28.2

Exhibit B-16, IRG 2.2 Exhibit B-1, page 108

Preamble: BCUC 81.1 states "The goal of the proposed TOU rates is to send price signals to reduce loads during on-peak hours to potentially lower the cost of power supply driven by peak loads".

AMC 9.1 states" As FBC has stated in the Application regarding the design of the TOU rates, there are power supply benefits that may result in rate mitigation from the shifting of consumption from on-peak to off-peak periods. Simple conservation of energy during off-peak periods will not have the same result and the lost revenue resulting from such conservation would likely place upward pressure on rates".

The Application states "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"

BCOPAO 55.2.1 states "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.

BCSEA 28.2 states "Based on EES' experience, TOU rates are generally not set on the basis of LRMC but instead are based on short term price or cost differentials.

ICG 2.2 states "The pricing for TOU rates was set to reflect the cost differentials for FBC power supply during different time periods. This was done so that customers would face the appropriate price signals as to how much FBC could save as a result of reduced consumption in on-peak periods.

105.1 Is the goal of TOU rates to reduce power supply costs or to reduce rates (i.e., revenue changes by customer response to TOU rates, either through load shifting or load increase/decreases are more than offset by changes in power supply costs)?

Response:

The Company consulted with EES to provide the following response.

The goal is to improve the load shape of the utility in order to reduce power supply costs, and subsequently reduce the bills for all FBC customers. Per unit rates may not necessarily be lower with TOU rates because overall sales might be lower, but average bills would be reduced.

105.2 With respect to the response to BCOAPO 55.2.1, is it the incremental cost or the average cost of serving customers at different times of the day that is the focus of TOU pricing? Similarly, with respect to ICG 2.2, is FBC referring to the differentials in incremental costs or average costs as between the different time periods?

Response:

The Company consulted with EES to provide the following response.

The TOU price differentials were based on the cost of resources used to meet loads during the various TOU periods. The resources used to determine costs in each TOU period had to do with the ability to dispatch those resources to meet peak loads. This is different than establishing an average price in each hour of the year, whether that is based on incremental costs in the market or average costs of existing resources. The use of the term average cost or incremental cost in explaining the pricing for the TOU periods was not intended to reflect specific definitions of those two terms. It was intended to reflect the approach whereby the costs for certain resources were assigned to the three different TOU periods and then divided by the energy falling in those three TOU periods.

105.2.1 If it is not the incremental cost, please explain why given that incremental costs indicate how changes in consumption will impact power supply prices.

Response:

The Company consulted with EES to provide the following response.

FBC's resource mix and dispatch order is not as simple as saying that there is an incremental cost in each hour and if 1 kWh is reduced from the highest hour FBC will avoid that incremental cost. FBC has a complex mix of resources to meet its peak loads and energy in every month. In some cases, a 1 kWh reduction will have no impact on cost because FBC will not see a reduction in any of its costs in the short term. In other periods a 1 kWh reduction could lower the amount of demand charges triggered by the BC Hydro 3808 contract and lead to a significant cost reduction. The TOU pricing differentials are intended to reflect costs that can be avoided if loads are reduced in that time period on a reliable basis such that FBC can adjust its planned power purchases.

106.0 Reference: Exhibit B-8, BCUC 86.2

Exhibit B-11, BCOAPO 56.3 Exhibit B-12, BCSEA 30.3

Exhibit B-11, BCOAPO 56.6 and 56.7

Preamble: BCUC 86.2 states "The differential is equal to the mid-peak amount related to variable energy costs of $42 million divided by the sum of the 530 GWh and 1,092 GWh of energy for the combined on-peak and mid-peak period. The variable energy costs are needed to provide power in both the on-peak and mid-peak periods.

BCUC 86.2 also states "All other costs, including long-term contracted resources from Brilliant, were included as baseload and applied to all hours."

BCOAPO 56.3 states "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".

BCOAPO 56.6 states "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".

BCOAPO 56.7 states "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."

BCSEA 30.3 states "All of FBC's energy resources are fully subscribed other than BC Hydro RS 3808 purchases and market purchases. Therefore, these two resources would be on the margin in all TOU periods."

106.1 Please confirm that the response to BCOAPO 56.3 is not meant to indicate that energy from FBC owned generation and purchases under the Brilliant PPA are only used to meet energy requirements in the off- peak period.

Response:

The Company consulted with EES to provide the following response.

Confirmed.

106.2 Rather please confirm that, as indicated in the response to BCUC 86.2 energy from FBC-owned generation and the Brilliant PPA is dispatched as baseload generation and used to meet energy requirements in all hour of the year. If not confirmed, please explain why.

Response:

The Company consulted with EES to provide the following response.

FBC's mix of resources is more complex than having a simple dispatch order where baseload units are dispatched first followed by peaking units. In the case of the Brilliant PPA, FBC gets a share of the output from the project, which is not flat across all hours like a typical baseload plant. FBC does not have the ability to dispatch the resource whenever it wants. It is like a baseload plant only in the sense that FBC takes all of the energy it can get from the Brilliant contract because there is a fixed cost for its share of the output and FBC cannot avoid charges by not taking power from the project. FBC-owned generation would be considered baseload in the sense that there is no fuel cost associated with the plant and so FBC would maximize the power generated from the plant. However, FBC does have some ability to dispatch these resources to better meet the shape of FBC loads and therefore they act, in part, like peaking plants. In reality, FBC must actively manage its various contracts and resources to abide by all of the constraints and capabilities of the different contracts and resources.

106.3 Please set out a schedule that for 2017 shows:

- The total energy provided by each of i) FBC's own generation plants and ii) the Brilliant PPA.
- The average energy per hour provided by each of i) FBC's own generation plants and ii) the Brilliant PPA on an annual basis.
- The average off-peak energy requirements (i.e., total off-peak energy divided by the number of hours in the off-peak).

Response:

The following table shows the total energy provided by each of FBC's own generation plants and the Brilliant PPA and the average energy per hour provided by each in all 8760 hours of the year.

2017 Forecast	Energy (GWh)	Energy per hour (MWh/hour)
FBC owned generation	1,593	181.8
Brilliant PPA	917	104.7
Total	2,510	286.5

With respect to the TOU rates, the on-peak and mid-peak hours represent 1,622 GWh of energy, as shown in Table 8-8 of the Application. Therefore, the off-peak energy requirements is equal to the 2017 forecast total energy requirements of 3,559 GWh less 1,622 GWh, equal to 1,937 GWh. The energy supplied from FBC owned generation and the Brilliant PPA, is greater than the energy requirement of the off-peak period.

106.4 Please confirm that energy resources other than just FortisBC's own generation and the Brilliant PPA are utilized to meet off-peak energy requirements.

Response:

Not confirmed. Please refer to the response to BCOAPO IR 2.106.3.

106.5 Given that load shifts between the mid-peak and off-peak periods do not change the composition of FBC's energy resources (per BCOAPO 56.7) and that incremental energy purchases would need to be sourced from either the BC Hydro PPA or from the market, regardless of the time they occurred (per BCOAPO 56.3 and BCSEA 30.3), please provide the justification for having a TOU energy price differential between the mid-peak and off-peak periods.

Response:

The Company consulted with EES to provide the following response.

FBC loads during off-peak hours can be met exclusively with output from the Kootenay River plants and Brilliant purchases, which are fixed cost resources. These resources alone could not meet the combined loads during the off-peak and mid-peak periods. For that reason, the BC Hydro PPA and market purchases are needed due to the added loads during the mid-peak period. Given those two purchases are needed to meet mid-peak loads, it is appropriate that the added cost of those purchases be added to the price during mid-peak hours.

107.0 Reference: Exhibit B-12. BCSEA 34.3

107.1 Based strictly on the sample of customers examined by FBC what was the lost revenue if just those customers who would be better off financially with no change in their consumption opted for TOU rates.

Response:

The Company consulted with EES to provide the following response.

Based on the sample of 232 residential customers, 45 would see savings under TOU rates with no change in consumption. The total lost revenue from these customers would be $17,667, which equated to 5.07 percent of total revenues for the sample.

107.2 Please explain how this result was "extrapolated" to the entire Residential class to arrive at the $9.4 M figure.

Response:

The Company consulted with EES to provide the following response.

A 5.07 percent reduction in revenues was seen from the sample of residential customers. This percent was multiplied by the total residential revenue of $185.2 million to arrive at an estimated total class loss in revenues of $9.4 million.

108.0 Reference: Exhibit B-13, CEC 15.2

Exhibit B-11, BCOAPO 56.3

Preamble: The response to BCOAPO 56.3 states "it cannot be determined with accuracy which energy resource was used in each hour".

The response to CEC 15.2 states "but the market purchases included as part of the analysis did not provide any capacity since they were not on peak hours".

108.1 If (per BCOPAO 56.3) FBC cannot determine which energy resources were used in each hour, how can FBC conclude (per CEC 15.2) that market purchases were not on peak hours?

Response:

The Company consulted with EES to provide the following response.

The market purchases included in the 2017 forecast were block purchases during off-peak hours to provide needed energy for the system.

108.2 If FBC is able to determine which hours market purchase were made, please use the same approach to provide a response to BCOAPO 56.3 (or, in the alternative, please explain why the same approach cannot be used to provide a response to BCOAPO 56.3)..

Response:

The Company consulted with EES to provide the following response.

There was no specific approach needed to determine that market purchases were not on peak hours as they were for block purchases. In the months when those block purchases were made, they included a fixed amount for every hour of the off-peak period.

109.0 Reference: Exhibit B-13, CEC 40.4

109.1 Please provide the Revenue to Cost Ratio resulting from the analysis (or alternatively explain how the release of this value would reveal information regarding the customer's operation that would be considered confidential).

Response:

CEC IR 1.40.4 requested that FBC provide a revenue to cost ratio for RS 37, "… on the basis used in the application." As stated in the response, there is no revenue to cost ratio for RS 37 since the class was not included in the COSA on the same basis as for other classes.

FBC provided a specific analysis to the Commission, utilizing certain assumptions that resulted in a proxy for the R/C ratio. This value, 51 percent, is not directly comparable to other R/C ratios since it was derived using COSA unit costs for RS 31 levied against the RS 37 load. However, this proxy R/C ratio is indicative of the "discount" from RS31 that RS37 has provided.

110.0 Reference: Exhibit B-15, ICG 7.2

Exhibit B-8, BCUC 51.1

110.1 With respect to the RS 21 class, please confirm that (per BCUC 51.1) the allocation of cost in the COSA reflects the fact that some customers are served at primary voltage and some are served at the secondary voltage?

Response:

The Company consulted with EES to provide the following response.

Not confirmed. The COSA assumes that all customers are served at the same secondary voltage. The COSA is currently not set up to accommodate customers within a single class that are not served at the same voltage level.

110.1.1 If not confirmed, is the data available such that the COSA could be revised to account for the fact that some RS 21 customers are served at primary voltage?

Response:

The Company consulted with EES to provide the following response.

In order to reflect the fact that customers are not all served at the same voltage level, a separate customer class would need to be set up for those RS 21 customers served at primary voltage. Note that roughly 7 percent of the load was served at primary. The two customer classes would then need to be added back together to get results for the class as a whole. The data is currently not available within the COSA to complete this step as FBC does not regularly break out the load and revenue forecasts separately for RS 21 customers served at different voltage levels.

110.1.2 If not confirmed, do the revenues used in the calculation of the Revenue to Cost Ratio reflect revenue before the application of the transformation discount?

Response:

The Company consulted with EES to provide the following response.

The revenues do not include the transformation discount. When developing the RC ratio, the revenues are higher because they do not include the transformation discount. At the same time the costs are higher by an equivalent amount because they do not include the reduced costs associated with those customers served at primary voltage. On a net basis, the two factors cancel each other out and results in appropriate RC ratios for the class.

110.1.3 If yes, do the revenues used in the calculation of the Revenue to Cost Ratio reflect revenue after the application of the transformation discount?

Response:

Please refer to the response to BCOAPO IR 2.110.1.2.

110.1.4 Based on the foregoing responses, are the revenues and costs for the RS 21 class (as used in the determination of the Revenue to Cost Ratio) calculated on a consistent basis?

Response:

Please refer to the response to BCOAPO IR 2.110.1.2.

110.2 With respect to the RS 30 class, does the allocation of cost in the COSA assume that all customers are served at primary voltage?

Response:

The Company consulted with EES to provide the following response.

Yes, the COSA assumes all RS 30 customers are served at primary voltage.

110.2.1 If yes, is the data available such that the COSA could be revised to account for the fact that some RS 30 customers are served at transformation voltage?

Response:

The Company consulted with EES to provide the following response.

In order to reflect the fact that customers are not all served at the same voltage level, a separate customer class would need to be set up for those RS 30 customers served at transmission voltage. Note that only one RS 30 customer is served at transmission voltage. The two customer classes would then need to be added back together to get results for the class as a whole. The data is currently not available within the COSA to complete this step as FBC does not regularly break out the load and revenue forecasts separately for RS 30 customers served at different voltage levels.

110.2.2 If yes, why doesn't the COSA recognize that customers are not all served at the "same" voltage as is done for the RS 21 class?

Response:

The Company consulted with EES to provide the following response.

In both the cases of RS 21 and RS 30 the COSA assumes that all customers within a class are served at the same voltage level. In looking at the appropriate level of a discount the COSA was run as if all customers were served at the higher voltage level, and the difference between the two cases was used to develop the appropriate discount level. This approach allows for the

rates at both voltage levels to be based on COSA results without having to create separate classes by voltage level within the same COSA.

110.2.3 If no, is there not an inconsistency in the calculation of RS 30 class' Revenue to Cost ratio, since the revenues used assume all the customers are served at primary voltage (per ICG 7.2) whereas the allocation of costs recognizes that some customers are served at transmission voltage.

Response:

The Company consulted with EES to provide the following response.

There is no inconsistency between calculation of revenues and costs. When developing the RC ratio, the revenues are higher because they do not include the transformation discount. At the same time the costs are higher by an equivalent amount because they do not include the reduced costs associated with those customers served at primary voltage. On a net basis, the two factors cancel each other out and results in appropriate RC ratios for the class.

111.0 Reference: Exhibit B-17, KSCA 1.15.2

111.1 Please confirm that in the COSA demand-related costs are allocated using: i) a 2 CP factor which reflects the peak demand for four hours of a single year and ii) a NCP factor which reflects estimates of customer class one hour peak demand based on a single year.

Response:

The Company consulted with EES to provide the following response.

Confirmed.

111.2 Given the comments of the Washington Utilities and Transportation Commission does FBC see merit in determining the allocators for demand-related cost using the results for more than one year?

Response:

The Company consulted with EES to provide the following response.

No, there are issues associated with using more than one year. In the case of FBC, the revenue requirements are based on a single year and the loads in the COSA reflect a forecast year, which is already adjusted for normal weather. If they were based on different years' data, there would be an inconsistency, particularly with respect to the cost of power supply. It may be appropriate in the future to develop load factors and coincidence factors, which are used to develop the NCP and CP amounts, to be based on more than one year of data. For 2017, FBC had only one year of AMI data upon which to develop those load and coincidence factors and so they were based on 2016 actual data. Going forward, FBC should be able to develop those factors on the basis of multiple years and apply them to the forecast of loads by customer class. That would allow the loads to be consistent with the revenue requirements, while at the same time include the benefits of considering usage patterns in multiple historic years.

112.0 Reference: Exhibit B-18, Resolution 10

112.1 The response states that no gas customers have "more electric heat" and are "less likely to peak at the same time as the total system". Taking these two responses together would suggest that the total system peak (which occurs in the winter) is not driven by space heating load.

Response:

The Company consulted with EES to provide the following response.

Space heating is one factor that contributes to the winter peak, along with many other factors. The winter peak typically occurs at 6 pm when residential customers are home from work and cooking, turning on lights, watching television, etc. Space heating may not be at its highest load level at that time of day since it is not the coldest part of the day; however, it may be higher than during daytime hours when the sun is out and customers often turn down their heat because they are out of the house. FBC does not have a breakdown of usage by type of appliance and cannot know with certainty the exact drivers of the system peak.

112.1.1 Please confirm whether or not this is the case. If the total system peak is driven by space heating load, please reconcile the two comments.

Response:

Please refer to the response to BCOAPO IR 2.112.1.

112.1.2 If the total system peak is not driven by space heating load, what is the main driver for the time of the system peak?

Response:

Please refer to the response to BCOAPO IR 2.112.1.