**From:** Andy Shadrack [ashadra@telus.net]
**Sent:** Friday, January 18, 2013 5:26 PM
**To:** Commission Secretary BCUC:EX
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**Subject:** FortisBC Inc. Advanced Metering Infrastructure CPCN: Reply Request for Third Round of Information Requests

Kaslo

Friday, January 18

Attention: Erica M. Hamilton, Commission Secretary

FortisBC Inc. Advanced Metering Infrastructure CPCN:

Subject: Reply Request for Third Round of Information Requests

I write, on behalf of Area D, RDCK, in reply to FortisBC's (B-22) response to Area D's (C13-12) application to the Commission for a third round of information requests in accordance with the direction of the Commission of January 11, 2013 (A-26).

In its response FortisBC argues that a third round of intervenor questions on the *"remaining gaps" in the wired vs wireless evidence* are not warranted, and goes on to state (4(b), page 2, last sentence):

*Pursuant to the Commission's decision* (A-19, Order G-198-12) *and in consideration of the Interveners' submissions, FortisBC anticipates a further evidentiary filing early in the coming week addressing the "wired" market and the issues with obtaining comparative information in the absence of a formal PLC-specific RFP process.*

Contrary to FortisBC's submission, this statement is a clear manifestation of Area D's contention that FortisBC has thus far failed to satisfy the informational requirements of its original application with respect to the issue of wired v. wireless systems.

FortisBC continues its submission by stating that a third round of IRs would be of limited value because there have been few PLC-AMI deployments since 2008. With the greatest of respect, Area D observes that FortisBC's argument is a circular one, made before the intervenors have seen FortisBC's proposed submission and before FortisBC has seen any of the interveners' questions.

There are two outstanding issues on which FortisBC has failed to satisfy Area D:

1. that the current proposal is the most cost effective deployment of smart meter technology; and

2. that there is not a technologically compatible and more cost effective smart meter technology available.

Further, Area D believes that anyone familiar with the RFP process knows that it is extremely important to look beyond the corporate hype and ensure that the product being considered:

i. can actually deliver the service being proposed; and
ii. is the most price competitive product available to do the job.

FortisBC, in its original application and argument, made certain evidentiary statements that PLC-AMI was neither technologically compatible with its requirements nor price competitive with FortisBC's preferred wireless RF-AMI choice. Intervenor Keith Miles (C11-3) challenged that claim in his first-round Information Requests on October 26, 2012, and FortisBC completely failed to address the testimonial evidence provided by Mr Miles with regard to the Idaho Power Ltd deployment of PLC - AMI between 2009 and 2011 (Idaho Public Utilities Commission Case No. IPC-E-08-16) .

As one small example, despite Keith Miles submission, on October 26th, that the testimony of Idaho Power Ltd Mark Heintzelman showed use of phone lines as part of the PLC-AMI deployment, FortisBC's responses to CSTC IR2# 12, 13 and 14 (page 9, lines 24 and 25, page10, lines 2 and 3, 9 to 13, and 26 to 28) deny any knowledge of use of phone lines as part of any Non-RF AMI deployment.

It is Area D's contention that the facts have so substantially changed since FortisBC submitted its application on July 26, 2012, and since the first and second round of IRs were submitted on October 26th and November 23rd, that a third round of IRs is warranted.

Area D is therefore submitting a portion of the proposed third round of IRs, which it believes is substantially necessary because the evidence provided by Idaho Power Ltd and comments made by Idaho Public Utilities Commission staff to the Commission during AMI CPCN proceedings in 2008 call into question the evidentiary testimony and statements of FortisBC in these proceedings.

At the heart of Area D's concern is the evidence provided before the Idaho Public Utilities Commission that PLC-AMI deployment, between 2009 and the end of 2011, would only cost $136 per meter, whereas Itron's cost estimate to FortisBC was $574 per meter, and FortisBC's cost estimate for deployment of RF Mesh AMI is $415. Area D simply submits that it is not in the public interest of FortisBC's customers that the company be permitted to deploy an RF-AMI option between two and half and nearly three times more expensive than a wired alternative. Further, Area D also contends that despite statements and claims to the contrary by FortisBC, there is no evidence that the PLC-AMI deployment undertaken by Idaho Power Ltd would not be equally technologically suitable in FortisBC's service area.

Area D also wishes to further submit that there is a growing contradictory conundrum emerging with regard the written PLC-AMI estimate provided to FortisBC by Itron.

FortisBC's submission (B-22) vociferously argues that a further process around PLC-AMI is not warranted as PLC AMI deployment in North America is *small and shrinking*. Conversely, without straying into a discussion about confidentiality, Itron, in its letter to the Commission (B-21), at BCUC IR No.2 Question 32.1 [**confidentiality requested**], substantively argues, in effect, the exact opposite - that is, that PLC is apparently such a hot market item that public release of its estimate could compromise its commercial prospects.

Area D submits that FortisBC and Itron cannot both simultaneously argue that further discussion of PLC-AMI is not warranted because of the insignificance of PLC-AMI market deployment, while at the same time making a stronger demand to protect Itron's PLC-AMI estimate from unfair market competitive advantage than the contents of Itron's RF Mesh AMI contract with FortisBC.

Area D further submits that the Commission, in the public interest, must satisfy itself that the Itron written cost estimate for PLC-AMI is, in fact, an accurate market reflection of what PLC-AMI deployment would cost in a normal competitive bid process. Area D additionally submits to the Commission that it is currently unclear what amongst FortisBC's evidentiary claims and statements about PLC-AMI are obtained from sources separate from the advice given it by Itron.

In this regard Area D submits that, at the time of the second IRs being submitted, it was completely unaware that Itron had undertaken a key contract with Idaho Power Ltd vis a vis implementation of an MDMS PLC-AMI deployment (C13-15, Appendix A, Staff, Comments, PDF, **Phase One Implementation**, last paragraph page 5 to first two paragraphs page 6). :

*Staff had expected a system-wide rollout of the technology before now, but recognized the problem encountered in the Phase One Implementation associated with the Meter Data Management System (MDMS) component. Idaho Power sought to implement an MDMS system that had not yet been developed. The Company contracted with Itron to implement an existing system that it believed could be modified to suit its needs. Modifications did not lead to the system passing the Company's Validate, Estimate and Edit (VEE) acceptance criteria.*

Given the centrality of the MDMS component to the RFP process as described by Keith Miles to FortisBC and FortisBC to Keith Miles at IR#2 1 (page 1, line 22 to page 2, line 13), Area D now has additional questions that it wishes to ask with regard Itron's successful and/or lack of successful deployment of PLC AMI in North America, and the contradictions which have developed between FortisBC's evidence as compared to the testimony of Idaho Power Ltd before the Idaho Public Utilities Commission.

To that aim Area D now attaches some of those questions as an appendix to this letter, in the sincere belief that the proposed questions are reflective of the outstanding substantive issues remaining, concerning the wired v. wireless controversy arising out of FortisBC's application - that they are not duplicative, and that it would be productive and in the highest and best public interest that they be answered.

Respectfully submitted,
Andy Shadrack
Director Area D
RDCK

**Appendix - Proposed Third I.R. Questions**

**<u>FortisBC and Itron Written Estimate Deployment Capital Costs Compared</u>**

1. In Direct Testimony Courtney Waites, pricing analyst of Idaho Power Company, filed evidence before the Idaho Public Utilities Commission (August 4, 2008, 4.32 PM) as follows:

**http://www.puc.idaho.gov/internet/cases/elec/IPC/IPCE0816/company/20080805WAITES%20DIRECT.PDF**

"*Q. What are the total capital costs associated with the Project?*

*A. The total capital costs associated with the Project are $70.9 million, as seen on Exhibit No. 4.*

*Q. Is the Company providing a capital cost "commitment" estimate for the capital costs of the Project?*

*A. Yes, the Company is willing to commit to the Commission that the total cost of the Project to be included in the Company's rate base will not exceed $70.9 million ("Commitment Estimate"). This amount includes*

*Information Technology ("IT") expenditures, meter costs, stations equipment expenses, plus additional costs the Company knows it will incur but cannot precisely quantify at this time. These additional costs include, but are not limited to, sales taxes, customer growth, fuel charges, additional IT hardware, software, and personnel time, and the cost of Idaho Power oversight of the Project. The Commitment Estimate also covers contingencies, such as change orders and customer growth. However, the Commitment Estimate is subject to adjustment to account for documented, legally-required equipment changes and material changes in assumed escalation rates or growth rates not*
*foreseen at the time of the Application*" (Waites, page 3, lines 1 to 23).

*"Q. Please describe the IT expenditures included in the Commitment Estimate.*

*A. The total IT expenditures associated with the AMI Project and allocated to the Idaho jurisdiction are $1,631,736, as shown on Exhibit No.4. These expenses are related to the hardware and software installations and the testing and interface development of the Meter Data Management System and the TWACS Net Server. These expenses include the costs of servers, licenses, sales tax, and labor with payroll loadings* (Waites, page 4, lines, 1 to 10).

*"Q. Please describe the meter costs included in the Commitment Estimate.*

*A. The meter costs included in the Commitment Estimate associated with the AMI Project and allocated to the Idaho jurisdiction are $54,964,643, as shown on Exhibit No.4. These costs are made up of three components: the meters, the TWACS communications modules, and the meter exchange services. As Mr. Heintzelman describes in his testimony, Landis+Gyr Inc. ("Landis+Gyr") will supply the residential meters and General Electric Company ("GE") will supply the commercial meters. In the contract, Landis+Gyr has committed to a fixed price for five years and GE has committed to a fixed price for three years. The Company has contracted with Aclara Power-Line Systems Inc. ("Aclara") to provide the TWACS communications modules with a five-year fixed price. These modules will be shipped directly to the meter manufacturers, Landis+Gyr and GE, for integration into the meters. The AMI equipped meter will then be shipped directly to Tru-Check, Inc. ("Tru-Check") the meter exchange vendor, which makes up the third component of the meter costs included in the Commitment Estimate. Tru-Check will then install the AMI equipped meters throughout the Company's service territory at a per meter cost based on the area of installation, which is defined in the contract. Together, with stores loadings, sales tax, and overheads, these three components make up the total meter costs of $54,964,643, shown in Exhibit No.4, included in the Commitment Estimate"* (Waites page 4, line 17 to page 5, line 20).

*"Q. Please describe the stations equipment expenses included in the Commitment Estimate.*

*A. The total stations equipment expenses associated with the AMI Project and allocated to the Idaho jurisdiction are $14,268,522, as shown on Exhibit No.4. This equipment is necessary for upgrades to the substations for the deployment of the Project which may include new modulation transformer units, third-party backhaul communications/frame relays, control receiver units, outbound modulation units, inbound pickup units, other miscellaneous materials, and the Idaho Power labor associated with the stations upgrades. All station*
*11 equipment material cost estimates are fully loaded with stores loading, sales tax, and overheads. The labor included in the estimate is also fully loaded"* (Waites page 6, line 23 to page 7, line 13).

*"Q. How does the Company propose that the Commission treat the costs associated with the Project for ratemaking purposes?*

*A. Provided the Project costs are less than the Commitment Estimate of $70.9 million, Idaho Power would expect the Commission to ultimately approve the total Project investment to be included in the Company's rate base for ratemaking purposes*" (Waites, page 8, lines 3 to 10).

Given the deployment time, of between 2009 to 2011 inclusive, and based on Exhibit 4 attached to Ms Waites' testimony, can FortisBC please explain where Itron's written cost estimates differ and why?

2. Further, would FortisBC agree that the Idaho Power Company PLC-AMI deployment period took place over the same time period that FortisBC, and Itron, were developing their written PLC-AMI estimate, and not 2004 as described in response to Shadrack IR2 #12 (1d.i, page 11, line1)?

3. In response to BCUC IR2 #35.2 (page 74 line 27 and 28) FortisBC confirms Itron's PLC-AMI cost estimate at $66 million or approximately $574 per customer, and later (page 75, line 4) FortisBC claims a comparative deployment cost for FortisAlberta of $478 per PLC-AMI meter versus FortisBC's RFAMI of $415 per meter (page 74, line 31).

How do FortisBC, and Itron, explain their contradictory pricing for PLC-AMI when compared to Ms Waites' testimony before the Idaho Public Utilities Commission and that of the Commission staff who observed that Idaho Power Company PLC-AMI deployment costs decreased from $292 to $136 (Order 30726, page 6, paragraph 3 [Id at 5] February 12, 2009), and/or the confirmed estimate of Mr Heintzelman's (Advanced Metering Infrastructure ["AMI"] Implementation Project Leader) of $152 per meter (Appendix 1, Heintzleman response question 6, to Shadrack, C13-9, December 7, 2012)?

4. Would FortisBC agree that if the Idaho Power Ltd capital deployment PLC-AMI costs are an accurate assessment at $152 per meter, then PLC-AMI is price competitive with FortisBC's own preferred AMI RF Mesh option?

**<u>Technological Capability Compared</u>**

5. Can FortisBC please re-explain the intent of their written testimony concerning Itron's written cost estimate at BCUC IR#1 106.3 (page 247, lines 17 to 19) when they state:

"*These enhanced capabilities require a more expensive PLC infrastructure than typical PLC-equipped meters generally available on the market*"?

6. Ms Waites' evidentiary testimony continues:

"*Q. What are the O&M benefits associated with the Project?*

*A. The Company expects quantifiable O&M benefits from the following areas: reduction in labor and transportation costs related to meter reading, regional operations benefit in confirming equipment outage to prevent crew dispatch, regional operations benefits in confirming service restored to prevent prolonged crew time Idaho Power Company in area, regional operations benefit on detecting overloaded distribution transformers, benefit with regards to the operation of the irrigation peak rewards program, and outage management operation benefits. The O&M benefits identified for the three-year deployment period are shown on Exhibit No.4*" (Waites page 9, line 17 to page 10, line 6).

Do the benefits so described by Ms Waites, to the Idaho Public Utilities Commission, compare favourably with FortisBC's own proposed AMI deployment proposal, and can FortisBC please confirm whether they will be introducing an irrigation peak rewards program for their irrigation ratepayers within the FortisBC service area?

6. In Direct Testimony Mark Heinztelman filed evidence with the Idaho Public Utilities Commission (August 4, 2008, 4.31 PM) as follows (noting Mr Heinztelman has "*given technical presentations on advanced metering and meter data management at national conferences of AMRA, the Itron & TWACS User's conferences, and the*

*Seattle Meter School*, page 2, line page 7 to 10):

" *Q. Could you please describe how Idaho Power selected the TWACS power line carrier technology from Aclara Power-Line Systems Inc. ("Aclara") for the system wide deployment of AMI technology?*

*A. The Company's experience with the TWACS system goes back to 1998, when it deployed a pilot program consisting of 1,000 meters in the Idaho City area. The purpose of this program was to evaluate the system's ability to read meters in remote locations and determine the feasibility of deploying what was then Automated Meter Reading ("AMR") to reduce operating costs by automating the monthly meter reading process in low customer density areas. In 2004, Idaho Power deployed the TWACS technology in the Emmett and McCall areas in conjunction with the Phase One Implementation Plan filed with the Commission in Case No. IPC-E-02-12. The Company also utilized this technology in its Energy Watch and Time-of-Day pilot programs for the Emmett Valley. With these programs the Company was able to evaluate the system's ability to gather hourly energy use data from all endpoints in support of dynamic time-of-use ("TOU") rate applications and evaluate the system's functionality related to direct load control through an air conditioner cycling program*" (Heinztelman, page 2, line 21 to page 3, line 20).

Mr Heinztelman's testimony later continues:

"*Aclara's proposed solution demonstrated superior system performance at scale, the functional capability to retrieve hourly data at scale, and the proven ability to deliver successful system performance economically in low customer density applications*" (Heinztelman, page 5, lines 6 to 11).

Could FortisBC please describe how long it has had a working deployment relationship with Itron and what pilot programs it has undertaken with Itron to test the equipment it is proposing to deploy?

7. Further, could FortisBC please explain why it would file written testimony before the Commission that PLC-AMI could not gather hourly energy-use data when it appears that the Idaho Power Company was evaluating such capability and an ability to run direct load control for an air conditioner cycling program from approximately 2004 on?

8. Would FortisBC now agree, given evidentiary testimony filed before the Idaho Public Utilities Commission, that its written testimony might be perceived as misleading as to the hourly and other capabilities of PLC-AMI?

**<u>Deploymment Area Compared</u>**

9. Mr Heintzelman's testimony continues:

"*Q. Does the proposed deployment cover the Company's entire service territory?*

*A. Yes. The deployment covers the entire service territory, and reaches approximately 99 percent of the Company's customers. There are approximately 4,000 customers, who make up approximately 1 percent of total customers, whose electrical service comes from Idaho Power's 53 smallest distribution substations. These customers are typically in the most remote edges of our service territory and are largely low or seasonal energy users. The TWACS technology will work in these locations but the station infrastructure cost per customer is very high and is not offset by the benefits that would be achieved through AMI at this time*" (Heinztelman, page 7, line 13 to page 8, line 2).

Does FortisBC agree that its own deployment assessment is similar in terms of number of customers covered by its proposed AMI meter deployment and that it has a similar cost benefit analysis as per FortisBC's response to

Shadrack IR2 #10 (page 6, lines 9 to 15)?

10. Can FortisBC, however, please now re-explain its response as described to BCUC IR1 #113.1.2 (page 277, lines 32 and 33):

"*Lower meter density negatively impacts the economics of an RF mesh solution relative to a PLC solution since RF mesh technologies rely on meter-to-meter communication*?

11. Mr Heintzelman's testimony continues:

"*Q. Could you generally describe the AMI system being implemented by Idaho Power and how it works?*

*The TWACS AMI system uses the electrical distribution system as the path for two-way communications between the TWACS substation communications equipment and the endpoint communications modules installed internally in the customers' electric meters or load control devices. The software for the AMI System is hosted on the Idaho Power network. It consists of proprietary software applications, a hardware operating system, backup and test applications, communications applications and servers, and database applications and servers. The software application will be connected to the substation control equipment through our existing internal network or through the phone system. The substation control equipment will be installed in our existing distribution substations. A typical installation would consist of a phone line with frame relay service, a phone protection package, a control receiver unit to provide the connection between software system and Idaho Power Company the station equipment and to control the operation of the station equipment, an outbound modulation unit to convert the data request to be transmitted across the electrical distribution system, a modulation transformer unit to inject the signal on the distribution system, and inbound pickup units to retrieve the data back from the endpoint communications modules.*

*The only equipment required on the electrical distribution system are the endpoint communications modules. The communications are modulated on the electricity flowing on the system and, therefore, no additional equipment is required between the substation and endpoints. Because of the unique method used by the TWACS system to modulate the electrical sine wave the signal requires no further modulation amplification and remains intact to the end of the electrical distribution system...As we add new customers, the only equipment required to expand the existing communications system will be a communications module in the electric meter or end device."* (Heinztelman, page 9, line 5 to page 10, line 16, and 20 to 22).

"*Q. Could you give a brief description of how the AMI two-way automated communications system works?*

*A. Yes. Please refer to Exhibit No.3 to my testimony for a simplified diagram of how the system is connected. Once the components of the system are installed, communications take place starting with the software initiating communications commands, typically on a predetermined schedule. The commands are processed through a communications server and sent out through our internal network or through a phone service provider to the appropriate distribution substation. At the substation, the communications command is received by the TWACS station equipment and sent out on the electrical distribution system. Each endpoint communications module (located in the meter) is uniquely identifiable and responds to requests for data only when specifically addressed by the system. When a communications module is addressed by the system, it will respond to the request by delivering the data requested in a predetermined format. There are typically data retrieval schedules for daily meter reads, predetermined blocks of hourly energy use data, and monthly billing reads. Once the substation control equipment has the information back from the individual communications modules, the data will automatically be sent back over the phone or network system to the TWACS network software. The data is then validated and moved to the system database. The TWACS system has built in features to continually optimize the communications process, and in cases where you are retrieving hourly energy use information, it is best not to interfere with the systems automatic operations by making frequent direct*

*unscheduled data requests from individual communications modules. Direct unscheduled communications will be limited to troubleshooting and necessary maintenance communications. This will allow the system to optimize communications and data retrieval performance*" (Heintzelman, page 10, line 23 to page 12, line 10).

Given that Mr Heinztelman filed this written testimony before the Idaho Public Utilities Commission in August 2008, could FortisBC please explain why it has stated in written testimony that it is unaware of any "broad deployment" of telephone lines for AMI deployment in response to CSTC IR2# 12, 13 and 14 (page 9, lines 24 and 25, page10, lines 2 and 3, 9 to 13, and 26 to 28)?

12. It is specifically noted that FortisBC has repeatedly stated that:

"*FortisBC is not aware of specific non-PLC, non-RF AMI implementations, so has not monitored the progress and results from any implementations*.

"*...FortisBC is not aware of any broadly-deployed AMI solution that uses third-party telephone lines for the LAN, so has not evaluated the cost*."

"*...FortisBC used the term "broadly-deployed" to differentiate the implementation of a telephone-based AMI system from downloading consumption data from a small number of large-power customer meters using telephone or cellular lines.*

*FortisBC is not aware of any utilities that have implemented AMI using third party telephone lines as an alternative to an RF mesh LAN solution, so has not evaluated the cost*".

"*..The Company respectfully submits that it did answer the question. FortisBC is unaware of any third-party telephone line based AMI systems or implementations, so there is no point in evaluating any theoretical barriers*".

Would FortisBC agree that, based on Mr Heintzelman's written testimony before the Idaho Public Utilities Commission, its knowledge and experience of PLC-AMI and Non-RF Mesh AMI deployment would in general appear to be very limited?

13. Further given Mr Heinztelman's filed written testimony:

"*A typical installation would consist of a phone line with frame relay service, a phone protection package, a control receiver unit to provide the connection between software system and Idaho Power Company the station equipment and to control the operation of the station equipment, an outbound modulation unit to convert the data request to be transmitted across the electrical distribution system, a modulation transformer unit to inject the signal on the distribution system, and inbound pickup units to retrieve the data back from the endpoint communications modules.*

*The only equipment required on the electrical distribution system are the endpoint communications modules. The communications are modulated on the electricity flowing on the system and, therefore, no additional equipment is required between the substation and endpoints. Because of the unique method used by the TWACS system to modulate the electrical sine wave the signal requires no further modulation amplification and remains intact to the end of the electrical distribution system...As we add new customers, the only equipment required to expand the existing communications system will be a communications module in the electric meter or end device."* (Heinztelman, page 9, line 21 to page 10, line 16, and 20 to 22)?

Can FortisBC please explain why in, its original application at, **Power Line Carrier Systems**, 7.3 (page 112, line 1 to 7) it stated:

"*Since the collectors are housed in the substations, the cost of the PLC option is, in part, dependent upon the number of endpoints served per substation. The cost of the infrastructure within the substation is the same no matter how many customers are downstream of that particular substation. However, the distance between the metering endpoint and the substation determines how many line devices need to be installed upon the distribution lines to ensure that the data can travel the required distance"*

14. Would FortisBC now agree that there are PLC-AMI systems available that do not need power "*line devices...to be installed upon the distribution lines to ensure that the data can travel the required distance"* as all that is needed between the substation and the customer's meter is a *"module in the electric meter or end device*"?

15. Further, in light of the above evidentiary testimony, can FortisBC please also explain why it gave written testimony in response to BCUC IR2 #35.3 (page 76, lines 3 to 7), as follows:

"*The largest driver of the increased cost per customer of the PLC system is the lower customer/PLC injection point ratio at FortisBC (which average 2,100 customers per PLC injector) versus FortisAlberta (which averages 2,900 customers per PLC injector). A PLC injector is needed at each substation, with additional injectors required for split busses or when there are multiple distribution voltages at a substation*"?

16. Given Mr Heintzelman's written testimony before the Idaho Public Utilities Commission:

*"The only equipment required on the electrical distribution system are the endpoint communications modules. The communications are modulated on the electricity flowing on the system and, therefore, no additional equipment is required between the substation and endpoints. Because of the unique method used by the TWACS system to modulate the electrical sine wave the signal requires no further modulation amplification and remains intact to the end of the electrical distribution system...As we add new customers, the only equipment required to expand the existing communications system will be a communications module in the electric meter or end device*" (Heinztelman, page 10, lines 8 to 16, and 20 to 22)?

Can FortisBC please also re-explain its written testimony, as compared to that of Idaho Power above (before the Idaho Public Utilities Commission), in response to CEC IR1 #44.2 (page 62, lines 9 to 15) when it states:

"*Compared with other utilities, FortisBC has a significant proportion of long rural distribution feeders and a lower number of customers per feeder. This was expected to have an impact on which technologies might be proposed by respondents to the RFP. For example, some technologies such as PLC require equipment to be installed on each feeder and require additional infrastructure to propagate the communications signal along a long feeder. For FortisBC, the costs to deploy this technology would likely not be as economical as it would be for other utilities*"?

17. In response to BCUC IR2 #31 (page 64, lines 18 t0 20) FortisBC states:

*"FortisBC did not indicate that PLC meters would be generally unsuitable for high-density customer service areas. The Company simply pointed out the relative economics of RF mesh and PLC solutions with respect customer density"*

Can FortisBC please explain why, then, at **Power Line Carrier Systems**, 7.3 (page 112, lines 8 to 13) it stated:

*"Depending on the number of endpoints and the frequency of reading intervals, the amount of data travelling between the meters and the collectors can overhwhelm the bandwidth of a PLC system. This becomes*

*increasingly challenging once load control or pricing signal data is included for transmission through these same communication channels. The volume of data can impact the speed of transmission and can cause delays in getting the information back to the central computer in a timely fashion.*"

18. Would FortisBC now agree that the implications of the statement in its original application would imply that PLC-AMI would be challenged in meeting its technological requirements?

19. Further at BCUC IR2 #31.2 (page 65, lines 6 to 10) FortisBC states:

"*Please note that the customer density figures provided in the response to BCUC IR No.1 Q113.1.2 were based on incorrect data from the Canadian Electricity Association. That data has since been corrected. The correct values are 2.3 meters per square kilometre for FortisAlberta and 6.4 meters per square kilometer for FortisBC. These corrected figures do not affect the original response*.

Can FortisBC please re-explain the point it was trying to make to BCUC when it originally stated that:

"*Fortis Alberta customer density is approximately 11.2 meters per square kilometer vs FortisBC density of 38.6 meters per square kilometer*"?

20. At C13-9, Appendix 1, Question 10, December 7, 2012 confirmation is requested as to the meter density for Idaho Power Ltd:

"*Can Idaho Power confirm that they currently serve 495,570 customers across 24,000 square miles (62,160 square kilometers) at an average density of 20.65 meters per square mile (7.97 meters per square kilometer)? We currently have just over 500,000 with 522,000 meters installed over 24,000 sqmi*"

Would FortisBC agree that it would appear Idaho Power Ltd has a higher meter density than FortisBC at approximately 8.4 meters per square kilometre?

21. In light of the observation above would FortisBC please now reconsider the statement it made to Keith Miles in response to IR#1 (page 1 lines 24 to 27), when it stated:

*"FortisBC cannot definitively say why Idaho Power chose a PLC system. However, several factors may have contributed when Idaho power filed its regulatory application in 2008 for a PLC-based AMI system: 1) PLC technology was more cost competitive at lower meter densities per square kilometer when the system was selected,..."*

Would FortisBC now agree that at a density of 6.4 meters per square kilometre, if FortisAlberta has deployed AMI PLC meters at 2.3 per square kilometre and Idaho Power Ltd at a density of approximately 8.4 meters per square kilometre, that meter density is not the issue FortisBC originally implied it was when first answering the Commission and other intervenors when it comes to deploying either RF Mesh AMI or PLC-AMI?

22. In Order 30726 the Idaho Public Utilities Commission observes (paragraph 2, page 7) that:

*"Staff emphasized the importance of providing "real time" usage information to customers. Accordingly, Staff recommended that the Company inform customers of the availability of power cost monitors such as the Blue Line, Aztech and Energy Detective devices. Id. at 15-16. These commercially available devices enable customers to acquire "information on energy usage and the associated cost on a real time basis" Id.*

Further at **Commission Decision and Findings** (page 8, second paragraph) the Commission specifically states:

*We find that deployment of AMI technology will also offer substantial future benefits by providing an essential platform for remote connect-disconnect capabilities*

Further, this statement is substantiated, in response to Shadrack on November 27, 2012, when Mark Heintzelman acknowledges that the deployed PLC AMI could add remote disconnect/reconnect functionality (C13-9, Appendix 1, response question 3, December 7, 2012).

In light of the observations above would FortisBC please also reconsider it's statement to Keith Miles in IR#1 that:

*2) Idaho Power did not require HAN functionality, 3) Idaho Power did not require remote disconnect/reconnect functionality*

Would FortisBC agree that these statements to Mr Keith Miles could be misconstrued as implying that the Idaho Power Ltd's PLC-AMI deployment would prevent their customers from obtaining real time energy usage information and would prevent Idaho Power Ltd from using remote disconnect/reconnect functionality?

**Wireless Smart Meter Disruption**

23. At Shadrack IR1#37 (page 17, lines 26 to 28) FortisBC provides written testimony:

"*Itron is now aware of the current issue with 900 MHz Interest Service Providers in BC Hydro service territory. Itron and BC Hydro are working with the ISPs to resolve this issue, which they believe may be related to the temporarily incomplete state of the AMI LAN network*"

Can FortisBC please explain why this kind of disruption will not be a permanent experience, for not just Wi-Fi users, given frequent power brown outs and black outs in certain portions of it's service territory, in that every time the smart meter RF Lan mesh network starts up it will disrupt other communication devices operating on the same band width?