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May 8, 2018

Resolution Electric Ltd.
600 Welke Road
Kelowna, B.C.
V1W 1A7

Attention: Mr. John Cawley, AScT

Dear Mr. Cawley:

Re: FortisBC Inc. (FBC)

Project No. 3698875

Application for the Net Metering Program Tariff Update (the Application)

Response to Resolution Electric Ltd. (Resolution) Information Request (IR) No. 1

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

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

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachment

cc (email only): Commission Secretary
Registered Parties

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.

<u>Response:</u>

The emerging technologies noted in the Application have the potential to change the manner in which the Company interacts with its customers. By extension, this may impact how the rates FBC has in place are able to reflect changes in how customers use power and may impose additional costs.

This discussion is at the early stages, and costs have not been determined. However, FBC acknowledges that as distributed generation technologies continue to evolve, and technologies such as micro-hydro and solar photovoltaic make residential-scale generation more feasible and reduce customer demand from the utility, different burdens are placed on the distribution system. Small-scale distributed generation technologies present some challenges for FBC that may cause additional cost. These include the following:

- Safety – potential for back-feeding onto the distribution grid must be properly addressed.
- Grid stability – the distribution grid must be able to handle unpredictable distributed generation output without causing power quality problems for other customers.
- With respect to information systems capacity, the Company expects that different rate structures and capturing data at a more granular level is expected to introduce IT costs and that as the uptake by customers of these programs increases, it will no longer be feasible to manually produce bills, as FBC does today for Net Metering program participants. These changes will require that some degree of additional automation be added to the billing system.

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.

<u>Response:</u>

FBC has not proposed to treat customers in different locations in a different manner and has not proposed rates that result in differing treatment of any customers that are in substantially similar circumstances.

FBC constructs rates that aim to ensure appropriate cost recovery from all customer classes. If the trend to lower use per customer continues, rates should be restructured to ensure that customers are paying their fair share to the extent possible. This principle would apply regardless of the reason for lower consumption levels.

FBC has proposed an increase to the Customer Charge in this Application to help minimize the transfer of cost recovery from one group of customers to another.

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?

Response:

Load characteristics of residential customers with NM systems were compared to the load characteristics of residential customers as a whole. As the statement indicates, based on the current mix of customers, NM customers appear to have different load profiles. However, as discussed in the Application, the NM group is relatively small and the program relatively new, so FBC is highlighting what may become an issue in setting rates in the future, but has chosen not to suggest changes to the NM rates at this time.

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.

Response:

TOU rates and rates that incorporate a demand charge can be implemented separately to good effect just as is the case today. With specific reference to the potential demand based component of net metering rates, the focus is on the recovery of fixed costs that do not vary with consumption and that can be avoided through customer owned generation. These are primarily costs related to the delivery system, which are not affected by the time that energy is consumed.

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.

<u>Response:</u>

In the view of FBC, it would not be discriminatory to create a separate rate for net metering customers in the circumstance where it could be demonstrated that they exhibit a load profile that is distinct from customers in general and place different demands on the utility system. Conceptually, this is no different than the similar segmentation of customers that is routinely done as part of the COSA exercise. Please note as well, however, that no net metering rate is being proposed in this Application.

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?

Response:

Please refer to the response to CEC IR 1.6.2.

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.

Response:

This question ventures far afield from the subject matter of the present Application. Management of load growth, infrastructure projects and DSM are the subject of separate proceedings including in relation to DSM expenditures and the long-term electric resource plan. Further, the preamble to the question includes commentary on the role of net metering customers which also properly falls into the ambit of other types of proceedings, including a recently concluded proceeding specifically related to net metering.

However, as background information, FBC notes the following.

FBC recently completed a Demand Response (DR) potential study, as part of the BC Conservation Potential Review additional scope services. Although the focus of the study was on mitigating winter peak periods that continue to set FBC's annual peak system load, some measures e.g. direct load control of hot water tanks, are applicable to offsetting summer peaks. The Company expects to file the DR potential report with its forthcoming multi-year DSM Plan expenditure schedule.

Currently FBC is undertaking a more detailed DR assessment for the Kelowna region that will quantify both summer and winter peak offsets. The target is larger commercial customers to enable the subsequent pilot phase that is anticipated to test both summer and winter DR. FBC considered assessing a primarily residential area that experiences summer peaking, but elected to proceed with the commercial customer assessment to get the additional benefit of testing winter peak clipping.

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.

a 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.

Response:

FBC does not agree with the arguments set out in the preamble to Resolution IR 1.8a. As no question is posed about those arguments specifically they are not addressed in this response, but for clarity, FBC should not be taken to agree with those arguments even if not responded to. FBC also notes, for clarity, that the preamble to this question does not constitute evidence that could be taken into account in this form.

The Company consulted with EES to provide the following response.

Specifically with respect to the question posed after the letter “a”, the calculation used follows standard COSA practice and is designed to provide a split between demand and customer related costs. The minimum system with PLCC adjustment is consistent with the approach used by FBC for the 2009 COSA as accepted by the Commission at the time. While the approach used may not account for all of the intricacies of a true minimally designed system, a more detailed approach would require engineering design and would not be cost-effective given the relative impact (which would at most be small) on the treatment in the COSA.

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

Response:

With respect to the preamble to the question, please refer to FBC’s response to Resolution IR 1.8a.

Since this question appears in a set dealing with the minimum system approach to allocating costs, FBC assumes that the request is for comment on what alternatives to the minimum system approach were explored.

The Company consulted with EES to provide the following response.

The zero-intercept approach and the 100% demand approach were considered. The minimum system approach was selected to best reflect the theoretical nature of how the system was designed and used, to reflect methods used by other utilities, and to reflect the method approved by the Commission in the past.

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

Response:

FBC does not agree with the apparent suggestion in Resolution IR 1.8c that the present figure is not realistic or not appropriate.

FBC would not consider an alternative approach due to the cost associated with a full engineering design compared to the limited if any expected benefits. Please see the further discussion in this regard, as well as in relation to the preamble, in the response to Resolution IR 1.8a.

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.

Response:

"Group" in this context is as described in the same sentence – customers that do not have natural gas service. This is the only defining characteristic referred to or intended in identifying the group, though as described elsewhere in the quoted passage, its members may tend to have an average annual electrical consumption that is higher than residential customers in general.

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.

Response:

As compared to customers in general, "no-gas" customers have higher usage per customer and therefore have more usage above the Tier 2 threshold.

In general, the no-gas group had higher load factors in the winter, likely due to more electric heat customers. They were also more likely to peak at the same time as one another, but were less likely to peak at the same time as the total system peak.

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.

Response:

FBC agrees with the statement in the preamble that the fixed Basic Charge in natural gas bills (not paid by customers who are not natural gas customers) should be factored in when comparing annual energy costs of homes who have access to both natural gas and electricity with annual energy costs of those who are only electric customers. Further, a residential customer currently using electricity for space heating would have to make considerable upfront investments to purchase and install a natural gas furnace and water heater, as well as potential costs for retrofits within the dwelling (e.g. ductwork and venting) to accommodate natural gas equipment. For a further discussion of electric versus natural gas costs please see the response to AMCS IR 1.4.1.

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.

Response:

FBC has provided information to customers regarding the breakeven point for the RCR and flat rate on its website, in rate-related information sessions and through various media opportunities. It has not considered adding this information to customer bills as well. On balance FBC does not believe that would be helpful, given the information already available elsewhere and the importance of keeping customer bills as straightforward as possible.

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.

Response:

Table 6-4 does not indicate the 58 percent of customers would see annual bill increases ranging from 3 to 10 percent. Please refer to the response to BCUC IR 1.44.1.3.1 for a discussion of table interpretation.

Generally speaking, an inclining block rate favours low-consuming customers and will result in higher consuming customers experiencing higher annual bills than under a flat rate. This is a function of consumption level, which may or may not include consumption related to what some may consider discretionary.

Given the lack of a cost driver for the energy components or threshold of the RCR, a flat rate provides that best balance in terms of equitable treatment of residential customers. FBC has recognized the impact that returning to a flat rate may have on customers and has proposed a phase in period as a mitigation strategy.

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.

Response:

The commentary contained in the question is one perspective and may not be representative of customers in general. Whether or not the optional TOU rate is attractive will depend on individual customer circumstances, and FBC will aid customers by providing information related to hourly load and the impacts of consumption changes. Ultimately, the decision to opt in to the TOU rate rests with the customer.

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.

Response:

The Company consulted with EES to provide the following response.

The minimum system analysis already uses a single-phase system as the minimum system. Therefore, the concern in the question that the pole count for three phase lines and associated conductor enter the cost equation when calculating the minimum system is not warranted.

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.

Response:

FBC does not agree with the analysis set out above, including the suggestions of flaws and miscalculations. Please refer to the response to Resolution IR 1.8a with respect to the status of and FBC's approach to preambles such as found above.

The Company consulted with EES to provide the following response.

Any amounts related to three-phase service are included in the demand-related component of the minimum system split. That amount would be allocated more heavily to customers that have higher demand levels than residential customers.

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.

Response:

The Company consulted with EES to provide the following response.

The minimum system is designed as single-phase and follows standard practice. Under standard practice the cost of a minimum sized transformer is applied to all transformers and the number of transformers is not reduced when calculating the minimum system. The minimum system approach is a theoretical concept and is not an attempt to redesign the entire system.

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?

Response:

Order G-63-18 was issued by the Commission after the Application was filed. Order G-63-18 contains directives related to revising the Net Metering rate schedule and FBC will be following the revised rate schedule.

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?

<u>Response:</u>

Please refer to the response to Resolution IR 1.18.

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

Response:

FBC is not proposing to alter the interconnection requirements related to net metering installation.