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March 29, 2018

Patrick Wruck
Commission Secretary
BC Utilities Commission
6th Floor 900 Howe Street
Vancouver, BC V6Z 2N3

Re: FortisBC COSA 2017 & Rate Design Application

Enclosed, please find Information Request submitted by Resolution Electric Ltd.

Regards,

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Resolution Electric Ltd

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IR#1
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section 3.4 The Challenge of Fixed Cost Recovery, Page 38/715 Line 30

"The adoption of these technologies tends to reduce consumption or change consumption patterns for customers, and requires utilities to acquire new technologies or information systems capacity to manage their systems. These trends can simultaneously increase costs and/or reduce customer consumption."

With reference to the new technologies or information systems capacity that utilities are required to adopt because of emerging technologies, please expand and describe what these new technologies or information systems capacity are, and the additional costs these emerging technologies add to FBC.

IR#2
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section 3.4 The Challenge of Fixed Cost Recovery, Page 39/715 Line 21

With respect to FBC concerns around the cost recovery, reduced revenues due to customers adopting energy management technologies, please explain why a residential customer with solar who manage to reduce the load significantly but not completely in the summertime should be treated differently from a residence in a community located in a high elevation or communities that experience cooler summers and colder winters or prolonged shoulder seasons. These geographic communities experience significant winter-time loading and virtually no summertime loading. An example of this summer / winter costing can be found on page 71/715 line 17 to 31. Is FBC proposing a minimum annual consumption amount for the rate recovery, if so what is this figure? Please comment.

IR#3
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section 3.6 A Potential Net Metering Rate. Page 42/715 Line 9

"The results indicate that NM customers have a lower load factor and R/C ratio than similar customers without NM systems."

Please expand on what is meant by the term "similar customers without Net Metering systems" What customer type does the application reference?

IR#4
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section 3.6 A Potential Net Metering Rate. Page 42/715 Line 15

"FBC did review potential NM rate variants that have been introduced or are under consideration in other jurisdictions, such as a demand-related rate."

Shouldn't this suggested "demand related rate" need to be qualified by a Time-of-Use ? Electricity demand, and associated energy consumed during this demand period, if imposed in an "off-peak" part of the day / week helps to improve the system utilization factor therefore helping to make the utility network more efficient. Please comment.

IR#5
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section 3.6 A Potential Net Metering Rate. Page 42/715 Line 16

"If FBC were to implement such a rate, it would be optional in the sense that it would be tied to the optional Net Metering Program, and mandatory in the sense that all Net Metering customers within the applicable rate classes would be required to utilize the rate."

If a demand were to become mandatory for Net Metering customers, would this not be viewed as being discriminatory between other residential customers? Customers who experience significant seasonal use as in the example previously referred to above found on page 71/715 line 17 to 31. Please comment.

IR#6
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section 3.6 A Potential Net Metering Rate. Page 43/715 Line 6

"Given the small sample size and early stage of the NM Program, FBC is not seeking Commission approval of a new rate element such as a demand-related rate for NM customers at this time. FBC will continue to monitor and assess the impact that net metering has on other customers. As such, FBC provides this discussion only to increase understanding of the issues around increasing participation in net metering and one solution that could be adopted to address them."

With reference to page 383/715 Residential Annual Consumption Distribution Chart Approximately fourteen percent of residential customers are using 4000kWh or less on an annual basis, roughly around 16,000 customers who experience low power bills on an annual basis.
Given that the total number of net metered customers totaled eighty-six in 2016 (reference Order Number G-63-18) at what level of Net Meter customers would FBC consider the need to introduce a demand element to the NM rate to recover system fixed charges due to lower revenue / lower energy consumption?

IR#7
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section 5.1.1.4 Load Forecast. Page 54/715 Line 10

"For comparison, in 2009 the total system energy was 3,107 GWh forecast for the year. The system energy change from 2009 to 2017 reflects an average annual increase of 0.7 percent per year. The number of customers, however, has increased by an average of 2.3 percent per year."

And with reference to the EES Consulting – Electricity Cost of Service Study page 176/715
"When comparing the 2017 forecast peaks to 2009 actual peaks (the year of the last COSA), the summer peak is growing nearly twice as fast as the winter peak. For that time period, the total growth was 47 MW in the winter, or about 0.8 percent per year. For the summer peak, the growth was 73 MW, or about 1.5 percent per year. This indicates that the summer peak is moving closer to the level of the winter peak, and that FortisBC system planning will continue to need to recognize the growth in the summer peak."

From the quoted figures above for electrical energy growth, it is evident the summertime growth is outstripping the winter growth by a factor of two to one. It would therefore seem logical to support technologies that facilitate a reduction in the peak summer loading. Technologies like solar electric, solar domestic hot water and solar pool heating systems

that remove summertime electrical loading during peak hours of summertime system loadings would be desirable to mitigate the need for system capacity upgrades driven by summer loading.

It would suggest a solar electric Net Metering customer would be actively supporting FBC and its customer base by removing their loading from system summer peak.
Please comment on how FBC intend to manage future summertime load growth, and the associated electrical system infrastructure projects which are driven by summertime growth, and identify which Demand Side Management technologies FBC could deploy to assist residential homeowners reduce summertime growth.

IR#8
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section 5.1.2.1 Rate Base. Page 59/715 Line 22

"The correction of the problem of over allocating demand can be achieved by the application of a Peak Load Carrying Capability (PLCC) adjustment. This adjustment was first introduced in the 2009 COSA. The precise amount of a PLCC adjustment should match the definition of the minimum system adopted. In the FBC case, it was determined that the average PLCC for the FBC system is 1.09 kW per customer. Appendix B to the EES Consulting Report provides a more detailed discussion of the PLCC and how the amount was calculated."

It would appear the Peak Load Carrying Capability (PLCC) of 1.09kW is extremely skewed, and given the following flawed methodology described in appendix B of the EES Consulting report, the PLCC does not reasonably identify the inherent capacity/demand factor of a basic system. The approach detailed on page 259/715 is aimed at identifying the cost associated for the system to deliver the minimum energy to each and every customer (1kWh per year) then calculating the actual system infrastructure costs, the difference in costing is then associated with the system demand.

The minimum system costs approach is converting all the existing system assets to a base "minimum design" example a transformer will be costed for a replacement unit at 15KVA regardless of present system sizing. This approach is open to a significant error rate in determining the true cost for a minimum system to deliver minimum supply to a customer.

The system of today is built based on evolving load growth and engineering an efficient system to deliver power to the end user. In the example of a transformer the existing network is designed to carry three phase loads, so as to balance the loading imposed on the network. In the minimum system approach it may not necessarily require a three phase system for all feeders as the load balancing would be negligible.

For example, a pole with three transformers would not necessarily require three units and could be replaced with one transformer (minimum load) therefore the calculation for transformers is grossly overestimated. Similar to the conductor count in km, the report calculates all three phase conductors and then gives an equivalent cost for a #2 ACSR, again minimum system design would suggest the need for only two conductors Phase & Neutral.

Clearly some three phase balancing is needed and some lines may warrant 3Ph similarly substations need three phase.

The analogy I could provide for the situation detailed above is flying. If the task was to get an airplane off the ground and airborne (flying) then a very moderate design with one engine and a small fuselage would suffice. Getting airborne would equate to delivering electricity. If you wanted to use the airplane for carrying significant payload (demand) then a sizable craft with several engines capable of long distance flight would be required. Therefore the demand cost would be based on the two designs for aircraft and the price differential between the two designs would bring about a closer reflection of demand cost.

Please comment on the effectiveness of the calculation to determine the minimum system costs vs the actual system cost and therefore the determination of the demand costing.

Please comment on what other methods FBC have looked at to assess the cost for supply.

Would FBC consider recalculating the minimum systems costing to establish a figure that is more realistic?

IR#9
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section 6.1.4.1 No Natural Gas Access Rate. Page 71/715 Line 32

"The Company agrees that as a group, customers that do not have natural gas service, whether as a result of the lack of gas delivery infrastructure or as a matter of choice, will have an average annual electrical consumption that is higher than residential customers in general. This is also a factor in higher than average annual bills."

Please identify what the term "group" is referring to, and how this group was determined.

IR#10
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section 6.1.4.1.1 No Basis in Cost Causation. Page 72/715 Line 10

With respect to the atypical load profile reference in line 10, is this reference to winter over summer demand characteristics as per customer example on the previous page (71 line 17). Please confirm or clarify otherwise.

IR#11
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section 6.1.4.1.1 No Basis in Cost Causation. Page 72/715 Line 29 to 38

With respect to operating costs for residential customers with natural gas supplies, do FBC agree with the following rational, that the natural gas delivery basic charge (meter charge) of $0.3890 per day is a fixed cost regardless of consuming natural gas, this fixed cost equates to $146.95 per year for the natural gas residential customer.
Given that the $146.95 would buy you the equivalent electricity of 950kWh at the Tier 2 rate or 1450 kWh at the Tier 1 rate, this factor should also be identified when discussing price comparisons.

I firmly believe this is a cost that is often overlooked by the non-gas consumer; I believe these costs should also factor in when determining annual energy costs and that FBC should include this relevant information in their presentations to the general public during open houses etc. Please comment.

IR#12
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section 6.1.4.2 Changes to the Existing RCR. Page 74/715 Line 8 to 13

Have FBC ever considered a simple equivalency statement on their utility bill to educate the customer as to what the equivalent charge per kWh would be based on a flat rate 1250kWh per month. This would provide some assurance to customers that going over the 800 kWh per month is not theoretically a financial addition until the 1250kWh threshold is reached.

IR#13
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section 6.1.4.2 Changes to the Existing RCR. Page 75/715 Table 6-4

It is evident that fifty-eight percent of the customer base would see an increase in utility costs, rising between three percent and ten percent. Would this not be viewed as a penalty to the group of residential customers who live a lifestyle with low to moderate (below FBC average customer) energy usage? Please comment.

IR#14
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section 8.2.1 Time of Use Rate Periods. Page 120/715 Table 8-4

With regard to the on-peak window it appears the 9pm threshold is late in the evening, given the on peak window should capture the time of power at ninety percent of system peak power as defined in the EES Consulting report.

For TOU tariffs to be effective they must also be realistic in as much as to enable the customer to make changes in lifestyle to delay electrical consumption until after the on-peak window has expired. Having an 8pm on-peak threshold would be more effective and encourage the residential consumer to adopt this rate structure and wait until the 8pm.

With reference to the TOU example on page 401/715 the hypothetical cost difference between the cost of energy on the RCR rate of $268 per month and Time of Use cost of energy of $234 is only $34 or approximately a dollar a day, and given the TOU rate also could potentially have additional unknown costs if more electricity is inadvertently consumed in the peak period it is difficult to imagine how this rate would appear attractive? Please comment.

IR#15
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section EES Consulting Report. Page 261/715 Table Minimum System Power Poles

The need for a three phase system under a the minimum system analysis would be dramatically reduced. The pole count for three phase lines which require more than a single pole in the construction design to cater for conductor loading from larger conductor sizing should not enter the cost equation when calculating the minimum system unless physical spans warranted such designs. Please comment.

IR#16
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section EES Consulting Report. Page 263/715 Table Minimum System Conductors

Again the argument for conductor count follows the three phase requirement which the present system evolved through load growth. Using the conductor Length in column two of the table will lead to significant over estimation for the true minimum system cost approach to supply 1kWh per customer per year it seems to me that using the present system components and downgrading them to serve a minimum loading is inherently flawed and leads to significant miss-calculations for the cost to supply minimum power and the associated PLCC.

The need for three phase in a residential application is based on load requirements, under the minimum load analysis there should be no requirement for a residential customer to take a three phase service.

Commercial customers may require three phase to run plant and processes, any feeder requiring three phase should be therefore be costed to the commercial class.

IR#17
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section EES Consulting Report. Page 266/715 Table Minimum System Transformers

The transformer count for a minimum system approach is largely overestimated. When converting a 2500KVA transformer (3 phase unit) to a 15KVA single phase unit to provide the conceptual analysis for minimum-cost approach it is completely in alignment with the principle, however the system is designed to three-phase construction for load balancing as previously outlined in IR#8. Given the high population of 15 and 25KVA transformers how many are configured as three phase? The minimum system analysis rule should only account for one transformer per pole as this would be reasonable to deliver the minimum power requirements for service drops. Please comment.

IR#18
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section Rate Schedule 95 – Net Metering. Page 670/715 - Billing Calculation item 3

"If in any billing period, the eligible Customer-Generator is a net generator of energy, the Net Excess Generation will be valued at the rates specified in the applicable Rate Schedule and credited to the Customers account."

Doesn't this statement contradict the new kWh bank per BCUC order G-63-18 with respect to establishing a kWh bank and not directed financial credits applied to the customers account?

IR#19
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section Rate Schedule 95 – Net Metering. Page 670/715 - Billing Calculation item 4

"For eligible Customers receiving Service under a Time-of-Use (TOU) Rate Schedule, consumption and generation during On-Peak Hours will be recorded and netted separately from consumption and generation during Off-Peak Hours such that any charges or credits applied to the account reflect the appropriate time-dependent value for the energy."

Shouldn't the statement in item 4 make reference to the potential mid-peak rate?

IR#20
Reference Exhibit B-1 2017 Cost of Service Analysis & Rate Design
Section Rate Schedule 95 – Net Metering. Page 672/715

"A Customer-Generator will, at its expense, provide lockable switching equipment capable of isolating the Net Metered System from FortisBC's system. Such equipment will be approved by FortisBC and will be accessible by FortisBC at all times."

Paragraph 2 states the lockable switch will be accessible by FortisBC at all times. For consistency throughout British Columbia would FortisBC consider making the appropriate changes to paragraph 2 of Rate Schedule 95 and remove the need for accessibility at all times and align the wording with BC Hydro?

The BC Hydro wording requirements does not place such a condition for accessibility at all times. See except below.

DG System Disconnect Means

All generators interconnected with the Distribution System require a means to safely disconnect them and ensure isolation in accordance with *CEC Part I*, Section 84. BC Hydro does not specify the physical location of the customer's means of disconnection.

As per *CEC Part I*, Section 84-030, the DG shall install a warning label at the revenue meter location and at the Disconnect Means, and a single-line, permanent, legible diagram of the interconnected system shall be installed in a conspicuous place at the disconnecting means.

R1 – October 17, 2014 6