REQUESTOR NAME: BC Sustainable Energy Association and Sierra Club of BC

INFORMATION REQUEST ROUND NO: Intervenor Evidence IR 1

TO: Electoral Area D Regional District Central Kootenay (RDCK) (Andy Shadrack)

DATE: February 7, 2013

PROJECT NO: 3698682

APPLICATION NAME: **Fortis BC Inc. Application for a Certificate of Public Convenience and Necessity for the Advanced Metering Infrastructure Project**

1.0 Topic: Idaho Power Company Advanced Metering Infrastructure application
Reference: Exhibit C13-17-1, evidence of RDCK, documents 1 through 5:

1. The Application of Idaho Power Company, Case No IPC-E-08-16, for a Certificate of Public Convenience and Necessity to Install Advanced Metering Infrastructure ("AMI");

2. Direct Testimony of Mark C. Heintzelman;

3. Direct Testimony of Courtney Waites;

4. Case No.IPC-E-08-16, Comments of the Commission Staff;

5. Case No. IPC-E-08-16 Order No 30726

Reference: Exhibit B-1, AMI Application, Table 3.2.2.a, page 24 and Table 7.5.d, page 123.

1.1 What is the point, in relation to the FBC AMI application, of your evidence regarding the cost of the Idaho Power Company's PLC advanced meter system? Is the point that a PLC advanced meter system would be feasible for FBC because one was feasible for the Idaho Power Company? Is the point that FBC's proposed AMI system is too expensive because Idaho Power Company obtained an advanced meter system for less cost?

Response: Both, and more. Idaho Power Company Ltd organized a Request For Interest (RFI) process to which ten wireless AMI and 3 wired AMI companies were asked to submit proposals, out of which two wireless and one wired company were sent Requests For Proposal (RFP) and subsequently bid on the proposal (C13-17-1/2 p 3, line 21 to p 5, line 11; Appendix 1 of this response, Heintzelman to Shadrack, February 8, 2013).

A comparison of the Idaho Power project with FortisBC's proposal indicates that the technology being proposed is compatible with FortisBC's requirements, even if Idaho Power chose not to use all of the attributes of the PLC technology that were available to them.

Further, in response to an Information Request from the Commercial Energy Consumers Association of British Columbia, for example, with regard FortisBC's unique operating environment, the company 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 (B-11, CEC IR1 #44.2, page 62, lines 9 to 15)*.*

To the contrary of what FortisBC states, Idaho Power confirms that in 1998 and 2004:

The 2 pilots were in remote mountainous areas on extremely long feeders with few customers, we only looked at PLC (Appendix 2 of this response, Heintzelman to Shadrack, February 15, 2013).

Boise and Pocatello, Idaho Power service area, at elevations of 824 meters and 1,360 meters respectively above sea level, are only slightly higher than Princeton and Rossland at 700 meters and 1,023, FortisBC service area. Whereas Kelowna at 344, Trail 440, Grand Forks 520, Nelson 535 and Creston at 597 are all in valley bottoms.

Truth is, however, that both service territories share a similar heavily forested portion and hilly and mountainous terrain. Compared to Idaho Power's territory, there is nothing unique about FortisBC's that Idaho Power does not already deal with. In fact meter density is 6.4 per sq km for FortisBC and 8.4 for Idaho Power (C13-26, question 20, p 8).

In that context Idaho Power Company Ltd deployment costs were approximately $152 per meter, whereas FortisBC is estimating that it will spend approximately $415 (C13-9, Appendix 1, response 6 and B-6, response BCUC IR#1 106.5, p 248, line 11).

It is obviously not in the interest of FortisBC customers for the company to spend $30,245,000 more than it needs to on installing smart meters and a smart grid (Ibid, p 248 line 10).

Again, as stated above, after extensive field testing in 1998 and 2004, Idaho Power deployed their smart meters and smart grid between 2009 and the end of 2011, during the same time period over which FortisBC and Itron were developing their cost analysis and estimates (C13-9, Appendix 1, response 7 and C-17-1).

Not only was the cost of Idaho Power Company deployment cheaper per meter than FortisBC is proposing to spend, but the Alcara TWACs system out-competed Itron in an open RFI and RFP bidding process.

This ultimately begs the question: why did Idaho Power Company's RFI and RFP process attract both wired and wireless proposals, whereas ostensibly FortisBC's did not?

1.2 FBC’s evidence is that the only accurate way to know how much an advanced meter system will cost for a particular utility in a particular location at a particular time is to obtain bids in response to a competitive call for proposals. Do you disagree with that?

Response: Only partially agreed to. In the case of the Idaho Power Company Ltd, in the RFP smart meter and smart grid bid process, Itron's wireless proposal was unsuccessful in competing with Aclara's wired option.

Prior to full deployment, Idaho Power ran two pilot projects - one starting in 1998 and the other in the fall of 2004. In this regard, anyone who has participated in an RFP bid system process knows that problems can arise, even after a contract is awarded if the workability of the RFP response is not verified.

Small rural and remote Internet Service Providers (ISP) have considerable problems delivering a line-of-sight wireless signal in densely forested, hilly and mountainous terrain. The 902 to 928 bandwidth is one of the few wavelengths on which ISPs can effectively operate in such conditions.

BC Hydro, for example, cannot complete deployment of its RF-AMI system in the Slocan Valley because of the incompatibility with and potential disruption of the local community ISP operations (Valley Voice, BC Hydro Lets up on smart meters Internet Interference continues to delay program in Arrow and North Slocan, February 6, 2013, p 14 http://www.valleyvoice.ca/_pdf_2012/ValleyVoice130206web.pdf). In how many other locations this has occurred is unknown as BC Hydro has not divulged an exact number at this time.

A face to face meeting with FortisBC in Kaslo, in August 2012, revealed that Itron knew nothing about the possibility of disrupting certain ISP providers across BC in the 902-928 band, and as of February 2013 this issue still has not been resolved. Further, a conversation with a retired Telus field technician has revealed that disruption of internet services will occur every time there is a disruption in FortisBC's service, be it a brown out or blackout.

In late January BC Hydro admitted that they still had not deployed 140,000 meters, of which 80,000 were for reasons of refusal by the customer. That leaves 60,000 meters where the reasons for non-deployment by the deadline are unknown. Field and pilot testing of Itron's meters before a full rollout was initiated would have identified any problems before full deployment was undertaken.

As mentioned above, Idaho Power first deployed 1,000 meters in 1998 and then another 23,500 in 2004 as part of its field testing program of smart meters and smart grid technology. Area D is not, as yet, aware of whether or not any long term field testing of equipment has taken place on FortisBC's service territory.

An RFP bid process therefore should include field and pilot testing, extensive enough to know if proposed deployment is going to actually work.

1.3 If PLC advanced meter systems were generically less expensive than wireless advance meter systems, do you have an explanation of why no PLC system was bid into FortisBC's request for proposals?

Response: Area D has not had access to the Idaho Power RFP and cannot compare it to the FortisBC RFP.

However, the Idaho Power RFP bid process included Itron and Elster offering a wireless proposal and Aclara a wired, after 8 wireless and 2 wired companies were eliminated after an RFI process (Appendix 1 of this response, Heintzelman to Shadrack, February 8, 2013).

FortisBC has not disclosed that it held an RFI search before entering into an RFP process, and stated in its application that when it chose to eliminate the PLC-AMI option, one of three reasons for dropping the PLC-AMI option was:

It is not consistent with the metering system and services deployed to 1.8 million BC Hydro electricity customers (B-1, 7.3 Power Line Carrier AMI Systems, p 115, line 4 and 5).

In contrast Idaho Power Company, in its application before the Idaho Public Utilities Commission, stated:

The team concluded that the Aclara TWACS power line carrier system was the best match to our requirements and provided the best value to Idaho Power and its customers. 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 (C13-17-1/2-Idaho Power Company-Direct Testimony - D. Heintzelman, p 5, lines 3 to 11).

1.4 If FBC was to put out a new request for proposals, say for PLC systems, do you have any reason to be confident that the actual bids FBC would receive would be for less cost than the proposed system?

Response: Based on the experience of dealing with and discussing RFP bids at the Regional District Central Kootenay Board since November 2005 and working with an operational budget of close to $78 million in 2011, after cross-comparing FortisBC's application and additional submissions with the testimony of Idaho Power Company before the Idaho Public Utilities Commission, Area D's answer is to say that it is confident that a PLC-AMI bid would

be substantially lower.

1.5 What features of the situation of the Idaho Power Company at the time of its AMI application make it comparable to Fortis's situation now, such that the Idaho Power Company's AMI experience is relevant to Fortis's current AMI application?

Response: In their application Idaho Power states:

The direct benefits that will increasingly be recognized following the start of the implementation are the operational savings associated with remote meter readings. Beyond the savings in meter reading costs and the benefits associated with time-of-use pricing, additional benefits as stated in the findings of this Commission are:

AMR would improve meter reading accuracy, eliminate the need for Idaho Power to gain access to customer property for monthly meter reads, and allow Idaho Power to develop new services in the future. An AMR system would improve outage monitoring, theft detection, and employee safety. AMR's capacity for remote connects and disconnects would also save customer time and employee labor. From a billing perspective, AMR would result in fewer estimated bills, less rebilling, flexible billing schedules, account aggregating, and flexible rate designs (C13-17-1/1-Idaho Power Company - AMI CPCN Application, p 6).

Courtney Waites in her testimony states:

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 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 (C13-17-1/3-Idaho Power Company - Direct Testimony - C.Waites, p 9, line 19 to p 10, line 4).

In his testimony Mark Heintzelman confirms other Idaho Power testimony and also explains the uniqueness of the TWACS system in determining the amount of equipment necessary at deployment:

The only equipment required on the electrical distribution system are the endpoint communications modules ...Because of the unique method used by the TWACS system...the signal...remains intact to the end of the electrical distribution system... Idaho Power sees this feature as an extremely valuable attribute of the 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 (C13-17-1/2-Idaho Power Company - Direct Testimony - D. Heintzelman, p 10 line 8 to 10, 13 and 14, and 18 to 22).

In contrast FortisBC, at the WLAN and it is believed LAN level, is going to have to maintain the existing power line distribution infrastructure and, depending on distance between meter and a

substation type collection point, is going to have to deploy multiple collector equipment devices to relay the wireless signals in their backhaul.

Anyone who has deployed a rural Internet Service Provider operation knows the difficulties of doing this in a densely wooded forest over hilly and mountainous terrain.

Consequently FortisBC will have to operate and maintain two separate sets of equipment, likely in two different locations. In contrast all Idaho Power has to do is run a signal or collect data to and from each meter to the substation along the pre-existing power line.

1.6 Please provide a comparison of the features of the Idaho Power Company's smart meters with those proposed by Fortis, using the format of Tables 3.2.2.a and Table 7.5.d of the AMI Application.

Response:

Table 1 Summary of SMI Requirements

Category	**Requirements of Smart Grid Regulation**	**Idaho Power Funtion**
Meter	Measures electricity to eligible premises	Yes
	Transmits and receives information in digital form	Yes
	Enables remote disconnect and reconnect for residential premises	Available from Aclara
	Records Intervals at a frequency of at least 60 minutes (Aclara can go as low as every 15 minutes)	Yes
	Can be configured remotely or onsite	Yes
	Can measure and record electricity generated at a premises and supplied to the electric distribution system	Believe so
	Can transmit information to and from an IHD Idaho Power uses a web portal to give customers secure access to personal consumption information in choosing time variant pricing	Available
Installation	An advanced meter will be installed for each eligible premises	Yes
	Secure hardware and software systems will be installed to: • Monitor, control and configure advanced meters and communications infrastructure • Store, validate, analyze and use the date measured by and received from advanced meters • Provide secure internet access for data about a customer's electricity consumption and	 Yes Yes Yes

Installation (continued)	generation, measured by the advanced meter • Bill customers in accordance with rates that encourage the shift of the use of electricity from periods of higher demand to periods of lower demand • Integrate with Idaho Power's systems	Yes Yes
	Communications infrastructure includes a telecommunications network that is capable of delivering two-way, digital and secure communications	Yes
	Communications infrastructure must integrate to Idaho Power systems	Yes
Smart Grid Enablement	To enable Idaho Power to perform electricity balance analyses for the electrical distribution system	Believe so
	Enables Idaho Power to perform analyses to estimate the unmetered load	Yes
	Enables Idaho Power to use investigative device and/or software to identify the location of unmetered loads	Yes
	Establish a telecommunications network with sufficient speed and bandwidth to facilitate distributed generation	Yes
	Establish a telecommunications network with sufficient speed and bandwidth to facilitate the use of electric vehicles	Yes
	Integrate the operation of the smart grid with Idaho Power's systems	Yes

Table 2 AMI Option Functionality Matrix Compared

Features Available	**FortisBC AMI RF**	**Idaho Power PLC-AMI**
Bi-Monthly Meter Readings	Yes	Assumed Available
Monthly Meter Readings for All Customers	Yes	Yes
Daily Meter Readings for All Customers	Yes	Yes
Hourly Meter Readings for All Customers	Yes	Yes
Reduction in Meter Reading Costs	Yes	Yes
Outage Notification	Yes	Yes
Restoration Verification	Yes	Yes
Flexible Billing Dates	Yes	Yes
Bill Consolidation for Customers	Yes	Yes
Home Area Network	Yes	No*

Meter Tamper Detection	Yes	Yes
System Modelling Enhancements	Yes	Yes
Time Based Rates	Yes	Yes
Virtual Disconnects	Yes	Available
Remote Disconnect	Yes	Available
Load Control	Yes	Yes
Conservation Voltage Reduction (VVO)	Yes	Believe so
Reduction in Energy Theft	Yes	Yes
Distribution Automation Device Support	Yes	Uncertain
Supports Energy Reduction Objectives	Yes	Yes
Only new equipment required when adding new customers will be the meter	No	Yes
Lower operation and maintenance cost of network	No	Yes
*Internet access to hourly customer power consumption data, with customer program to assist variant pricing choice	No	Yes
Irrigation peaks reward program	No	Yes

1.7 Order No. 30726 of the Idaho Public Utilities Commission that approves the AMI application of Idaho Power Company is dated 12 February 2009. Has the proposed AMI been installed? If so, have there been any post-installation assessments of the actual costs and performance of the system relative to the forecast costs and performance? Please provide references to any such assessments and summary descriptions.

Response: The meters were deployed between 2009 and the end of 2011 (C13-9, Appendix 1, response 7).

Area D is filing two reports with BCUC and is working with staff at the Idaho Public Utilities Commission to identify other publicly available reports that can be filed by the February 21, 2013 filing deadline:

A: Courtney Waites, Inclusion of Advanced Metering Infrastructure ("AMI") Investment In Rate Base, Case No IPC-E-10-06, March 15, 2010, 5.07 PM.

B: Compliance filing of Time Variant Pricing Implementation Plan Case No.IPC-E-08-16, Idaho Power, January 19, 2012.

1.8 What significant changes in technologies or costs of technologies for smart meters have emerged between the time of the Idaho Power Company AMI application and the present that might affect the expected capabilities and costs of a smart meter system being proposed today relative to when the Idaho Power Company filed its application?

Response: Idaho Power specifically acknowledges that costs rose

from its estimated $70.9 to $74 million - a 4.4% increase (C13-17-1/3-Idaho Power Company - Direct Testimony - C.Waites, page 8, line 7 and Exhibit No 4 and C13-18), however Area D does not know how those costs were attributed.

Area D cannot speak to other PLC-AMI system changes, but cites the changes described by Aclara at 3 and 4 of Bill Weber's response (C13-26, Weber to Shadrack, February 7, 2013, p 10).

Further, Area D submits as an addenda an email and attachment to that email received from Aclara, February 19, 2013, in direct response to question 1.8.

1.9 Did the Idaho Power Company receive any subsidies for the installation of its smart meter system?

Idaho Power confirms receiving a subsidy on its website at **Smart Grid Frequently Asked Questions**:

11. What will the Department of Energy contribute in terms of funding?

The intent of the Smart Grid Investment Grant (SGIG) funding is to provide federal financial assistance for up to 50 percent of eligible project costs. Idaho Power's proposed projects totalled $94 million, of which $47 million is from the company's investment and $47 million from SGIG funds.

This financial assistance is intended to enable measurable improvements through accelerated achievement of Smart Grid projects, including:

- *Reliability of the electric power system*
- *Consumer electricity costs, bills and environmental impacts*
- *Clean energy development and greenhouse gas emissions*
- *Economic opportunities for businesses and new jobs for workers.*

12. What projects did Idaho Power propose as part of this funding opportunity?

Idaho Power committed to completing 12 projects within three main categories:

- *Advanced Metering Infrastructure*
- *Customer Systems*
- *Electric Infrastructure Improvements*

Advanced Metering Infrastructure (AMI) meter exchanges began in 2009 and completed in 2011. The company replaced 500,000 existing traditional meters with advanced, digital wired meters.

Smart meters are capable of measuring and collecting hourly interval energy-use data to support future time-variant rates.

Customer Systems projects will provide customer access to smart meter information and programs enabled by the Smart Grid. Project components will include an upgraded customer information database and an energy-use advising tool.

Electric Infrastructure Improvements are necessary to fully enable the Smart Grid. The projects planned under this category include:

- *Updates to the outage management system*
- *Development of renewable integration tools to improve load and wind forecasting*
- *Self-healing network pilot project*

Implementation of a transmission situational awareness project (http://www.idahopower.com/AboutUs/CompanyInformation/SmartGrid/FAQs.cfm#11)

Area D therefore cannot definitively say what portion of the grant was attributed to deployment of the smart meters and the smart meter grid.

2.0 Topic: Advanced Metering Infrastructure
Reference: Exhibit C13-17-1, document 14, Advanced Metering Infrastructure, "Conducted by the National Energy Technology Laboratory" for the U.S. Department of Energy Office of Electricity Delivery and Energy Reliability, February 2008

In cross-examination, Mr. Heintzelman is asked to "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 (page 2, lines 21 to 24).

Mr. Heintzelman is quoted on pages 3 to 5:

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.

In November 2007, pursuant to the Company's August 31, 2007, AMI Implementation Plan filed in Case No. IPC-E-06-01, the Company formed a cross-functional team made up of Idaho Power employees with the assistance of a strategic sourcing consultant, and led by the Company's Procurement Department professionals, to evaluate and assess the possible AMI solutions and ultimately to select vendors and successfully negotiate contracts for the deployment of the AMI technology. This approach is part of the Company's Strategic Sourcing Process. The team is made up of employees with expertise in procurement/purchasing, pricing/regulatory, meter support, finance, and other subject matter experts. In 2008, the team issued a Request for Information ("RFI") to thirteen of the industry's leading AMI technology providers, including Aclara, for a system-wide deployment. The RFI requested specific information related to deployment scale, system functionality, and technology. The responses were evaluated against our system and functional requirements by a Strategic Sourcing team assembled for the AMI project, with an emphasis on specific demonstrated functionality at scale. The RFI evaluation reduced the field of thirteen AMI technology providers down to two."

The Company then issued a Request for Proposals ("RFP") to the two remaining technology providers, one of which was Aclara. The analysis of the proposals was performed by the same cross-functional Idaho Power team again with the assistance of a strategic sourcing consultant. The proposals were evaluated against our functional requirements, financial requirements, and our physical electrical system requirements. The team concluded that the Aclara TWACS power line carrier system was the best match to our requirements and provided the best value to Idaho Power and its customers. 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." [underlines added]

2.1 Please confirm that TWACS means "two-way automated communication system."

Response: Confirmed

2.2 Please confirm that the proposed "TWACS power line carrier system" is a "PLC" system in the sense used by Fortis in the current application.

Response: Confirmed

TWACS works by modulating the power at the zero cross, not by injecting a carrier onto the power line. The reason the TWACS system works and the carrier systems have problems is because the power delivery distribution networks are constructed to deliver power at 60 Hz., not to deliver a signal injected at a higher frequency. That is the strength of TWACS! It communicates at 60 Hz and the TWACS signal will go everywhere the distribution power lines go. Distance is no problem. We communicate very reliably on feeders in excess of 100 miles long (C13-26, Weber to Shadrack, February 7, 2013, p 10, third para).

2.3 Detail the functional requirements of Idaho Power Company for an AMI system.

Response: see answers to 1.6

2.4 In what ways did the performance offered by the Aclara TWACS system offer a better “match to [Idaho Power Company’s] requirements” than the performance offered by Alcara’s competitors in the RFI and RFP?

Response: In a telephone conversation with a representative of Idaho Public Utilities Commission it was confirmed that making wireless work in heavily forested, hilly and mountainous terrain is extremely difficult (Shadrack to Rob Loeb, February 15, 2013). In contrast Idaho Power has achieved the desired functionality as described in **Compliance filing of Time Variant Pricing Implementation Plan**.

2.5 Were the RFI and RFP issued by the Idaho Power Company technology-neutral with respect to wired back-haul versus wireless back-haul? Or did they specify a non-wireless system? In other words, was the decision to use a TWACS power line carrier system the result of the RFI or RFP process, or did it pre-date those processes?

Response: The RFI was sent out to ten AMI-RF companies and 3 PLC-AMI. For the RFP bid, Itron and Elster's were AMI-RF and Aclara's PLC-AMI (Appendix 1 of this response, Heintzelman to Shadrack, February 8, 2013).

The fact that ten AMI wireless companies were invited into the RFI process and two went head-to-head in the RFP bid process provides sufficient evidence that the TWACS proposal won on merit during the RFI and RFP processes.

Unlike the FortisBC situation, both a wireless and wired option were considered as part of RFP process.

2.6 Did all of the 1998 TWACS pilot, the Emmett and McCall deployments or the Energy Watch and Time-of-Day deployments use PLC technology?

Response: Yes. Idaho Power states:

The 2 pilots were in remote mountainous areas on extremely long feeders with few customers, we only looked at PLC (Appendix 2 to this response, Heintzelman to Shadrack, February 15, 2013).

The initial 1,000 meter deployment in 1998 was AMR not AMI and concerning the 2004 23,500 meter deployment, the Idaho Power Company Ltd application states in their 2008 full deployment application:

In December 2003, after a collaborative workshop amongst the Company, Commission Staff, vendors and interested individuals, the Company filed its Phase One Implementation Plan to install AMI technology in the Emmett and McCall operating Areas. Case No. IPC-E-02-12. Phase One implementation was

completed on October 26, 2004, and consisted of approximately 23,500 meters along with other associated infrastructure (C13-17-1/1-Idaho Power Company - AMI CPCN Application, p 3, bottom to p 4, first para).

2.7 What process did the Idaho Power Company go through to determine whether to use wireless or PLC technology in its 1998 TWACS pilot, the Emmett and McCall deployments or the Energy Watch and Time-of-Day deployments?

Response: Please see response to 2.6 above

2.8 Did the cross-functional team that was formed in 2007 consider wireless technology options?

Response: Yes. After the RFI elimination process, Itron and Elster were invited to submit an RFP bid which was a wireless option (C13-18).

3.0 Topic: Comparative costs
Reference: Exhibit B-23, FortisBC Inc. Evidentiary Filing regarding costs of wireless and wired advanced meter systems

Table 1 shows "Cost/Meter" for some 20 advanced meter projects in various jurisdictions based on data from a 2012 report by the Institute for Electric Efficiency (IEE). The "Cost/Meter" figures range from a low of $43/meter to a high of $4,690/meter.

3.1 Do you have any disagreement with the data in Table 1?

Response: Without knowing the parameters by which FortisBC gathered its data, Area D can neither confirm nor deny that the data presented by FortisBC is accurate.

3.2 Do you agree that the very wide range of "Cost/Meter" figures indicates that "Cost/Meter" is not a particularly good measure of the actual cost or cost-effectiveness of a particular advanced meter system?

Response: Cost per meter is a very good measure when one can verify that the cost input items are equal between the projects being compared. Area D stands by what was stated in C13-10, some highlights of which are below:

Without knowing the veracity of what is attributed and whether appropriate cost comparisons can be made I would like to make some additional comments to the Commission.

From the list below it would appear that British Columbians will be paying, with the exception of Texas, the highest cost to have smart meters installed in North America.

...In conclusion, until the actual cost of installing smart meters, wireless or wired, is definitively and appropriately known, it will be almost impossible to have a contextual discussion about which technological option might best suit FortisBC and its customers (C13-10, Shadrack to Commission, p 1, paragraphs 1, 2 and 5).

3.3 On pages 1 to 4 of Exhibit B-23, FortisBC provides additional

evidence regarding AMI communications technologies. If you disagree with any of this evidence, please provide the basis for your disagreement.

Response: FortisBC, at page 3 and 4 of its B-23, submission states that the cost of the Idaho Power Company project was $94 million, but the November 2011 Update Recovery Act Selections for Smart Grid Investment Grant Awards - By Category actually states:

Modernize the electric transmission and distribution infrastructure, including deploying a smart meter network for all 475,000 customers throughout the service area and implementing an outage management system and irrigation load control program that will reduce peak and overall energy use and improve system (Energy.Gov, Office of Electricity Delivery and Energy Reliability (http://energy.gov/oe/downloads/recovery-act-selections-smart-grid-investment-grant-awards-category-updated-november), SGIG Awards by Category 2011 11 15.pdf , RECOVERY ACT SELECTIONS FOR SMART GRID INVESTMENT GRANT AWARDS - BY CATEGORY, Category 6 Integrated and/or Crosscutting Systems Category, (reliabilityhttp://energy.gov/sites/prod/files/SGIG%20Awards%20by%20Category%202011%2011%2015.pdf).

Mark Heintzelman in C13-18 confirmed that 485,000 meters were deployed over a three year period and:

The total cost for meters, labor, backhaul and IT was about $74 M (C13-18, response 2).

This indicates to Area D that some $20 million in non-smart grid modernization was undertaken at the same time.

Area D stands by the statement originally made by Idaho Power Company in C13-9:

The overall cost of the system including software and data management systems divided by meter endpoints is approximately $152 (C-13-9, response 6).

At page 3 FortisBC states that the Idaho Power deployment was PLC, but Bill Weber, Director, Account Management, Aclara Technologies LLC in C13-26 states:

TWACS is not a carrier signal (C13-26, Appendix 1, Weber to Shadrack, p 12, response to 3, February 7, 2013).

At page 1 FortisBC states that only 16 Non-RF deployments have occurred in North America, whereas Aclara alone reports:

We have 361 TWACS customers with 13M TWACS devices. Twelve of these customers are outside of the US and Canada and are located in Mexico, South America, Asia and the Caribbean. Another 12 TWACS customers are IOUs in the US and Canada. The remaining customers are Electric Cooperatives and Municipals in the US. Of the customers in the US and Canada, one was installed starting in 1986 involving a significant development period (C13-26, Appendix 1, Weber to Shadrack, p 11, response to 1,

February 7, 2013).

In addition Aclara identifies two more PLC-AMI companies in North America for which deployment numbers by Hunt's Turtle system and Cannon by Cooper Power Systems remain unknown (C13-26, Appendix 1, Weber to Shadrack, p 12, response to 3, February 7, 2013). Further, while FortisBC reports elsewhere that few Non-RF deployments have occurred since 2008, Aclara reports that 113, 31.3%, of their deployments occurred between 2008 and 2012 (C13-26, Appendix 1, Weber to Shadrack, p 11, response to 1, February 7, 2013).

Of the 2.9 million meters deployed in Canada, FortisAlberta's 480,000 represents 16.6%, not the 4.7% that FortisBC ascribes by adding in planned future installations (B-23, AMI Communications Technologies, p 1, para 2). Consequently, for all of the above facts, Area D questions the veracity of the B-23 submission made by FortisBC with regard deployment of Non-RF smart meters in North America.

FortisBC then states on page 1 that:

RF meters are also the only form of remote gas and water metering in North America, with over 50 million gas and approximately 50 million water RF AMR/AMI meters shipped in North American as of third-quarter 2012 (B-23, Attachment 1, AMI Communications Technologies, p 1, para 6).

Aclara reports:

ATCO Electric [Edmonton, Alberta] *and several of the Municipal utilities deploy electric and water and/or gas meters. Aclara partners with Badger Meter who supplies their Orion module for the gas or water meters. The Orion module transmits the water or gas meter reads back to a receiver that is located under the glass of the electric meter. Those reads are then brought back over the power line via the TWACS network. Other utilities have deployed both our TWACS and STAR networks to read the electric (TWACS) and water or gas (STAR)* (C13-26, Appendix 1, Weber to Shadrack, response 2, p 12, February 7, 2013).

What FortisBC failed to report, in its B23 submission, is that water and/or gas meter information is being transported over power lines to data receiving centres that handle power, water and gas consumption and billing information, which is not the same as the information given by FortisBC above (B-23, Attachment 1, AMI Communications Technologies, p 1, para 6) or to CSTS elsewhere earlier.

FortisBC then cites a report that finds PLC-AMI systems have problems with:

...infrastructure costs, high latency, bandwidth constraints, and problems with line noise (B-23, Appendix 1, AMI Communication Technologies, p 2, para 1).

Not being an engineer I am not sure what the problem is with line

noise, also known as humming, but I do know that this was a problem long before smart meter technology was introduced.

Courtney Waites in her testimony identifies Station Investment and IT costs at 20.1% and 2.3% of overall project estimate respectively (C13-17-1/3-Idaho Power Company - Direct Testimony - C.Waites, Exhibit No 4, Total), whereas FortisBC identifies a completely different cost structure in its response to BCUC (B-6, IR#1 106.3, p 247, lines 20-22).

A careful cross-comparison of FortisBC's application and a variety of IR responses with Mark Heintzelman's testimony reveals huge variances in the type of equipment FortisBC suggests should be deployed by a PLC system and where in the power distribution system it should be deployed, Area D believes that described by Heintzelman uses less equipment, hence the cost differential between Waites' estimates and those of FortisBC (C13-17-1/2-Idaho Power Company - Direct Testimony - D. Heintzelman, p 9, line 20 to p 10, line 22).

The evolving issue of bandwidth and high latency problems is dealt with extensively in the Idaho Power Company application, Heintzelman's testimony, an Idaho Public Utility Commission staff submission (C13-17-1) and by Aclara itself which states:

Strengths of the TWACS network are:

1) Surety of cost. The network equipment is installed in the substation and it communicates reliably everywhere the distribution circuits go

2) *Performance: We have customers with as many as 1.4 M [1.4 million] meters that have read these meters successfully for the past 3 years at the following performance rates:*

a. Daily Consumption Reads – 99.72%

b. Hourly Interval Data – 99.65%

c. Billing Reads – 99.87%

3) Most of our customer have the original TWACS networks deployed. We recently introduced an enhancement to TWACS that we call eTWACS or TWACS 20. The original TWACS network would read meters serially on one phase of one feeder of a bus at a time. Today's eTWACS system is able to read meters on every phase, feeder and bus in parallel instead of serially. With eTWACS most utilities can read hourly interval data and daily/billing reads in under 4 hours and have the TWACS network available for Demand Response, Distribution Automation, Outage Management Support, Customer Service real time power and read checks, voltage checks, prepay, connect/disconnect, etc.

4) The key to TWACS is that we can read any single meter in under 15 seconds and we can get basic AMI data (hourly and daily reads) from all the meters in just a few hours. The competitors look at the TWACS fundamental signal below and say its slow because it runs at the 60 Hz. The facts are that because every feeder and phase is

*a parallel communication node that supports 6 channels of data that the system is power, fast and reliable (*C13-26, Appendix 1, Weber to Shadrack, Strengths of the TWACS Network are, p 10, February 7, 2013).

Further, in C13-9, Area D reported on a specific question submitted concerning bandwidth and the answer from Idaho Power:

Has Idaho Power found any problems in the high density meter portions of their service area, retrieving data from meters or in relaying instructions and/or information to their meters? Our largest substation serves just over 16,000 customers and we have not seen any issues related to data retrieval (C13-9, Appendix 1, question and response to 11)*.*

Aclara confirms this in C13-26 by stating distances that data can travel along power lines:

Distance is no problem. We communicate very reliably on feeders in excess of 100 miles long (C13-26, Appendix 1, Weber to Shadrack, p 10, third para, February 7, 2013).

Area D does not know why FortisBC persists in stating that there are problems with bandwidth and high latency. One of two possibilities emerges: either FortisBC's knowledge of the evolution of PLC is outdated and inaccurate, or their knowledge of the types of PLC systems available on the market is limited.

FortisBC's submission then uses a quote from a report that states:

Utilities have been using phone lines and fibre optic protocols for many years. Generally speaking, however, these are not well suited for the requirements of field-area networks, which require low cost solutions with sufficient bandwidth (B-23, Attachment 1, p 2, para 2)*.*

Elsewhere Area D has asked FortisBC to clarify whether it is talking about collection of data from a meter or endpoint to a substation, or from the meter all the way back to the data collection centre where the billing process is performed (C13-26, question 13).

Again Mark Heintzelman's testimony clearly identifies that Idaho Power is effectively using phone lines from the substation to the data collection centre where the billing process is performed. Another option which Area D suggests might be available is fibre-optic (C13-17-1/2-Idaho Power Company - Direct Testimony, D.Heintzelman, p10, line 23 to p 12, line 10). Area D cannot confirm use of fibre-optic at this time.

With regard the lengthy quote from Pike's **Smart Meter Backhaul Communications and the Role of Broadband Satellite** report, the best Area D can say, not being an engineer, is that Mark Heintzelman's testimonial description of the equipment being used markedly differs from that described in Pike's report. Area D's observation is that FortisBC is talking about one kind of PLC technology and Heintzelman another (C13-17-1 and B-23).

Consequently Area D concludes that FortisBC's B23 submission, in its entirety, has failed to substantiate its claim that a PLC-AMI system could not meet its technological requirements and that its cost of deployment of RF-AMI is not substantially more per meter

4.0 Topic: Idaho Power Company Advanced Metering Infrastructure Reference: Exhibit C13-17-1, evidence of RDCK, document 2, Direct Testimony of Mark Heintzelman

On the second page, the disclaimer says:
"This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. … [underline added]

4.1 Given the disclaimer, who, if anyone, is prepared to take responsibility for the accuracy and/or completeness of the information in the report?

4.2 What weight should be given to the report in this proceeding?

5.0 Topic: Evidence of David O. Carpenter before the Energy Board of Quebec re Docket No. R-3770-2011, Authorization of an Investment by Hydro-Quebec Distribution – Advanced Metering Project Phase 1

Reference: Exhibit C13-17-1, document 8, "THE STATE OF SCIENTIFIC RESEARCH AS TO WHETHER ADVANCED METERS TRANSMITTING BY RADIOFREQUENCIES, AS PROPOSED IN THE PRESENT CASE, MAY CONSTITUTE A RISK OF SERIOUS OR IRREVERSIBLE DAMAGE TO HEALTH" "Expert Report" "David O. Carpenter", April 30, 2012, Exhibit SE-AQLPA-7 – Document 1 [underline added]

Reference: Exhibit C11-7, "THE STATE OF SCIENTIFIC RESEARCH AS TO WHETHER ADVANCED METERS TRANSMITTING BY RADIOFREQUENCIES, AS PROPOSED IN THE PRESENT CASE, MAY CONSTITUTE A RISK OF SERIOUS OR IRREVERSIBLE DAMAGE TO HEALTH" "Expert Report" "David O. Carpenter", April 30, 2012, Revised May 14, 2012Exhibit SE-AQLPA-7 – Document 1.1 [underline added]

5.1 Please describe the proceeding "Authorization of an Investment by Hydro-Quebec Distribution – Advanced Metering Project Phase 1" ("HQ-AMI") and explain its relevance to the current proceeding.

5.2 Please confirm that the intervenor (Strategies Energetiques/Energy Strategies/Quebec Association to Fight Against Air Pollution ("SE/AQLPA")) filed two different versions of David O. Carpenter's evidence in the HQ-AMI proceeding.

5.3 Please explain why SE/AQLPA filed two different versions of David

O. Carpenter's evidence in the HQ-AMI proceeding.

5.4 Please describe the differences between Document 1, dated April 30, 2012, filed by RDCK in this proceeding and Document 1.1, dated May 14, 2012, filed by Keith Miles in this proceeding.

5.5 Why did RDCK choose to file Document 1 in this proceeding, rather than Document 1.1?

5.6 Please confirm that Carpenter's evidence in either Document 1 or Document 1.1 does not cite or discuss any studies that deal specifically with health issues in relation to the radiation from smart meters. Otherwise, indicate where in the evidence such studies or discussion occurs.

5.7 Did SE/AQLPA seek to have David Carpenter qualified in the HQ-AMI proceeding as an expert witness?

5.8 Was David Carpenter qualified as an expert witness in the HQ-AMI proceeding?

6.0 Topic: "DVD – Smart Meters & Electromagnetic Radiation"
Reference: Exhibit C13-17-1, .pdf pages 1 & 3.

Mr. Shadrack says: "Please find enclosed as part of the documentary evidence of Area D of the RDCK: … 27. DVD – Smart Meters & Electromagnetic Radiation"

6.1 Please confirm that "DVD – Smart Meters & Electromagnetic Radiation" is not in evidence in this proceeding. Otherwise, please explain and provide the referenced item.

7.0 Topic: Smart Meters, various topics
Reference: Exhibit C13-19, *Smart Meters and the 21st Century*

7.1 Please confirm that Robert McLennan is the author of *Smart Meters and the 21st Century*. If not, please explain.

Response: Confirmed.

7.2 Exhibit C13-19 says, "… unless I am wrong and stand corrected, this module will cost the user an additional monthly fee …" [second page, last paragraph to third page]. Does this mean that the ZigBee chip in the meters would cost the user an additional fee, or that in-home devices that might communicate with the ZigBee chip would cost an additional fee? Please give the basis for saying that there would be an additional monthly fee, as distinct from, say, a one-time acquisition cost.

7.3 Exhibit C13-19 says, "… I would recommend all metering go through the Internet, even though that is the industry I am in." [sixth page, last par.] Can Mr. McLennan provide any existing examples of residential distribution customers using the internet to communicate electricity metering information with their utilities?

7.4 Exhibit C13-19 says, "There are a number of power-line

communications systems available today that would bring data from the smart meter to the collector. However, I believe fibre-optic cabling would be the most effective" [eight to ninth page]. Can Mr. McLennan provide any existing examples of residential distribution customers using fibre-optic cabling to communicate electricity metering information with their utilities?

Appendix 1

From: "Heintzelman, Mark" <MHeintzelman@idahopower.com>
To: "'Andy Shadrack'" <ashadra@telus.net>
Date: Mon, 11 Feb 2013 09:56:09 -0700
Subject: RE: FortisBC Functionality Requirements

Andy,
1. 3 were PLC, 10 were RF
2. Itron and Elster were RF solutions

-----Original Message-----
From: Andy Shadrack [mailto:ashadra@telus.net]
Sent: Friday, February 08, 2013 10:22 PM
To: Heintzelman, Mark
Subject: FortisBC Functionality Requirements

Kaslo, BC

Canada

Friday February 8

Dear Mark and Bill

I have contacted Aclara as you suggested Mark. I really appreciate the time that both of you have taken to answer my questions to date...

1. In terms of the RFI how many of the thirteen were RF-AMI and how many were Non-RF-AMI (PLC-AMI)?

2. Was the Itron RFP bid RF-AMI and what was the Elster RFP bid?...

Respectfully submitted
Andy Shadrack
Director Area D
Regional District Central Kootenay

Appendix 2

From: "Heintzelman, Mark" <MHeintzelman@idahopower.com>
To: "'Andy Shadrack'" <ashadra@telus.net>
Date: Fri, 15 Feb 2013 08:28:55 -0700
Subject: RE: Questions for Idaho Power

Andy,

....The 2 pilots were in remote mountainous areas on extremely long feeders with few customers, we only looked at PLC.