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November 9, 2012

Via Email
Original via Mail

Ms. Erica Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: FortisBC Inc. (FortisBC) Application for a Certificate of Public Convenience and Necessity (CPCN) for the Advanced Metering Infrastructure Project – Responses to Intervener Information Request No. 1

Please find attached FortisBC's responses to Information Request No. 1 from the British Columbia Pensioners' and Seniors Organization et al. (BCPSO), British Columbia Sustainable Energy Association (BCSEA), British Columbia Residential Utility Customers Association (BCRUCA), Citizens for Safe Technology Society (CSTS), Industrial Customers Group (ICG), Keith Miles, Andy Shadrack, Joe Tatangelo, Commercial Energy Consumers of British Columbia (CEC), Nelson Creston Green Party Constituency Association (NCGP), and West Kootenay Concerned Citizens (WKCC).

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

cc: Registered Interveners

1.0 Reference: Exhibit B1, Executive Summary, page 4 (lines 14-15)

BCUC 1.3.1

1.1 To-date, what payments has FortisBC made to Itron Canada?

<u>Response:</u>

FortisBC has not made any payments to date to Itron Canada.

2.0 Reference: Exhibit B1, Executive Summary, page 3 (lines 27-29)

Exhibit B1, Tab 1, page 6

2.1 Does the AMI project cost of $47.7 M include all of the costs associated with integrating the AMI project with existing FortisBC systems? For example, does it include all of the costs associated with making operational-related data available to FortisBC operators (per page 6)?

<u>Response:</u>

Yes, the proposed AMI Project includes all costs associated with integrating the AMI Project with existing FortisBC systems, including making operational-related data available to FortisBC operators.

2.2 If not, what activities and costs are not included?

<u>Response:</u>

Please refer to the response for BCPSO IR No. 1 Q2.1.

3.0 Reference: BCUC 1.1 and 1.2

3.1 Did FortisBC's most recent depreciation study specifically address the depreciation rate applicable to smart meters?

<u>Response:</u>

No, the depreciation rate applicable to smart meters was not addressed in the most recent depreciation study.

3.2 Are the Itron CENTRON Openway meters used by any other utilities? If so, which ones and what is the depreciation rate that these utilities use for such meters?

Response:

The OpenWay Centron meter is used by the following utilities in North America:

- San Diego Gas and Electric (used a 17 year analytical life);
- Southern California Edison (20 years);
- CenterPoint Energy (unknown);
- DTE Energy (20 years);
- BC Hydro (20 years);
- Glendale Water and Power (unknown); and
- Early deployments and pilots underway at National Grid, First Energy, Duke Energy, Duquesne Light Company (unknown).

4.0 Reference: Exhibit B1, Tab 1, page 6, lines 6-9

Exhibit B1, Tab 1, page 7, lines 15-17

BCUC 1.2.1 and 1.2.2

4.1 Is the AMI Project totally discretionary such that there is no "need" it is responding to other than the benefits (financial and otherwise) that it offers customers?

Response:

FortisBC's decision to proceed with its proposal to implement AMI is based on number of considerations including (but not limited to) the following:

- Existing legislation requiring BC Hydro to implement smart meters and a smart grid for its customers;

- Existing provincial energy policy and legislation articulating the government's desire to have advanced meters and a smart grid in place for customers of other public utilities other than BC Hydro;
- The transition by the electric industry towards the use of advanced meters as the standard form of metering technology;
- Pursuant to Order G-168-08, page 31, encouragement from the Commission for FortisBC to continue its efforts to develop and, in due course, reapply for approval of a program for the installation and implementation of AMI;
- The level of benefits attributable to FortisBC's proposed project.

The decision of the Company to proceed with its Application to implement AMI at this time is based on the considerations identified above, and the fact that the Project is beneficial to customers in terms of its impact on the following:

- Rates – as discussed in Section 5.0 of the Application, financial analysis of the Project shows that rates will be lower than they otherwise would be in absence of the Project as evaluated over the 20 year study period;
- Customer service – as discussed in Sections 3.2.5 and 5.3, the Project provides a number of financial and non-financial customer service benefits primarily related to the provision to customers of more detailed information regarding their electricity usage;
- Safety – as discussed in Section 3.2.5, the Project will reduce safety risks related to the current manual meter reading process; and
- Reliability – as discussed in Sections 3.2.3 and 6.3 of the Application, AMI is a smart grid building block, and is required for the future implementation of additional smart grid technologies that will enhance system reliability, as well as the future implementation of an Outage Management System. As well,

Based on these considerations, it is clear that the Project as proposed ought to be considered as being in the public interest.

Please also refer to the response to BCUC IR No. 1 Q2.1.

5.0 Reference: Exhibit B1, Tab 1, page 12, lines 24-25

5.1 Please provide details regarding the "experienced consultant" engaged by FortisBC to facilitate the AMI system procurement process. Is this the same consultant identified in response to BCUC 1.4.1?

Response:

Please refer to the response from BCUC IR No. 1, Q4.1.1. This is the same consultant that was engaged by FortisBC to facilitate the AMI system procurement process.

6.0 Reference: Exhibit B1, Tab 3, page 17

6.1 Is the MV-90 system also used for FortisBC's wholesale municipal electric utility customers?

Response:

Yes, the MV-90 system is used for all of FortisBC's wholesale municipal electric utility customers.

6.2 What are the total service lives for electro-mechanical meters and for digital meters respectively?

Response:

Please refer to the response to BCUC IR No. 1 Q90.5.

7.0 Reference: Exhibit B1, Tab 3, pages 28-29

BCUC 1.12.3

7.1 Please confirm that the AMI Project will enable FortisBC to fully deploy, without further expenditures (i.e. AMI is necessary and sufficient), the first four components referenced in response to BCUC 1.12.3. If not, what additional expenditures will be required?

Response:

Confirmed, the costs associated with the first four components are included in the AMI Project financial model.

7.2 Please identify those components for which the AMI Project is required but additional work/spending will be required in order to deploy (i.e. AMI is necessary but not sufficient).

Response:

The inter-linkages and dependencies between AMI and the implementation of subsequent components are depicted graphically in the response to BCUC IR No. 1 Q44.2. For further clarity, FortisBC considers that AMI is a prerequisite to support the following components:

- Automated Outage Management System (OMS);
- Distribution Management System (DMS);
- Distribution automation (DA);
- Demand response (DR) load control;
- Wide-scale integration of electric or plug-in hybrid vehicles (EVs or PHEVs);
- Wide-scale integration of distributed generation (DG); and
- Conservation voltage reduction (CVR).

8.0 Reference: BCUC 1.8.1.3

8.1 Is the $0.25 M capital cost of the customer portal included in the overall $47.7 M project cost?

Response:

Yes, the $0.25 million capital cost of the customer portal is included in the overall project cost.

9.0 Reference: BCUC 1.8.1.3.1

9.1 Does FortisBC have any plans to limit the frequency with which it will provide additional printed data to customers?

Response:

FortisBC does not have any plans to limit the frequency with which it will provide additional printed data to customers.

10.0 Reference: Exhibit B1, Tab 3, pages 31-32

10.1 To what extent do FortisBC's costs actually vary by time of use? In responding please distinguish between a) shifts in time of day or the particular days that energy is used and b) reductions in a customer's use at the time of system peak use.

Response:

To understand how power supply costs may be impacted by time of use, both long term resource planning and short term operational requirements must be considered. Long term resource planning will drive the requirement for new supply while short term operational requirements will impact the real-time optimization of the existing resources to minimize power purchase costs.

For planning purposes, the critical numbers are the monthly, and especially, the annual peak. Therefore, if a time of use program is to impact the costs needed to acquire new resources, it must reduce customer demand at the time of the system peak. FortisBC expects that the required detailed information on how a time of use program will impact system peak will only be available once greater experience with time of use is gained.

However, regardless of the impact on long term planning, FortisBC expects that daily operational benefits can potentially be obtained on any day of the year. As explained in response to BCUC IR No. 1 Q110.4 this is estimated at up to $11 per MWh on a go forward basis. For comparison purposes, the historical number over the past six years is $9 per MWh. This is only a potential cost reduction as operational realities such as power supply contracts that are not sensitive to time of use may reduce the actual value realized.

Please also refer to the BCUC IR No. 1 Q108 series.

11.0 Reference: Exhibit B1, Tab 3, page 32 (lines 20-22)

BCUC 1.16.1

11.1 Please explain how the 2.2 GWh savings in 2015 and 5.3 GWh savings in 2025 were derived.

Response:

The cumulative CIP savings as a percentage of the before-savings gross residential load is set at 0.15% in 2015 and 0.30% from 2016 onwards as per the BC Hydro business case and can be referenced in the Application (Exhibit B-1) at Appendix C-4, p31. The before-savings gross residential load in 2015 and 2025 is forecast at 1,490.0 GWh and 1,770.3 GWh respectively. Therefore, CIP saving in 2015 is 0.15%*1,490.0 = 2.2 GWh and in 2025 is 0.30%*1,770.3 = 5.3 GWh.

12.0 Reference: Exhibit B1, Tab 3, page 32

BCUC 1.8.1

12.1 Has FortisBC reviewed the nature of the billing enquiries made to its Contact Centre to determine whether or not customers would have been able to address them (independently) through the use of the online customer information portal (without an IHD)?

Response:

Based on the nature of the billing inquiries made to the FortisBC Contact Centre, especially those related to high-bill enquiries, FortisBC believes that providing a customer access to more granular time-based data on their consumption will allow a customer to more easily determine the primary cause of their usage. Currently, the only known time period on when power was definitively used, is on a bi-monthly basis. An online customer information portal that can provide hour by hour usage data would assist customers in addressing high-bill inquiries, through the observations of usage and temperature patterns (i.e. days of the week with highest usage, or how usage relates to temperature).

12.2 If yes, what was the result of the review? What specific types of issues can the information portal help a customer resolve and what specific issues can it not help with?

Response:

Please refer to the response to BCPSO IR No. 1 Q12.1. It is likely that the on-line portal can help with the majority of billing inquiries. Customers may continue to find it more convenient, however, to call the FortisBC Contact Centre.

The on-line portal will not be able to help directly with billing inquires that require account changes such as name changes, rate changes and tax changes.

12.3 Has FortisBC discussed with other utilities implementing AMI (per page 13) whether or not AMI and customer information portals reduce customer calls/billing enquiries? What has been their experience?

Response:

FortisBC has discussed this with one California utility (Southern California Edison), which has indicated that their billing-related call volume had declined (but did not provide specific numbers). The same utility indicated they were not sure how much call volume had increased as a result of deployment since those calls were largely handled by the deployment vendor.

12.4 Have any of the utilities implementing AMI and customer information portals experienced an increase in calls (i.e., the availability of additional information actually triggers more calls/queries)?

Response:

FortisBC has not talked to any utilities about call volumes other than the one described in the response to BCPSO IR No. 1 Q12.3.

13.0 Reference: Exhibit B1, Tab 3, page 33

13.1 In those cases where meter reads had to be estimated (lines 4-6) were the meters subsequently read on a later scheduled cycle such that overall customers' total billings were correct?

Response:

Yes, once a meter reading is obtained after an estimate, a customer's total billing is corrected.

13.2 Are there currently circumstances where meters fail, bills must be estimated and there is no way to ultimately "true-up" the estimate? If yes, how many such situations arose in 2011?

Response:

In 2011, FortisBC had 13 electro-mechanical meters reported to be faulty or stopped. The bills had to be estimated as a final reading could not be ascertained, and as such the estimate could not be 'trued-up".

13.3 Please confirm that there are circumstances under which a meter "read" will have to be estimated with AMI (e.g. failure of communication system, failure of meter, etc.). If not, please explain the role of the Editing and Estimation algorithms referenced on page 42?

Response:

Please refer to the response to BCUC IR No. 1 Q35.4.

13.4 Based on the experience of other utilities, what is FortisBC's understanding as to how frequently such circumstances are likely to arise with AMI-enabled meters?

Response:

Based on the experience of other utilities, such circumstances are rare and can generally be remedied by adjusting the RF network to ensure better meter communications.

13.5 After the implementation of AMI, does FortisBC plan to inform customers (on their bills or otherwise) when their monthly reading has been based (in whole or part) on estimated usage?

Response:

Yes, FortisBC intends to continue (as it does today) informing customers when their billing is based (in whole or in part) on estimated usage.

14.0 Reference: Exhibit B1, Tab 3, page 33 (lines 21-23)

14.1 Please explain why "estimates" of monthly usage are required when customers are on the Equal Payment Plan.

Response:

The Equal Payment Plan is a plan with a monthly billing cycle and bi-monthly meter reads. This means that the Customer Information System must provide an estimate on the month that FortisBC does not read the meter at the customer premise.

This process is sometimes a source of customer dissatisfaction and confusion. The ability to economically obtain an actual meter reading for every billing period will improve bill accuracy and eliminate the need to cancel and rebill if a previous estimate was out of line.

15.0 Reference: Exhibit B1, Tab 3, pages 33-34

15.1 Does the AMI project cost include all of the costs involved in adapting FortisBC's billing systems such that they can integrate the meter reading obtained from the new systems, including consolidation of multiple accounts and flexible billing dates?

Response:

Yes, the AMI project costs include integration of the new AMI systems to FortisBC's billing system, including consolidated billing and flexible billing dates.

16.0 Reference: Exhibit B1, Tab 3, pages 35 (lines 27-33) and 38 (lines 28-30)

16.1 Will the installation of AMI allow FortisBC to monitor electricity flows to customers in real time? If not, what is the "time-delay factor"?

Response:

FortisBC will not be able to monitor electricity flows to customers in "real-time". The system will be configured to download information in batches a few times a day, so information received by the utility would normally be delayed by several hours.

A "snapshot" of current meter data can also be requested on a meter-by-meter basis. The delay of such a request is less than one minute under normal conditions.

17.0 Reference: BCUC 1.24.1

17.1 Are Worksafe BC premiums paid by Fortis directly related to the number of hours worked/number of employees such that a reduction in labour costs will actually lead to a reduction in premiums?

Response:

Yes, Worksafe BC premiums are included in labour "loading" costs. As fully loaded labour costs are reduced, so too are applicable Worksafe BC premiums.

18.0 Reference: Exhibit B1, Tab 3, page 39 (line 12)

18.1 Please describe more fully the variety of operating conditions that the AMI meters FortisBC will purchase/install will be set to provide alarms for.

Response:

There are a variety of event types, including power loss and restoration, temperature, tamper, tilt, and voltage. FortisBC has not yet determined how these events should be reported the Company, and at what trigger points these reports will occur. The initial configuration of the events and alarms will be determined during the Define/Design phase of the project, and this configuration will be refined as FortisBC gains operational experience with the system.

19.0 Reference: Exhibit B1, Tab 4, page 40 (lines 11-13)

19.1 Please outline the "existing FortisBC Systems" that the planned project spending includes integration with.

Response:

The existing FortisBC Systems that the planned project spending includes integration with are:

- Customer Information System (CIS) or FortisBC's billing system; and
- Geographic Information System (GIS)

20.0 Reference: Exhibit B1, Tab 4, page 41 (lines 5-8)

BCUC 1.6.7

20.1 What are the relative unit cost of the different types of AMI-enabled meters that FortisBC will be installing (i.e., capital and installation cost)?

Response:

Commercial and industrial meters are 2-5 times more expensive to purchase and install than residential meters.

20.2 Has FortisBC completed a full assessment of the metering required for each customer? If not, what contingency allowance has been included in the project costs to address this uncertainty?

Response:

Yes, FortisBC has completed an assessment of the metering required. FortisBC has allowed for additional complexities with some installations, and has included a contingency allowance of approximately $700,000 in the project costs with respect to meter deployment.

21.0 Reference: Exhibit B1, Tab 4, pages 43-45 and page 70

BCUC 1.30.1

21.1 What are the overall HAN-related costs of the project, what are the costs for and what cost category on page 70 includes these costs? Please specifically address the costs associated with providing Zigbee-based capabilities.

Response:

There are no HAN-specific hardware, computer equipment, software, or communications equipment costs since HAN capabilities are embedded into the AMI solution. HAN-related capabilities are built into all software and hardware procured as part of the project.

Please also see the response to BCUC IR No. 1 Q30.1.1.

21.2 Please break the HAN-related costs down so as to separate out computer equipment costs, computer software and communications equipment.

Response:

Please refer to the response to BCPSO IR No. 1 Q21.1.

22.0 Reference: BCUC 1.28.1.1 and 1.28.1.2

22.1 What annual percentage energy savings value is required in order for the TRC B/C ratio to be greater than 1.0?

Response:

Annual savings of 3.4%, or 437 kWh/yr based on the average UPC of 12.7 MWh, will yield a B/C ratio slightly greater than unity.

22.2 Will the results of the pilot be used to assess/confirm the validity of Navigant's 5.4% savings estimate prior to implementing a full program?

Response:

The pilot results and research into the IHD savings found in other jurisdictions will be used to determine whether to continue with and/or modify the IHD program.

23.0 Reference: Exhibit B1, Tab 4, pages 45-46 and page 70

23.1 What are the overall LAN-related costs of the project and what cost category on page 70 includes these costs?

Response:

LAN-related costs cannot be separated from the total project costs since the meters form part of the LAN (and the LAN-related cost components were not separately priced). Therefore, LAN-related hardware costs are embedded in the Meters (Including Deployment) and Network Infrastructure costs shown in Table 5.1.a (Lines 2 and 3) on page 70 of the CPCN Application.

LAN-related capabilities, such as network management, are also embedded within the Third-Party Software and Services on Line 1 of Table 5.1.a.

23.2 Please break down the LAN-related costs so as to separate out meter costs, collectors/range extenders, computer software and other (if any) communications equipment.

Response:

Please refer to the response to BCPSO IR No. 1 Q23.1.

LAN-related costs can only be segregated from Network Infrastructure costs, and total approximately $1.9 million.

24.0 Reference: Exhibit B1, Tab 4, Section 4.1.2

24.1 Has the design been sufficiently completed to confirm that the planned LAN will be able to effectively communicate with all customers' AMI-enabled meters?

Response:

The issue with communicating to all AMI-enabled meters is not LAN-related, but WAN-related. The LAN refers to the communications network between collectors and meters. The preliminary LAN design is sufficient to confirm that the planned LAN will be able to effectively communicate with all AMI-enabled customer premises.

Please refer to Section 4.1.2 and 4.1.3 of the CPCN Application, particularly page 49, lines 3-10, and the response to BCUC IR No. 1 Q32.1.

24.2 What are FortisBC's contingency plans if this does not prove to be the case?

Response:

Please see Section 4.1.3 of the CPCN Application which discusses potential WAN options to be considered to bring data from the collectors to the utility. Manual meter read downloading will be considered if other available WAN options prove to be uneconomic. FortisBC has allowed, within its financial analysis of the proposed AMI Project, for a small percentage of AMI meters to be manually read.

Please refer to the responses to BCPSO IR No. 1 Q24.1 and CEC IR No. 1 Q41.1.

25.0 Reference: BCUC 1.31.2.1 to 1.31.2.5

25.1 In the event that AMI meters and the associated communication infrastructure do interfere with existing devices using wireless communications, how does FortisBC plan to address the problem?

Response:

Please refer to the response Shadrack IR No. 1 Q26.

26.0 Reference: Exhibit B1, Tab 4, Section 4.1.3

26.1 What are the WAN-related costs of the project and what cost category on page 70 includes these costs?

Response:

WAN-related costs are approximately $2.6 million. They are a portion of the Network Infrastructure costs shown in Table 5.1.a (line 3) on page 70 of the CPCN Application. WAN-related capabilities are also embedded within the software infrastructure on Line 1 of Table 5.1.a.

26.2 Please break these costs down so as to separate out computer equipment costs, computer software and communications equipment.

Response:

Please refer to the response for BCPSO IR No. 1 Q26.1 for communications equipment costs. There are no WAN-specific computer equipment and software costs so these cannot be separated.

26.3 This section sets out a range of approaches that can be used for the WAN and indicates that the final choice will be made at the time of deployment (page 48).

Has FortisBC included any contingency allowance to address unforeseen costs related to this aspect of the project?

Response:

Yes, FortisBC has included a contingency of 30% in the WAN estimate to account for the preliminary nature of the WAN design.

27.0 Reference: Exhibit B1, Tab 4, Section 4.1.3, page 49

BCUC 1.33

27.1 Please confirm that for this 1% of customers the customer information portal will not provide timely access to usage data.

Response:

Correct, for these customers the information on the customer portal would be current as of the last meter read, as opposed to the near-real-time data available for AMI meters communicating via the proposed AMI system.

27.2 Does the financial cost/benefit evaluation include both the meter reading labour and equipment costs required to manually download the data from these customers' meters?

Response:

Yes.

28.0 Reference: Exhibit B1, Tab 4, Section 4.1.4

28.1 What are the HES-related costs of the project and what cost category on page 70 includes the HES costs?

Response:

HES-related computer software (licensing/installation/integration) costs are embedded in Line 1 (Third Party Software and Services), and line 4 (System Integration) of Table 5.1.a (page 70) of the CPCN Application. While the overall costs related to these categories are as stated in the table, total HES-specific costs cannot be accurately separated from other costs.

28.2 Please break these costs down so as to separate out computer equipment costs, computer software and communications equipment.

Response:

Please refer to the response for BCPSO IR No. 1 Q28.1.

29.0 Reference: Exhibit B1, Tab 4, Section 4.1.5

29.1 What are the overall MDMS-related costs of the project and what cost category on page 70 includes these costs?

Response:

MDMS-related computer software (licensing/installation/integration) costs are embedded in Line 1 (Third Party Software and Services), and line 4 (System Integration) of Table 5.1.a (page 70) of the CPCN Application. While the overall costs related to these categories are as stated in the table, total MDMS-specific costs cannot be accurately separated from other costs.

29.2 Please break these costs down so as to separate out computer equipment costs, computer software and communications equipment.

Response:

Please refer to the response to BCPSO IR No. 1 Q29.1.

30.0 Reference: Exhibit B1, Tab 4, Section 4.1.6 and page 70

30.1 What are the overall Customer Information Portal-related costs of the project and what cost category on page 70 includes these costs?

Response:

Please refer to the response to BCUC IR No. 1 Q8.1.3 for incremental Customer Portal Integration costs. Total Customer Information Portal-related computer software (licensing/installation/integration) costs are embedded in line 1 (Third Party Software and Services), and line 4 (System Integration) of Table 5.1.a (page 70) of the CPCN Application. While the overall costs related to these categories are as stated in the table, total Customer Information Portal-specific costs cannot be accurately separated from other costs.

30.2 Please break these costs down so as to separate out computer equipment costs, computer software and communications equipment.

Response:

Please refer to the response to BCPSO IR No. 1 Q30.1.

31.0 Reference: Exhibit B1, Tab 4, pages 53 - 54

31.1 Will FortisBC ultimately own/operate the MDMS repository? If not, will this be Itron's responsibility?

Response:

Yes, once the project is complete, ownership and operation of the MDMS repository will be with FortisBC.

31.2 In both instances (MDMS and AMI) was Itron's the lowest (compliant) cost bid? If not, on what basis was it considered superior and selected?

Response:

In the instance of the MDMS RFP, Itron was the lowest cost proposal. In the instance of the AMI (Hardware) RFP Itron was the second-lowest cost proposal.

FortisBC selected Itron as the vendor in both RFPs after considering total capital cost, operating cost and system functionality.

32.0 Reference: Exhibit B1, Tab 4, page 57

32.1 The schedule indicates that deployment of AMI-enabled meters will start Q2 2014 and that final implementation will be Q4 2015. For a customer where the AMI-enabled meter is installed in say Q3 2014, please confirm the following:

- When will the AMI-enabled meter be declared in-service and subject to depreciation?
- When will the existing meter be declared as a "surplus/stranded" asset and how will it be treated for purposes of deprecation?

Response:

An AMI-enabled meter installed in Q3 2014 would be declared in-service in Q3 2014 and would then be subject to depreciation in the following fiscal year. The existing meter would be retired from service in 2014 and the net book value would be to depreciation expense in 2014.

32.2 The schedule calls for transition of the responsibility for the operation of the HES and MDMS to FortisBC in Q4 2015. Who is responsible for operation of these prior to this date?

Response:

FortisBC and Itron will operate the system jointly until final system acceptance is complete in Q4 2015.

33.0 Reference: Exhibit B1, Tab 4, page 58

33.1 Does the project cost include an allowance for the additional range extenders and/or collectors that may be necessary in order to optimize the communications system? If yes, what is the size of the allowance?

Response:

Yes, the project cost includes an allowance of approximately 10% for range extenders, and 6% for collectors to accommodate network optimization.

34.0 Reference: Exhibit B1, Tab 4, pages 67 and Tab 5, page 70

34.1 Which of the cost categories on page 70 is the 6.4% contingency applicable to?

Response:

Contingency is included in lines 1 through 6 of Table 5.1.a (page 70) of the CPCN Application.

34.2 How was the 6.4% value for project contingency established?

Response:

Please refer to the responses to BCUC IR No. 1 Q53.3 and Q53.4.

35.0 Reference: Exhibit B1, Tab 5, page 70

35.1 The Application states that the cost of meters is fully contracted for at firm prices (line 4) and that meters includes deployment costs (lines 16-17). Does the contract for meters and meter installation include any allowance for difficult meter installations (e.g. situations where the physical removal of the existing meter and/or installation of the AMI-enabled meter may be non-standard and require additional time)? If yes, how does this affect the "fixed" price?

Response:

Please refer to the response to BCPSO IR No. 1 Q20.2.

35.2 What are the "sunk costs" of Project assuming that the BCUC was to deny the CPCN Application?

Response:

As noted in Table 5.1.a from the Application, the Company has forecast expenditures of $4.9 million related to the development of the Application and regulatory review of the proposed Project. It is difficult to quantify what portion of these forecast expenditures could be considered to be "sunk costs" without speculating on what conditions might be included as part of a decision denying the Company's CPCN Application. In the event, however, that the entire project was denied and FortisBC was directed to not reapply for the implementation of AMI, it is likely that the total forecast expenditures of $4.9 million related to the development and regulatory review of the proposed Project could be considered as "sunk costs" as discussed in Section 5.1.1 of the Application.

35.3 The page notes that FortisBC has completed fixed price contracts for a number of aspects of the Project. Does FortisBC have any existing financial obligations under these contracts or, in all cases, are FortisBC's financial obligations under the contracts subject to BCUC approval of the CPCN?

Response:

FortisBC's financial obligations under the contracts are subject to BCUC approval except as described in the responses to BCUC IR No. 1 Q3.1 and CEC IR No. 1 Q7.1.

36.0 Reference: Exhibit B1, Tab 5, pages 70-71

36.1 What is the per customer cost of the AMI project? Please compare this cost with that in other jurisdictions that are implementing AMI and indicate the sources used to obtain the costs for other jurisdictions.

Response:

FortisBC has compared per unit costs of the AMI project to BC Hydro and FortisAlberta.

The FortisBC cost per customer is approximately $415 per customer.

The BC Hydro cost per customer is approximately $516 per customer (derived from Exhibit B-1, Appendix C-4).

The FortisAlberta cost per customer is approximately $268 per customer. Please also refer to the response to BCUC IR No. 1 Q106.5.

36.2 Please explain what additional metering is required on the system in order for loss/theft detection benefits to be achieved. Is this the metering for Energy Balancing discussed at page 88?

Response:

The metering required for strategic energy balancing described on page 88 of the Application is the additional metering required to assist in theft detection. This metering is described in the response to BCUC IR No. 1 Q54.1.

36.3 Is the cost of this additional metering included in the financial analysis of the project?

Response:

These costs are included in the project capital costs. Please refer to Table 5.1a, page 70, line 6 of the Application.

37.0 Reference: Exhibit B1, Tab 5, page 70

FortisBC's December 2007 AMI CPCN Application, page 29, Table 6.3

37.1 Please provide a schedule that breaks down the current AMI Project costs ($47.7 M) down using the same categories as were used in Table 6.3 from the 2007 AMI CPCN Application.

Response:

Table 6.3 from the 2007 Application is amended to include the 2012 proposed AMI Project data, and provided below:

2007 CPCN Application		2012 CPCN Application		2012 Application minus 2007 Application ($000)				
	Costs ($000) ($2007)		Costs ($000)	Inflationary Impacts	Customer Growth	Additions to Scope	Other	Total Change
Project Capital Costs		**Project Capital Costs**						
Meters and Modules (including Deployment)	$19,507	Meters and Modules (including Deployment)	$20,323	$1,194	$780	$2,258	-$3,416	$816
Network Infrastructure	$6,700	Network Infrastructure	$4,449	$410	$268	$0	-$2,929	-$2,251
IT Infrastructure and Upgrades	$1,483	IT Infrastructure and Upgrades	$8,179	$91	$59	$275	$6,271	$6,696
Project Management	$2,701	Project Management	$3,130	$165	$0	$0	$264	$429
		Theft Detection	$1,100	$0	$0	$1,100	$0	$1,100
		CPCN Development Costs	$2,915	$0	$0	$2,915	$0	$2,915
		Forecast Regulatory Process Costs	$2,000	$0	$0	$2,000	$0	$2,000
AFUDC	$950	AFUDC	$1,061	$58	$38	$0	$15	$111
		CapOH	$2,947	$0	$0	$0	$2,947	$2,947
		PST	$1,584	$0	$0	$0	$1,584	$1,584
Total Project Capital Costs *5	**$31,341**	**Total Project Capital Costs**	**$47,688**	$1,918	$1,146	$8,548	$4,735	$16,347
Non-Project Costs		**Non-Project Costs**						
Incremental Meter Costs *1	$1,336	Incremental Meter Costs *2	$3,591					$2,255
Avoided Future Costs *3	-$1,250	Avoided Future Costs *4	-$19,704					-$18,454

note *1: over ten years
note *2: over twenty years
note *3: specific to handheld meter reading equipment
note *4: includes handhelds and avoided Measurement Canada compliance costs
note *5: includes provision for PST

Please see the 2007 AMI CPCN Application, Section 6.3 for elaboration upon the categories. The category totals in the 2012 column of the table above are drawn from Table 5.1.a (page 70) of the 2012 AMI CPCN Application (the subject of this proceeding), as follows:

- Meters and Modules is line 2 of table 5.1.a;
- Network Infrastructure is line 3;
- IT Infrastructure and Upgrades are lines 1 and 4;
- Project Management is line 6;
- Theft Detection is line 5;
- CPCN Development and Forecast Regulatory Approval Costs is line 7; and
- AFUDC / Cap OH / PST is line 8.

The proposed AMI Project is approximately $16 million more than that proposed in 2007, made up of the following:

- Inflationary impacts added approximately $1.9 million;
- Customer growth added approximately $1.2 million;
- Additions to scope added approximately $8.6 million, including:
    - Remote disconnect/reconnect functionality;

- Customer Information Portal (CIP);
- Theft Detection infrastructure;
- CPCN development costs (as discussed in the response for BCUC IR No. 1 Q50.1 and 50.1.1); and
- Forecast Regulatory costs (as discussed in the response for BCUC IR No. 1 Q50.1.2).

- Net "other" add approximately $4.7 million. This includes:
    - Approximately $6.3 million reduction in cost for meters, their deployment and the network infrastructure gained in fixing their costs;
    - An addition of approximately $6.3 million for IT Infrastructure and Upgrades, including MDMS, HES, Vendor Professional Services and additional internal IT integration costs;
    - Provision for Capitalized Overhead of approximately $3 million; and
    - PST forecast of approximately $1.6 million[1].

The 2012 CPCN Application numbers are largely based upon contracted firm prices and firm unit prices, inclusive of the Third Party Software and Services. FortisBC internal effort costs (such as System Integration and Project Management) are estimated based upon the industry consultant (Util-Assist) and the contractor's (Itron) experience in implementing similar projects. The higher degree of confidence that FortisBC has assigned to the 2012 proposed Project costs can be seen in the blended contingency of 6.4%.

37.2 Please explain the change in costs by category particularly noting where the scope of the project has changed.

Response:

Please refer to the response to BCPSO IR No. 1 Q37.1.

[1] Note that PST was included in the embedded capital costs noted in the 2007 application.

38.0 Reference: Exhibit B1, Tab 5, page 72

38.1 Are the increases in operating expenses set out in Table 5.1.b shown for prior to 2016 due to the fact that a portion of the AMI-enabled meters are in-service prior to 2016 or are any of them implementation-related operating costs?

Response:

New Operating Expenses prior to 2016 are for portions of the proposed AMI Project that have been complete and put into operation. For example, the back office will be operational in 2014. None of the New Operating Expenses prior to 2016 relate to implementation costs.

38.2 If any are implementation related, please provide a schedule that sets out the costs by year and explain what they are for.

Response:

Please refer to the response to BCPSO IR No. 1 Q38.1.

38.3 Are the decreases in Meter Growth and Replacement costs for 2014-2016 attributable to not having to replace existing meters on a like for like basis over this period?

Response:

Meter Growth and Replacement costs in the corrected Table 5.1.b (please see Exhibit B-1-1, Errata No. 1) demonstrate that AMI costs will be higher than in the Status Quo case, accounting for the higher unit costs associated with the AMI meters.

38.4 Are there Measurement Canada compliance costs associated with the new AMI-enabled meters? If yes, are they included in the New Operating Costs?

Response:

The net Measurement Canada compliance costs (the difference between compliance costs for Status Quo and AMI meters) are included in the Meter Exchanges row.

39.0 Reference: Exhibit B1, Tab 5, pages 72-73

39.1 What is the "life of the project" for purposes of amortizing the CPCN Development/Approval Costs?

Response:

The "life of the project" for purposes of amortizing the CPCN Development/Approval Costs is estimated to be 19.2 years (1 divided by the composite depreciation rate for the project, or 1/.0522 = 19.2).

39.2 Do the costs in Table 5.1.1.a include the carrying costs for the deferral account balances?

Response:

Yes, pursuant to Commission Order G-184-10 regarding the 2011 Revenue Requirements Negotiated Settlement Agreement, AMI project development costs are being collected in a non-rate base deferral account attracting AFUDC.

40.0 Reference: Exhibit B1, Tab 5, pages 74-75

40.1 What are "all of the benefits" referred to on page 74, line 3?

Response:

The benefits being referenced are detailed in Sections 3.2.5 and 5.3 of Exhibit B-1.

40.2 Why is the WAN identified as a new operating and maintenance cost category but the LAN, MDMS and HES are not?

Response:

There are no new operating expenses associated with the HES, MDMS and LAN other than those included in "Software Licencing/Support". The WAN will result in ongoing expenses related to communications carrier fees.

41.0 Reference: Exhibit B1, Tab 5, pages 12 and 76

41.1 What are the depreciation rates/estimated service lives for AMI-enabled meters that are used by Fortis Alberta, Fortis Ontario and Southern California Edison?

Response:

FortisAlberta is using a 25 year life for their meters, FortisOntario used a 15 year life as directed by the Ontario Energy Board. Southern California Edison used a 20 year useful life.

Please also refer to the response to BCUC IR No. 1 Q69.1.

42.0 Reference: Exhibit B1, Tab 5, page 76

BCUC 1.69.1.1

Preamble: A recent Application by Ontario's IESO (EB-2012-0100, Exhibit C, Tab 1, page 2) indicates that the asset service life of its MDM/R (the equivalent of ForitsBC's MDMS) is 10 years and that this estimate is "based on industry practice and consistent with service lives used for comparable meter processing and database systems". (http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/333014 /view/IESO_SME_A PPL_20120615.PDF)

42.1 Did FortisBC investigate the service lives adopted by other jurisdictions implementing AMI for their computer equipment and software or communications structures and equipment? If yes, what were the findings with respect to the service lives used?

Response:

No, the Company did not investigate the service lives adopted by other jurisdictions implementing AMI for their computer equipment and software or communications structures and equipment.

Please refer to the response to BCUC IR No. 1 Q69.2.

43.0 Reference: Exhibit B1, Tab 5, page 77

43.1 Does the revenue requirement/rate impact analysis include the costs of writing off the existing meters?

Response:

Yes. Please see Line 64 on the excel spreadsheet included as part of Exhibit B-3.

43.2 If not, what is the cost of the write-off and how would it impact the overall net benefit calculation?

Response:

Please refer to the response to BCPSO IR No. 1 Q43.1.

44.0 Reference: Exhibit B1, Tab 5, page 80

44.1 Please explain what assumptions were made regarding the future treatment of the existing 20 employees in the meter reading workforce in deriving the Net Meter Reading Savings. To what extent are they assumed to be redeployed elsewhere, retired or terminated?

Response:

The AMI Project financial analysis assumes the elimination of manual meter reading operations, and therefore the costs associated with this function are removed from future operating expenses.

FortisBC has not made specific assumptions regarding whether employees will be redeployed within the Company or whether they may choose to leave the company or retire. However, the Project does include talent transition actions in order to facilitate the existing meter reading workforce's ability to transition into other existing roles within the Company if they desire to do so and presuming that they are qualified for any open positions. Any transition would be to otherwise unfilled, but existing, positions.

Any costs associated with talent transition are expected to be minimal, and are accommodated within existing HR and meter reading operating budgets.

44.2 Does the determination of savings include the employee costs associated with each of these actions?

Response:

Please refer to the response to BCPSO IR No. 1 Q44.1.

45.0 Reference: Exhibit B1, Tab 5, pages 83-84

45.1 Please confirm the basis for the 8% theft discovery rate on page 83 (lines 8-9).

Response:

The rate is calculated as the number of thefts identified divided by the number of sites investigated under the Status Quo scenario for the period 2007-2011.

45.2 Could a more aggressive (and cost effective) theft protection program be implemented under the status quo approach? If not, why not? If yes, how would it change the results set out in Table 5.3.2.c

Response:

The low discovery rate with the Status Quo is a result of the poor quality of data received. In the absence of more reliable data, additional resources will not yield a corresponding increase in theft detection. Both an increase in quality and quantity are possible only with AMI deployment. Please refer to the responses to BCUC IR No. 1 Q82.4 and Q85.5

45.3 Will implementation of AMI also assist in the identification of (paying) premises that are illegal grow ops? If not, why not?

Response:

FortisBC currently has no visibility on how customers use electricity and so cannot determine if a premise contains an illegal grow operation. This activity is confirmed only when the RCMP execute a search warrant. This scenario will not change with AMI deployment since the same consumption data will be collected but at a more frequent interval. Please refer to BCUC IR No. 1 Q85.3 and Tab 8.4.4, page 139, line 1 of the Application.

45.4 If yes, please revise Table 5.3.2.by appropriately reducing the number of paying sites assumed in the AMI Forecast.

Response:

Please refer to the response to BCPSO IR No. 1 Q45.3.

46.0 Reference: Exhibit B1, Tab 5, page 88

46.1 Are AMI-enabled meters on customers' premises required in order to gain the benefits from energy balancing? If yes, please explain why.

Response:

AMI–enabled meters at customer premises are required in order to complete energy balancing. Please refer to the responses to BCUC IR No. 1 Q78.3.1, Q82.4.1, and Q84.1.1 and CEC IR No. 1 Q20.1 and Q20.2.

46.2 If not, would the installation of such feeder meters be cost-effective under the status quo? If yes, please re-do Table 5.3.2.c assuming the Status Quo approach includes such meters and the related benefits.

Response:

Please refer to the response to BCPSO IR No. 1 Q46.1.

47.0 Reference: Exhibit B1, Tab 5, pages 89-91

47.1 What portion of FortisBC's annual disconnects (e.g. 7,700 in 2011) are for non-payment as opposed to for vacant premises?

Response:

Approximately 40 percent of disconnects are for non-payment.

47.2 Please provide a brief summary (similar to page 90) of the process for disconnect in the case of non-payment.

Response:

A process flowchart has been provided that provides a summary of the disconnection for non-payment process. Please refer to the AMI CPCN Application, Section 8, Figure 8.4.5.a. Please also refer to the responses to BCUC IR No. 1 Q116.1-116.3.

47.3 Please explain more fully how and why the "consumption that would previously have been unbilled" is included in the analysis (page 91, lines 18-20).

Response:

The lost revenue margin from annual unbilled consumption of approximately 230,000 kWh is included as a benefit in Exhibit B-1. Table 5.3.3.a - Forecast Savings from Remote Disconnects/Reconnects.

47.4 Please provide the details supporting the results in Table 5.3.3.a.

Response:

The additional costs related to site visits for the 50% of vacant sites and 100% of non-pay sites are budgeted in the New Operating Costs line shown in Table 5.1b from the Application. The Company will dispatch meter readers and existing Customer Service Persons ("CSP") to visit these premises. CSPs are already budgeted and included in the Company's 2012 and 2013 revenue requirement. CSPs currently perform the bulk of the meter removals and exchanges, so it is expected that they will have spare capacity after the implementation of AMI to perform the required site visits. Therefore, the benefit shown in Table 5.3.3.a reflects the full avoided cost of all reconnects and disconnects.

On this basis, the benefit shown for 2016 (the first year in which the full benefit will be realized) in Table 5.3.3.a is calculated as follows:

Total disconnects (BCUC IR1 Q91.2):	2,655
Total reconnects (BCUC IR1 Q91.2):	2,575

Cost per connect/disconnect (Fortis tariff):	$100
Number of kWh saved from vacant sites (BCPSO IR1 Q47.3):	230,000
Marginal revenue per kWh saved (Exhibit B-3, Theft Reduction):	$0.09216 per kWh
Total savings = 2655 x $100 + 2575 * $100 + 230000 * $0.0926 =	$544,000

48.0 Reference: Exhibit B1, Tab 5, pages 93 & 95

48.1 Please explain the derivation of the $68.86 incremental capital cost for AMI enabled meters.

Response:

The incremental capital cost for AMI meters is arrived at by subtracting the average cost of existing (electro-mechanical and digital) meters from the average cost of the proposed AMI meters. The cost of the AMI meters is contractually sensitive and detailed cost information was filed confidentially.

48.2 In the analysis what has FortisBC assumed regarding the service life of electro-mechanical meters relative to AMI-enabled meters?

Response:

Please refer to the response to BCUC IR No. 1 Q90.5.

48.3 Please explain the basis for the six-year period after which compliance and meter exchange activities will resume.

Response:

Meters are initially installed in "compliance groups". When installed, these groups have a defined seal period, which specifies how long the meter is to be considered accurate. Meters cannot be left in service past their seal date.

When a compliance group's seal date is approaching, a sample of the population can be removed and tested for accuracy. If the meters pass these tests then the entire group will have their seals extended. This allows a sampling of a subset of the group to occur and the results of the testing on these samples to be applied to the entire group. For example, if there is a compliance group of 1000 meters and 100 meters are removed for testing (exchanged):

- If the 100 meters pass the test, all 1000 meters pass;
- If the 100 meters fail the test, all 1000 meters fail.

The proposed AMI project would replace the entire FortisBC meter population with meter groups having initial seal periods of ten years. Since the project proposes meter installation in 2014 and 2015, there would be no required compliance sampling needed until the year 2023 (sampling usually occurs the year before the seals expire to allow time for replacement). To limit the impact on meter shop resources, FBC assumed that this compliance sampling would be brought forward one year for 25% of the meters to help smooth out expenditures of the compliance program (otherwise the entire population would need to be sampled in 2 years). This means that compliance sampling is expected to begin again in 2022.

The six year period referred to in the application corresponds to the six years after the project has completed meter installation until the year in which compliance sampling resumes; i.e. 2016-2021.

48.4 Please explain why, in Table 5.3.5.a, some years' values are negative while others are positive.

Response:

The values in Table 5.3.5.a correspond to the cost of compliance sampling activities each year. These costs are compared to the status quo option.

A negative value in this table means that FortisBC expects a savings (benefit) in that year resulting from new meters installed by the proposed AMI project. Alternatively, a positive value means additional costs are expected.

As discussed in BCPSO IR No. 1 Q48.3, based on an entirely new meter population to be installed by the proposed AMI project there are several years where FortisBC will not be required to do any compliance sampling. This is then followed by years where compliance sampling for the entire meter population will need to occur in several years and then a period where once again no compliance sampling is required.

49.0 Reference: Exhibit B1, Tab 5, pages 97-98

49.1 Would the implementation of feeder meters (as discussed on page 88) help identify losses on the distribution system – even without AMI-enabled customer meters?

Response:

The implementation of feeder meters without AMI-enabled customer meters is not an effective tool in identifying distribution losses. Please refer to the responses to BCUC IR No. 1 Q78.3.1 and Q82.4 and CEC IR No. 1 Q20.1 and Q20.2.

50.0 Reference: Exhibit B1, Tab 5, pages 102-103

BCUC 1.103.1

50.1 Would pre-pay require the installation of a new/different meter?

Response:

No, pre-pay would not require the installation of a new/different meter.

50.2 Are there currently AMI-enabled meters on the market that provide the functionality FortisBC requires and allow for pre-payment?

Response:

Yes, there are currently AMI meters on the market that provide pre-pay functionality, including the Itron meters that FortisBC is purchasing. All of the elements required to implement pre-pay are included in the cost of the project, aside from some system configuration costs (Exhibit B-1, p. 104) and possibly an in-home display device (BCUC IR No. 1 Q103.2).

Please also refer to the response to BCUC IR No. 1 Q110.5.

51.0 Reference: Exhibit B1, Tab 5, page 104

51.1 It seems counter intuitive that capacity savings would be less under a CPP type of rate (which focuses on peak usage) than under a TOU type rate (which typically used the same price for a number of pre-defined peak hours). Is this apparent inconsistency reconciled in the supporting documentation?

Response:

The figures are supported in the Navigant study included in Exhibit B-1, Appendix C-1. The 10.5% TOU figure is based on BC Hydro Conservation Research Initiative summary results.

Table 6 from the same study shows that critical peak savings (those savings achieved during shorter duration higher capacity peaks versus shorter duration lower peaks) were 5.7% in the one study referenced for TOU, and between 17.5% and 25.4% for TOU/CPP rates.

Peak savings are likely higher for TOU rates over longer peak periods since that is the way the pricing is designed (as opposed to CPP rates which have higher prices for shorter durations).

52.0 Reference: Exhibit B1, Tab 6, pages 105-107

52.1 Are there enhanced theft detection practices (e.g., energy balancing meters) that could be adopted under the Status Quo alternative?

Response:

Improved theft detection cannot reasonably be achieved under the Status Quo scenario. Please refer to the response to BCPSO IR No. 1 Q46.1 and Q49.1 as well as BCUC IR No. 1 Q78.3.1 and Q82.4.

52.2 If yes, how would their implementation impact the costs and benefits as set out in Table 7.1.a?

Response:

Please refer to the response to BCPSO IR No. 1 Q52.1.

53.0 Reference: Exhibit B1, Tab 8, page 131

53.1 After the implementation of AMI-enabled meters, will FortisBC's billing process still pro-actively review bills in order to determine if they are potentially in error (see lines 20-22)? If so, how will this be done and will the process differ from that used currently?

Response:

After the AMI implementation, FortisBC will continue to use the configured tolerances currently used by the billing system in order to catch and proactively review any bills that could be considered potentially in error prior to being sent to customers. Once the Company has gained operational experience with the systems, the billing processes and error tolerances may be adjusted according to the needs of the business.

53.2 If different, has this been factored into the cost/benefit analyses in Tab 6?

Response:

Please refer to the response to BCPSO IR No. 1 Q53.1.

54.0 Reference: Exhibit B1, Tab 8, page 141

54.1 Please confirm that, per page 91 (lines 17-18), there will be at least one visit to the premise prior to disconnect. Please also describe what, if any, follow-up will take place if this one visit does not result in any actual (one on one) contact with the customer.

Response:

Please refer to Exhibit B-1, Sections 5.3.3 and 8.4.5, and BCUC IR No. 1 Q116.1-116.3.

54.2 Please provide a schedule that integrates both the customer service and billing/collections activities leading up to a service disconnection.

Response:

The following is a high level summary of FortisBC's customer service and billing/collections activities leading up to a disconnection.

1. Customer is sent Bill #1;

2. Bill #1 becomes due;
3. If payment of Bill #1 has not been received by the time Bill #2 is ready to be sent, Bill #2 will be sent with an overdue message;
4. If payment amounts are still overdue, a disconnect notice is sent via regular mail;
5. If payment amounts are still overdue at least 2 weeks after a disconnection notice has been mailed, the collections representative will determine eligibility for disconnection. Please also refer to process flowchart in Exhibit B-1, Section 8, Figure 8.4.5.a.

Time between activities listed above will vary depending on whether the customer is on a monthly or bi-monthly billing cycle, and whether they have a previous credit history.

55.0 Reference: Exhibit B1, Tab 8, pages 142-143
BCUC 1.117.1

55.1 Does FortisBC have any information regarding the "opt out rate" (i.e., % of customers that choose to opt-out) in those jurisdictions where there is a choice?

Response:

FortisBC understands that Central Maine Power, which has one of the more established opt-out programs, has an opt-out rate of just over 1 percent of customers and that the rate is declining.

55.2 On what other bases (page 143, lines 5-6) does FortisBC expect there to be refusals?

Response:

FortisBC cannot predict on what other bases customer may refuse an advanced meter, but is aware that jurisdictions with opt-out programs still have customer refusals.

56.0 Reference: Exhibit B1, Appendix C1, page 8 of 65

56.1 In Table ES-1 are the "peak savings" % MW savings at the time of system peak or % MWh savings over a broadly defined peak period?

Response:

FortisBC understands the savings in Table ES-1 to be MWh savings over a broadly-defined peak period. Please also refer to the response to BCPSO IR No. 1 Q51.1.

56.2 Please reconcile the comment in this report about FortisBC's plans to roll out TOU rates in 2014 with FortisBC's stated plans for AMI-enabled innovative rate structures as discussed at page 104 of the main Application.

Response:

At the time the Navigant study was written, FortisBC was planning an earlier implementation of AMI and therefore an earlier time frame for a possible implementation of voluntary TOU rates.

57.0 Reference: Exhibit B1, Appendix C4, pages 12 and 21 of 44

57.1 Please compare the methodology and assumptions used by FortisBC to estimate Theft Protection savings (starting at page 80 of main Application) with those of BC Hydro?

Response:

The methodology and assumptions behind the calculation of theft benefit is necessarily sensitive in nature and FortisBC has limited visibility of the detail behind the BC Hydro business case. Please refer to the responses to BCUC IR No. 1 Q82.1 and Q82.2.

57.2 Please describe the similarities and differences between FortisBC's AMI Project and BC Hydro's in terms of the scope of the project (resulting capabilities) and sources of potential benefits.

Response:

The AMI systems for both utilities have similar capability but not all of the potential benefits have been quantified in the FortisBC Application. The following table identifies the financial benefits listed in Table 1 on page 12 of the BC Hydro Business Case and differentiates those which are deemed to be possible future benefits for FortisBC.

Table BCPSO IR1 Q57.2

Description of Benefit	FortisBC	BC Hydro
Meter Reading Automation	Included	Included
Meter Sampling	Included	Included
Remote Re-connect Automation	Included	Included
Distribution Asset Optimization	Future	Included
Outage Management Efficiencies	Future	Included
Continuous Optimization and Load Research	Future	Included
Call Center & Billing	Included	Included
Voltage Optimization - Commercial Customer Sites	Future	Included
Voltage Optimization - Distribution System	Future	Included
Theft Detection	Included	Included
Voluntary Time of Use Rates	Future	Included
Conservation tools (in-home feedback tools)	Included	Included

1.0 Topic: Version of ZigBee

FortisBC notes that it "is proposing that the advanced meters include HAN functionality at implementation" [1]. For the HAN, FortisBC notes that "initially the meters will use ZigBee Smart Profile v1.1 . . . also support Zigbee Smart Energy v2.0".

1.1 Please explain why the meters need to support two different versions of ZigBee.

Response:

Zigbee SEP 2.0 is an emerging standard that is not yet finalized or commercially available. ZigBee SEP 1.1 may be the only available standard that can be implemented initially.

1.2 Will the two versions be running concurrently in the meter, or will they need to be switched (if so, how will the switch be done)?

Response:

Only one version or the other can be implemented in the meter at any point in time. The HAN firmware can be upgraded "over the air" (remotely).

1.3 Can an In-Home Display using v1.1 communicate to a meter running with v2.0?

Response:

It is expected that gateway devices will be available that can allow a meter running v2.0 to interoperate with devices running v1.1 (or vice-versa). The Zigbee Alliance intends to start working on such a solution by the end of 2012.

1.4 Can an In-Home Display using v2.0 communicate to a meter running with v1.1?

Response:

Please see the response to BCSEA IR No. 1 Q1.3.

[1] Exhibit B-6, BCUC IR 30.1 Response, Page 47, Line 30

1.5 It is noted that v2.0 " . . . is being developed . . . " [2].

1.5.1 When is v2.0 expected to be complete, what hurdles need to be overcome before it is complete and what are the risks?

Response:

The Zigbee Alliance expects to have a ratified specification by the end of 2012 (although the date has slipped previously). FortisBC does not have information regarding the hurdles that need to be overcome to achieve a ratified specification, nor what the risks may be.

1.5.2 How can v2.0 be delivered if it is not yet complete?

Response:

Please see the response to BCSEA IR No. 1 Q1.2

1.5.3 What testing has been done for v2.0 or is expected before it is considered complete? Does FortisBC plan any pilot testing?

Response:

No testing has been done or is planned before the standard is considered complete.

FortisBC expects to do pilot testing as described in the response to BCUC IR No. 1 Q28.1.2.

1.6 Whose responsibility is it to work out the technical issues for different versions – FortisBC/Itron or the suppliers of the In-Home Display?

[2] Exhibit B-1, Section 4.1.1, Page 43, Line 14

Response:

FortisBC considers it the responsibility of all Zigbee Alliance members to work out technical issues related to the two versions.

1.7 How will different versions of ZigBee affect the end customer?

Response:

The impact to the end customer will be quite small until v2.0 features such as support for electric vehicles are in high demand. Even then, it is possible that v1.1 will be enhanced to provide some of the same features.

2.0 Topic: BC SMI Regulation

FortisBC states: "the Smart Meters and Smart Grid Regulation (2010) details the prescribed requirements of 'Smart Grid' and 'Smart Meter'". Please confirm that the reference is to the Smart Meters and Smart Grid Regulation, B.C. Reg. 368/2010, under the Clean Energy Act (located at http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/368_2010).

2.1 For convenience, please file a copy of the Smart Meters and Smart Grid Regulation or indicate its location in the filed materials.

Response:

Confirmed. A copy of the Smart Meters and Smart Grid Regulation, B.C. Reg. 368/2010 is provided as Appendix BCSEA IR1 2.1.

2.2 Please confirm that the Smart Meters and Smart Grid Regulation applies primarily to BC Hydro. Please identify any aspects of the Regulation that apply directly to FortisBC and the circumstances under which it does.

Response:

Confirmed. Please also refer to the responses to BCUC IR No. 1 Q9.2 and Q9.2.1.

2.3 Please provide FortisBC's interpretation of how the Clean Energy Act, Part 5, Section 17 (6) [3] applies to the AMI proposal.

Response:

As articulated in Section 3.2.2 of the Application, FortisBC interprets section 17 (6) of the *Clean Energy Act* to apply to FortisBC's proposed Project in that it requires the Commission, as part of its assessment of the Company's application for a CPCN, to consider the government's energy objectives as they relate to the implementation of smart metering and smart grid technologies for customers of utilities other then BC Hydro. Based on the government's goal with respect to this technology, and the legislative requirements prescribed to BC Hydro, it is evident that the provincial government has determined the implementation of smart metering for customers served by BC Hydro to be necessary and in the public interest, and directed the Commission to consider this determination as part of its assessment of FortisBC's application for a CPCN.

2.4 Table 3.2.2.a - Summary of SMI Requirements[4] - of the FortisBC application lists requirements of the Smart Meters and Smart Grid Regulation, with a column indicating requirements that FortisBC's AMI project compiles with in the Regulation. Row 2 of the Table states the requirement that the meter "transmits and receives information in digital form" and the tick in the third column indicates that FortisBC complies with this requirement. Please provide a table listing:

a) all the specific types of digital information that need to be transmitted and received between the meter and the LAN in order to meet the SMI Requirements, (e.g. data such kWh and commands such as connect/disconnect),

[3] Exhibit B-1, Section 3.2.2, Page 22, Lines 13-19
[4] Exhibit B-1, Section 3.2.2, Table 3.2.2.a, Page 24

b) all the specific types of digital information that will be transmitted and received between the meter and the LAN for the “the AMI solution proposed by Itron” [5] ,

c) explanations in each instance where the Itron meter will be transmitting and receiving a type of information not required to be transmitted and received by the Smart Meters and Smart Grid Regulations and each instance (if any) where the Itron meter will not be transmitting and receiving a type of information required to by the Smart Meters and Smart Grid Regulation.

Response:

Please see Table BCSEA IR1 Q2.4 below.

[5] Exhibit B-1, Section 4.2.2, Page 55

Table BCSEA IR1 Q2.4 – Digital Information Transmission

Proposed FortisBC AMI System Digital Information to be Transmitted	BC Hydro SMI Digital Information to be Transmitted (as required by the Smart Meters and Smart Grid Regulations)
Measurement of electricity supplied to a premises	Measurement of electricity supplied to an eligible premises
Disconnect/reconnect commands	Disconnect/reconnect commands
Date and time of recorded measurements of electricity supplied to an eligible premises in intervals at least as frequently as 60-minute intervals	Date and time of recorded measurements of electricity supplied to an eligible premises in intervals at least as frequently as 60-minute intervals
Measurement of electricity generated at the premises and supplied to the distribution system	Measurement of electricity generated at the premises and supplied to the distribution system
Transmission of information to and receipt of information from an in-home feedback device	Transmission of information to and receipt of information from an in-home feedback device
Meter exceptions (meter inversion, removal, reverse power flow, power outages)	
Electric service errors (reverse polarity, cross-phase and energy flow, phase voltage deviation, inactive phase current, phase angle displacement, current waveform distortion	

As detailed above, FortisBC's proposed Project complies with the information transmission requirements as detailed in the Regulations.

With respect to part (c) of the above question, it should be noted that although the additional information identified to be transmitted for the FortisBC solution is not prescriptively identified in the requirements specified in the Regulations, the transmission of this information (for FortisBC) is necessary to provide customers with the benefits identified in the Application, is not information that is not currently gathered as required, and does not result in any incremental costs associated with the proposed Project. Further, considering BC Hydro and FortisBC have selected the same vendor (Itron) for implementing an AMI/SMI system, it is likely BC Hydro will also be able to transmit the same types of information identified for FortisBC as shown in the table above.

2.5 Row 8 of Table 3.2.2.a[6] states the requirement that the meter "can transmit information to and from an IHD". Please provide a table listing:

a) all the specific types of information that needs to be transmitted to and from an IHD in order to meet the SMI Requirements (e.g. kWh),

b) all specific types of digital information that will be transmitted to and from an IHD for the "the AMI solution proposed by Itron" [7],

c) explanations in each instance where the Itron meter will be transmitting a type of information not required by the Smart Meters and Smart Grid Regulations and each instance (if any) where the Itron meter will not be transmitting a type of information required by the Smart Meters and Smart Grid Regulation.

Response:

As per the definition of "in-home feedback device" in the Smart Meters and Smart Grid Regulations (referred to as in-home displays in the Application), the specific information required to be transmitted includes measurements of electricity supplied to an eligible premises and the cost of electricity measured by the smart meter. FortisBC's proposed AMI system will allow it to transmit the same types of information (kWh consumed, electricity pricing) to customer IHDs (should they so elect to allow an IHD to receive such information).

Please also refer to the response to BCSEA IR No. 1 Q2.6.3.

2.6 FortisBC states "If another HAN technology/protocol becomes dominant in home automation, FortisBC expects the market to respond with protocol-bridging gateway devices capable of interfacing Zigbee to other protocols" [8].

2.6.1 Could all the information beyond that which is described for the SMI Requirements in the previous IR (# 2.5, above) be incorporated into a gateway? If not, please explain.

Response:

[6] Exhibit B-1, Section 3.2.2, Page 24
[7] Exhibit B-1, Section 4.2.2, Page 55
[8] Exhibit B-6, BCUC IR #30.2.1, Page 48, Lines 32-33

The use of the gateway is to bridge the message carrying protocol (i.e. Zigbee to WiFi). The content of the message remains the same when messages are carried using products that have had this functionality certified by the AMI provider.

2.6.2 Please explain how expanded use of gateways might reduce the complexity in the meters. Please include a discussion of the trade-offs between complexities in the meters versus in the gateway devices and compare upgrading the fleet of smart meters versus gateway products.

Response:

The Zigbee communications board in the meter is sealed in the meter and cannot be replaced without breaking the Measurement Canada meter seal and recertifying the meter. Gateway devices allow FortisBC to purchase current industry standard HAN technologies and allow them to migrate to market needs that may become available in the future without the need to break the seal on the meter to replace communication boards. Thus, gateways reduce complexity and future costs associated with possible HAN technology changes.

2.6.3 Please describe the features of what FortisBC anticipates will be the most common In-Home Display device and list all the specific types of digital information that will be transmitted to and from the IHD.

Response:

FortisBC anticipates that customers will most frequently view historical and current consumption, either in kWh or in dollars.

Please see the responses to CSTS IR No. 1 54.11, BCSEA IR No. 1 10.2 and BCSEA IR No. 1 Q15.6.8 for a description of the types of information that can be transmitted to and from an IHD.

3.0 Topic: Canadian Smart Grid Roadmap

3.1 Please file a copy of "The Canadian Smart Grid Standards Roadmap: A strategic planning document" [9] ("Canadian Smart Grid Roadmap"). Does FortisBC agree that the Canadian Smart Grid Roadmap, in providing: "a roadmap – a strategic plan- to advance the standards environment from today's legacy electricity grid to tomorrow's full deployment, operation and evolution of the Canadian Smart Grid," is relevant and helpful to the FortisBC AMI application process? If not, please explain.

Response:

The referenced document has been provided as Appendix BCSEA IR1 3.1.

In general, FortisBC agrees that the referenced document is helpful in establishing a common reference point for Canadian Smart Grid deployments.

3.2 Does FortisBC agree that the Canadian Smart Grid Roadmap can help the FortisBC AMI application process as it provides "guidelines for utilities and manufacturers to participate in the emerging Smart Grid marketplace"? If not, please explain.

Response:

In general, FortisBC agrees that the referenced document is helpful in establishing a common reference point for utilities and manufacturers.

3.3 The "Canadian Smart Grid Roadmap" document notes that the "Government of Canada's approach toward the future for Smart Grid is focused on three core energy policy objective: . . . . environmental performance" [10]. It also notes that "a Smart Grid will contribute to our goal of improved environmental performance, by

[9] The Canadian Smart Grid Standards Roadmap: A strategic planning document, October 2012, http://www.scc.ca/sites/default/files/publications/Smart-Grid-Report_FINALOCT2_EN.pdf

[10] The Canadian Smart Grid Standards Roadmap: A strategic planning document, October 2012, Section 2.1, Page 4

reducing greenhouse gas (GHG) emissions" [11]. Please discuss the ways in which FortisBC is using the Smart Grid to improve environmental performance.

Response:

One of the benefits that FortisBC has already realized from previous smart grid projects (such as Distribution Substation Automation) is reduced travel – with a consequent reduction in fuel consumption and GHG emissions. Historically, substation equipment could only display information locally; there was no way to access protection or metering devices remotely as legacy equipment did not support that capability. As shown in Figure 3.2.3.a on Page 26 of the application, in the 1990s FortisBC began installing microprocessor-controlled equipment which could be accessed remotely. Further, with the completion of the Distribution Substation Automation Program this year, the Company now has remote control and visibility of almost all of its 65 substations. As a result, today it is possible for an engineer in Trail to remotely interrogate devices in the Princeton substation without leaving their desk. Similarly, System Control Centre operators can turn feeder reclosers at substations on and off by remote control. Previously, in both cases it would have been necessary for a technician to drive to the location, collect the information or change the position of a control switch, and then drive back. These travel reductions result in ongoing savings and hence lower O&M and capital costs as well as improved environmental performance.

The implementation of AMI will have similar travel reduction benefits, but on a larger scale. As discussed on page 38 of the Application, the current manual meter reading process consumes approximately 80,000 litres of fuel and results in 191 tonnes per year of GHG emissions. The AMI project will reduce the need for travel associated with meter reading which will result in a consequent reduction in the environmental impact of this activity.

Future smart grid project implementations such as an Outage Management System (OMS) – in combination with AMI – would further reduce vehicle travel. This is because it would no longer be necessary for crews to drive long distances to search/patrol for the location of outages. Instead, the OMS would essentially pinpoint the location of failed equipment by using the AMI information of exactly which customers are out of power. Crews would then be able to travel directly to the work location to repair the failure.

[11] The Canadian Smart Grid Standards Roadmap: A strategic planning document, October 2012, Section 2.1, Page 4

3.4 The one specific recommendation within the “Smart Grid Policy, Legislation and Regulatory” section of the “Canadian Smart Grid Roadmap” document is targeted to the Provincial role. Recommendation R1 states that:

“SCC’s CNC/IEC should encourage Provincial, Territorialregulators and utilities, when developing business plans for Smart Grid initiatives, to ensure that systems migrate from proprietary technologies to open standards, and from their current architecture to theCanadian Smart Grid Reference Framework described in this report. This step will enable regulators and utilities to compare roadmaps and therefore identify areas of commonality, interoperability, deployment timing and possible technological risk.” [12]

3.4.1 Please discuss how FortisBC has implemented its AMI system to use open standards. Please include a discussion about areas of commonality, interoperability, deployment timing and possible technological risk.

Response:

FortisBC placed importance on the use of open standards during its AMI system RFP process. The chosen solution(s) make use of a significant number of complete and developing standards at multiple levels of the system, including:

- HAN;
  - Zigbee – Wireless protocol for personal area networks;
- Meter;
  - ANSI C12.1- Standard for Electric Meters / Code for Electricity Metering;
  - ANSI C12.18 – 18 standards and specifications for meter communications via the ANSI Type 2 Optical Port;
  - ANSI C12.19 – Standard for Utility Industry End Device Data Tables;
  - ANSI C12.21 – Protocol Specification for Telephone Modem Communication;
  - ANSI C12.22 – Protocol Specification for Interfacing to Data Communication Networks;
- LAN;

[12] The Canadian Smart Grid Standards Roadmap: A strategic planning document, October 2012, Section 2.3, Page 7

  - IPv6 - Internet Protocol version 6 defines a protocol for packet switched communications;
  - 802.15.4g – RF mesh OSI physical layer standard;
  - 802.15.4e – RF mesh OSI Media Access Control layer standard;
- WAN;
  - IPv4 – Internet Protocol version 4 defines a protocol for packet switched communications;
  - 802.16 – Open standard to define wireless broadband;
  - 802.1 – Ethernet;
- HES/MDMS;
  - FIPS PUB 180-3 Secure Hash Standard – Used to provide integrity checking for firmware and configuration downloads to the endpoint;
  - FIPS PUB 186 Digital Signatures Standard (DSS) – Used to sign and authenticate digital commands and other information from the HES to the endpoint;
  - FIPS PUB 197 Advanced Encryption Standard (AES) – Used to provide confidentiality of system commands from the HES to the endpoint as well as confidentiality of meter data being reported to the HES and ultimately to the MDMS;
  - FIPS PUB 198 Keyed-Hash Message Authentication Code (HMAC) – Used to provide integrity checking for firmware and configuration downloads to the endpoint;
  - ISO/IEC 10164-8:1993 Security Audit Trail Function - Information technology - Open Systems Interconnection - Systems Management;
  - ISO/IEC 18014-1:2002 Time-Stamping Services - Information technology – Security Techniques - Part 1: Framework;
  - ISO/IEC 10181-7:1996 Security Audit and Alarms Framework - Information technology Open Systems Interconnection - Security Frameworks for Open Systems;

- NIST IR 7628 Guidelines for Smart Grid Security – NIST IR 7628 provides a comprehensive input into the development of security controls and a framework for which AMI systems can be audited against;
- AMI-SEC AMI Security Profile; and
- AMI-SEC System Security Specification.

Commonality is fundamental to the open standard approach. This commonality is usually defined using frameworks and best practices, and in the case of Advanced Metering Infrastructure defines the functionality of the system. This allows development of open standards for the interoperability of devices.

The open standard approach enables technology to be sourced from multiple vendors and function within the system. For example in the RF LAN it is expected that smart grid devices will appear in the marketplace from many different vendors and meters from other manufactures will also be capable of joining the LAN. In the WAN, multiple different vendors manufacture equipment for cellular networks and WiMAX. This interoperability removes some technology risk as the continued operation of the network is not dependent on a single source for equipment supply. This also reduces cost because competition is introduced in the marketplace and economies of scale are realized by increased volume. Furthermore, the widespread adoption of a standard will increase the length of time a technology is supported and available because the more widely it is deployed, the more difficult it is to change.

3.4.2 Please discuss how FortisBC is using the "Canadian Smart Grid Reference Framework described in this report" for its AMI system. Please include a discussion about areas of commonality, interoperability, deployment timing and possible technological risk.

Response:

FortisBC was not previously aware of this report and as such has not used the framework for definition of its proposed AMI system. However, FortisBC has briefly reviewed the document and believes that previously developed plans and technology choices are consistent with the recommendations contained in this document. FortisBC will refer to this report as it further develops smart grid functionality after the implementation of AMI.

3.5 Please refer to Figure 5 on page 27 of the “CanadianSmart Grid Roadmap” which shows a diagram for a “Smart Grid Advanced Metering Infrastructure Logical Architecture” [13] (Logical AMI Diagram). Figure 1 below shows the Logical AMI Diagram with a purple oval and a red arrow added for the purpose of the questions that follow.

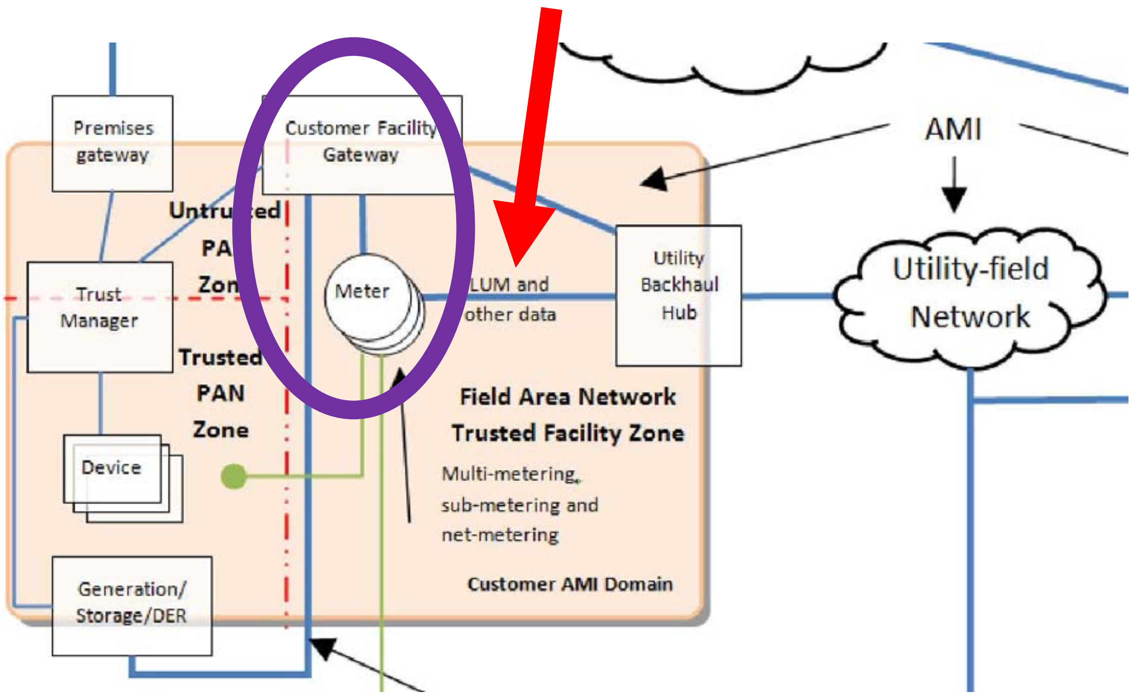

Figure 1: Source: The Canadian Smart Grid Standards Roadmap: A strategic planning document, Standards Council of Canada, October 2012, Section 5.2, Page 27, Figure 5; [with red arrow and purple ovals added for emphasis]

3.5.1 Please refer to FortisBC’s response to IR 1.2.4 (regarding SMI Requirements concerning “transmits and receives information in digital form” [14]), above. Would FortisBC agree that the information listed in IR 1.2.4 is depicted by the red arrow (pointing to “LUM and other data”) in Figure 1, above? If not, please explain.

Response:

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[13] The Canadian Smart Grid Standards Roadmap: A strategic planning document, October 2012, Section 5.2, Page 27, Figure 5

[14] Exhibit B-1, Section 3.2.2, Table 3.2.2.a, Page 24 - which refers to Section 2(b) of the Smart Meter and Smart Grid Regulation (2010)

FortisBC agrees that the information listed in BCSEA IR1 Q2.4 (referred to in the question as IR 1.2.4) is depicted by a red arrow in the included Figure 1.

3.5.2 It is noted that the "Canadian Smart Grid Roadmap" recommends communication of Legal Units of Measure (LUM) [15]. Does the proposed FortisBC AMI system communicate LUM at the location shown by the red arrow in Figure 1, above?

Response:

In Canada, Legal Units of Measure for electricity include the watt hour, the volt-ampere hour, the var hour and the joule for consumption and the watt, volt-ampere or var for demand. The meters to be used in the proposed AMI project have registers to meter and store at minimum the watt hour, volt-ampere hour, volt-ampere reactive hour (VAR hour), volt-ampere, volt-ampere reactive (VAR), and the watt. These registers are all LUM and the contents of these registers are transmitted back to the utility. FortisBC confirms that Legal Units of Measure are communicated at the location shown by the red arrow in Figure 1.

3.5.3 Does the proposed FortisBC AMI system meet all sections of Recommendation M2[16]? If not, please explain.

Response:

For reference, recommendation M2 of the cited document is included below:

> "The CNC/IEC should recommend to utilities and regulators that smart meter regulation and policies be established, as needed, to ensure that Measurement Canada-approved smart meters:
>
> • communicate LUM to the billing systems, just as they do for their local meter display;

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[15] The Canadian Smart Grid Standards Roadmap: A strategic planning document, October 2012, Section 5.3, Recommendation M2, Page 29

[16] The Canadian Smart Grid Standards Roadmap: A strategic planning document, October 2012, Section 5.3, Recommendation M2, Page 29

> • where the time of use is relevant to calculating customer billing: that SLUM is also tested for the accuracy of the start, end and duration of the time periods used to measure the SLUM communicated by the meter to the billing systems, to compute a PLUM; and
>
> • communicated interval or period-based LUM for demand measurement is tested for the accuracy of the demand measurement and for accuracy of the start, end and duration of the demand interval time, for the intervals or periods of the LUMs—where required for reporting by the meter to the billing systems."

FortisBC's proposed AMI system meets these recommendations.

Furthermore, FortisBC contends that the second and third recommendations are not specifications that an AMI system can comply with, but are instead best practices for managing the meter population.

3.6 Considering that the "Logical AMI Diagram" shows a logical architecture, would FortisBC agree that the Itron meter with the ZigBee technology are generally described by the "Customer Facility Gateway" and Meter together depicted by the purple circle in Figure 1 above? If not, please discuss.

<u>Response:</u>

Yes, FortisBC agrees that the Itron meter with integrated Zigbee technology will contain both the Meter and the Customer Facility Gateway depicted in Figure 1 and delineated by the purple oval.

3.7 The "CanadianSmart Grid Roadmap" provides "a list of key standards referenced in electricity metering requirements" [17].

3.7.1 Please provide a table listing the standards from Table 9[18] of the "CanadianSmart Grid Roadmap" and indicate ones the FortisBC AMI

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[17] The Canadian Smart Grid Standards Roadmap: A strategic planning document, October 2012, Section 5.2, Page 26, section 5.1

[18] The Canadian Smart Grid Standards Roadmap: A strategic planning document, October 2012, Section 5.3, Table 9, Page 31

system will follow or not follow. Please give an explanation where a standard is not followed.

Response:

Please refer to the table provided below. In instances where the FortisBC AMI system does not support the referenced standard, an explanation is included below the table.

Table 9: List of Standards Used in North American Electricity Metering (highlight the gaps)**				
Standard	**Title**	**Status**	**TC/SC/WG**	**Supported by FBC AMI System**
S-EG-05	Measurement Canada Specifications for the Approval of Software Controlled Electricity and Gas Metering Devices	Published 2012 **Priority**	Measurement Canada WG	Yes
S-EG-06	Measurement Canada Specifications Relating to Event Loggers for Electricity and Gas Metering Devices	Published 2012 **Priority**	Measurement Canada WG	Yes
ANSI C12.18	Protocol Specification [same as IEEE 1701] for ANSI Type 2 Optical Port	V2.0 Pub. 2006 **Priority**	ASC12WG4* SC17	Yes
ANSI C12.19	Utility Industry End Device Data Tables [same as IEEE 1377]	V2.0 Pub. 2008 **Priority**	ASC12WG2* SC17	Yes
ANSI C12.21	Protocol Specification for Telephone Communication [same as IEEE 1702] Modem	V2.0 Pub. 2006	ASC12WG4* SC17	N/A[1]
ANSI C12.22	Protocol Specification For Interfacing to Data Communication Networks [same as IEEE 1703]	V1.0 Pub. 2008 **Priority**	ASC12 SC17 WG2*	Yes
IEEE 1377	Standard for Utility Industry Metering Communication Protocol Application Layer (End Device Data Tables) [same as ANSI C12.19]	V2.1 Approved Ballot 2010 **Priority**	IEEE SCC31 P1377 WG*	Yes
IEEE 1701	Standard for Optical Port Communication Protocol to Complement the Utility Industry End Device Data Tables [same as ANSI C12.18]	V2.0 Pub. 2010 **Priority**	IEEE SCC31 P1701/P1702 WG*	Yes
IEEE 1702	Standard for Telephone Modem Communication Protocol to Complement the Utility Industry End Device Data Tables	V2.0 Pub. 2010	IEEE SCC31 P1701/P1702 WG*	N/A[1]

Table 9: List of Standards Used in North American Electricity Metering (** highlight the gaps)				
Standard	**Title**	**Status**	**TC/SC/WG**	**Supported by FBC AMI System**
IEEE 1703	Standard for Local Area Network/Wide Area Network (LAN/WAN) Node Communication Protocol to Complement the Utility Industry End Device Data Tables [same as ANSI C12.22]	V1.0 published 2012 **Priority**	IEEE SCC31 P1703 WG*	Yes
XML-2008	Extensible Mark-up Language (XML) Recommendation (Fifth Edition) [used by ANSI C12.19 / IEEE 1377 for enterprise data exchange language, configuration management and Table model Definition Language]	V1.0 Pub. 2008	W3C	Yes
XHTML	XHTML 1.0 The Extensible HyperText Markup Language (Second Edition)) [used by ANSI C12.19 / IEEE 1377 for configuration management documentation of Table model Definition Language]	E2.0 Pub. 2002	W3C	Yes
ISO/IEC 62056-62	Electricity metering—Data exchange for meter reading, tariff and load control—Interface classes. OBIS/COSEM [incorporates the ANSI C12.19 / IEEE 1377 Data (Tables) Model]	Pub. 2006	IEC/TC13	No[2]
ISO/IEC 15955 X.237 bis	Information Technology—Open Systems Interconnection—Connectionless Protocol for the Application Service Object Association Control Service [defines the message format used by ANSI C12.22 / IEEE 1703]	Pub. 1999 **Priority**	ITU X	Yes
ISO/IEC 10035-1, X.237 / Amendment 1	Information Technology—Open Systems Interconnection—Connectionless Protocol for the Association Control Service Element: Protocol Specification	Pub. 1995	ITU X	Yes
ISO/IEC 8824-1 / ITU-T X.680	Information technology – Abstract Syntax Notation One (ASN.1): Specification of basic notation [defines the abstract syntax notations used by ANSI C12.22 / IEEE 1703]	Pub. 1995	ITU-X	Yes

Table 9: List of Standards Used in North American Electricity Metering (highlight the gaps)**				
Standard	**Title**	**Status**	**TC/SC/WG**	**Supported by FBC AMI System**
ISO/IEC 8825 / ITU-T X.690	Information technology—ASN.1 encoding rules: Specification of Basic Encoding Rules (BER), Canonical Encoding Rules (CER) and Distinguished Encoding Rules (DER) [defines the payload encoding rules used by ANSI C12.22 / IEEE 1703]	Pub. 2003 Priority	ITU-X	Yes
RFC 6142	ANSI C12.22, IEEE 1703, and MC12.22 Transport Over IP	Pub. 2011 **Priority**	IETF	Partially[3]
AEIC Interoperability Guidelines	Smart Grid/AEIC AMI Interoperability Standard Guidelines for ANSI C12.19 / IEEE 1377 / MC12.19 End Device Communications and Supporting Enterprise Devices, Network and related accessories.	V2.0 Pub. 2010 Priority	AEIC / AMTI , and NIST/SGIP PAP5/ Measurement Canada WG	Partially[4]
FIPS PUB 180-2	Secure Hash Signature Standard (SHS) FIPS PUB 180-2). [used by ANSI C12.19 / IEEE 1377 logger hash function]	Pub. 2002	NIST	Yes
**FIPS Pub 197	Advanced Encryption Standard (AES), Federal Information Processing 28 Standards Publication 197 [used by ANSI C12.22 / IEEE 1703 logger hash function]	Pub. 2001 Gap	NIST	Yes
**SP800-38A	Recommendation for Block Cipher Modes of Operation; Methods and 32 Techniques [used by ANSI C12.22 / IEEE 1703 logger hash function]	Pub. 2001 Gap	NIST	Yes
**NIST SP 800-38B	Recommendation for Block Cipher Modes of Operation: The CMAC Mode for 38 Authentication [used by ANSI C12.22 / IEEE 1703 logger hash function]	Pub. 2005 Gap	NIST	Yes

1. ANSI C12.21 and IEEE 1702 are not supported as they are modem based standards and are not applicable to wireless IP devices.
2. IEC 62056-62 is DLMS/COSEM, a metering protocol widely used in Europe, but not in North America. Itron has many DLMS/COSEM based products, and actively supports it. However, the Openway AMI meters proposed in FortisBC's AMI project do not support it.
3. RFC 6142 is an informational RFC, not a standard.

4. The AEIC guidelines were recently updated. Itron, as well as Elster, GE, Landis+Gyr, worked in good faith along with utilities to ensure a set of guidelines that met utility objectives while being commercially viable. Itron is only partially compliant with the current AEIC guidelines. A device fully compliant with the current AEIC guidelines would impact Itron's ability to cost effectively manufacture meters and to offer innovative features. The added costs and reduced capabilities would have to be passed on to utilities, something that Itron is unwilling to do.

3.7.2 Do the FortisBC AMI smart meters meet the ANSI C12.19 standard[19] as reference in the “Canadian Smart Grid Roadmap” for storing of energy information to be transmitted to the Head End System?

Response:

Yes, the FortisBC AMI meters comply with the ANSI C12.19 standard.

4.0 Topic: SMI Network Requirements for Electric Vehicles

The Summary of SMI Requirements states that the Smart Grid should: “Establish a telecommunications network with sufficient speed and bandwidth to facilitate the use of electric vehicles.” [20]

4.1 Please describe the specific types of network characteristics (speed, bandwidth, end-to-end latency, reliability, etc.) which FortisBC believes appropriate to describe the telecommunications network performance to facilitate the use of electric vehicles. Please include the limiting values of those characteristics that FortisBC believes to be “sufficient”, and describe how the FortisBC system will meet those values through the range of WAN configurations.

Response:

[19] The Canadian Smart Grid Standards Roadmap: A strategic planning document, October 2012, Section 5.3, Table 9, Page 31

[20] Exhibit B-1, Section 3.2.2, Table 3.2.2.a, Page 24

FortisBC does not currently have defined values for the network characteristics listed in the question above. Company engineers have worked with Itron to define and understand the communications network capabilities. The Cisco GridBlocks™ communications network proposed in the AMI Project application is based on open and extensible standards such as IPv6. Please refer to Appendix BCSEA IR1 4.1 for a description of the communications network and how it supports the integration of field devices such as electric vehicles. The Company believes that the proposed system has sufficient capacity, flexibility and expandability to facilitate the use of electric vehicles.

4.2 Please discuss in general terms what measures FortisBC taking to ensure the telecommunications network can handle the electric vehicles.

Response:

Please refer to the response to BCSEA IR No. 1 Q4.1.

4.3 Please discuss what FortisBC is doing to align with the Province of BC program to set up a province-wide network of charging stations[21]. Please describe how FortisBC interprets and has accommodated in its AMI system the following requirements of Community EV chargers:

"- communications capability for data access and charging station management, and

- *Ability to measure and record energy usage and time of use statistics"* [22]

Response:

As discussed in the response to BCSEA IR1 Q4.1, FortisBC engineers have worked with Itron to define and understand the communications network capabilities. The Cisco GridBlocks™ communications network proposed in the AMI Project application is based on open and

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[21] Community Charging Infrastructure, Fraser Basin Council; http://www.fraserbasin.bc.ca/programs/community_charging_infrastructure.html

[22] Community Charging Infrastructure Fund, September 21, 2012; http://www.livesmartbc.ca/incentives/transportation/Level2-EVSE-List-of-Qualified-Products.pdf

extensible standards such as IPv6. FortisBC would require high-capacity EV charging units connected to the power system to also support open protocols and interfaces such that they could interoperate with the FortisBC AMI communications network. In the event that direct communications is not possible, FortisBC expects that protocol converters would be available in the market to enable the necessary interoperability. The Company believes that the proposed system has sufficient capacity, flexibility and expandability to facilitate the interconnection of EV charging systems.

4.3.1 Please discuss how FortisBC intends to address Recommendation M5 of the "Canadian Smart Grid Roadmap" [23] dealing with electric vehicles.

Response:

Recommendation M5 states:

> "The CNC/IEC should recommend to utilities that they deploy advanced metering infrastructure and metering communications networks for the Smart Grid in a manner that does not operate in isolation and does permit energy usage retrieval billing and roaming Plug-in Electric Vehicle capabilities that span multi-utility networks across the entire Smart Grid. Such billing and credit capability will be the basis for utility-to-utility roaming operations, communications, micro-grid and resource usage settlement agreements.

FortisBC's AMI Project is consistent with the above recommendation in that it will include the deployment of advanced metering infrastructure and the metering communications network. As discussed in previous responses, the communications network will be based on open and extensible protocols which will facilitate interconnection with electric vehicle charging systems for the retrieval of billing information. Further, the fact that FortisBC will be using a similar AMI communications system as that being deployed by BC Hydro will support any needed exchange of information and thus support roaming of vehicles between the company's neighbouring service areas.

[23] The Canadian Smart Grid Standards Roadmap: A strategic planning document, October 2012, Section 5.3, Recommendation M5, Page 30-31

5.0 Topic: Itron Specifications

5.1 Please supply a specification for the Itron meter that will be used for the FortisAMI system. Please confirm if the Itron meter meets the SMI Requirements.

Response:

The requested specification is provided as Appendix BCSEA IR1 5.1.

Compliance with SMI requirements is discussed in the response to BCSEA IR No. 1 Q2.4.

6.0 Topic: Connected Products

In a June 2012 release, Itron announces that "It also extends to integrated products and communications modules, incorporating ZigBee into third party products." [24]

6.1 Please describe how FortisBC will ensure a competitive market for products which connect to the Itron meters.

Response:

ZigBee standards are maintained and published by the ZigBee Alliance, which is a group of organizations and companies. The term ZigBee is a registered trademark of this group, not a single technical standard. The Alliance publishes application profiles that allow multiple OEM vendors to create interoperable products.

Many different vendors currently offer ZigBee-certified products. ZigBee compliance is certified by independent testing firms.

FortisBC expects that the market for a variety of ZigBee products will remain competitive and does not intend to participate directly in it. FortisBC will support compatible ZigBee products by providing customers with the option of pairing them with AMI meters and by providing purchase incentives for in-home displays.

[24] Itron Expands Portfolio of ZigBee Smart Energy-Certified Products, June 7, 2012; https://www.itron.com/newsAndEvents/Pages/Itron-Expands-Portfolio-of-ZigBee-Smart-Energy-Certified-Products.aspx

6.2 Please confirm that any certified ZigBee product (of the appropriate version) can connect to the Itron meter, and will be given authorization to do so in an unbiased manner.

Response:

Confirmed.

6.3 Please describe the process by which manufacturers will be able to develop and introduce products to connect to the Itron meter.

Response:

The ZigBee certification process is described on the ZigBee Alliance website at http://www.zigbee.org/Certification/CertificationFAQ.aspx .

7.0 Topic: SMI Network Requirements for Distributed Generation

7.1 The SMI Requirements note that the Smart Grid should: "Establish a telecommunications network with sufficient speed and bandwidth to facilitate distributed generation." [25]

Please describe the specific types of network characteristics (speed, bandwidth, end-to-end latency, reliability, etc.) which FortisBC believes appropriate to describe the telecommunications network performance to facilitate distributed generation. Please include the limiting values of those characteristics that FortisBC believes to be "sufficient", and describe how the FortisBC system will meet those values through the range of WAN configurations.

Response:

[25] Exhibit B-1, Section 3.2.2, Table 3.2.2.a, Page 24

FortisBC does not currently have defined values for the network characteristics listed in the question above. The Cisco GridBlocks™ communications network proposed in the AMI Project application is based on open and extensible standards such as IPv6. FortisBC has worked with Itron to define and understand the communications network capabilities. The Company believes that the proposed system has sufficient capacity, flexibility and expandability to facilitate distributed generation.

8.0 Topic: FortisBC RFP

"FortisBC used a competitive RFP process for the two primary components of the AMI system: one for the MDMS software solution, and a second one for the AMI hardware infrastructure." [26]

8.1 Please provide a copy of the RFP for the AMI hardware infrastructure.

Response:

A copy of the RFP for the AMI hardware infrastructure is provided as Appendix BCSEA IR1 8.1.

8.2 Regarding the LAN side, FortisBC states: "The RFP did not specify the type of meter-to-collector communications technology (RF, PLC, BPL or other) to be used for the AMI system . . . "[27]

Regarding the IHD side, FortisBC states: "One of the requirements of the procurement process was that vendors be able to meet emerging industry standards for IHDs using the Zigbee communications protocol. Initially the meters will use Zigbee Smart Profile v1.1, which is supported by a wide variety of commercially available IHDs.

The selected meters also support Zigbee Smart Energy v2.0, which is being developed by the ZigBee Alliance specifically to provide additional functionality related to the delivery and use of energy and water." [28]

[26] Exhibit B-1, Section 4.2.1, Page 53, Lines 2-4
[27] Exhibit B-1, Section 4.2.2, Page 55, Lines 7-8
[28] Exhibit B-1, Section 4.1.1, Page 43, Lines 10-16

8.2.1 Please explain why the meter-to-collector communications was not specified, yet the meter-to-IHD communications was specifically required to be ZigBee.

Response:

FortisBC did not specifically require that the meter-to-IHD communications was to be ZigBee, although it was believed to be the only standard supported "on-meter" in Canada. In Section 5.9.1 and 5.9.2 of the RFP, the vendors were asked to confirm which versions of ZigBee they supported, and any other standards supported.

8.2.2 Please provide a copy of the portion(s) of the RFP that relates to ZigBee.

Response:

Please refer to Appendix BCSEA IR1 8.1. The sections relevant to ZigBee are 5.1.4 *AMI Communication Standards / Protocols* and 5.9 *Home Area Network (HAN)*, subsections 5.9.1 and 5.9.2.

8.2.3 Please provide a copy of the portion(s) of BC Hydro's RFP for smart meters that relates to ZigBee or other communications protocols between the meter and the IHD and explain the differences. Alternatively, please explain FortisBC's understanding of BC Hydro's RFP in this regard.

Response:

FortisBC does not have access to BC Hydro's RFP for smart meters as it is not a publically available document. It is the Company's understanding that HAN-specific (Home Area Network) requirements were similar.

9.0 Topic: BC Hydro In-Home Feedback RFEI

9.0 Please file a copy of the BC Hydro document "Request for Expression of Interest, In-Home Feedback Devices (RFEI #1089) Issue Date December 2, 2011" available on the Internet at https://docs.zigbee.org/zigbee-docs/dcn/11/docs-11-5774-00-0mwg-bc-hydro-rfi.pdf, plusany updates.

Response:

The requested document is provided as Appendix BCSEA IR1 9.0.

9.1 Will FortisBC be releasing a requirements document for the HAN devices and gateways themselves (similar to BC Hydro's document)? If so, please include the wording or describe. If not, why not?

Response:

FortisBC has not decided whether it is necessary to issue a document such as the referenced BC Hydro document.

9.2 Noting that the document concerns the devices that communicate to the Smart Meters, but not the Smart Meter itself, please confirmthat the HAN devices for BC Hydro must meet SEP 1.1 (see Section 1.2, Section 1.5 (REQ 1), and Section 1.6.1 (REQ 6)), but these devices are not required to meet SEP 2.0.

a) Please explain the expected operation should a SEP 2.0 HAN device attempt communication with the Smart Meter.

b) Will FortisBC be placing the same requirements on its HAN devices as BC Hydro? If not, please explain any differences.

Response:

SEP 1.1 HAN device will not be able to authenticate with an SEP 2.0 meter and therefore will not exchange information.

FortisBC has not decided whether it is necessary to place the same requirements on its HAN devices as BC Hydro – it will decide in part based on the need to provide interoperable HAN devices throughout the province.

9.3 Please confirm that Gateway products for BC Hydro must be upgradeable to SEP 2.0 (see Section 1.6.4, (REQ 37)), and elaborate on how this is accomplished.

a) Will FortisBC be placing the same requirements on its Gateway devices as BC Hydro? If not, please explain any differences.

Response:

FortisBC has not decided whether it is necessary to place the same requirements on its gateway devices as BC Hydro – it will decide in part based on the need to provide interoperable HAN devices throughout the province.

10.0 Topic: Smart Energy Profile

10.0 Please confirm that "Zigbee Smart Profile v1.1" [29] should be written "ZigBee Smart Energy Profile V1.1"; and "Smart Energy v2.0" [30] should be written "Smart Energy Profile V2.0"? If not, please explain and provide references.

Response:

Confirmed.

10.1 Please file a copy of "ZigBee Smart Energy Features" [31] .

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[29] Exhibit B-1, Section 4.1.1, Page 43, Line 12
[30] Exhibit B-1, Section 4.1.1, Page 43, Line 14
[31] ZigBee Smart Energy Features, https://docs.zigbee.org/zigbee-docs/dcn/08-0013.pdf

Response:

A copy of the ZigBee Smart Energy Features is provides as Attachment BCSEA IR1 10.1.

ZigBee Smart Energy Features

Metering Support:

- NEW - Meter swap outs
- Multiple commodities including electric, gas, water, and thermal
- Multiple units of measure for international support
- Battery or mains powered
- Multiple measurement types such as load profile, power factor, summation, demand, and tiers
- Real-time information
- Historical information (previous day, today, etc.)
- Status indicators including tampering
- Ability to record both generation (delivered) and consumption (received)

Demand Response and Load Control Support:

- Scheduling of multiple events
- Auditing of event enrollment, participation, and other actions
- Ability to individually or simultaneously target specific groups of devices including HVACs, water heaters, lighting, electric vehicles, and generation systems
- Multiple control methods including temperature set points and offsets, criticality levels (such as emergency signals) and duty cycling
- Ability to randomize start and end times to avoid spikes

Pricing Support:

- NEW - Block tariffs (inclining/declining block rates)
- NEW - Prepayment
- Multiple commodities including electric, gas, water, and thermal
- Multiple units of measure for international support
- Multiple currencies for international support (using ISO 4217)
- Unregistered devices allowed to request and receive pricing information
- Support for multiple providers and rates in a single location
- Support for price ratios and price tiers
- Support for separate generated (delivered) and consumed (received) prices

Text Message Support:

- Scheduling and canceling of messages
- Ability to request message confirmation
- Unregistered devices allowed to request and receive messages
- Multiple urgency levels
- Optional message duration for short-lived messages
- Support for multiple international character sets

Preliminary Device Support:

- Meter-integrated or standalone energy service portals
- In-premise displays including low-cost, standalone devices such as refrigerator magnets and energy orbs
- Programmable communicating thermostats (PCT)
- Generic load control devices for appliances such as water heaters. lights and pool pumps
- Smart appliances
- Electric vehicles and plug-in hybrid electric vehicles
- Energy management systems
- Range extenders

Security:

- Support for utility registration and utility-only networks
- Automatic, secure network registration using either pre-installed keys or ECC certificate exchange
- Support for ECC public key infrastructure for authentication and mobility
- Data encryption

Other:

- NEW - Tunneling of manufacturer specific protocols
- NEW – Over-the-air updates
- NEW – Backwards compatible with ZigBee Smart Energy version 1.0 ZigBee Certified products
- Time Synchronization provided by ESP
- Designed for easy upgrade and adaptability within version 1.x

NEW features found in ZigBee Smart Energy version 1.1

10.2 Please confirm that the “ZigBee Smart Energy Features” accurately describes the features provided in ZigBee Smart Energy V1.1 and are the same features provided by the Itron solution. If not, please note changes.

Response:

Zigbee Smart Energy v 1.1 defines a set of optional features. A subset of these features are implemented on the Itron meter and relate to metering, pricing, messaging and demand response.

10.3 Did the RFP specify specifically that “Zigbee Smart Energy Profile V1.1” was required in the meters or was the statement regarding ZigBee more generic?

Response:

Please see the response to BCSEA IR No. 1 Q8.2.1.

10.4 FortisBC notes that Smart Energy Profile v2.0 was developed by the ZigBee Alliance[32]. Please clarify the role of WiFi and HomePlug for the development of Smart Energy ProfileV2.0.

Response:

The Zigbee Alliance, WiFi Alliance, and HomePlug Alliance have created a new organization called CSEP (Consortium for SEP 2 Interoperability) that is running the interoperability testing and will provide the certification program for SEP 2.0.

[32] Exhibit B-1, Section 4.1.1, Page 43, Lines 14-15

10.4.1 Please compare the ZigBee Alliance[33] to the North American Energy Standards Board (NAESB)[34] and the Institute of Electrical and Electronics Engineers (IEEE)[35] which are referenced in numerous places throughout the “CanadianSmart Grid Roadmap”. Please include comparisons of whether they are considered standards making bodies, how standards are developed, membership requirements, use of open standards, etc.

Response:

FortisBC notes that the ZigBee Alliance is a group of companies that maintain and publish the ZigBee standard. For non-commercial purposes, the ZigBee specification is available free to the general public. An entry level membership in the ZigBee Alliance provides permission to create products for market using the specifications.

IEEE Is a professional association and is considered one of the leading standards making organizations in the world, with standards affecting many industries, including power and energy industries. In order for an individual to qualify for membership with the IEEE, the individual must fulfil certain academic or professional criteria and abide to the code of ethics and bylaws of the organization.

The North American Energy Standards Board (NAESB) is an industry association, and is focused primarily on the development and promotion of standards related to the advancement and adoption of electronic technologies for use in the wholesale and retail energy markets. Standards and model business practices developed by NAESB are based on a standards development process accredited by the American National Standard Institute.

10.5 FortisBC states that ZigBee is “based on an IEEE 802 standard”[36].

a) Please confirm that ZigBee is based upon IEEE 802.15.4 and explain the relationship between the two.

b) Please describe the relationship of IEEE 802.15.4 to SEP 2.0 and the relationship of ZigBee to SEP 2.0.

Response:

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[33] Exhibit B-1, Section 4.1.1, Page 43, Lines 16-17
[34] “*CanadianSmart Grid Roadmap*”, Section 3, Page 9
[35] “*CanadianSmart Grid Roadmap*”, Section 2.2, Page 5
[36] Exhibit B-1, Section 4.1.1, Page 43, Footnote 8

a) Confirmed. 802.15.4 is a sub-standard of the IEEE 802 standard related to low power personal networks;

b) IEEE 802.15.4 is the physical layer for Zigbee SEP 1.x and is an optional physical layer for SEP 2.0 which is physical layer agnostic.

11.0 Topic: WIBEEM

11.0 The "Canadian Smart Grid Roadmap" discusses the work of ISO/IEC JTC 1/ SC 25 which the Roadmap says "has a new focus on home and building energy management, and a connection to the Smart Grid" [37]. Please file a copy of the Working Group 1's smart grid report: "Smart Grid Standards for Residential Customers" [38] found at http://hes-standards.org/doc/SC25_WG1_N1516.pdf.

Response:

A copy of the requested document is provided as Appendix BCSEA IR1 11.0.

11.1 The SC 25 / WG 1 Smart Grid Standards for Residential Customers mentions a "low power radio that uses energy for a mesh network efficiently", called WiBEEM[39]. Please confirm that WiBEEM is an International Standard being developed based on IEEE 802.15.4. Discuss whether it could be a firmware/software upgrade to ZigBee radios in the Smart Meters.

Response:

FortisBC has no knowledge of WiBEEM. Limited research has indicated that there appear to be some entities attempting to develop this as an "international standard" but FortisBC has no knowledge that this has occurred, or been embraced by any international bodies. Furthermore, based on this same research, any interest in this technology is limited to a few countries in Asia.

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[37] The Canadian Smart Grid Standards Roadmap: A strategic planning document, October 2012, Section 5.3, Recommendation M6, Page 31

[38] Smart Grid Standards for Residential Customers, ISO/IEC JTC 1/ SC 25/WG 1

[39] Smart Grid Standards for Residential Customers, ISO/IEC JTC 1/ SC 25/WG 1, Page 8,

FortisBC is unable to confirm or deny the statement, but has not found evidence that WiBEEM is an "international standard".

Itron has not performed an analysis of WiBEEM and cannot comment on the feasibility of future migration to that potential standard.

12.0 Topic: Consortium for SEP 2

Please refer to the series of documents by the Consortium for SEP 2 Interoperability (CSEP) athttp://www.csep.org.

The CSEP home page states:

"The Smart Energy Profile 2 is the forthcoming standard for applications that enable home energy management via wired and wireless devices that support Internet Protocol." [40]

12.1 Please confirm that the "Zigbee Smart Energy v2.0" that FortisBC refers to is the same as the "Smart Energy Profile 2" that is referred to by CSEP. If not, please explain. If yes, please answer the following questions:

<u>Response:</u>

Confirmed.

12.1.1 Is Itron a member of CSEP? If not, why not, and are there plans to become a member and at what level?

<u>Response:</u>

Yes, Itron is a member of CSEP (Consortium for SEP2), and has been since its founding.

The consortium is composed of three member Alliances: The HomePlug Powerline Alliance, the Wi-Fi Alliance and the ZigBee Alliance. Itron is a member in good standing in all three of these Alliances.

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[40] Consortium for SEP 2 Interoperability home page, http://www.csep.org

12.1.2 Is FortisBC a member of CSEP? If not, why not, and are there plans to become a member and at what level?

Response:

FortisBC is not a member of the Consortium for SEP 2. There are large number of entities and organizations that are developing AMI and Smart Grid standards. Due to limited resources, it is not practical or cost-effective for FortisBC to participate in every group. In the interests of ensuring cost-effectiveness, FortisBC participates in standards bodies when it is felt that meaningful expertise can be contributed, or important knowledge gained. In the case of CSEP, FortisBC does not have personnel with sufficient knowledge to add to the standard, and is comfortable that the industry and participating utilities will develop a standard that suits the needs of FortisBC customers. FortisBC has no plans to become a member of CSEP.

12.2 Is FortisBC, Itron, or both, familiar with the work of CSEP?

Response:

Yes. Please see the response to BCSEA IR No. 1 Q12.1.1.

12.3 Do FortisBC, Itron or both have any disagreements with the CSEP approach? If so, please explain.

Response:

FortisBC and Itron do not have any disagreements with the CSEP approach at this time.

12.4 The press release of CSEP[41] states: "The Consortium will create and maintain a comprehensive test and certification test suite to validate interoperability for a variety of wired or wireless devices. Products to be certified as a result of the Consortium's work are expected to include thermostats, appliances, electric meters, gateways, electric vehicles, and countless other devices in the Smart Grid."

Will the Itron solution meet the CSEP "comprehensive test and certification test suite"?

Response:

Yes, Itron intends at this time to comply with the testing criteria produced by CSEP.

12.5 What testing for interoperability between the Itron meter and other products will be done?

Response:

Itron's AMI meters currently implement ZigBee Smart Energy v1.1, and therefore all interoperability testing has been based on devices which implement that standard. Itron has provided a ZigBee developer's kit, representing their AMI meter ZigBee implementation, to over 80 organizations. Itron meters are also test units for ZigBee test houses certifying ZigBee Smart Energy-compliant devices.

12.6 The CSEP Organizational Resolutions[42] state: "RESOLVED, that with respect to the qualifications of membership as a Sponsor set forth in Section 4.1(a)(1) of the bylaws, the board of directors shall use the following elements in determining whether an industry trade association is focused on supporting an international standard MAC/PHY [lower layers of Media Access Control/Physical Layers (e.g. radio or powerline)]:

[41] CSEP press release, Oct 25, 2011; http://www.csep.org/media/uploads/documents/consortium_for_sep_2_interoperability_launches_pr_111025.pdf

[42] http://www.csep.org/media/uploads/documents/csep_org_resolutions_120524.pdf

(1) *The industry trade association focuses on supporting an open MAC/PHY that is developed and maintained through a collaborative and consensus driven process, one that facilitates interoperability and data exchange among different products or services and is intended for widespread adoption;*

(2) *The IPR [Intellectual Property Rights] essential to implement the MAC/PHY can be licensed by all applicants on a worldwide, non-discriminatory basis, either for free and under other reasonable terms and conditions, or on reasonable terms and conditions (which may include monetary compensation);*

(3) *The MAC/PHY is not dominated by a single interest group;*

(4) *Development and maintenance of the MAC/PHY is driven by the market and is open to all interested parties;*

(5) *The quality of the MAC/PHY is sufficient to permit the development of a variety of competing implementations of interoperable products;*

(6) *The MAC/PHY is easily available to the general public at a reasonable price, i.e., RAND;*

(7) *The MAC/PHY is transparent, meaning that there are no masked or hidden features or normative references that do not conform to these open standards principles; and*

(8) *The MAC/PHY is intended to be supported over a long period of time."*

Does the solution provided by Itron meet these considerations? If not, please explain.

Response:

The referenced Organizational Resolutions do not contain requirements for products or solutions provided by Itron.

13.0 Topic: Smart Grid Interoperability Panel SEP Document

In the Foreword of the "CanadianSmart Grid Roadmap", John Walter, CEO of the Standards Council of Canada and Serge P. Dupont, Deputy Minister of Natural Resources Canada, states:

"By identifying a path forward on the priority standards for Canada, this work supports that of the United States National Institute of Standards and Technology to develop a broad range of standards for the smart grid." [43]

The Smart Grid Interoperability Panel[44] (SGIP) of the National Institute of Standards and Technology (NIST) developed 20 Priority Action Plans (PAP) which "*categorized priority actions to define the challenges to and objectives for developing interoperability for the Smart Grid*"[45].

Priority Action Plan #18 is the "*Smart Energy (SEP) Profile 1.X to 2.0 Transition*". It is a detailed 92-page document[46] (***SGIP SEP document***) to "*specifically address SEP 1.x to SEP 2.0 migration and coexistence*"[47].

FortisBC states: "*Initially the meters will use Zigbee Smart Profile v1.1.*"[48]. and that "*the selected meters also support Zigbee Smart Energy v2.0.*"[49].

The "*SGIP SEP document*" states: "*As a result of significant architectural changes and feature upgrades, SEP 2.0 is not backwards compatible with SEP 1.x neither at the network and application layers nor in the security architecture.*"[50]

13.1 Please confirm that FortisBC/Itron intends to implement both SEP 1.1 and SEP 2.0 in the same meters.

Response:

Please see the response to BCSEA IR No. 1 Q1.2.

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43 The Canadian Smart Grid Standards Roadmap: A strategic planning document, October 2012, Foreword
44 Web site of SGIP; http://www.nist.gov/smartgrid/priority-actions.cfm
45 SGIP, Priority Actions; http://www.nist.gov/smartgrid/priority-actions.cfm
46 PAP 18: SEP 1.x to SEP 2.0 Transition and Coexistence Guidelines and Best Practices, Page 6, Line 136, SGIP; http://collaborate.nist.gov/twiki-sggrid/pub/SmartGrid/SEPTransitionAndCoexistenceWP/PAP_18_SEP_Migration_Guidelines_and_Best_Practices_ver_1_03.docx
47 SGIP SEP document, Page 6, Line 136
48 Exhibit B-1, Section 4.1.1, Page 43
49 Exhibit B-1, Section 4.1.1, Page 43
50 SGIP SEP document, Page 6, Lines 116-118

13.2 Does FortisBC agree with the “SGIP SEP document” that “SEP 2.0 is not backwards compatible with SEP 1.x”? Please respond regarding (a) the network and application layers and (b) the security architecture. If not, please explain.

Response:

FortisBC agrees that SEP 2.0 is not backwards compatible with SEP 1.x. SEP 2.0 utilizes an IP framework for its network and application layers. The security architecture is grounded in Transport Layer Security and utilizes standard web technologies. SEP 1.x utilizes different networking technology and the Zigbee Cluster Library to define all the Open System Interface layers.

13.3 Please discuss the consequences of implementing both SEP 1.1 and SEP 2.0 in the same meters.

Response:

Please see the response to BCSEA IR No. 1 Q9.2.

13.4 Will the AMI solution proposed by FortisBC meet the requirements described in the “SGIP SEP document”? If not, please explain.

Response:

Although it has not studied the SGIP SEP document in detail, FortisBC expects the AMI solution be able to be able to migrate between SEP 1.1 and SEP 2.0.

13.5 Regarding the SEP V1.x and SEP V2.0 issues, the “SGIP SEP document” states:

“Stranded devices and a negative experience by the Customer will translate directly into costs and lost opportunities for all parties involved in the migration. Costs due to adverse migration events identified in the use cases included replacing failed devices, additional call center technical support, truck rolls for onsite technical support, the processing of regulatory complaints, lost sales opportunities, addressing adverse publicity, and the cost of the Customer's time to determine what went wrong with the migration and how to repair it. Cost is also a factor when Utilities and regulators are determining time durations for support of various best practice migration recommendations." [51]

In addition, the "SGIP SEP document" states that: "there is a risk of stranding some of those existing investments" [52].

13.5.1 Please discuss what FortisBC will be doing to:

a) reduce the potential for migration costs,

b) reduce lost opportunities,

c) minimize the potential for negative customer experiences, and

d) minimize the risk of stranding investments.

Response:

Please see the response to BCSEA IR No. 1 Q1.3.

13.5.2 Is the migration from SEP V1.x and SEP 2.0 included within FortisBC's budget for the AMI program? If there are problems with the migration from SEP V1.x and SEP 2.0 will the costs be borne by FortisBC, Itron or customers who use or want to use IHD?

Response:

The migration from SEP 1.1 to SEP 2.0 is expected to be a no-cost over-the-air upgrade to the meter HAN. SEP 1.1 to SEP 2.0 migration will be tested prior to implementation to ensure that there are minimal problems, and that problems identified have workable solutions.

[51] SGIP SEP document, Page 17, Lines 578-585
[52] SGIP SEP document, Page 18, Lines 589-590

13.5.3 Does FortisBC agree that many of the issues and complexities in the "SGIP SEP document" do not apply for systems that involve only one version of SEP? If not, please explain.

Response:

FortisBC agrees that there are more complexities with having mixed versions of SEP 1.x and SEP 2.0 in the AMI meters and customer devices. Please also see the response to BCSEA IR1 Q1.3 and Q13.5.2.

13.5.4 Please discuss the advantages/disadvantages and consequences if the FortisBC AMI project only used SEP 1.x.

Response:

Significant investments in SEP 1.1 have been made in Texas, California, UK and the EU. Therefore, the technology will continue to evolve and is not likely to significantly disadvantage customers relative to SEP 2.0. Please also see the response to BCSEA IR No. 1 Q1.7.

14.0 Topic: HAN Projects in North America

FortisBC proposes that advanced meters for its program will include HAN functionality at implementation[53]. FortisBC discusses AMI projects throughout Canada[54].

14.1 Please provide estimates for the total number of in-home display units deployed and provisioned/activated throughout Canada.

Response:

[53] Exhibit B-6, BCUC IR 30.1 Response, Page 47; Exhibit B-1, Page 1, Line 25; Exhibit B-1, Section 4.1.1, Page 44, Lines 1-9.
[54] Exhibit B-1, Section 8.1.1, Page 125, Line 10 to Page 126, Line 22

According to providers of in-home displays contacted on behalf of FortisBC, the Ontario market has active programs in progress deploying in-home displays with an estimated volume of 40,000+ devices provisioned in homes today.

14.2 Please provide estimates for the number of in-home display units with ZigBee Smart Energy Profile V1.x deployed and provisioned/activated throughout Canada.

Response:

This information is currently not available as ZigBee programs are new to the market.

14.3 Please provide estimates for the total number of in-home display units deployed and provisioned/activated throughout the United States.

Response:

According to a GBI research report, there were 142,000 in-home display units installed in the United States in 2010.

http://www.marketresearch.com/GBI-Research-v3759/Smart-Grid-Americas-EU-Collaboration-6855311/

14.4 Please provide estimates for the number of in-home display units with ZigBee Smart Energy Profile V1.x deployed and provisioned/activated throughout the United States.

Response:

Requests for the estimated number of IHDs with ZigBee Smart Energy Profile V1.x are not currently available, but the deployments at Oncor in Texas and Southern California Edison and San Diego Gas & Electric in California include implementations of a HAN based on the SEP 1.x specifications.

(source: Pike Research Smart Meters Research Report – published in Q2 2012)

14.5 What area has the highest penetration of In-Home Displays in North America? Please describe the type and number of HANs installed, the number of HANs provisioned/activated, and the number of Smart Meters.

Response:

Please see response to BCSEA IR No. 1 Q14.4 above.

14.6 Please provide any studies that provide projections for the number and type of in-home displays throughout North America.

Response:

FortisBC notes the following studies regarding IHDs throughout North America:

GBI Research

GBI Research, a leading business intelligence provider, has released its latest research, "Smart Grid Market in Americas to 2020 - US-EU Collaboration on Standards to Solve Interoperability & Data Security Issues to Encourage Innovation". The report gives an in-depth analysis of the North and South America smart grid market, covering the three major technologies: smart meters, synchrophasors and in-home displays. The report provides information on the cumulative installed units and revenue from 2010-2020 for the three technologies for the US, Canada, Brazil and Mexico.

The cumulative number of units installed in the American in-home displays market is expected to grow from 142,000 units in 2010 to 20,367,073 units in 2020 at a CAGR of 64.3%.

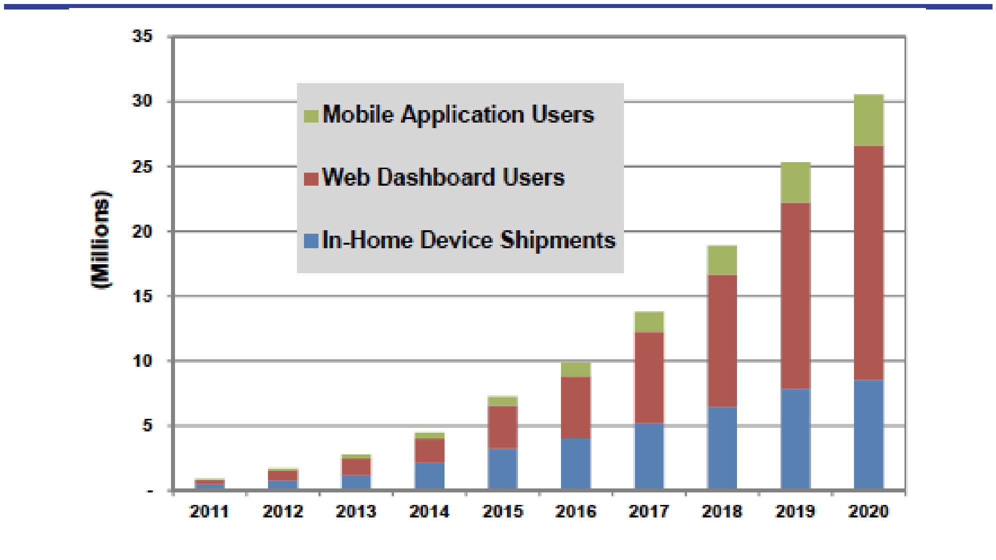
http://www.marketresearch.com/GBI-Research-v3759/Smart-Grid-Americas-EU-Collaboration-6855311/

Pike Research

A new report from Pike Research predicts that users of home energy management systems will reach 63 million by 2020, up from just over 1 million in 2011.

The report, "Home Energy Management," anticipates that the increased energy efficiency concerns of consumers, along with utility energy efficiency programs in both deregulated and more highly regulated markets, will stimulate greater demand for home energy management (HEM) capabilities, including in-home display (IHD) devices, web-based energy management dashboards, and smartphone applications.

Chart 1.1 Home Energy Management Users by Interface Type, World Markets: 2011-2020



(Source: Pike Research)

http://greentechadvocates.com/2011/06/23/63-million-will-use-home-energy-management-by-2020/

Global Data

Global Data's report ("In-Home Displays for Energy Management - Market Analysis and Forecasts to 2020) provides information related to the past deployment trends and the outlook for IHDs in key countries such as including the US, the UK, Canada, Australia, Denmark, Sweden, Finland and Norway. (This report is for purchase.)

http://www.globaldata.com/reportstore/Report.aspx?ID=In-Home-Displays-for-Energy-Management-Market-Analysis-and-Forecasts-to-2020&ReportType=Industry_Report&title=Smart_Grid

American Council for an Energy-Efficient Economy

The current end user market for in-home energy displays continues to consist primarily of early adopter types, however there is evidence that interest is expanding quickly.

http://www.smartgrid.gov/sites/default/files/pdfs/ami_initiatives_aceee.pdf

15.0 Topic: Adoption Rate for In-Home Displays

FortisBC cited a recent In-Home Display pilot program and survey by the US Department of Energy and CenterPoint Energy in Texas[55].

From the July 2012 compliance reports from CenterPoint and other Texas smart meter implementations, it is noted that the following number of HANs have been provisioned:

Utility	HANs	Total Meters	Percentage
CenterPoint Energy Houston Electric[56]	9,562	2,283,012	0.4%
AEP[57]	76	593,784	0.01%
TNMP[58]	0	52,451	0%

15.1 Please confirm the numbers in the table, and adjust as necessary.

Response:

The numbers in the table appear to be correct.

15.2 FortisBC estimates an adoption rate of 30% for In-Home Displays[59], and that penetration between 2015 and 2020[60]. Please provide the estimated adoption rate on a year by year basis.

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[55] Exhibit B-1, Section 4.1.1, Page 44, Line 10 to Page 45, Line 2

[56] CenterPoint Energy Monthly Report to AMIT, July 31, 2012; http://www.puc.texas.gov/industry/projects/electric/34610/AMITMtg071912/CNP_Monthly_Compliance_Report.pdf

[57] TDU Montly Report to AMIT, July 31, 2012; http://www.puc.texas.gov/industry/projects/electric/34610/AMITMtg071912/AEP_Monthly_Compliance_Report.pdf

[58] TNMP Monthly Report to AMIT, July 31, 2012; http://www.puc.texas.gov/industry/projects/electric/34610/AMITMtg071912/TNMP_Monthly_Compliance_Report.pdf

Response:

The estimated ramp rate used was the new technology measure adoption curve, provided by EES Consulting as part of the 2010 CDPR (Conservation Demand Potential Report). The last year (10) was curtailed to limit the overall adoption rate to 30%.

Year:	1	2	3	4	5	6	7	8	9	10
Penetration:	0.25%	0.50%	0.90%	1.50%	2.50%	4.50%	5.80%	6.20%	6.40%	1.45%

15.3 Please discuss how FortisBC developed its forecast IHD adoption rate and compare the rates to other jurisdictions.

Response:

This 30% IHD adoption rate is within the opt-in and opt-out participation rates identified in Table ES-2 of the Navigant report in Exhibit B-1, Appendix C-1, p 9. It is reasonable to assume participation between opt-in and opt-out rates since FortisBC (and BC Hydro) intend to offer rebates from their energy efficiency programs to support customer purchases. The Navigant study used assumption from the ACEEE meta-analysis cited in the report.

The 2020 IHD adoption rate of 30% is the same as the rate used in the BC Hydro Smart Meter business case, which in turn was based on information from Pacific Gas and Electric and BC Hydro qualitative focus group research. FortisBC does not have information from other jurisdictions.

15.4 Please discuss what measures FortisBC plans to take in order to reach its estimated adoption rate for In-Home Displays.

Response:

FortisBC intends to use a variety of methods to promote in-home displays, similar to those already used to promote energy efficiency products through its PowerSense program.

[59] Exhibit B-6, BCUC IR #8.2 Response, Page 20, Lines 5-10
[60] Exhibit B-6, BCUC IR #30.3 Response, Page 49, Lines 11-18

Those methods include product rebates, promotion of IHD's in customer billing inserts, promotion of IHDs in community energy conservation programs such as the Rossland Energy Diet and home show displays of sample devices

FortisBC has a long and successful track record of creating demand for energy efficiency products.

15.5 What version of ZigBee was used for the Texas projects?

Response:

The Smart Meter Texas program requires compliance with ZigBee Smart Energy v1.1.

The CenterPoint Energy smart meters support ZigBee Smart Energy v1.1.

15.6 Please refer to the presentation titled "Smart Meter Texas, Proposed Scope for Summer Release" [61]. Please file a copy of Slide 22, showing an example of how a customer adds a thermostat to his or her own HAN device through Smart Meter Texas website.

15.6.1 Please confirm that Slide 22 shows the customer adding a HAN device (the example show is "Den – thermostat") via the utility's website.

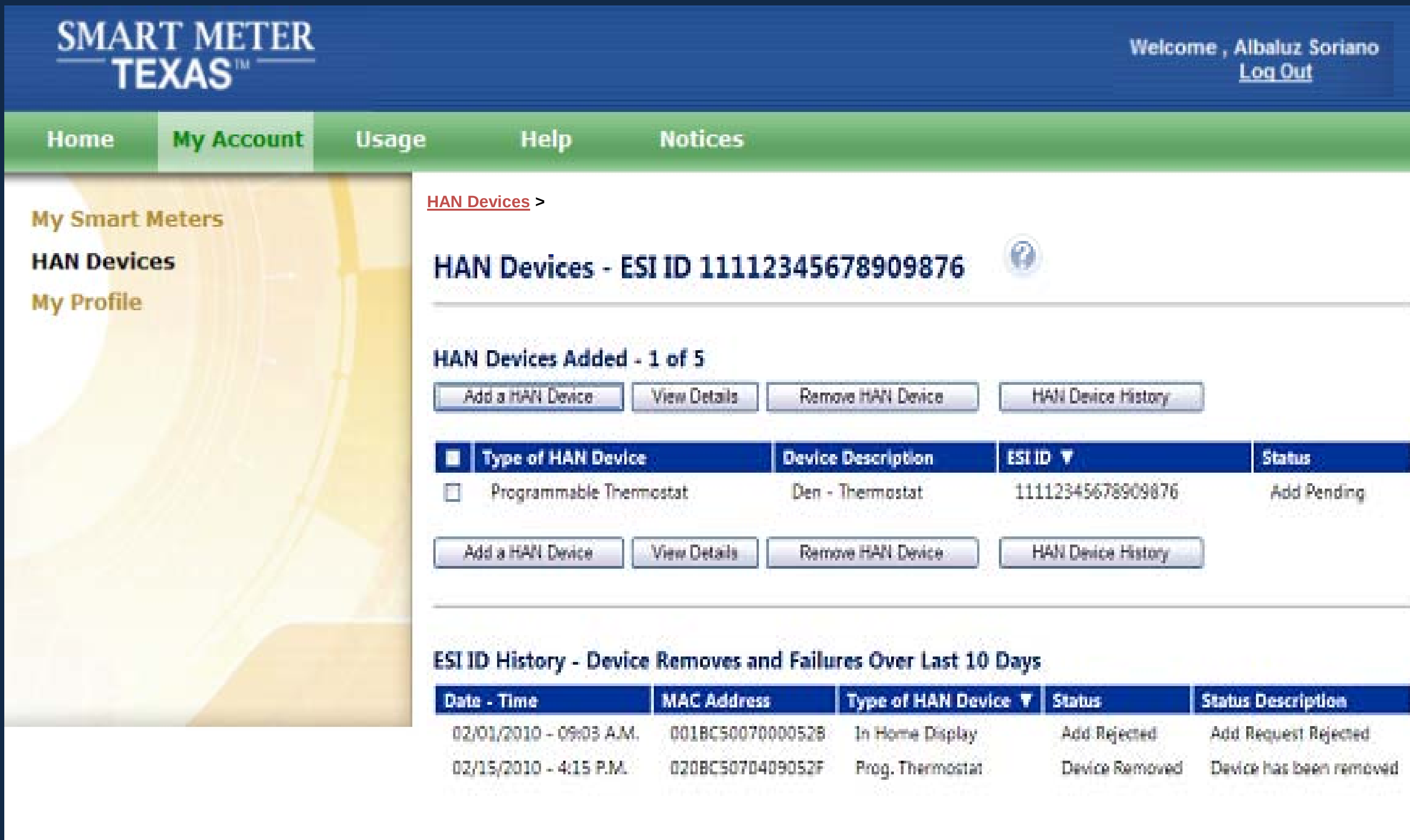
Response:

A copy of Slide 22 is provided as Attachment BCSEA IR1 15.6.

Slide 22 appears to be a HAN device overview screen, showing devices that are currently associated with the electricity account and a history of devices that have been added, removed or rejected. There also appear to be buttons that can be clicked to add new HAN devices as well as buttons for removing and viewing details about currently registered devices.

[61] Smart Meter Texas, Proposed Scope for Summer Release, Slide 22, http://www.puc.state.tx.us/industry/projects/electric/34610/AMITMtg052510/SMT-Summer-Functionality.ppt

Customer HAN Device – ESIID List View



15.6.2 As far as FortisBC knows, is this the current method by which customers add HAN devices in the Texas projects? If not, please explain.

Response:

FortisBC does not know if Slide 22 depicts the current method by which customers add HAN devices in the Texas project. Account setup requires a Smart Meter Texas meter and ESI ID, so FortisBC could not test the functionality.

Slide 22 does show a reasonable HAN device overview screen, showing devices that are currently associated with the electricity account and a device history.

15.6.3 Does this mean, for the Texas projects, that the customer's own HAN is managed by the utility, with all the information of each device stored at the utility? Please discuss, including why this is necessary and the privacy considerations.

Response:

FortisBC cannot address how or where the information regarding HAN devices is stored for Smart Meter Texas.

Customers will be required to provide a unique identifier for their HAN devices to FortisBC (such as the MAC address of the device) so that FortisBC can associate that device with the electricity account and ensure data is exchanged with only that device.

Only information that is required to securely connect HAN devices to the AMI network will be collected from the customer, and only if the customer requests a HAN device to be connected.

15.6.4 Is FortisBC planning to incorporate the same HAN process as is used in the Texas example? If so, what measures is FortisBC planning to incorporate to address privacy considerations. If not, please describe how the FortisBC HAN process will be different.

Response:

The FortisBC HAN device registration process is not finalized, but will ensure customer privacy as required by the Personal Information and Privacy Act. Please also see the response to BCSEA IR No. 1 Q15.6.3.

15.6.5 Please comment on the proposition that if the customer had a gateway device, then only that device would need to be registered and the customer's other HAN products would be up to the customer to configure the customer's own HAN network and would not be registered at the utility? Please explain for both Texas and FortisBC.

Response:

FortisBC agrees that gateway devices such as those described in the response to BCUC IR No. 1 Q30.2.1 could allow customers to register only one ZigBee device with FortisBC and then connect other devices (on other networks) behind the gateway device. This should be possible in Texas as well as at FortisBC.

15.6.6 Is the Smart Meter the coordinator of the network for customer's HAN network? Please explain for both Texas and FortisBC, including the role and functions of the coordinator. Please discuss any limitations this might entail, including how many devices the coordinator can connect.

Response:

FortisBC expects AMI meters to be the ZigBee network coordinator controlling the formation and security of the ZigBee HAN network. FortisBC believes this to be the case in Texas as well.

The Zigbee addressing scheme is capable of supporting more than 64,000 nodes per network and multiple network coordinators can be linked together to support extremely large networks.

The Itron meter supports up to 10 registered HAN devices.

15.6.7 If a customer wishes to create his/her own HAN network with its own coordinator, (and not have the Smart Meter as coordinator but as an end device), is this possible? Please explain for both Texas and FortisBC.

Response:

It is technically possible in both jurisdictions. The customer's HAN device would need to both be a Zigbee end device (to connect to the meter) and a Zigbee server (to connect to the customer HAN network).

15.6.8 Please describe the type of messages that will be sent to the homes from FortisBC – are individual appliances given commands (e.g. adjust thermostat setpoints) or are more general commands given such as to reduce overall load?

Response:

FortisBC expects the AMI system to be able to send control messages (on/off, thermostat setpoints) to customer devices that are equipped to receive these commands.

These controllable devices incorporate settings that allow the customer to decide whether to accept signals from the utility or not.

FortisBC has no intention of sending control signals to customer devices for any reason. If customer demand warranted such a service, FortisBC would only send such control signals at the explicit request of a customer or as part of an approved rate structure.

15.6.9 Please confirm that commands that can be sent by FortisBC to the customer's IHD will require prior approval by the Commission such as by an approved rate structures.

Response:

Please see the response to BCSEA IR No. 1 Q15.6.8.

16.0 Topic: Hardware Requirements for SEP 2.0

From a design point of view, it is noted that “the code for a SEP1.x stack, . . . requires roughly 160 Kbytes of flash . . . plus 10-12 Kbytes worth of RAM.” [62]

For “running SEP2.0 . . . it may require as much as 256 Kbytes of flash and 24-32 Kbytes of RAM.” [63]

16.1 Are these estimates accurate regarding Itron’s solution?

Response:

Please refer to the response to BCSEA IR No. 1 Q16.4.

16.2 Since the Itron solution has both V1.1 and V2.0 SEP, will it require the combined capacity of both the V1.1 and V2.0 devices?

Response:

No. Please see the response to BCSEA IR1 Q1.2.

16.3 Commentator Lee Goldberg states that “. . . there is no firm consensus on what it will take. . . ” [64] for what is needed for devices to implement SEP 2.0. Does FortisBC agree? Please explain.

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[62] ZigBee’s Smart Energy 2.0 Profile Brings New Capabilities and Design Challenges, 3/7/2012, Lee Goldberg, Electronic Products; http://www.digikey.ca/ca/en/techzone/energy-harvesting/resources/articles/zigbees-smart-energy-20-profile.html

[63] ZigBee’s Smart Energy 2.0 Profile Brings New Capabilities and Design Challenges, 3/7/2012, Lee Goldberg, Electronic Products; http://www.digikey.ca/ca/en/techzone/energy-harvesting/resources/articles/zigbees-smart-energy-20-profile.html

[64] ZigBee’s Smart Energy 2.0 Profile Brings New Capabilities and Design Challenges, 3/7/2012, Lee Goldberg, Electronic Products; http://www.digikey.ca/ca/en/techzone/energy-harvesting/resources/articles/zigbees-smart-energy-20-profile.html

Response:

FortisBC agrees only because the SEP 2.0 standard is not yet complete. Once it is complete, FortisBC expects there to be firm consensus on what is needed to implement SEP 2.0.

16.4 Please discuss the level of confidence that FortisBC has that the Itron solution has adequately accommodated the needs for SEP 2.0.

Response:

FortisBC understands that Itron has adequately accommodated the needs for SEP 2.0.

16.5 It seems that the ZigBee is acting as the center control manager for all the HAN products, as shown in Figure 4[65]. Please discuss for the FortisBC implementation.

Response:

The AMI meter will be ZigBee Network Coordinator. This ensures that FortisBC can ensure that only devices that will not harm the meter and that will adequately secure customer data can be registered.

17.0 Topic: In-Home Displays

FortisBC includes a picture of a sample In-Home Display in its application[66]. Looking at the picture of the display, it is evident that the display shows present power ("right now"), energy profile in the past hours, and projected electricity bill.

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[65] ZigBee's Smart Energy 2.0 Profile Brings New Capabilities and Design Challenges, 3/7/2012, Lee Goldberg, Electronic Products; http://www.digikey.ca/ca/en/techzone/energy-harvesting/resources/articles/zigbees-smart-energy-20-profile.html

[66] Exhibit B-1, Section 4.1.1, Figure 4.1.1.a, Page

17.1 In the view of FortisBC, does this one screen meet the data information requirements for the Table 3.2.2a SMI Requirements? If not, please explain what other information needs to be displayed in order to meet the requirements.

Response:

FortisBC believes that the data show on the referenced picture would meet the requirements of the smart grid regulation.

17.2 How is the Projected Electrical Bill calculated?

Response:

FortisBC cannot comment how individual IHDs would calculate a Projected Electrical Bill. FortisBC notes that this capability is not a requirement of the smart grid regulation, which requires display of energy supplied and the cost of electricity measured, not predicted energy or costs.

18.0 FortisBC notes that the In-home display will be "purchased by customer with PowerSense incentive" [67].

18.1 What procedure will be necessary for a customer to connect their IHD to his or her IHD to the meter? How long will it take, how complex is the procedure and what support will be provided to the customer?

Response:

FortisBC expects the HAN device registration process to be quick and straightforward for the customer. Although FortisBC expects customers to be able to register their devices online, the Company also intends to provide basic support for the process through its Contact Centre. Please also see the response to BCSEA IR No. 1 Q15.6.4.

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[67] Exhibit B-6, BCUC IR #8.2 Response, Page 20, Line 9-10

18.2 Will there be any restrictions on which customers can connect?

Response:

FortisBC does not intend to restrict customers that accept an AMI meter from connecting ZigBee HAN devices to their meter.

18.3 Please estimate the time frame at which customers will be able to connect IHDs to the meter and discuss the factors which determine whether or not a customer can connect IHDs to the meter.

Response:

Please see the responses to BCUC IR No. 1 Q28.1.2 and BCSEA IR No. 1 Q18.2. In order for customers to be able to connect ZigBee HAN devices to their meter, the ZigBee radio signal from the meter must be sufficiently strong at the customer's ZigBee HAN device. Distance and physical obstructions will reduce the strength of the ZigBee signal. In cases where the ZigBee signal from the meter is too weak, ZigBee range extenders may be required.

19.0 The Advanced Metering Infrastructure (AMI) Future Program Study done by Navigant Consulting for FortisBC includes a description and picture of a Blue Line In-Home Display unit used for Hydro One[68] .

19.1 Navigant implies that The Energy Detective (TED) can track energy without a smart meter – can the Blue Line Innovations also track energy without a smart meter? Please explain the operation of these products.

Response:

[68] Exhibit B-1, Appendix C-1, Page 15 of 65 to Page 16 of 65

FortisBC is not an expert in the operation of Blue Line Innovations in-home displays that work without advanced meters. However, the Company understands that they work by placing a sensor on the customer's meter that reads the spinning disc (on electro-mechanical meter) or the optical port (on digital meters) and wirelessly transmits those pulses to a display device in the home in which the pulses are converted to energy consumption.

19.2 Can the Itron meters track energy and output to an In-Home Display as fast as products such as the TED and Blue Line Innovations? Please explain any performance that Itron meters (communicating with appropriate In-Home Display units) may lack including the speed of energy updates (e.g. how many seconds between energy updates) compared to these types of products.

Response:

There should be no significant difference in update speeds between non-ZigBee in-home display and ZigBee HAN enabled devices. In either case, FortisBC understands the units should update information no less than approximately every 30 seconds.

20.0 Topic: Measurement Canada Certified Meters

FortisBC states that in reference to a list of HAN alternatives, including LonWorks that: "None of the alternative protocols listed this question are available in Measurement Canada-certified meters." [69]

20.1 Please discuss any significant differences in Smart Meters approved for the United States and for Canada. How long does it typically take for a meter certified in the US to be certified by Measurement Canada?

Response:

In the US, each state has its own requirements stating which meters are approved for use. In Canada, this is controlled at a Federal level by Measurement Canada. The length of time to

[69] Exhibit B-6, BCUC IR #30.2, Page 48, Lines 10-22

receive Measurement Canada approval varies, with reported times from meter manufacturers ranging between 9 and 16 months.

20.2 Please list the number and suppliers of Measurement Canada certified meters with ZigBee versions 1.0.

Response:

FortisBC has identified five suppliers of Measurement Canada certified meters supporting Zigbee SEP 1.0: Elster, GE, Itron, Landis & Gyr, and Sensus.

20.3 Please list the number and suppliers of Measurement Canada certified meters with ZigBee versions 1.1.

Response:

Please see the response to BCSEA IR No. 1 Q20.2 above for the number and suppliers of Measurement Canada certified meters.

Within the industry, most vendors support ZigBee SEP 1.1 today. This is accomplished through a remote firmware update to the HAN communication board in the meter. However, in reviewing the Measurement Canada Notice of Approvals, it was not clear as to which vendors have migrated to ZigBee SEP 1.1 as the approvals just state ZigBee.

20.4 Please list the number and suppliers of Measurement Canada certified meters with ZigBee versions 2.0.

Response:

No vendors are Measurement Canada approved for ZigBee SEP 2.0 as they are waiting for the standard to reach final approval before presenting any required meter changes to Measurement Canada.

21.0 Topic: Collaboration Between FortisBC and BC Hydro

FortisBC discusses its collaboration with BC Hydro in various places in the application. In Section 8.2, FortisBC states:

"As part of the Company's AMI Project, FortisBC, FortisBC Energy (FEI) and BC Hydro initiated a process to review the opportunities and benefits of collaboration and coordination on Smart Meter (AMI) projects." [70]

21.1 Noting that this FortisBC AMI application followed BC Hydro's SMI Project, please discuss any improvements or changes that FortisBC made to its AMI project as a result of BC Hydro's experience with SMI.

Response:

FortisBC does not believe it made any material changes or improvements to its AMI project as a result of BC Hydro's experience with SMI. FortisBC expects future information related to best practices and any other information beneficial to both companies will be exchanged as required.

21.2 FortisBC states that "BC Hydro, FEI and FortisBC will continue to work together to ensure that in-home display devices will work for any of the three utilities." [71] Does this mean that all three utilities will have meters that will use ZigBee Smart Energy Profile V1.1 and Smart Energy Profile V2.0? If not, please explain.

Response:

The meters selected by BC Hydro and FortisBC will have the same capabilities, including their capability to operate with different versions of Smart Energy Profile.

21.3 Please describe the differences between the BC Hydro and FortisBC smart meters.

[70] Exhibit B-1, Section 8.2, Page 127, Line 1 to Page 129 Line 3
[71] Exhibit B-1, Section 8.2.3, Page 128, Lines 8-10

Response:

Please see the response to BCSEA IR No. 1 Q21.2.

22.0 Topic: Delay for SEP 2.0 Completion

Commentator Jeff St. John states that: "big utilities like California's Pacific Gas & Electric insist they want to wait until SEP2.0 is commercially available before they go full-bore into connecting smart meters to home area networks." [72]

22.1 In FortisBC's view is Mr. St. John's statement accurate?

Response:

FortisBC understands that all California utilities have implemented an SEP 1.x HAN solution as required by the CPUC.

22.2 Please discuss the advantages, disadvantages and consequences if the FortisBC AMI project was delayed until SEP2.0 was commercially available.

Response:

FortisBC believes that delaying the entire AMI project until SEP 2.0 availability is unnecessary. The Company plans to deploy a HAN solution until 2015, allowing time for SEP 2.0 finalization and evaluation.

22.3 Please discuss the advantages, disadvantages and consequences if the FortisBC AMI project was redesigned to support only SEP2.0 and not SEP 1.1.

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[72] "*Smart Grid Standards: SEP 1.0 vs 2.0 vs. the Proprietary Old School*", Jeff St. John, Aug 27, 2012; http://www.greentechmedia.com/articles/read/smart-grid-standards-sep-1.0-vs.-2.0-vs.-the-proprietary-old-school

Response:

Please see the response to BCSEA IR No. 1 Q1.7.

22.4 Please discuss the advantages, disadvantages and consequences if the FortisBC AMI project was redesigned to utilize other HAN solutions.

Response:

FortisBC believes that Zigbee is the best HAN solution given its relative market strength and strong vendor support for consumer devices. Please also see the response to BCUC IR No. 1 30.2.1.

22.5 Mr. John states that "some in the smart grid industry are worried that today's SEP1.x systems will have trouble upgrading to SE 2.0 when it rolls out over the next couple of years." [73] Does FortisBC share that view? Please explain what FortisBC is doing to overcome the potential concerns in the industry.

Response:

Please see the responses to BCSEA IR No. 1 Q13.5.2, Q13.5.3 and Q16.4. FortisBC does not intend to implement any solution that is not in the best interests of its customers.

[73] "*Smart Grid Standards: SEP 1.0 vs 2.0 vs. the Proprietary Old School*", Jeff St. John, Aug 27, 2012; http://www.greentechmedia.com/articles/read/smart-grid-standards-sep-1.0-vs.-2.0-vs.-the-proprietary-old-school

23.0 Topic: Pilot Testing

23.1 Does FortisBC plan pilot testing, such as BC Hydro's Conservation Research Initiative (CRI) pilots[74], for any part of the FortisBC AMI system? Please describe in detail.

Response:

FortisBC does not plan pilot testing for any part of the FortisBC AMI system. The conservation results from the BC Hydro CRI were considered in the Navigant study including as Exhibit B-1, Appendix C-1.

24.0 Topic: ZigBee Performance and Sealing of Meters

FortisBC states that the meters have "the addition of the ZigBee and LAN communications radios sealed inside the meter." [75]

24.1 Please describe the upgrade process across the FortisBC AMI system if a new version of ZigBee requires the ZigBee radio hardware to be upgraded.

Response:

New HAN firmware is "pushed out" to metering endpoint devices in groups. This process may take several days depending on the size of the group. Meters will send confirmation messages that the firmware upgrade has taken place successfully. In isolated cases some meters may not successfully upgrade, requiring a field visit to manually upgrade the meter using a field tool through the optical port on the meter.

24.2 Please describe the minimum and maximum distances for the ZigBee signals under a range of conditions, including walls and floors.

Response:

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[74] Exhibit B-1, BC Hydro Smart Meter Business Case, Appendix C-4, Page 25 and 26
[75] Exhibit B-1, Section 4.1.2, Page 46, Lines 10-11

The communication range is dependent on the environment in which the Zigbee devices are operating; however, there is indication that 100 meters of free space range is a reasonable expectation. Walls, floors and other physical obstructions (particularly if they are metallic) will reduce this distance.

24.3 How do ZigBee signals perform in apartment or similar situations where there may be longer distances from the meter to the In-Home Display and where there may be several walls or floors? Also, please describe how ZigBee performs in rural situations where the meter may be a significant distance from the premises or where there may be obstructions such as trees and hills?

Response:

ZigBee currently has challenges in an apartment environment or at long distances. There are vendors working on solutions and within future Zigbee specifications there is a design for a federated trust centre solution that would allow for meshing of meters with per suite security to address the apartment range challenges.

24.3.1 Are repeaters anticipated, and if so do they need to be powered?

Response:

The need for repeaters is implementation specific. If they are required, they need to be powered.

24.3.2 Does FortisBC guarantee a HAN signal all the way to inside the premises? If so, how is this determined or specified? What happens for sporadic errors? If not, who is responsible to get the signal from the meter to the premises and who pays if extra costs are incurred?

Response:

FortisBC does not guarantee that the HAN signal will communicate with customer devices or that communication will be error-free. The customer is responsible to get the signal to the location of their ZigBee devices.

24.3.3 Are other communication methods than ZigBee anticipated for the Meter to In-Home Displays for difficult situations? If so, please explain. Is powerline communications being considered?

Response:

Please see the response to BCSEA IR No. 1 Q24.3. FortisBC is not currently considering powerline communications as an alternative.

25.0 Topic: WAN

FortisBC states that for its WAN[76] it will use an "optimal combination" [77] of WAN technologies.

25.1 FortisBC estimates 136 collector locations to be used. What level of confidence does FortisBC have on this number? What are the factors which might change this number?

Response:

The RF LAN coverage and resulting collector locations were predicted using a computerized coverage model. The geographic locations of all FortisBC meter locations and other infrastructure were included as input parameters to this model. The exercise was completed in collaboration with the vendor, which has experience with similar deployments. FortisBC engineers helped ensure that local considerations and constraints were factored into the model.

FortisBC has reasonable confidence that the number of collector locations estimated in the preliminary network design is accurate, but is aware that the design is preliminary and that RF

[76] Exhibit B-1, Section 4.1.3, Page 46, Line 21 to Page 49, Line 10
[77] Exhibit B-1, Section 4.1.3, Page 46, Line 27

propagation studies are not exact. A contingency has been allowed for an increased number of collectors.

Factors which may cause the number of collectors in the final design to be increased or decrease slightly include:

- The addition of customers outside existing coverage areas;
- Suitability of the structures identified for mounting collector equipment;
- Better or worse RF propagation than predicted by the model.

25.2 If more collector locations or routers are required, or more expensive WAN techniques are needed, please describe how the extra costs will be handled. Does the budget include a contingency for such an eventuality?

Response:

The budget has included contingency for installation of additional collectors. However, as stated in BCSEA IR No. 1 Q25.1, FortisBC has confidence that the number of collectors deployed in the final design will be close to the number from the preliminary design that appears in the Application.

25.3 Please describe the over system performance in terms of characteristics such as speed, bandwidth, end-to-end latency, and reliability and how the use of different WAN technologies can affect that performance. Please also describe peak situations such as outages.

Response:

All proposed WAN backhaul technologies provide higher performance than required by the AMI system, including during outage conditions. This includes offered bandwidth, latency and reliability as the requirements of an AMI system are not stringent compared to current technology.

As discussed in Section 4.1.3 of the Application, the main factors driving technology choice for the WAN are services availability available and the capital and operating costs of these services.

26.0 Topic: IPv6 Stack

26.1 FortisBC states that for the LAN, "the network will use an IPv6 stack." [78] It is noted that FortisBC discussed IPV6 only within the section on Local Area Network. Please discuss the plans of FortisBC for IPV6 throughout all areas of the proposed AMI system.

Response:

As stated in Section 4.1.2 of the Application, IPv6 will be used in the RF Local Area Network. FortisBC has not completed a final design of the entire AMI system, but the preliminary design indicates that IPv6 will be used in the Home Area Network, RF Local Area Network and between the HES and MDMS. The Wide Area Network backhaul between the LAN and the HES is expected to use IPv4 technology due to the current unavailability of services or equipment based on IPv6.

27.0 Topic: PLC Alternative

27.1 FortisBC considered a number of project alternatives[79] to the FortisBC proposed system including status quo, AMR and Power Line Carrier (PLC). An Itron system PLC system was used for comparative purposes[80]. A range of BCUC IRs regarding the PLC system, including detailed pricing[81] were answered by FortisBC[82].

27.1.1 Please confirm that all comparison features and pricing for the PLC systems were based on one PLC system, the Itron system. If not, please explain.

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[78] Exhibit B-1, Section 4.1.2, Page 45, Line 30
[79] Exhibit B-1, Section 7.0, Page 105, Line 1 to Page 123 Line 6
[80] Exhibit B-1, Section 7.3, Page 111, Line 22 to Page 115 Line 7
[81] Exhibit B-6, BCUC IR #48, #96 and others
[82] Exhibit B-6

Response:

Comparison of features and pricing in Exhibit B-1 were based on the Itron PLC system. BCUC IR No. 1 Q106.5, Q113.1 and Q113.1.1-113.1.3 dealt with the cost and features of the FortisAlberta PLC system.

27.1.2 Please describe the PLC technology used for the Itron system, including its advantages and disadvantages. Please provide references for installations throughout North America.

Response:

Please refer to the response to BCUC IR No. 1 Q106.3 for a description of the Itron PLC system. The Itron PLC system has not been deployed to date in North America.

27.1.3 Would FortisBC agree that there is a wide variety of PLC systems in use, with a range of features and pricing; and that the Itron system is only one of those PLC systems. Please describe and compare other types of PLC systems.

Response:

FortisBC agrees that there is a wide variety of PLC systems available. FortisBC does not have extensive information regarding these PLC systems since it did not receive any RFP responses for them. However, FortisBC has limited information regarding the Itron and FortisAlberta PLC systems that it obtained after the first public AMI open houses. Costs and features of the Itron PLC system are described in Exhibit B-1 Section 7.3, and of the FortisAlberta PLC system in BCUC IR No. 1 Q106.5, Q113.1 and Q113.1.1-113.1.3.

28.0 Topic: Hybrid Systems

FortisBC states "On a net present value basis, FortisBC determined the cost of implementing a 100 percent PLC AMI solution in the FortisBC service territory would not be cost competitive relative to the proposed AMI project. Given the cost comparison, the 100 percent PLC option was eliminated from further consideration." [83]

In answer to a BCUC IR about hybrid systems, FortisBC states: "FortisBC assumed vendors would propose hybrid alternatives in optimizing their responses to the RFP." [84]

28.1 Please comment on the viability of a hybrid system.

Response:

FortisBC is not aware of any hybrid (PLC/RF) systems in North America. It is aware of some utilities that have incorporated more than one type of RF solution.

FortisBC believes that a hybrid system is viable, particularly if the solution:

- Provides comparable capabilities to the proposed RF mesh system, particularly with respect to hourly readings; and
- Provides the ability to integrate feeder meters.

The above capabilities are most critical to benefit realization, although the lack of ZigBee and remote disconnects are also important.

If a hybrid solution required a significant additional investment in head-end software or security layers, the viability could be impacted.

28.2 Please provide references to hybrid systems in North America.

Response:

Please also refer to the response to BCSEA IR No. 1 Q28.1 and BCUC IR No. 1 Q106.1.

[83] Exhibit B-1, Section 7.3, Page 114, Line 13 to Page 115, Line 2
[84] Exhibit B-6, BCUC IR #106.1, Page 246, Lines 1-18

28.3 As a reason for eliminating the PLC option, FortisBC states that "it is not consistent with the metering system and services deployed to 1.8 million BC Hydro electricity customers" [85]..

28.3.1 Please explain in detail what FortisBC means by "consistent".

Response:

"Consistent" in this context means "capable of delivering the same advanced metering benefits to customers throughout the province".

28.3.2 Does FortisBC believe it is restricted in its metering system and services because of the selection by BC Hydro?

Response:

FortisBC does not believe it is restricted in its metering system and services because of the selection by BC Hydro. However, as discussed in Section 8.0 of the Application, it is important to note that FortisBC's proposed AMI Project will ensure that the Company is able to provide consistent provincial AMI benefits to customers, including the ability for customers to access detailed consumption information, as well as consistent support for in-home displays.

28.3.3 Does FortisBC believe that it cannot choose a PLC system because BC Hydro chose an RF system?

Response:

No.

[85] Exhibit B-1, Section 7.3, Page 115, Lines 4-5

29.0 Topic: Support for Gas and Water Meters

In this present AMI application, FortisBC notes that:

"Further, the AMI system proposed is capable of supporting gas and water meters within the Company's service area, which may create revenue opportunities for the utility and its customers in the future as explained in section 8.3" [86]

29.1 Please describe at a high level what plans FortisBC has to integrated gas and water meter reading with the AMI system, any discussions Fortis has had with gas and water utilities in this regard and relevant time-lines.

Response:

FortisBC does not have any plans to integrate gas and water meter reading at this time. FortisBC Energy Inc. (the gas utility) is still evaluating AMR and AMI options, with consideration given to the electric AMI systems being installed and contemplated in the province. No timelines have been set.

Utility collaboration discussions are summarized in Section 8.2 of Exhibit B-1.

29.2 Within the referenced section 8.3[87] of Exhibit B-1, it was not clear how the benefits would transfer to the customers. Please clarify and expand on how the proposed FortisBC implementation for the present AMI application will be "to the benefit the utility customers within the FortisBC franchise and the broader public interest across the Province." [88]

Response:

If FortisBC agreed to share the proposed FortisBC AMI system, it expected that the customers of all utilities would benefit. FortisBC would only enter a sharing arrangement with other utilities if the arrangement was beneficial to its customers (and assumes that the partner utilities would apply the same principle).

[86] Exhibit B-1, Section 4.1, Page 42, Lines 2-5
[87] Exhibit B-1, Section 8.3, Page 130, Lines 4-25
[88] Order G-168-08, Section 4.5, page 15, last paragraph.

30.0 Topic: Theft reduction

Reference: Exhibit B-1, section 5.3 Financial benefits; Exhibit B-6, Table BCUC IR1 Q15.1 – Ranking of Customer Benefits, pdf p.30 of 519

Table BCUC IR1 Q15.1 – Ranking of Customer Benefits has a note stating "NPV of avoided capital costs, not NPV of revenue requirement."

30.1 Please explain what "NPV of avoided capital costs, not NPV of revenue requirement" means in this context.

Response:

The note is intended to reflect that the net present values provided for the Avoided Measurement Canada compliance costs represent the avoided capital costs, and not the avoided revenue requirement which would otherwise have to be collected from customers. FortisBC notes that the financial analysis model does convert the avoided capital costs to avoided revenue requirement, which is reflected on rows 2-4 of the Excel spreadsheet attached as part of Exhibit B-3. As per Errata 1, the reduction in the revenue requirement due to the AMI Project has an NPV of approximately $17.6 million as determined over the 20 year project analysis period based on an 8 percent discount rate.

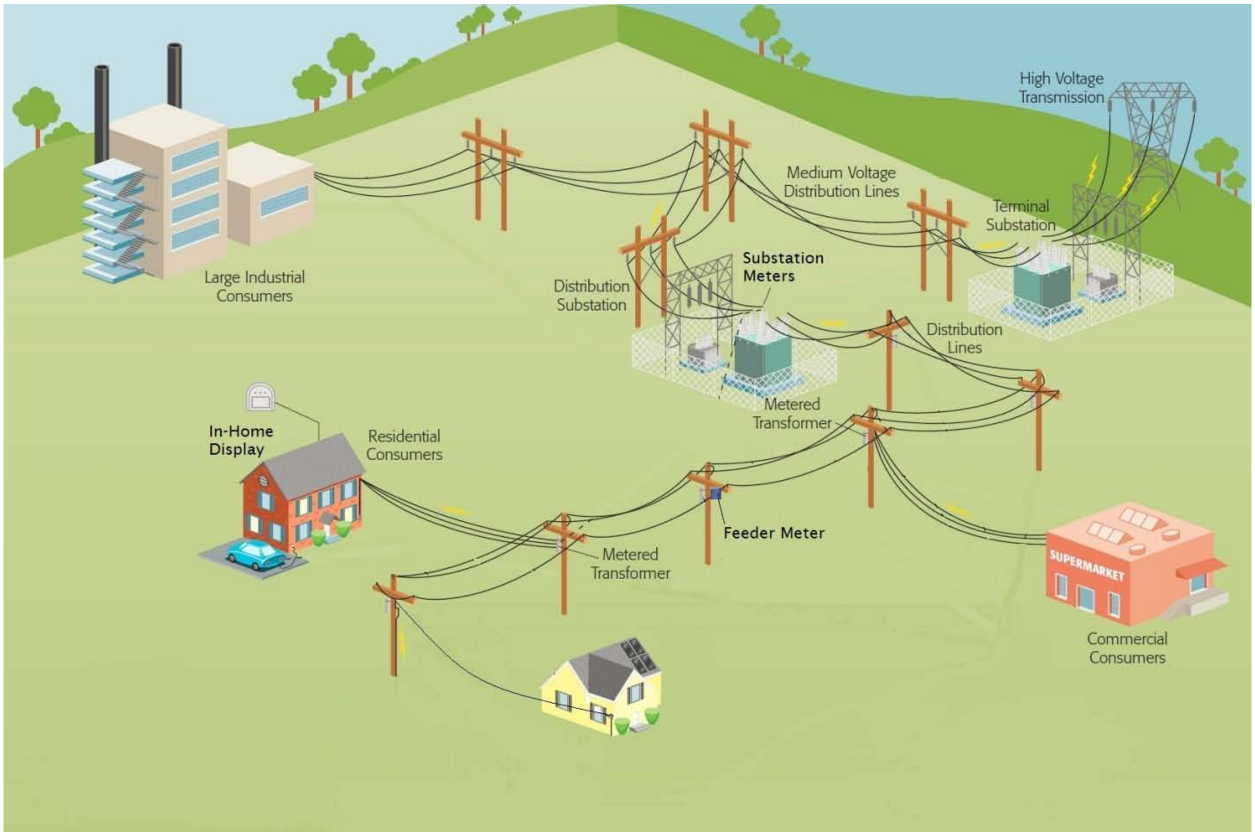
31.0 Topic: Theft Reduction

Reference: Exhibit B-1, section 5.3.2, page 88: "Based on the data supplied by the feeder meters, AMI connected transformer meters can be strategically deployed downstream to effectively balance the energy inventory in targeted areas of the feeder."

31.1 Please provide a diagram showing feeder, transformer, portable wireless meters and in-home meters, showing how they would be deployed in a typical situation.

Response:

The diagram below shows feeder meters and metered transformers deployed in a typical situation. The location of portable meters would be similar to feeder meters.



31.2 Are the feeder meters and AMI-connected transformer meters typically permanently installed?

Response:

Feeder meters at the substations are permanently installed while transformer meters are temporary devices that can be redeployed depending on which section of a feeder is under review. Please refer to the responses to BCUC IR No. 1 Q54.1, CEC IR No. 1 Q77.2 and CEC IR No. 1 Q20.1.

31.3 Is the detection of theft the only purpose of energy balancing in this context?

Response:

Theft detection is the primary focus of energy balancing in the context under discussion; however energy balancing will also enable the detection and analysis of commercial and technical system losses which ultimately reduces power purchase costs and customer rates. Please refer to the response to BCUC IR No. 1 Q78.3.2, CEC IR No. 1 Q77.2, CEC IR No. 1 Q20.1 and Q20.2.

32.0 Topic: Theft Reduction

Reference: Exhibit B-6, response to BCUC IR 87.2, lines 24-25: "Easton reports that 13 percent of operators detected by the police in BC faced criminal charges compared to 60 percent in the rest of the country."

32.1 Please discuss the implications to the NPV of the AMI program if the rate of charges brought against detected operators in BC were to approach the 60% average of the rest of the country within, say, ten years.

Response:

Please note a correction in lines 24-25 of the FortisBC response to BCUC IR No. 1 Q87.2. These figures apply to marijuana users versus producers. The correct figures are 27 percent of BC cultivators detected by the law enforcement face criminal charges versus 37 percent in the rest of the country. FortisBC does not consider this a likely development as an increase in criminal charges will require additional law enforcement and court resources.

However should this scenario develop, the risk of operating will increase for marijuana producers; and as all other conditions remain constant (i.e. market demand and product price), they will be further motivated to avoid detection through energy theft. The theft ratio will increase under the Status Quo and the paying ratio under AMI will decline. The financial impact on the NPV of the net benefit related to theft reduction will be similar to the scenario presented in the response to BCUC IR No. 1 Q87.2.3 which is an increase to $48.5 million.

33.0 Topic: Theft detection

Reference: Exhibit B-1, section 5.3.2, page 83, lines 19-20: "… the current deterrence benefit will drop from 75 percent in 2012 to 70 percent by 2017."; Tables 5.3.2.b and 5.3.2.c; page 84, line 6; page 89, line 11.

33.1 Please describe how Fortis determined the numeric values for the deterrence benefits.

Response:

The numeric value for theft deterrence is calculated as (1 - the estimated theft ratio of 25 percent) for 2012. It is based on FortisBC experience under the current program. The decline to 70 percent by 2017 in the absence of AMI deployment at FortisBC is estimated at 1 percent per year to reflect the assumption that producers will move from BC Hydro to FortisBC with the intent to steal electricity. Deterrence under AMI is estimated to increase from 70 percent to 84 percent by 2016 as the presence of advanced meters in conjunction with energy balancing will increase the risk of detection for those who wish to steal. Please see also the responses to BCUC IR No. 1 Q87.1, CEC IR No. 1 Q80.1 and Q80.2.

33.2 How does Fortis evaluate the probabilities for the values it uses for deterrence benefits?

Response:

FortisBC did not evaluate probabilities for the deterrence values however, supplemental analyses were completed which produced High and Low Range estimates in addition to the Probable and Potential presented in the Project. Please refer to Table 5.3.2.d on page 87 of the Application.

34.0 Topic: Theft detection

Reference: Exhibit B-1, section 5.3.2, pages 84 and 86, Tables 5.3.2.b and 5.3.2.c

34.1 For clarity, does "deterrence" in this context mean that the parties in question have chosen to pay for the electricity they consume, rather than stealing it, i.e. as opposed to being deterred from illegally growing marijuana?

Response:

"Deterrence" in both tables refers to the percentage of the estimated indoor marijuana producers who are paying for electricity used in production.

34.2 Please confirm that "Total sites" means the total of sites in the Fortis service area that are estimated to have grow-ops.

Response:

"Total sites" is the estimated number of indoor marijuana producers in the FortisBC service area that consume electricity.

34.3 Please confirm that "Total paying sites" means the number of grow-op sites in the Fortis service area that are estimated, based on the estimated "deterrence" ratio, to pay for their electricity, rather than stealing it.

Response:

"Total paying sites" is the calculated number of indoor marijuana producers in the FortisBC service area that pay for the electricity consumed in marijuana production. Specific detail on the calculations in Tables 5.3.2b and 5.3.2c are provided in the four tables which follow.

1 **Table BCSEA IR1 Q34.3a - Status Quo-Probable**

Line	Input	Assumption
A	Marginal Revenue	FortisBC Residential Tariff Forecast (Tier 2)
B	Marginal Cost	BC Wholesale Energy Market Forecast
C	Marginal Revenue Margin	(A-C)
D	Deterrence (% paying sites)	Deterrence ratio will decline from current 75% to 70% by 2017 without AMI and remain at 70% thereafter.
E	Investigation success	The investigation success rate will remain at 8% as leads will not increase.
F	Total sites	Total sites are 6 % of the total estimated provincially. This number is inflated by 2% per year to reflect estimated customer growth.
G	Total paying sites	Total paying sites are the net of theft sites and total sites 2013- 2017 and 70% of the total sites thereafter.
H	Total theft sites	Total theft sites increase by 75% of the growth in total sites 2013-2017 and 30% of total sites thereafter.
I	Identified theft sites	Identified theft sites are calculated as ((E*F*(1-D)) from 2012-2032.
J	Revenue Margin paying sites	Revenue Margin from paying sites is calculated for each year as (C*G*151,200kWh)/1000)
H	Power purchase cost of theft sites	Power purchase costs of theft sites is calculated for each year as (B*H*151,200kWhs/1000)
I	Recovered revenue from theft identification	Recovered revenue for theft sites is calculated each year as (I*A*151,200kWhs/1000) +20% This assumes that each theft site is billed for an average 1 year loss and collection success is 20% likely.
J	Total Benefit/(cost) of Status Quo Scenario	The benefit(cost) is calculated for each year as J-H+I
K	NPV of the Total Benefit for the Status Quo-Probable	The NPV is calculated as the sum of J for 2012-2032 discounted at 8%

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Table BCSEA IR1 Q34.3b - AMI Program-Probable

Line	Input	Assumption
A	Deterrence (% paying sites)	Deterrence ratio will increase from the current 75% to 95% by 2021 with AMI and remain at 95% thereafter.
B	Investigation success	The investigation success rate will increase from 8% to 25% by 2016 and remain at 25% thereafter.
C	Total sites	Total sites are 6 % of the total estimated provincially. This number is inflated by 1% per year to reflect the net of estimated customer growth at 2% and growers who may move to alternate energy sources or leave FortisBC altogether with AMI.
D	Total paying sites	Total paying sites are the net of theft sites and total sites 2013- 2020 and 95% of the total sites thereafter.
E	Total theft sites	Total theft sites are the previous year's total less 90% of the sites which were detected in for 2013-2020 and 5% of total sites thereafter. The assumption is that 90% of detected sites will become paying customers.
F	Identified theft sites	Identified theft sites are calculated as ((B*C*(1-A)) from 2012-2032.
G	Revenue Margin paying sites	Revenue Margin from paying sites is calculated for each year as(Marginal Revenue *D*151,200kWh)/1000)
H	Power purchase cost of theft sites	Power purchase costs of theft sites is calculated for each year as (Marginal Cost*E*B*151,200kWhs/1000)
I	Recovered revenue from theft identification	Recovered revenue for theft sites is calculated each year as (F*Marginal Revenue*151,200kWhs/1000) +20% This assumes that each theft site is billed for an average 1 year loss and collection success is 20% likely.
J	Total Benefit/(cost) of AMI -Probable	The benefit(cost) is calculated for each year as G-H+I
K	NPV of the Total Benefit for the AMI Program-Probable	The NPV is calculated as the sum of J for 2012-2032 discounted at 8%
L	NPV of Net Benefit	The sum of the annual differences between the NPV Total Benefit for AMI-Probable and Status Quo-Probable for 2012-2032 discounted at 8%.

Table BCEA IR1 Q34.3c - Status Quo-Potential

Line	Input	Assumption
A	Marginal Revenue	FortisBC Residential Tariff Forecast (Tier 2)
B	Marginal Cost	BC Wholesale Energy Market Forecast
C	Marginal Revenue Margin	(A-C)
D	Deterrence (% paying sites)	Deterrence ratio will decline from current 75% to 68% by 2017 without AMI and remain at 68% thereafter.
E	Investigation success	The investigation success rate will remain at 8% as leads will not increase.
F	Total sites	Total sites are 6 % of the total estimated provincially. This number is inflated by 3% per year 2013-2017 and by 2% per year thereafter to reflect estimated customer growth.
G	Total paying sites	Total paying sites are the net of theft sites and total sites 2013- 2020 and 68% of the total sites thereafter.
H	Total theft sites	Total theft sites increase by 75% of the growth in total sites 2013-2017 and 32% of total sites thereafter.
I	Identified theft sites	Identified theft sites are calculated as ((E*F*(1-D)) from 2012-2032.
J	Revenue Margin paying sites	Revenue Margin from paying sites is calculated for each year as (C*G*181,440kWh)/1000)
H	Power purchase cost of theft sites	Power purchase costs of theft sites is calculated for each year as (B*H*181,440kWhs/1000)
I	Recovered revenue from theft identification	Recovered revenue for theft sites is calculated each year as (I*A*181,440kWhs/1000) +20% This assumes that each theft site is billed for an average 1 year loss and collection success is 20% likely.
J	Total Benefit/(cost) of Status Quo Scenario	The benefit(cost) is calculated for each year as J-H+I
K	NPV of the Total Benefit for the Status Quo-Potential	The NPV is calculated as the sum of J for 2012-2032 discounted at 8%

Table BCSEA IR1 Q34.3d- AMI Program-Potential

Line	Input	Assumption
A	Deterrence (% paying sites)	Deterrence ratio will increase from the current 75% to 100% by 2030 with AMI and remain at 100% thereafter.
B	Investigation success	The investigation success rate will increase from 8% to 25% by 2016 and remain at 25% thereafter.
C	Total sites	Total sites are 6 % of the total estimated provincially. This number is inflated by 1% per year to reflect the net of estimated customer growth and growers who may move to alternate energy sources or leave FortisBC altogether with AMI.
D	Total paying sites	Total paying sites are the net of theft sites and total sites 2013- 2032.
E	Total theft sites	Total theft sites are the previous year's total less 90% of the sites which were detected for 2013-2032. The assumption is that 90% of detected sites will become paying customers.
F	Identified theft sites	Identified theft sites are calculated as ((B*C*(1-A)) from 2012-2032.
G	Revenue Margin paying sites	Revenue Margin from paying sites is calculated for each year as(Marginal Revenue *D*181,440kWh)/1000)
H	Power purchase cost of theft sites	Power purchase costs of theft sites is calculated for each year as (Marginal Cost*E*B*181,440kWhs/1000)
I	Recovered revenue from theft identification	Recovered revenue for theft sites is calculated each year as (F*Marginal Revenue*181,440kWhs/1000) +20% This assumes that each theft site is billed for an average 1 year loss and collection success is 20% likely.
J	Total Benefit/(cost) of AMI -Probable	The benefit(cost) is calculated for each year as G-H+I
K	NPV of the Total Benefit for the AMI Program-Potential	The NPV is calculated as the sum of J for 2012-2032 discounted at 8%
L	NPV of Net Benefit	The sum of the annual differences between the NPV Total Benefit for AMI-Potential and Status Quo-Potential for 2012-2032 discounted at 8%.

34.4 Please confirm that "Total theft sites" means the number of grow-op sites in the Fortis service area that are estimated, based on the estimated "deterrence" ration, to steal all (or most of) the electricity they use.

Response:

"Total theft sites" are the calculated number of indoor marijuana producers in the FortisBC service area that are diverting the electricity consumed by the operation. Please refer to the response to BCSEA IR No. 1 Q34.3 for specific detail on the calculation.

34.5 Please provide the calculation used to derive the "NPV of Net Benefit" figure at the bottom of each table.

Response:

The requested calculation for Table 5.3.2.b is provided as part of Exhibit B-3. Please refer to Section 5.3.2 of the Application for detail regarding the change in assumptions for the AMI potential scenario as compared to the AMI probable scenario.

34.6 Please provide the calculation for "Recovered revenue from theft identification."

Response:

Please see the responses to BCSEA IR No. 1 Q34.3, and BCUC IR No. 1 Q87.1.2.

35.0 Topic: Theft detection: alternative energy sources

Reference: Exhibit B-1, section 5.3.2, page 83, lines 30-32; "It is expected that with an AMI-enabled theft detection program, marijuana grow operators may choose to switch to alternate energy sources rather than pay for electricity."; and Exhibit B-6, response to BCUC IR 87.2.5; Exhibit B-1, section 3.2.5, page 38, Reduced GHG Emissions.

35.1 Please confirm that the "alternative energy sources" Fortis expects grow operators to switch to are fossil fuel powered generators. If not, please explain and discuss.

Response:

Confirmed.

35.2 For each year of the AMI program life, please provide Fortis's estimate of the quantity of greenhouse gas emissions that would result from the use of alternative energy sources.

Response:

Please refer to the response to BCSEA IR No. 1 Q35.3.

35.3 Has Fortis factored greenhouse gas emissions from alternative energy sources used by grow operators into its estimate of the greenhouse gas emissions effects of the AMI program?

Response:

The Company is unable to speculate on what proportion of marijuana grow operators who elect to discontinue service with FortisBC will choose to remain in operation using alternative energy sources as compared to simply relocating to another jurisdiction.

36.0 Topic: Meter technology upgrades

Reference: Exhibit B-6, BCUC IR 1.2

"...Itron CENTRON OpenWay meters are designed to have a service life of 20 years."

36.1 Does FBC agree that smart meter software expectations and opportunities will evolve significantly over the 20-year design service life of the proposed meters?

Response:

FortisBC believes that the expectations from advanced metering systems will remain relatively consistent over the life of the meter. The metering system will be expected to continue reading consumption, supporting time-based rates, connecting and disconnecting services and interfacing with HAN devices.

The Itron meters can have their firmware upgraded remotely, so functionality can be modified and enhanced within the hardware limitations of the meter. Already, that firmware upgradeability is expected to enhance the meters with the ability to remotely sense temperature and disconnect service, for example.

Expectations from the LAN are more likely to increase over time as more devices are added to the system to support smart grid applications. As long as the LAN remains compatible with the meters over the life of the system, there are opportunities to improve the LAN and WAN networking capabilities while allowing the meters to continue operating.

36.2 Is the software in the proposed Itron CENTRON OpenWay meters capable of being updated remotely, i.e., without opening the meters?

Response:

Please see the response to BCSEA IR No. 1 Q36.1.

37.0 Topic: Tracking original meter manufacturing dates

Reference: Exhibit B-6, BCUC IR 6.2; BCUC IR 6.3

FBC does not track original meter manufacturing dates for its meter population therefore the average age of the approximately 80,000 mechanical meters [IR 6.2] and 35,000 digital meters [IR 6.3] is not available.

37.1 Does FBC intend to track original meter manufacturing dates and internal hardware and software versions for the proposed smart meters?

Response:

Yes.

37.2 If not, will FBC be able to implement batch software updates?

Response:

Please see the response for BCSEA IR No. 1 Q37.1.

38.0 Topic: Net metering

Reference: Exhibit B-1, Table 4.2.a - Business Use Cases for Advanced Metering System, C2 Customer billed on net metering tariff; Exhibit B-6, BCUC IR 18.3

BCUC IR 18.3 "Do the residential advanced meters proposed by FortisBC have the ability to meter both import and export power? If yes, what is the incremental cost of including this functionality within each meter? If no, please explain why not.

Response:

Yes, all Itron OpenWay meters are equipped with net metering capabilities at no additional cost."

38.1 With the AMI in place, will net metering customers be able to see both production (as well as consumption) of electricity and the corresponding credit (as well as charge) on the Customer Information Portal? On an In-Home Device?

Response:

Net metering customers will be able to view the information provided by the Itron OpenWay meters through the Customer Information Portal. This information will reflect the net consumption and net generation as well as the cost or credits associated with each value.

In-Home Devices are a fairly new and emerging technology, with a variety of makes and models. The visibility of net metering functionality will be highly dependent on the type and capabilities of the In-Home Device that the customer chooses to use.

39.0 Topic: Future benefits

Reference: Exhibit B-1, section 6.0 Future Benefits; Table 5.3.2b Probable AMI Forecast

Table 5.3.2b Probable AMI Forecast shows a "Marginal Revenue Margin" of $65.35/MWh for 2012, and escalating annually to 2016. Section 6 Future Benefits discusses several types of future benefits enabled by the AMI Project, including Distribution Loss Reduction, Power Grid Voltage Optimization, Outage Management, Customer Pre-Pay Tariff, Future Conservation Rate Structures. These are "subject to potential additional capital expenditure." [p.97]

39.1 Is FortisBC's substantial positive Marginal Revenue Margin an impediment to future implementation of future benefits of the AMI Project discussed in section 6?

Response:

The current positive Marginal Revenue Margin may impact future projects that result in energy conservation such as Distribution Loss Reduction and Power Grid Voltage Optimization. Any implementation of future projects such as those identified in the preamble above would be the subject of a separate application which would include the Company's assessment of the project's cost-effectiveness and whether or not the project is in the best interests of customers.

40.0 Topic: Weather information on IHD

Reference: Exhibit B-6, BCUC IR 8.1.2

"The Itron Customer Care applications, that form part of the AMI project, trend temperature delivered from a variety of weather feeds against meter data. FortisBC intends to subscribe to live hourly weather feeds at several locations throughout its service territory at a cost of less than $3,000 annually in order to provide this information to customers."

40.1 Will customers who access electricity consumption information through an In Home Display (IHD), as distinct from the Customer Internet Portal (CIP), be able to see consumption data displayed with the weather data, as on the CIP?

Response:

FortisBC is not currently planning to transmit temperature information to the IHD, although dependent on the IHD selected it may obtain weather feeds from other sources such as the Internet.

41.0 Topic: Smart Grid

Reference: Exhibit B-6, Table BCUC IR1 Q12.3 – Smart Grid Vision.

41.1 Please add a column to Table BCUC IR1 Q12.3 indicating what if any changes would be required to implement each component, such as hardware in meter, firmware update in meter, communications infrastructure upgrade, MDMS system upgrade, or other.

Response:

None of the smart grid components described in Table BCUC IR1 Q12.3 would require direct changes or upgrades to the software or hardware systems proposed to be installed as part of the AMI Project. Instead, the future components would add additional hardware or software systems that would communicate with the AMI system through established software protocols. For example, the future addition of an Outage Management System (OMS) would use existing outage data contained within the AMI system. The OMS would interface to either the HES or MDMS as necessary using standard software interfaces to extract the needed outage data. An additional example would be the future addition of distribution automation: while this would require additional power system infrastructure (switching or metering devices), these devices would interface to the AMI wireless communications network using standard hardware/software interfaces.

42.0 Topic: Conservation benefits

Reference: Exhibit B-1, section 3.2.5 Non-financial customer service and operational benefits; Exhibit B-6, Table BCUC IR Q16.1 Residential CIP Savings.

"...By its design, the RIB rate only results in bill reductions for customers that are able to reduce their overall consumption. The availability of information to customers regarding their level of consumption in relation to the RIB threshold in any particular billing period will be enhanced by AMI." [p.31]

Table BCUC IR Q16.1 shows corrected customer information portal savings, by year, and the dollar value of each.

42.1 Are the figures in Table BCUC IR Q16.1 based on the Forecast Adoption Rate for CIP shown in BCUC IR 8.2? Please describe the source and assumptions behind the data.

Response:

Yes, the figures in BCUC IR No. 1 Q16.1 are based on the Forecast Adoption Rate for the CIP shown in BCUC IR No. 1 Q8.2. FortisBC assumed a linear increase in adoption between 2015 and 2032.

Please refer to the response to BCSEA IR No. 1 Q15.3 for the source and assumption behind the 30% adoption rate.

42.2 Please provide a table similar to Table BCUC IR Q16.1 showing electricity and cost savings attributable to In-Home Displays.

Response:

The savings from IHDs results from reaching the 30% adoption rate explained in the response to BCSEA IR No. 1 Q15.3 and the 5.4% savings rate (Exhibit B-1, p44).

Residential IHD Savings (MWh)		
Year	IHD Gross Savings	Value @$85 MWh
2014	150	$ 12,700
2015	500	$ 42,500
2016	1,100	$ 93,400
2017	2,100	$ 178,400
2018	3,700	$ 314,300
2019	6,600	$ 560,600
2020	10,200	$ 866,400
2021	13,800	$ 1,172,200
2022	17,100	$ 1,452,500
2023	16,400	$ 1,390,000
2024	16,400	$ 1,390,000
2025	16,400	$ 1,390,000
2026	16,400	$ 1,390,000
2027	16,400	$ 1,390,000
2028	16,400	$ 1,390,000
2029	16,400	$ 1,390,000
2030	16,400	$ 1,390,000
2031	16,400	$ 1,390,000
2032	16,400	$ 1,390,000
		$ 18,593,000

43.0 Topic: Conservation Benefits

Reference: Exhibit B-1, section 3.2.1, page 19, lines 20-21: "This information will help customers make decisions regarding their energy consumption relative to their personal needs."

43.1 What energy conservation savings does Fortis believe are achievable through the provision of in-home energy consumption information? Would the savings be predominantly behavioural? Please discuss.

<u>Response:</u>

The IHD savings stream shown in the response to BCSEA IR No. 1 Q42.2 above, are predominantly behavioural in nature i.e. customers modifying their energy usage patterns in response to the informational feedback provided through the IHD.

For example: the approximately 6 kW spike caused by starting their (electric) clothes dryer could prompt some customers to use their clothesline instead. Another example: if the IHD model chosen provides a signal that the customer's usage for the month to-date has exceeded the Tier 1 allowance, the customer might respond to the Tier 2 conservation price signal by seeking out opportunities to reduce unnecessary consumption.

43.2 Has Fortis researched the experience of other jurisdictions in this regard? What did it find?

Response:

FortisBC believes the March 2011 Navigant Consulting report was a reasonably thorough review of AMI-enabled program effects.

43.3 Does Fortis plan any programs to engage its customers in energy conservation supported by the use of in-home energy consumption information?

Response:

FortisBC will implement several energy conservation education and customer-empowerment initiatives once the AMI meters are operational, including:

- a free account online customer information portal that allows customers to track daily energy usage and receive alerts, by email or text, if their usage exceeds a self-identified threshold
- an incentive for customers to purchase and use IHD (in-home displays) that display real-time usage information, including current rates charged, which helps the customer budget usage and makes them aware of consumption habits.
- An education program, which would leverage existing face-to-face information sessions, web site information, newsletters, brochures, advertising and public relations explaining how AMI aids conservation efforts. On-line contests and pledges might also be deployed to garner customers' attention and commitment to voluntarily reduce energy use.

44.0 Topic: Conservation Benefits

Reference: Exhibit B-1, section 6.5.

44.1 Please confirm that Fortis does not rely on the cost savings from any conservation measures in its business case for the AMI program.

Response:

Confirmed.

44.2 Does Fortis believe that time-of-use rates, critical peak pricing and pre-payment are the only energy conservation measures that would be supported or enabled by the AMI program? Please discuss.

Response:

No, FortisBC believes that HAN-enabled devices such as in-home displays and "smart appliances" could also help consumers reduce energy consumption. In the future, AMI enabled "smart grid" applications such as distribution loss reduction and power grid voltage optimization also have the potential to help conserve energy.

44.3 Please discuss the proposition that time-of-use pricing and critical peak pricing mainly shift load, rather than reducing it. Please confirm that the savings shown in Table 6.5.a are intended to represent genuine savings of energy, i.e. as opposed to shifted loads. Please discuss how these estimates were derived.

Response:

As the referenced Table 6.5.a and Table ES-1 (Exhibit B-1, Appendix C-1, p8) show, TOU and CPP rates both shift and reduce load. This is because load reductions made at a particular point in time due to a higher time-based rate will not necessarily require replacement energy later. For example, if a customer turns off a light bulb or reduces heating during a peak period, they would not generally require incrementally more lighting or heat once the peak period is over.

44.4 Please discuss the commitment for "submission of a regulatory application in 2016 or later." Would Fortis be willing to commit to an earlier time-line? Why or why not?

Response:

FortisBC believes that 2016 is a reasonable target date that allows for more AMI-enabled load data to be collected and the activities listed at Exhibit B-1, p104 to be completed.

44.5 How does the 2016 date relate to Fortis's long-term energy planning work and its regulatory filings of long-term resource plans, DSM expenditure schedules and other filings?

Response:

The 2016 date for possible conservation rate filings does not relate directly to Fortis's long-term energy planning work and its regulatory filings of long-term resource plans or DSM expenditure schedules. There is limited interdependence between these filings, although conservation rates could impact the timing of specific initiatives within them. Please also see the response to BCSEA IR No. 1 Q44.6.

44.6 How does the AMI program relate to Fortis's existing energy conservation and efficiency programs and plans?

Response:

Conservation rate structures enabled by AMI have the potential to increase the participation rate in FortisBC demand-side management programs.

44.7 Would the AMI program help or enable the integration of energy efficiency and conservation programs between Fortis's gas and electricity services? Please discuss.

Response:

AMI is not anticipated to provide any immediate benefit with respect to the integration of the Company's gas and electricity efficiency and conservation programs. Despite this, it is conceivable that the improved level of electric consumption information that will be available with AMI will assist the Company in designing future combined efficiency and conservation programs for combined gas/electric customers.

45.0 Topic: In-Home Display and Customer Information Portal

Reference: Exhibit B-6, BCUC IR 8.2

"FortisBC has rated customer demand for IHD and portal features on a scale of 1 to 10 based on the forecast adoption rates.

IHD/Portal Feature	Forecast Adoption Rate	Demand (1-low, 10-high)
Pre-pay	3-8%	1
In-home display (purchased by customer with PowerSense incentive)	30%	3
Use of customer portal to monitor consumption	15%	2

45.1 What is the source of the data in BCUC IR 8.2? Please provide a copy of the applicable report.

Response:

The source of the forecast adoption rate data is Exhibit B-1, Appendix C-1, Table ES-2 and Exhibit B-1, Appendix C-4, p31.

45.2 How does the data in this table compare to the results found by other utilities?

Response:

FortisBC is not aware of actual results from other utilities. These numbers are derived in part from pilot studies referenced in the Navigant report in Exhibit B-1, Appendix C-1. There are very few utilities that have offered these features in a broad deployment for a sufficient period to evaluate the long-term adoption rate.

45.3 What is the definition of “Forecast Adoption Rate”?

Response:

The forecast adoption rate is the proportion of residential customers that take advantage of the applicable IHD/portal feature.

45.4 In BCUC IR 30.3, FortisBC says “30 percent penetration of IHDs is expected to occur between 2015 and 2020 (assuming BCUC approval of the AMI Project is received by July 20, 2013).” Does that apply to the data in the table in BCUC IR 8.2?

Response:

Yes.

45.5 Is the figure of 15% for Forecast Adoption Rate for Use of CIP to monitor consumption also based on the same time period of 2015 to 2020?

Response:

Yes.

46.0 Topic: In-Home Display and Customer Information Portal

Reference: Exhibit B-1, section 4.1.1 Home-Area Network

46.1 Please provide a table comparing the features available on the In-Home Display and Customer Internet Portal, such as the lag time, the granularity of consumption information (how frequently it is updated), ambient temperature, etc.

Response:

Please see the table below:

Table BCSEA IR1 Q46.1

Hi-level functionality	Customer Portal	In-Home Display
Granularity of data	Hourly, daily, weekly and monthly data	One minute or less, depending on capabilities
Frequency of update	Within 24 hours of data being received	Less than 30 seconds
Ambient temperature	Yes	*Yes
Price indicators	Yes	*Yes
Usage Details	Yes	*Yes
Display of Messages	Yes	*Yes
Historical Data	Yes	*Yes
Avg Consumption per day	Yes	*Yes

** Dependent on type and capabilities of In-Home Display. These features are anticipated to be in the most common in-home display devices.*

46.2 To clarify, if the smart meter provides hourly data to the head end confirm that the maximum granularity that the CIS can provide is hourly data. If not, please explain.

Response:

Confirmed (with the clarification that the hourly data will come from the MDMS, not the CIS).

46.3 Can the smart meter provide sub-hourly data to an IHD even though it is providing hourly data to the head end? What granularity?

Response:

Yes. Please see the response to Tatangelo IR No. 1 Q14 for the granularity of the IHD device.

47.0 Topic: In-Home Display

Reference: Exhibit B-6, BCUC IR 28

"Preliminary research indicated a price range of $80-$150 per In-Home Display (IHD) device. The approved 2012-13 DSM Plan includes a nominal $50 incentive or up to half the cost, of eligible IHDs. The net Customer Portion of Cost would be $40-$100 of the price range indicated above."

"The IHD devices will be piloted in 2014, with availability to customers expected in 2015."

47.1 Are the In-Home Display units (suitable for the smart meters FortisBC proposes to install) currently available? If so, please provide product information. If not, when will they be available?

Response:

Yes, products are currently available that are compatible with the proposed AMI system. For example, please see http://www.rainforestautomation.com/emu for a specific product. Also http://www.zigbee.org lists a range of available products. BC Hydro plans to issue a public listing of compatible products late in 2013, which FortisBC will refer to.

47.2 Are the IHD devices that will be piloted in 2014 unique to FBC's AMI system?

Response:

No, they are expected to be compatible with any compatible ZigBee-enabled meter.

47.3 Will In Home Display units be certified, and if so by what body?

Response:

Please refer to the response to BCSEA IR No. 1 Q6.1.

48.0 Topic: GHG emission reductions

Reference: Exhibit B-1, p.2; p.20; p.38

"The BC Government is committed to reducing GHG emissions by one-third, as compared to 2007 levels, by 2020. The proposed AMI Project supports the GGRTA through the reductions in the manual meter reading function (and associated vehicle usage). This reduction is expected to contribute to a decrease in GHG emissions (currently estimated at 191 tonnes per year) associated with the existing manual meter reading function." [p.20]

48.1 Is the GHG emissions reduction estimate based on GHGenius? If not, please provide an estimate using GHGenius v.4.0.

Response:

No, the calculation of the current GHG emissions related to the manual meter reading process was not based on GHGenius, but rather a calculation of GHG emissions based on information available at the following link:

http://oee.nrcan.gc.ca/publications/transportation/fuel-guide/2007/calculating-co2.cfm?attr=8

However, using GHGenius v4.0, it is estimated that approximately 234 tonnes of annual GHG emissions beginning in 2015 will be avoided as a result of the reduction in vehicle usage associated with the implementation of AMI.

48.2 Please provide an estimate of the cumulative GHG emissions reductions over the project lifetime.

Response:

Based on GHGenius v4.0, and the assumptions included in the status quo analysis (growth in the number of meter readers), the Company estimates a cumulative reduction of 4,996 tonnes of GHGs over the 20 year project analysis.

48.3 Please confirm that induced GHG emissions is factored into the calculation of GHG emissions reductions, such as increased fossil fuel energy use by marijuana grow-ops that are induced by theft detection to move away from electricity use.

Response:

Not confirmed.

49.0 Topic: Safety and meter installation

Reference: Exhibit B-6, BCUC IR 27.1.1

"Itron OpenWay meters are capable of reporting temperature conditions from the meter over the network. Itron is currently making necessary enhancements to the HES to receive temperature data from the meter. If overheating is detected, the system will be able to remotely disconnect the meter and service. FortisBC expects this functionality to be enabled (at no additional cost) prior to meter deployment."

49.1 If the temperature reporting functionality is enabled prior to meter deployment will the AMI system prevent fires associated with cracked meter bases, remote disconnection of service?

Response:

This functionality cannot be guaranteed to prevent fires associated with faulty meter bases.

50.0 Topic: Privacy

Reference: Exhibit B-1, section 8.4.4 Privacy; Exhibit B-9 Supplemental Privacy Information; Exhibit B-9 Attachment 1, Investigation Report F11-03, British Columbia Hydro And Power Authority. Information and Privacy Commissioner, December 19, 2011

The B.C. Information and Privacy Commissioner issued Investigative Report F11-03 concerning BC Hydro's Smart Meter and Infrastructure Initiative (SMI) under the Freedom of Information and Protection of Privacy Act ("FIPPA").

"...However, the Commissioner found that BC Hydro is not complying with the requirement to notify customers of the purposes for collecting the personal information in relation to the SMI project, the legal authority for the collection, and providing the contact information for a person within BC Hydro who can answer questions regarding the collection." (at para. 7). The report made a series of recommendations to address these concerns, but overall, did not object to the implementation of smart meters. For reference, a copy of the report prepared by the Office of the Information and Privacy Commissioner is provided as Attachment 1 to this letter."

50.1 Does FortisBC assert that its implementation of its proposed AMI program will meet all of the privacy recommendations that the Information and Privacy Commissioner made to BC Hydro regarding BC Hydro's SMI program?

Response:

Please refer to the supplemental letter filed by FortisBC with the BCUC on October 19, 2012 (Exhibit B-9).

As noted in Exhibit B-9, FortisBC and BC Hydro are governed by two different provincial privacy laws. BC Hydro is governed by the British Columbia *Freedom of Information and Protection of Personal Information Act* ("FIPPA") because it is a public sector organization. Private sector organizations within British Columbia are governed by the *Personal Information Protection Act* ("PIPA").

Notwithstanding that FortisBC is governed by a different piece of legislation, FortisBC has reviewed the recommendations that have been made by the British Columbia Office of the Information and Privacy Commissioner and has ensured that those recommendations that would apply to FortisBC have been considered in the design and development of the AMI Project.

50.2 Please provide a table showing the Information and Privacy Commissioner's 14 recommendations to BC Hydro regarding privacy aspects of BC Hydro's SMI program and the corresponding measures FortisBC is or will take regarding its AMI program.

Response:

As noted in the response to BCSEA IR No.1 Q50.2, FortisBC and BC Hydro are governed by two different pieces of privacy legislation. As a result, the analysis and recommendations of the British Columbia Office of the Information and Privacy Commissioner ("OIPC") may not be entirely applicable to FortisBC. Notwithstanding these differences, FortisBC has reviewed the recommendations of the OIPC and has the following comments:

	BC Hydro Recommendation	**FortisBC Comments**
1.	As BC Hydro introduces new elements to the smart grid, or increases the functionality of existing elements of the grid, it should continue to complete privacy impact assessments in each instance and provide it to the OIPC for review and comment before implementation.	Section 69(5) of FIPPA requires that all public bodies conduct privacy impact assessments when engaging in a project that has privacy implications. FortisBC and other private sector organizations do not have the same obligation to complete a privacy impact assessment under PIPA; however, FortisBC has made privacy a key consideration in the design and development of the AMI project.
2.	BC Hydro must develop more comprehensive web pages and paper notices for its customers for the SMI project regarding the purposes for collecting hourly electricity consumption data, the legal authority for collection, and the contact information for the person within BC Hydro who can answer questions regarding the collection.	While Section 27(2) of FIPPA and section 10 of PIPA are different, FortisBC has made efforts and will continue to make efforts to communicate with the public to notify them of the AMI project and the purposes for which the collection of hourly consumption information is necessary. FortisBC also has a Chief Privacy Officer whose contact information is made available on FortisBC's website (www.fortisbc.com)
3.	Before any future secondary uses of electricity consumption information take	Section 69(5) of FIPPA requires that all public bodies conduct privacy impact

	place, BC Hydro should complete a privacy impact assessment and provide it to the OIPC for review and comment prior to implementation.	assessments when engaging in a project that has privacy implications. FortisBC and other private sector organizations do not have the same obligation to complete a privacy impact assessment under PIPA; however, FortisBC will ensure that should any future uses for the information it has collected arise, it will make privacy a key consideration in determining whether the use is appropriate.
4.	BC Hydro should follow through with its plans to document in detail its role-based access model for the SMI project. This model should include a comprehensive roles matrix that maps job functions with personal information and privileges required to perform those functions. Roles should be defined as specifically as possible. In accordance with the least privilege principle, BC Hydro should ensure each role only has access to the minimum amount of personal information necessary to perform their functions. BC Hydro should fully document the role-based access matrix and regularly check and update it as required. BC Hydro should also implement a monitoring/auditing plan to evaluate whether its staff is properly accessing and using information.	FortisBC has instituted a roles-based access model whereby only those employees that require access to personal information to complete their job function are given such access.
5.	If, in the future, BC Hydro becomes involved in offering its customers the option of disclosing their consumption information to third parties, it should take reasonable steps to ensure that the third parties are transparent about their personal information practices.	If FortisBC becomes involved in offering its customers an additional service which involves the disclosure of their personal information to a third party, FortisBC will take reasonable steps to ensure that such third parties are transparent about their personal information practices.

6.	BC Hydro should ensure that it reviews all policies relating to information security and privacy on a regular basis to ensure that they remain current and relevant. BC Hydro should document this review process; including putting dates on policies to reflect BC Hydro's most recent review.	FortisBC does review its security and privacy policies over time to ensure that they remain current and relevant. FortisBC currently includes a date on its policy showing its most recent review.
7.	BC Hydro should make annual privacy and information security training mandatory for all employees and contractors.	Privacy does form part of the training that new and current FortisBC employees receive.
8.	While it appears to be BC Hydro's intention, it should ensure that it introduces read-access logging prior to commencing the collection of hourly electricity consumption information. BC Hydro should also implement a monitoring/auditing plan to evaluate the effectiveness of its read-access logging.	FortisBC currently uses audit logging.
9.	BC Hydro should archive SMI project records containing personal information that are no longer required for the delivery of customer services on a regular and ongoing basis. BC Hydro should develop a classification scheme to identify those records.	FortisBC is currently reviewing its retention policy and its application to AMI related data. As noted in the response to BCUC IR1 Q. 35.1, FortisBC anticipates that three years of data will be available for immediate retrieval and four additional years of information will be archived.
10.	BC Hydro should not retain customer personal information indefinitely. BC Hydro should continue to develop and implement a records retention and disposition policy that sets out when the disposal of personal information of its customers and former customers will occur.	FortisBC is currently reviewing its retention policy and its application to AMI related data.
11.	BC Hydro should ensure that it has designated an individual to be responsible for privacy within the organization. This individual should have primary	FortisBC has a Chief Privacy Officer whose contact information is made available on FortisBC's website (www.fortisbc.com).

	responsibility for privacy within BC Hydro and within the SMI project. This individual should be a member of BC Hydro's executive team and/or should be fundamental to BC Hydro's business decision-making process.	
12.	BC Hydro should develop annual and/or multi-year privacy performance plans for the SMI project.	FortisBC will review the performance of the AMI system on an ongoing basis.
13.	BC Hydro should ensure it has reporting mechanisms regarding its privacy management framework and it should state these mechanisms in its privacy policies and procedures.	FortisBC is currently reviewing its reporting mechanisms.
14.	BC Hydro should develop policies relating to training of employees and service providers, audit and breach management.	Privacy does form part of the training that new and current employees receive. FortisBC is currently reviewing its privacy related policies and most recently has updated its general privacy policy (effective November 1, 2012)

50.3 Please discuss any privacy concerns and requirements to inform customers regarding the use of customer information to detect electricity theft.

Response:

Customers have been informed of the purposes for collection, use and disclosure of their personal information in FortisBC's Privacy Policy, which was recently updated and became effective on November 1, 2012. Specifically, section 2.3 of FortisBC's Privacy Policy states that FortisBC will use information collected "to avoid and investigate fraud and identity theft" and "to reduce energy and revenue theft which may include the collection of outage, voltage, load profile and consumption information".

51.0 Topic: Privacy

Reference: Exhibit B-9

The Ontario Information and Privacy Commissioner published "Privacy by Design:Achieving the Gold Standardin Data Protection for the Smart Grid, June 2010,"("Privacy by Design"), available at http://www.ipc.on.ca/images/Resources/achieve-goldstnd.pdf. The document is apparently the joint product of the Information and Privacy Commissioner of Ontario, Hydro One Inc. and Toronto Hydro. The executive summary states:

"Privacy by Design (the Gold Standard for data protection), is the standard to be adopted for Smart Grid implementation for data protection."

51.1 Is FortisBC familiar with Privacy by Design? Please file a copy.

Response:

"Privacy by Design" is a tool that was developed by Dr. Ann Cavoukian to assist organizations in implementing new technology into their working environments. There are several similar tools and methodologies developed by various organizations and consultants throughout Canada and beyond. The requested document is provided as Appendix BCSEA IR1 51.1.

51.2 Privacy by Design sets out seven "best practices." Please provide a table listing these best practices and indicate whether and how FortisBC's AMI program will meet each one.

Response:

As stated in the response to BCSEA IR No. 1 Q51.1, Privacy by Design is a tool that may be used by organizations to assist in implementing new technology into their work environments.

FortisBC has no legal or other requirement to use this particular tool in assessing the AMI project. That being said, FortisBC has made privacy a key consideration in the design and development of the AMI project which is consistent with the main premise of Privacy by Design. Furthermore, FortisBC has reviewed the seven "best practices" indicated in the article referenced above and notes that these principles are consistent with the design of the AMI project.

52.0 Topic: Privacy

Reference: Exhibit B-9, Attachment 2, FortisBC Privacy Policy, pdf p.41 of 46

"FortisBC has a privacy policy in place and an updated privacy policy coming into effect on November 1, 2012 that protects personal information in accordance with PIPA." [p.2, underline added]

"This Privacy Policy was last updated in July of 2012."

52.1 Please explain why FortisBC's Privacy Policy was last updated July 2012 but is not in effect until November 1, 2012.

Response:

FortisBC's Privacy Policy was updated in July of 2012 and then made available to the general public for review in August of 2012. From a customer service perspective, FortisBC wanted to give its customers ample notification that the Privacy Policy was being updated prior to it becoming effective. The only reason for the delay between the date the policy was updated and the effective date was to allow customers to be notified of the change and have time to seek clarification or ask any questions they may have had.

53.0 Topic: Information security

Reference: Exhibit B-1, section 8.4.3 Security

"FortisBC's objective is to follow the security specifications set out in the AMI-SECAMI System Security Requirements, provided as Appendix F-1." [p.135, footnote omitted]

53.1 How does the information security design for the FortisBC AMI program compare with the information security design for BC Hydro's SMI program? Are there any significant differences? If so, please explain.

Response:

FortisBC does not have information pertaining to the security design for BC Hydro's SMI program and therefore is unable to provide a response.

54.0 Topic: Health

Reference: Exhibit B-1, Appendix C-5, Status of Research on Radiofrequency Exposure and Health in Relation to Advanced Metering Infrastructure ("RF Health Report"), pdf p.521

54.1 Who are the individual authors of the RF Health report, and what are their qualifications?

<u>Response:</u>

Please refer to the responses to CSTS IR No. 1 Q23.1 and Q23.4.

54.2 Has Exponent, Inc. provided reports on radiofrequency exposure and health in relation to advanced metering infrastructure for clients other than FBC? If so, please provide the number of such reports by year.

<u>Response:</u>

Drs. Bailey and Erdreich have summarized the status of health research relevant to advanced metering infrastructure for Central Maine Power in 2010 and 2012, NV Energy in 2012 and BC Hydro in 2012.

Please also see the response to CSTS IR No. 1 Q23.5.

54.3 Please provide a copy of any other report by Exponent on RF exposure and health in relation to the Itron AMI7 meter.

<u>Response:</u>

A copy of an Exponent report that discusses RF exposures from the Itron meter and RF health research is provided as Appendix BCSEA IR1 54.3.

55.0 Topic: Health

Reference: Exhibit B-1, Appendix C-5, Status of Research on Radiofrequency Exposure and Health in Relation to Advanced

Metering Infrastructure, (Sub-)Appendix A, Technical Memorandum, Advanced Metering Infrastructure Exposure Assessment, p.A-2 (pdf p.564 of 747)

"In the 900 MHz band, the signal power from the Itron AMI7 meter (FCC ID SK9AMI7) is 689 milliwatts (mW) for an antenna gain of 1.66. Under typical use, the duty cycle is between 0.02% and 0.58% with a mean of 0.06%. The maximum duty cycle under all circumstances is 5%.20" [underline added]

55.1 Please confirm that the Itron AMI7 meter (FCC ID SK9AMI7) is the model of advanced meter in FBC's AMI Project. If not, please explain.

Response:

Confirmed.

55.2 Please confirm that the characteristics of the Itron AMI7 meter described in the passage quoted above accurately describe the characteristics of the advanced meters in the configuration and usage that FBC proposes in the AMI Project.

Response:

Confirmed.

55.3 Please describe the term "duty cycle" in this context.

Response:

Duty cycle is the percentage of time the transmitters in the meters are active. For instance, if a meter transmits for a total of 1 minute in a 24 hour period, the duty cycle is 1/(24x60) = 0.0694%.

55.4 What does a duty cycle “between 0.02% and 0.58% with a mean of 0.06%” and a maximum of “5%” mean in terms of seconds or minutes per hour or per day?

Response:

Please see the table below:

Table BCSEA IR1 Q55.4

Duty Cycle (%)	Minutes per Day of Transmission
0.02	0.3
0.58	8.4
0.06	0.9
5	72

55.4.1 Does this duty cycle include all data from the meter, including data for supporting the mesh network and other network traffic?

Response:

Yes.

55.5 Please explain why the duty cycle is given as a range. Does the duty cycle range apply to each specific installed meter, or to the fleet of meters? Will some installed meters be at the low end of the range while others are at the high end of the range? What factors determine the length of the duty cycle for a particular meter; for the fleet of meters?

Response:

With a hierarchical mesh structure, meters will relay upstream and downstream traffic within the RF mesh. The total number of transmissions will include the scheduled reads, on-demand reads, alarms/alerts along with the network traffic needed for command and control (synchronization, security, data integrity and dynamic network resiliency). Based on data gathered from a large, representative OpenWay network deployment (using 2 load profile reads + one register read + one event read per day), distribution of the duty cycle is graphed in the Itron white Paper (Wireless Transmissions: An Examination of OpenWay Smart Meter Transmissions in a 24-Hour Duty Cycle), provided as Appendix BCSEA IR1 55.5 .

55.6 In what circumstances does the maximum duty cycle of 5% occur? Would this occur with a specific installed meter, or with the fleet of meters? How frequently does the maximum duty cycle of 5% occur?

Response:

The maximum duty cycle of 5% (72 minutes) is a theoretical maximum capability of the installed network. Analysis of an actual larger field deployment has shown that the Smart Metering application had a maximum duty cycle of 0.58% (8 minutes).

55.7 Please define the mean duty cycle. Is it a weighted average? Does the mean duty cycle of 0.06% include the expected occurrences of the maximum duty cycle?

Response:

The mean duty cycle is the arithmetic mean (simple average) duty cycle calculated from the 6,865 meters that were included in the referenced Itron white paper provided as Appendix BCSEA IR1 Q55.5 (Wireless Transmissions: An Examination of OpenWay Smart Meter Transmissions in a 24-Hour Duty Cycle).

55.8 Please provide a copy of “Analysis of Radio Frequency Exposure Associated with Itron OpenWay® Communications Equipment” by Itron, Inc. and “Wireless Transmissions: An Examination of OpenWay Smart Meter Transmissions in a 24-Hour Duty Cycle” by Itron. Inc., cited in footnote 20.

Response:

Wireless Transmissions: An Examination of OpenWay Smart Meter Transmissions in a 24-Hour Duty Cycle is attached above, and Analysis of Radio Frequency Exposure Associated with Itron OpenWay® Communications Equipment is provides as Appendix BCSEA IR1 55.8.

56.0 Topic: Health

Reference: Exhibit B-1, Appendix C-5, Status of Research on Radiofrequency Exposure and Health in Relation to Advanced Metering Infrastructure, (Sub-)Appendix A, Technical Memorandum, Advanced Metering Infrastructure Exposure Assessment, p.A-1, p.A-2

"Advanced meters utilized by FortisBC, provided by Itron, Inc., incorporate two radios. The first radio, called RF-LAN, operates in the frequency range of 902 Megahertz (MHz) to 928 MHz. Its purpose is to communicate the power usage at the residence by radiofrequency (RF) signals back to FortisBC."[p.A-1]

Table 1. RF Exposure at 902 MHz to 928 MHz

Condition	Exposure at 0.5 meters (mW/cm^2)
Mean duty cycle 0.06%	0.000056
Maximum typical duty cycle 0.58%	0.00054
Maximum supported duty cycle 5%	0.0047
Exposure Limit 902 MHz [21]	0.6

[p.A-2]

56.1 Please show the calculation of the Exposure Limit for the RF-LAN, with references from Health Canada Safety Code 6 (2009).

<u>Response:</u>

Exposure limit at the 902 to 928 MHz frequency band utilized by RF-LAN is specified in Table 6 of the Health Canada Safety Code 6 (2009). Using the row corresponding to 300 – 1,500 MHz, the limit for power density in units of W/m2 is frequency f (in MHz) divided by 150. Dividing 902 by 150 results in power density limit value of 6 W/m2; likewise, dividing 928 by 150 results in power density limit value of 6.2 W/m2. Using a conversion factor of 1 W/m2 = 10 mW/cm2, the result is 6 mW/cm2 to 6.2 mW/cm2.

57.0 Topic: Health

Reference: Exhibit B-1, Appendix C-5, Status of Research on Radiofrequency Exposure and Health in Relation to Advanced Metering Infrastructure, (Sub-)Appendix A, Technical Memorandum, Advanced Metering Infrastructure Exposure Assessment, p.A-1

"The second radio, called Zigbee, operates in the frequency range of 2,400 MHz to 2,484 MHz. This radio provides consumers, if they wish, with a way to interact with compatible appliances in the home and to read out the appliances' respective contribution to overall household power use."

57.1 Does the ZigBee radio operate (in terms of emitting RF) even if the customer does not choose to install an In-Home Device?

Response:

FortisBC intends to deploy the AMI meter configured with the Zigbee radio set to "quiet mode" where it will not send any signals unless a valid HAN device requests a beacon. The Utility can provision meters to accept requests from devices or to ignore requests and remain silent

57.2 If so, is there some way that the customer, or FBC at the customer's request, can turn off the ZigBee radio in a specific installed meter?

Response:

Please refer to the response to BCSEA IR No. 1 Q57.1.

58.0 Topic: Health

Reference: Exhibit B-1, Appendix C-5, Status of Research on Radiofrequency Exposure and Health in Relation to Advanced Metering Infrastructure, (Sub-)Appendix A, Technical Memorandum, Advanced Metering Infrastructure Exposure Assessment, p.A-3

Table 2. RF Exposure at 2,400MHz

Condition	Exposure at 0.5 meters (mW/cm^2)
Duty cycle 1%	0.00013
Exposure Limit at 2400 MHz	1

58.1 Please show the calculation of the Exposure Limit for the ZigBee radio, with references from Health Canada Safety Code 6 (2009).

Response:

The exposure limit at the 2,400 to 2,484 MHz frequency band used by RF-LAN is specified in Table 6 of the Health Canada Safety Code 6 (2009). Using row corresponding to 1,500 – 15,000 MHz, the limit for power density is 10 W/m2. Using a conversion factor of 1 W/m2 = 10 mW/cm2, the result is 1 mW/cm2.

58.2 What does a duty cycle of 1% for the ZigBee radio mean in terms of seconds or minutes per hour or per day?

Response:

1% duty cycle = 14 minutes/day

58.3 What is the output level of the ZigBee and does it adjust according to the strength required?

Response:

The ZigBee radio RF transmission output is as follows:

Radio Power: 18.13 dBm (65.01 mW)

Antenna Gain: 3.8 dbi (2.399 mW equivalent)

Emitted Power: 21.93 dBm (155.96 mW)

The output level is fixed and does not adjust.

59.0 Topic: Health

Reference: Exhibit B-1, Appendix C-5, Status of Research on Radiofrequency Exposure and Health in Relation to Advanced Metering Infrastructure, (Sub-)Appendix A, Technical Memorandum, Advanced Metering Infrastructure Exposure Assessment, p.A-2

"In a typical installation, the advanced meter is installed on the outside wall of the residence, mounted on a metal enclosure, and has a faceplate pointing away from the house. In such a configuration, the signal sent by the advanced meter toward the house is 1/10th of the signal sent away from the house. Moreover, the RF signal from the advanced meter is greatly reduced by reflection and absorption from the metal enclosure and the structural materials of the residence walls."

59.1 The RF exposure estimates in Appendix C-5, Appendix A for RF-LAN and ZigBee are formula-based. Please provide information that confirms or modifies these estimates on an empirical basis (i.e., on-site measurements).

Response:

The exposure under 100% duty cycle can be obtained from the FCC website under FCC ID SK9AMI7.

The BC Centre for Disease Control conducted measurements of the power density of RF emissions from Itron smart meters (and other common household devices) to compare the readings to the public exposure limits (uncontrolled environments) set by Health Canada Safety Code 6. That report, available at http://www.bccdc.ca/NR/rdonlyres/43EF885D-8211-4BCF-8FA9-0B34076CE364/0/452012AmendedReportonBCHydroSmartMeterMeasurements.pdf, showed that at 30 cm, the time-averaged power density from the meter was only 0.00037 percent of the Safety Code 6 limit (Table 3).

59.2 If a customer was particularly interested in reducing the RF signal within the premises, would placing a dense barrier of some type on the inside wall opposite the meter further reduce the RF signal?

Response:

Considering that an AMI meter mounted on a building or a house already has a metal backplate that reduces the RF signal that enters the house, it is unlikely that the addition of a dense barrier of some type would improve that reduction significantly.

60.0 Topic: Health

Reference: Exhibit B-1, Appendix C-5, Status of Research on Radiofrequency Exposure and Health in Relation to Advanced Metering Infrastructure, (Sub-)Appendix A, Technical Memorandum, Advanced Metering Infrastructure Exposure Assessment

60.1 Appendix A provides RF exposure data for the Itron advanced meters that FBC proposes in this application. How does the RF exposure from these Itron meters compare to the RF exposure from the types of meters in the RFP proposals that were not accepted by FBC? Please provide a table comparing the WAN and LAN RF exposure of the various types of meters in the proposals that FBC considered.

Response:

FortisBC did not request RF emission data from proponents responding to the RFP, only a statement of compliance with Health Canada Safety Code 6.

60.2 Is there any significant difference between the RF exposure of the Itron AMI7 meter and any of the other types of meters considered by FBC?

Response:

Please see the response to BCSEA IR No. 1 Q60.1.

61.0 Topic: Health

Reference: Exhibit B-1, Appendix C-5, Status of Research on Radiofrequency Exposure and Health in Relation to Advanced Metering Infrastructure, (Sub-)Appendix A, Technical Memorandum, Advanced Metering Infrastructure Exposure Assessment, Figure 1, RF Exposure, p.A-4.

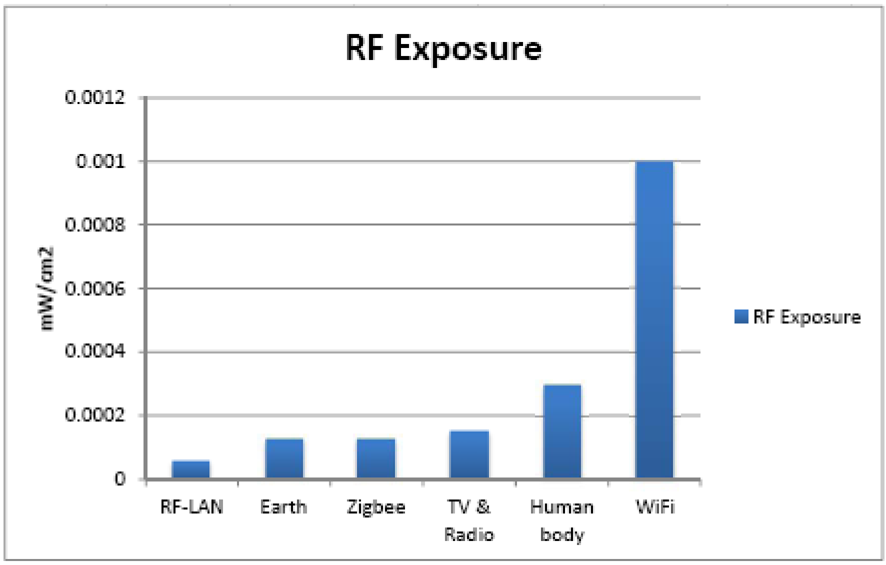


Figure 1. Comparison of RF exposure from RF-Lan and Zigbee signals to RF exposure from other sources under typical use. RF-LAN and Zigbee exposure is for an outside exposure at a distance of 0.5 meters. Exposure at larger distances or inside the residence is much smaller.

"The exposure limit increases with frequency and is equal to 0.62 mW/cm2 at 928 MHz." [Footnote 21, p.A-2]

61.1 Confirm that the fact that "the [Health Canada] exposure limit increases with frequency" means that RF exposure in mW/cm2 is less of a potential health consequence at higher RF frequencies and more of a potential health consequence at lower frequencies.

Response:

The Health Canada exposure limit can be interpreted to mean that a similar level of protection from adverse effects of the absorption of electromagnetic energy is provided at the exposure limits for both higher and lower frequencies.

61.2 Confirm that Figure 1 shows various sources of RF Exposure that are at different frequencies and therefore the potential health consequences of the various sources do not necessarily correspond to the indicated RF Exposure.

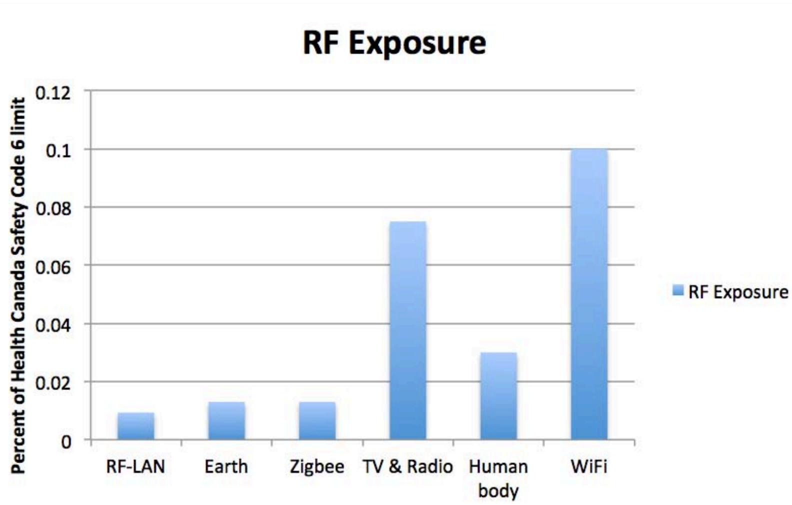
Response:

All RF exposures shown in Figure 1 are well below Health Canada exposure limits irrespective of the frequency of the sources. Safety Code 6 states: "The exposure limits in Safety Code 6 are based upon the lowest exposure level at which scientifically-established human health hazards occur. Safety factors have been incorporated into these limits to add an additional level of protection for the general public and personnel working near RF sources." (Safety Code 6, 2009, p. 7).

61.3 Please provide a table and graph showing the various sources of RF Exposure as a ratio of the corresponding exposure limit, and include cell phone exposure referred to on p.A-5.

Response:

The chart calculating RF exposure as percent of the Health Canada Safety Code 6 limit is shown below. For TV & Radio, a frequency of approximately 30-300 MHz is assumed.



The chart does not show the comparison to the cell phone signal, as it is difficult to show cell phone signal on the same scale as the other sources (due to the cell phone's much greater RF signal strength).

Health Canada Safety Code 6 prescribes using the specific absorption rate (SAR) as basis of comparison to the limit value for devices such as a cell phone. Based on a 1.8 minute call and a typical cell phone SAR of approximately 1 W/kg, cell phone signal would be approximately 20% of the Health Canada Safety Code 6 limit.

61.4 What do the authors intend to convey by showing RF Exposure from “Earth” and “Human Body” at levels equal to or higher than RF Exposure from RF-Lan and ZigBee? Is the implication that RF Exposure from RF-Lan and ZigBee are at levels lower than natural background levels?

Response:

Figure 1 shows that RF Exposure from RF-Lan and ZigBee are at levels lower than natural background levels.

61.5 Please discuss how the RF exposure of RF-Lan in the 902-928 MHz range and ZigBee in the 2400-2482 MHz range compare with exposure at similar distances to the electric and magnetic fieldsof electric current at 60 Hz at the customer meter.

Response:

A customer meter would not be a significant source of 60-Hz electric or magnetic fields.

62.0 Topic: Health

Reference: Exhibit B-1, Appendix C-5, Status of Research on Radiofrequency Exposure and Health in Relation to Advanced Metering Infrastructure, 6. Conclusion, p.30 [pdf p.555 of 747]

”The advanced meters utilized by FortisBC will operate in compliance with the regulations of Health Canada. Exposure to RF energy will be far below the exposure limits recommended by Health Canada, and those of ICNIRP and other scientific and regulatory agencies. In this report, recent scientific research regarding cancer and symptoms has been summarized to determine whether it might suggest adverse effects at levels below exposure limits recommended by these organizations. The reviews and the recently published research with improved exposure information do not provide a reliable scientific basis to conclude that the operation of the advanced meters will cause or contribute to adverse health effects or physical symptoms in the population.”

62.1 The RF Health Report's conclusions are stated with reference to the Itron AMI7 meters proposed by FBC. Would the conclusions of the authors of the RF Health Report quoted above be any different in reference to any of the other types of advanced meters considered by FBC?

Response:

Exponent is not aware of other advanced meters considered by FortisBC but would not expect that any advanced meter would not comply with Safety Code 6.

63.0 Topic: Health

Reference: Exhibit B-1, Appendix B-6, Limits of Human Exposure to Radiofrequency Electromagnetic Energy in the Frequency Range from 3 kHz to 300 GHz (Health Canada Safety Code 6 (2009)), p.11

"The scientific literature with respect to possible biological effects of RF energy has been monitored by Health Canada scientists on an ongoing basis since the last version of Safety Code 6 was published in 1999. During this time, a significant number of new studies have evaluated the potential for acute and chronic RF energy exposures to elicit possible effects on a wide range of biological endpoints including: human cancers (epidemiology); rodent lifetime mortality; tumor initiation, promotion and co-promotion; mutagenicity and DNA damage; EEG activity; memory, behaviour and cognitive functions; gene and protein expression; cardiovascular function; immune response; reproductive outcomes; and perceived electromagnetic hypersensitivity (EHS) among others. Numerous authoritative reviews have summarized this literature(13–30)."[p.11 of 30]

63.1 Does Health Canada deny the existence or validity of perceived electromagnetic hypersensitivity?

Response:

Health Canada has considered studies and reviews on this topic as part of its evaluation for the exposure limits as per the text quoted from Safety Code 6 at p. 9. Health Canada has also issued a statement in 2011 about Electromagnetic Hypersensitivity on its website that concludes, "In summary, there is no scientific evidence that the symptoms attributed to EHS are actually caused by exposure to EMFs." (http://www.hc-sc.gc.ca/ewh-semt/radiation/cons/electri-magnet/electromagnet-eng.php). This statement does not deny reports of symptoms by persons but does state that a causal relationship of symptoms to EMFs is not supported by scientific evidence.

64.0 Topic: Health

Reference: Exhibit B-1, Appendix B-6, Limits of Human Exposure to Radiofrequency Electromagnetic Energy in the Frequency Range from 3 kHz to 300 GHz (Health Canada Safety Code 6 (2009)), p.11

"Despite the advent of thousands of additional research studies on RF energy and health, the predominant adverse health effects associated with RF energy exposures in the frequency range from 3 kHz to 300 GHz still relate to the occurrence of tissue heating and excitable tissue stimulation from short-term (acute) exposures. At present, there is no scientific basis for the premise of chronic and/or cumulative health risks from RF energy at levels below the limits outlined in Safety Code 6."

64.1 Can it be said that Health Canada Safety Code 6 is intended to protect only against thermal consequences of RF exposure? Or is Health Canada Safety Code 6 intended to protect against any levels of RF exposure?

<u>Response:</u>

No. Safety Code 6 also states that "For frequencies from 3 to 100 kHz, the predominant health effect to be avoided is the unintentional stimulation of excitable tissues, since the threshold for electrostimulation in this frequency range will typically be lower than that for the onset of thermal effects." (p. 9)

It is important to understand that Health Canada did not find that there was a scientific basis for other effects at levels below the limits:

"At present, there is no scientific basis for the premise of chronic and/or cumulative health risks from RF energy at levels below the limits outlined in Safety Code 6. Proposed effects from RF energy exposures in the frequency range between 100 kHz and 300 GHz, at levels below the threshold to produce thermal effects, have been reviewed. At present, these effects have not been scientifically established, nor are their implications for human health sufficiently well understood. Additionally, a lack of evidence of causality, biological plausibility and reproducibility greatly weaken the support for the hypothesis for such effects. Thus, these proposed outcomes do not provide a credible foundation for making science-based recommendations for limiting human exposures to low-intensity RF energy." (Safety Code 6, 2009, p. 9)

65.0 Topic: Health

Reference: Exhibit B-1, Appendix B-6, Health Canada Safety Code 6 (2009)

"Proposed effects from RF energy exposures in the frequency range between 100 kHz and 300 GHz, at levels below the threshold to produce thermal effects, have been reviewed. At present, these effects have not been scientifically established, nor are their implications for human health sufficiently well understood. Additionally, a lack of evidence of causality, biological plausibility and reproducibility greatly weaken the support for the hypothesis for such effects. Thus, these proposed outcomes do not provide a credible foundation for making science-based recommendations for limiting human exposures to low-intensity RF energy." [p.11 of 30]

65.1 Does this mean that Health Canada considers human exposure to RF energy at levels below those specified in Safety Code 6 to be acceptable?

<u>**Response:**</u>

Yes.

66.0 Topic: Health

Reference: Exhibit B-1, Appendix B-6, Health Canada Safety Code 6 (2009)

"For frequencies from 100 kHz to 300 GHz, tissue heating is the predominant health effect to be avoided. Other proposed non-thermal effects have not been conclusively documented to occur at levels below the threshold where thermal effects arise. Studies in animals, including non-human primates, have consistently demonstrated a threshold effect for the occurrence of behavioural changes and alterations in core-body temperature of ~1.0 oC, at a whole-body average SAR of ~4 W/kg(7–9). This forms the scientific basis for the whole-body average SAR limits in Safety Code 6. To ensure that thermal effects are avoided, a safety factor of 10 has been incorporated for exposures in controlled environments, resulting in a whole-body-averaged SAR limit of 0.4 W/kg. A safety margin of 50 has been incorporated for exposures in uncontrolled environments to protect the general public, resulting in a whole-body average SAR limit of 0.08 W/kg. [p.11 of 30, underline added]

"controlled environment – A condition or area where exposure is incurred by persons who are aware of the potential for RF exposure and are cognizant of the intensity of the RF fields in their environment, where exposures are incurred by persons who are aware of the potential health risks associated with RF exposure and whom [sic] can control their risk using mitigation strategies." [p.24 of 30]

66.1 Please confirm that the proposed Itron AMI7 RF-LAN radio in the 900 MHz band and ZigBee radio in the 2400 MHz band are within the "frequencies from 100 kHz to 300 GHz" range discussed in the Safety Code 6 passage above.

Response:

Confirmed.

66.2 Please confirm that an advanced meter installed in a customer's premises would be in an "uncontrolled environment" as the term is used in Safety Code 6.

Response:

Confirmed.

67.0 Topic: Health

Reference: Exhibit B-1, Appendix B-6, Health Canada Safety Code 6 (2009), Table 6. Exposure Limits for Uncontrolled Environments

67.1 Please confirm that Table 6 row 5 (300 – 1500 MHz) is applicable to the Itron AMI7 RF-LAN and row 6 (1500 – 15000 MHz) is applicable to the ZigBee radio.

Response:

Confirmed.

68.0 Topic: Opt-out provisions

Reference: general

68.1 Has FortisBC considered 'opt-out' provisions for customers who are opposed to having an advanced meter at their premises? If so, what options has FortisBC considered and what were the results? If not, why not?

Response:

Please see the responses to CEC IR No. 1 Q50.1-50.7.4.

68.2 If 'opt-out' provisions were to be made available for customers who are opposed to having an advanced meter at their premises, who should pay for any incremental cost – the customer or ratepayers as a whole?

Response:

FortisBC believes that the "opt-out" customer should pay for incremental costs and lost benefits related to their choice. Please see the response to CEC IR No. 1 Q50.3.

69.0 Topic: Indirect customers

Reference: Exhibit B-6, BCUC IR 6.6; BCUC IR 115.3; Exhibit B-1, Section 8.3, Additional Utilities and Cost Sharing of AMI; Exhibit B-1, Section 9.4 Other BC Utilities

"FortisBC has received correspondence from a representative of BCMEU who has indicated that a majority of the BCMEU members are not interested in the implementation of AMI in their respective service territories. FortisBC notes that Nelson, Grand Forks, and Penticton have already implemented or are in the process of implementing AMR solutions. The City of Kelowna has indicated that if they believe there is merit to move towards an AMI system through some type of partnership/procurement advantage for the City supported by a positive business case, then Kelowna would most likely pursue the installation of AMI for its customers. FortisBC and the City of Kelowna have deferred further discussion of a possible AMI solution for Kelowna pending the outcome of the regulatory process for FortisBC's application." [Exhibit B-1, p.130]

"The 162,000 customer count referenced on page 15 of the Application refers to the total direct and indirect customer count served by FortisBC. For clarity, direct customers (approximately 115,000) are those customers served directly (metered and billed) by FortisBC within its service territory. The remaining approximately 47,000 indirect customers are those customers of the five municipalities (Kelowna, Summerland, Penticton, Grand Forks, Nelson) to which FortisBC provides wholesale service. FortisBC's proposed AMI Project will only impact the metering technology for the Company's direct customers." [BCUC IR 6.6]

69.1 What are the implications for the theft detection function of the AMI system of the fact that 47,000 indirect customers will not get smart meters in the defined proposal?

Response:

The 47,000 indirect municipal customers are metered beyond the wholesale point of delivery at FortisBC substations. The metering technology used by Municipal customers will have no impact on the theft detection function of the proposed AMI deployment at FortisBC.

69.2 FBC notes that BC Hydro's implementation of smart meters within the BC Hydro service territory will tend to motivate operators of grow-ops to relocate to the FBC service territory. Will the combination of BC Hydro's SMI program and FBC's AMI program tend to motivate grow-ops operators to relocate to the five municipalities to which FBC provides wholesale service?

Response:

The risk versus reward model dictates that producers will operate in a manner and location that best minimizes risk. This will include consideration of municipal utilities served by FortisBC. Three of FortisBC municipal customers have already or intend to deploy a form of advanced metering (i.e. AMR) however, the Company has no visibility on the status of theft detection programs in place at these utilities. Metering technology, the effectiveness of a theft detection program and municipal response to the 2006 amendment to the Safety Standards Act will be considered by producers. Please see Appendices BCUC IR1 74.1 and BCUC IR1 86.1.

69.3 What is FBC's understanding of how BC Hydro is dealing with the question of whether municipal utilities to which BC Hydro provides wholesale service will implement smart meters within their service areas.

Response:

FortisBC is not aware of how BC Hydro is dealing with the question of whether municipal utilities to which BC Hydro provides wholesale service will implement "smart" meters within their service areas.

69.3.1 Please describe the content of any discussions FBC has had with BC Hydro on this topic.

Response:

Please refer to the response to BCSEA IR No. 1 Q69.3.

69.3.2 Please describe the content of any discussions FBC has had with the B.C. government on this topic.

Response:

FortisBC has not had discussions with the B.C. government related to how BC Hydro is dealing with the question of whether municipal utilities to which BC Hydro provides wholesale service will implement “smart” meters within their service areas.

70.0 Topic: Remote connection, disconnection

Reference: Exhibit D-1

Interested party Christina Postnikoff quotes an organization as stating that:

"‘AMI by itself will not allow for remote disconnections or connections. To do this, FortisBC would have to purchase and install “collars”’...”

70.1 Is it correct that “AMI by itself will not allow for remote disconnections or connections” and that to do this FBC “would have to purchase and install ‘collars’”? Please explain.

Response:

The proposed meters that FortisBC will use in the implementation of AMI will allow for remote disconnections and reconnections without collars or additional cost.

70.2 Please discuss how the disconnection and reconnection procedures for FortisBC might change with the ability to remote disconnect and reconnect.

Response:

Please refer to Exhibit B-1, Sections 5.3.3 and 8.4.5, and BCUC IR No. 1 Q116.1-116.3 for further details outlining the remote disconnection and reconnection process.

70.3 How long does it take to send a remote signal end-to-end (minimum and maximum)?

Response:

Timing is variable based on a number of factors including network backhaul (bandwidth) and depth of meters within the mesh itself. In general, a few seconds to a minute is expected.

71.0 Topic: Outage notification

Reference: Exhibit B-6, BCUC IR 17.1

"At this time, FortisBC has not included in the project cost the design to include an email notification system that will advise a customer of an outage for a specific meter. This is a customer benefit that will be considered for implementation in the future. FortisBC intends to allow customers to select the method (if any) by which they wish to be notified of a power outage, including automated e-mail and Short Message Service (text message) notifications. The immediate benefit of Automated Outage Notification is intended to inform FortisBC of the duration of outages, the number and location of outages. This will also aid in identifying specific meters that are still out before a crew leaves an area."

71.1 Will any software or hardware upgrades to the proposed smart meter units be required in order to implement automated customer outage notification to customers?

Response:

No, the proposed advanced meters will not require software or hardware upgrades in order to support automated outage notification to customers. The advanced meters will send outage notifications through the AMI system, which will be available to FortisBC system operators.

72.0 Topic: Hourly interval data

Reference: Exhibit B-6 BCUC IR 18.1; BCUC IR 121.1; BCUC IR 35.1

"FortisBC does consider it a requirement of TOU and CPP rates that the AMI meter has hourly interval data availability at minimum." [BCUC IR 18.1]

'"One of the largest drivers of data volumes for a utility is the meter reads from all of the smart meters in its territory. Prior to the implementation of a smart meter, utilities would conduct one meter read a month per meter. With the new smart meters that capture usage data in 15-minute intervals, utilities will collect more than 3,000 meter readings a month for each meter. This translates to terabytes (TB) of data being collected and stored at the customer level. We can expect 300 TB per year of meter data by 2012, according to the FPL Group..." [BCUC IR 121.0, lines 17 – 20]

"FortisBC has provided for the storage, retrieval and archiving of customer metering data for seven years using the most cost effective storage available while preserving reliability and security. Please also refer to the response to BCUC IR1 Q35.1." [BCUC IR 121.1]

"The MDMS is designed to store data from 150,000 AMI metering endpoints. Three years of data will be available for immediate retrieval and four additional years will be archived. For the solution, FortisBC has estimated and accounted for 1.5TB per year of storage." [BCUC IR 35.1]

72.1 Is the hourly interval data built into the proposed smart meter model? Could the data interval be changed (e.g., made more frequent than hourly) in the future? If so, could this be done by an electronic software update or would it require physical changes to the meters?

Response:

Yes, the capability for the collection of hourly interval data is built into the proposed FortisBC advanced meter. This data interval could be changed in the future through software without physical changes to the meters.

72.2 How did FBC determine that hourly interval data, as opposed to, say, half-hourly interval data, is a requirement for TOU and CPP rates?

Response:

FortisBC experience with its own TOU rates and the implementation of TOU rates in Ontario indicate that hourly intervals are sufficiently granular for TOU and CPP rates. The proposed AMI system can support more granular information if required.

72.3 Is 15-minute interval data standard, or common, for smart meter systems in North America?

Response:

The collection of 15-minute interval data is common in industrial metering installations.

72.4 To clarify, can FBC confirm that Table 1 and the quoted text in the preamble to BCUC IR 121.1 is from http://www.elp.com/index/display/article-display/6753277598/articles/utility-automation-engineering-td/volume-16/issue-9/features/addressing-the-big-data-concern-in-the-utilities-sector.html ?

Response:

Yes, the table and quoted text in the preamble to BCUC IR No. 1 Q121.1 appears to be from the link above.

73.0 Topic: Choice of Itron package

Reference: Exhibit B-1, p.125; Exhibit B-6

73.1 Are the Itron Openway meters that FortisBC proposes exactly the same as the Itron Openway meters being installed by BC Hydro? Are the Itron Openway meters that FortisBC proposes in use elsewhere at the present time? Where?

<u>Response:</u>

Yes, the Itron OpenWay meters proposed by FortisBC are the same as those being installed by BC Hydro.

The OpenWay Centron meter is used by the following utilities in North America:

- San Diego Gas and Electric (1.4 million)
- Southern California Edison (4.7 million)
- CenterPoint Energy (2.25 million)
- DTE Energy (800,000)
- BC Hydro (1.8 million)
- Glendale Water and Power (85,000)
- Several smaller deployments at municipal utilities
- Early deployments and pilots underway at National Grid, First Energy, Duke Energy, Duquesne Light Company.

73.2 Is the combination of the Itron Openway meters and the Itron WAN system that FortisBC proposes in use elsewhere at the present time? If so, where?

<u>Response:</u>

Itron does not supply the WAN – the Wide Area Network, communicating between the collectors and the utility. It is likely the utilities listed in the response to BCSEA IR No. 1 Q73.1 use some or all of the WAN technologies planned for use by FortisBC.

73.3 Did FortisBC's RFP require that the proposed technology have been in commercial service for some period of time? Please provide details.

Response:

FortisBC's RFP did request the duration and quantity of deployments of the proposed technologies.

73.4 Does FortisBC have evaluation reports on implementation of (a) the Itron Openway meters or (b) the Itron Openway meters and head-end systems? If so, please provide copies, confidentially if necessary.

Response:

Evaluation reports are not a customary element of utility AMI projects. There are no such reports available for Itron's projects.

73.5 What economic life estimate is used for Itron meters used by other utilities?

Response:

Please see the response to BCPSO IR No. 1 Q3.2.

74.0 Topic: Wireless v. Wired

Reference: Exhibit B-6, BCUC IR 38.2

"Although FortisBC cannot say with certainty that the requirements did not eliminate non-RF communication technologies from being proposed, the Company is confident that the requirements in the RFP were reasonable, prudent and did not needlessly restrict vendor proposals. For example, FortisBC required that proposals should support hourly consumption reads to ensure that time-based rates could be supported. Although older PLC technologies might be challenged to meet this requirement, FortisBC understands that wired technologies exist that are perfectly capable of meeting the requirement."

74.1 Would any of the wired technologies that are capable of meeting the hourly consumption reads requirement be capable of meeting the other requirements of the Request for Proposals?

Response:

FortisBC cannot know how proponents that didn't respond with a non-RF solution would have responded, so cannot answer this question.

74.2 When FBC designed and issued the RFP did FBC anticipate that all the proposals would be for wireless systems?

Response:

FortisBC did not expect any particular result with respect to the type of communications technologies that would be proposed, but was aware that the North American AMI market had generally shifted to RF technologies.

"FortisBC did not specify any particular type of communications technology based on the experience of other Fortis Inc. companies (or any other utilities), including FortisAlberta (which uses PLC) and FortisOntario (which uses RF). This decision was made for two main reasons:

1. AMI communications technologies are continuously evolving, so it was prudent to test the market with business requirements, not technology requirements; and

2. FortisBC AMI requirements are unique to its operating environment."

74.3 When was FortisAlberta's PLC-based metering system selected and implemented? Was the PLC-based system selected from an RFP? If not, what factors caused FortisAlberta to chose PLC system over a wireless metering system? If there was an RFP, did it specify a non-wireless system? Were any wireless systems proposed?

Response:

The factors that caused FortisAlberta to choose a PLC system over wireless were discussed in the responses to BCUC IR No. 1 Q113.1.2 and Q113.1.3.

The FortisAlberta RFP specified functional specifications but did not define technology. Proposals received included RF only, PLC only and hybrid PLC/RF technologies.

Final selection and contract award for the FortisAlberta contract occurred December 18, 2006. A pilot of 30,000 meters began immediately and was completed Q2 of 2007. Upon further regulatory approvals, full implementation began in 2008.

74.4 Please answer the same questions regarding FortisOntario's Radio Frequency-based metering system.

Response:

FortisBC has responded to this question as if it were worded as follows:

> When was FortisOntario's RF-based metering system selected and implemented? Was the RF-based system selected from an RFP? If not, what factors caused FortisOntario to choose RF system over a wired metering system? If there was an RFP, did it specify a wireless system? Were any non-wireless systems proposed?

In Ontario a consortium of some of the largest utilities created and issued a RFP in 2006 in conjunction with other provincial agencies. A Fairness Officer's Office was created to assist in the evaluation and selection. That RFP narrowed the field down to three suppliers, all of whom proposed some form of wireless communications; point to point, cell based and mesh network. Following this selection process, each utility in the province (including FortisOntario) aligned its self to this RFP or a subsequent RFP (in which the vendors were provided an opportunity to bring forward more current technologies and pricing).

FortisOntario does not believe that the Ontario RFP specified any particular technology.

74.5 What did Util-Assist tell FBC about the relative merits, costs and benefits of wired versus wireless metering systems?

Response:

FortisBC understood that both types of metering systems were viable solutions. Util-Assist aided FortisBC in creating the RFPs and evaluating the proposals submitted by each technology vendor based on FortisBC requirements. Through the RFP process, the documented requirements focused on what FortisBC needed the system to accomplish then Util-Assist helped to evaluate each proposal on the relative merits, costs and benefits and how the proponent's proposed system fit with FortisBC's functional requirements.

FortisBC and Util-Assist discussed the merits of variety of different systems and vendors, but those discussions did not impact the process described above.

74.6 Is FBC aware of any electricity utilities in North America that are currently implementing wired metering systems?

Response:

Please refer to the response to CSTS IR No. 1 Q11.1.

74.7 What is it about FortisBC's operating environment and associated AMI requirements that differs from utilities such as FortisAlberta that have chosen wired metering systems?

Response:

Please see the responses to BCUC IR No. 1 Q113.1.2 and Q113.1.3. FortisBC understands that the FortisAlberta requirements were driven in part by the need to get daily reads (as opposed to hourly reads) from meters in order to reduce costs and improve accuracy related to the load settlement process that occurs between energy retailers, energy suppliers and transmission and distribution operators in Alberta.

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SMART METERS AND SMART GRID REGULATION 368/2010

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SMART METERS AND SMART GRID REGULATION 368/2010

B.C. Reg. 368/2010

[deposited December 15, 2010]

Contents

[Provisions of the *Clean Energy Act*, SBC 2010, c. 22, relevant to the enactment of this regulation: section 37 (g)]

Definitions

1. In this regulation:

"Act" means the *Clean Energy Act*;

"automation-enabIed device" means a device that, when installed on the authority's electric system, is capable of being used by the authority, at a location remote from the device, to control the flow of electricity;

"connectivity model" means a computer model of the electric distribution system identifying all of the following:

(a) the locations at which eligible premises are connected to the electric distribution system;

(b) the locations known to the authority at which unmetered buildings, structures or equipment are connected to the electric distribution system;

(c) the locations of

(i) distribution transformers,

(ii) distribution circuit conductors,

(iii) substations,

(iv) system devices, and

(v) switches,

that are within the electric distribution system;

(d) the locations of generators connected to the electric distribution system;

(e) the phase and direction of the electricity flowing through the conductors referred to in paragraph (c);

(f) whether or which of the distribution circuit conductors connected to switches referred to in paragraph (c) are energized;

"electric distribution system" means the equipment of the authority that is energized at less than 60 kilovolts and is used by the authority to provide electricity at less than 60 kilovolts;

"electricity balance analysis" means an analysis of the electricity in a portion of the electric distribution system, including an analysis of the amount of electricity that

(a) is measured by the smart meters at all eligible premises supplied from that portion,

(b) is measured by the system devices installed on that portion,

(c) is supplied from that portion to unmetered loads known to the authority, and

(d) is lost in that portion because of resistance or another cause known to the authority;

"eligible premises" means a building, structure or equipment of a customer of the authority if the building, structure or equipment is connected to the electric distribution system and has an electricity meter;

"in-home feedback device" means a device that is capable of

(a) displaying

(i) a smart meter's measurements of electricity supplied to an eligible premises, and

(ii) the cost of the electricity measured by the smart meter, and

(b) transmitting information in digital form to and receiving information in digital form from a smart meter with which the authority has established a secure telecommunIcations link;

"system device" means a device, including a distribution system meter and a sensor, that, when installed on the electric distribution system, is capable of

(a) measuring and recording measurements of electricity as frequently as smart meters,

(b) transmitting and receiving information in digital form,

(c) measuring bi-directional flow of electricity, and

(d) being configured by the authority at a location either remote from or close to the device.

Prescribed requirements for smart meters

2. For the purposes of the definition of "smart meter" in section 17 (1) of the Act, the prescribed requirements for a meter are that it is capable of doing all of the following:

(a) measuring electricity supplied to an eligible premises;

(b) transmitting and receiving information in digital form;

(c) allowing the authority remotely to disconnect and reconnect the supply of electricity to an eligible premises, unless

(i) the point of metering for the eligible premises

(A) is greater than 240 volts,

(B) is greater than 200 amperes, or

(C) is three phase, or

(ii) the eligible premises

(A) has a bottom-connected meter,

(B) has an output or input pulse meter, or

(C) has a meter that measures maximum electricity demand in watts;

(d) recording measurements of electricity, and recording the date and time of the recording, at least as frequently as in 60-minute intervals;

(e) being configured by the authority at a location either remote froth or close to the meter;

(f) measuring and recording measurements of electricity generated at the premises and supplied to the electric distribution system;

(g) transmitting information to and receiving information from an in-home feedback device, unless the point of metering for the eligible premises meets any of the criteria set out in paragraph (c) (i) or the eligible premises meets any of the criteria set out in paragraph (c) (ii).

Installation of smart meters and related equipment

3. (1) Subject to subsection (3), by the end of the 2012 calendar year, the authority must install and put into operation

(a) a smart meter for each eligible premises, and

(b) all of the following related equipment:

(i) communications infrastructure for transmitting information among smart meters and the computer hardware and software systems described in subparagraph (ii);

(ii) secure computer hardware and software systems that enable the authority to do all of the following:

(A) monitor, control and configure smart meters and the communications infrastructure referred to in subparagraph (i);

(B) store, validate, analyze and use the information measured by and received from smart meters;

(C) provide, through the internet, to a person who receives electricity from the authority secure access to information about the person's electricity consumption and generation, if any, measured by a smart meter;

(D) establish a secure telecommunications link between in-home feedback devices and smart meters that are compatible with each other;

(E) 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;

(F) integrate the systems with the authority's other business systems.

(2) The communications infrastructure referred to in subsection (1) (b) (i) must include a telecommunications network that is capable of delivering two-way, digital, and secure communication.

(3) If it is impracticable because of distance, electromagnetic interference, physical obstruction or other similar cause for the authority to establish a telecommunications link between the smart meter at an eligible premises and the computer hardware and software system referred to in subsection (1) (b) (ii), the authority is not required to install or put into operation the communications infrastructure referred to in subsection (1) (b) (i) for the purpose of establishing that telecommunications link.

(4) The authority must integrate the operation of smart meters and related equipment with the authority's other operations.

Smart grid

4. (1) The program required under section 17 (4) of the Act must be established by the end of the 2015 calendar year and include the following components:

(a) the establishment and operation of a connectivity model and the installation and operation of

(i) at least 9 000 but no more than 35 000 system devices, and

(ii) computer hardware and software systems

to enable the authority to

(iii) perform electricity balance analyses for the electric distribution system, and

(iv) estimate the amount of electricity supplied from a portion of the electric distribution system to unmetered loads that are not known to the authority and to estimate the location of those loads;

(b) the acquisition of investigation devices and computer software to enable the authority to identify the location of the unmetered loads referred to in paragraph (a) (iv);

(c) the establishment and operation of telecommunications networks that

(i) have sufficient speed and bandwidth, and

(ii) enable two-way, digital, and secure communication among system devices, automation-enabled devices and the systems and equipment used by the authority for monitoring and controlling its electric system

to facilitate

(iii) the operation of the authority's electric system,

(iv) the integration, on a large scale, of distributed generation into the electric distribution system, and

(v) the provision of electricity service that allows for the large-scale use of electric vehicles by its customers.

(2) The authority must integrate the operation of the smart grid with the authority's other operations.

[Provisions of the *Clean Energy Act*, SBC 2010, c. 22, relevant to the enactment of this regulation: section 37 (g)]

Appendix BCSEA IR1 3.1

The Canadian Smart Grid Standards Roadmap:

A strategic planning document

Prepared by the CNC/IEC Task Force
on Smart Grid Technology and Standards

October 2012

Standards Council of Canada
Conseil canadien des normes

Canada

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- Task Force Working Group 1 (WG1) members included Avy Moise (chair), Ludo Bertsch, Andre Brandao, Luc Tessier, Edward Arlitt, Eric Mewhinney, Alexandre Prieur and Bill Bryans. WG1 provided advice on standards for advanced metering systems, customer applications, electric vehicles and the interface requirements between the utility and its customers;
- Task Force Working Group 2 (WG2) members included Jean Goulet (chair), Dan Blanchette, Devin McCarthy, Avy Moise, Eric Mewhinney, Grant Gilchrist, Jamie Hall, Keith Jansa, Brent Jorowski, Tab Gangopadhyay and Lisa Dignard-Bailey. WG2 provided advice on Smart Grid transmission and distribution standards, the applications of distributed energy resources, the utility requirements regarding the electromobility infrastructure and conducted a Canadian utility survey to identify key priority areas;

- Task Force Working Group 3 (WG3) included Bill Bryans, Ed Juskevicius, Tony Capel, Mahendra (Mike) Prasad, Edward Arlitt and John O'Neill. WG3 contributors addressed Smart Grid cyber security, the North America Reliability Corporation standards and the consumer privacy legislative framework.

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DISCLAIMER:

Foreword

The transition to a smarter electric grid holds significant promise for the achievement of a number of important public policy objectives. Smart grid technologies will enhance the reliability, resiliency and efficiency of the electric network, as well as improve environmental performance by enabling consumers to play a more active role in their energy use decisions and helping to integrate renewable resources such as wind.

Many of the technologies that will enable this transition have yet to be demonstrated, while others are still under development. As these technologies mature and are brought into the marketplace, standardization will become increasingly necessary to ensure the development of an efficient and effective smart grid.

Indeed, standards form the basis for virtually all products and services in any economy. For the smart grid, an effective standards regime will enable smart appliances and smart meters to inform consumers of the amount of energy they consume, and at what cost. It will spur infrastructure development and investment in related technologies such as plug-in electric vehicles. Importantly, an effective standards regime enhances Canada's competitiveness by ensuring alignment with the global marketplace, without which Canadian technology vendors could find their products incompatible or obsolete.

For these reasons, Natural Resources Canada and the Standards Council of Canada's National Committee to the International Electrotechnical Commission created a Task Force on Smart Grid Technology and Standards to recommend priority standards for the smart grid. This document is a product of a two-year project undertaken by the Task Force, and serves as a roadmap to navigating the evolving standards environment. The evolution of the smart grid is such that the new standards environment must both support a smarter North American electric grid as well as provide guidelines for utilities and manufacturers on their participation in the emerging global marketplace.

This project supports a number of key government objectives, including expanding Canada–United States collaboration under the Clean Energy Dialogue. By identifying a path forward on the priority standards for Canada, this work supports that of the United States National Institute of Standards and Technology to develop a broad range of standards for the smart grid. Continental alignment in this regard is critical, given the interconnectedness of our trading relationship and electrical infrastructure.

On behalf of the Standards Council of Canada and Natural Resources Canada, we would like to extend our gratitude to all the organizations and experts who have contributed their time and knowledge to the publication of the Smart Grid Standards Roadmap, as well as to those who will help pave the way for its implementation.

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Standards Council of Canada

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Deputy Minister
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1 Introduction

Over the past two years, Natural Resources Canada (NRCan), in cooperation with the Standards Council of Canada's (SCC's)[1] Canadian National Committee to the International Electrotechnical Commission (CNC/IEC), recognized the pressing need for a national body to define and coordinate Canada's Smart Grid standardization initiatives. Under the divisions of legislative responsibility of the Canadian constitution, electricity matters falling within the boundaries of a single province are a provincial jurisdiction.

The CNC/IEC provides policy advice to SCC on matters pertaining to IEC and has oversight responsibility for Canadian activities at IEC.[2] To meet that need, the CNC/IEC created the *Task Force on Smart Grid Technology and Standards*, hereinafter referred to as the *Task Force*, which first convened in February 2010 and has continued to meet on a regular basis through to January 2012. SCC provided three guiding principles for the Task Force's work:

- ensure that Canada's needs are reflected in products developed under the IEC's Smart Grid initiatives;
- leverage—to the maximum extent possible—national and North American efforts to ensure Canadian Smart Grid priorities are identified and incorporated into the IEC's work plan; and
- coordinate standards development in such a way as to avoid national and regional differences as much as possible (unless appropriately identified and understood as necessary).

Task Force membership consists of experts representing the entire spectrum of Smart Grid stakeholder sectors, including:

- generation, transmission and distribution utilities
- utility equipment vendors
- building infrastructure experts
- enterprise- and consumer-level equipment manufacturers
- federal, provincial and municipal regulators
- standards development organizations (SDOs)

As a technically oriented advisory group, the Task Force is formally charged with:

- *providing advice* to CNC/IEC on policy regarding Canadian participation in national and international standardization on Smart Grid technology and standards, including harmonization of Canadian and international technical work;
- *supporting integration* of national and international electrotechnical standardization by working toward IEC standards on Smart Grid technology having the widest possible acceptance in Canada and its trading partners;

[1] *Standard Council of Canada (SCC): http://www.scc.ca/en/home.*
[2] Refer to the *Canadian Procedural Document CAN-P-7 2011 Canadian Participation in ISO and IEC: http://www.scc.ca/en/publications-can-p-7-2011-canadian-participation-in-iso-and-iec*

- *assessing and providing feedback* on the effectiveness of the work program in meeting the needs of this electrotechnical sector;
- *establishing and maintaining liaisons* with other sector players, as appropriate (with a view to coordinating Smart Grid technology standardization activities within the electrotechnical sector); and
- *providing recommendations* to CNC/IEC on potential new fields of activity in Smart Grid technology and standards.

The goal of this document is to provide a *roadmap*—a strategic plan—to advance the standards environment from today's legacy electricity grid to tomorrow's full deployment, operation and evolution of the Canadian Smart Grid. The new standards environment will not only support a North American Smart Grid but will also provide guidelines for utilities and manufacturers to participate in the emerging global Smart Grid marketplace.

This report provides a brief overview for all stakeholders of Canada's Smart Grid policy, legislative and regulatory environment. Following Section 1 introduction, the roles played by the federal and provincial governments are highlighted in Section 2. Key Smart Grid initiatives and recommendations are described in Section 3 for privacy and security requirements. The Canadian roadmap recommendations in Section 4 provide a comprehensive technical review of high-priority standards projects within the transmission and distribution domains—including cross-cutting recommendations on spectrum standardization and cyber security. Section 5 presents a detailed description of the key issues for metering systems. Section 6 summarizes the key elements produced by three working groups:

- Working Group 1 (WG1), focused on standards for advanced metering systems (e.g., smart meters) and other post-distribution elements of the Smart Grid, such as customer networks, electric vehicles as Smart Grid storage devices, and the interface requirements between the utility and its customers;
- Working Group 2 (WG2), focused on transmission and distribution standards; and
- Working Group 3 (WG3), focused on Smart Grid privacy and security issues, particularly with respect to cyber security as it affects both consumers and utilities.

The work of these groups of the Task Force yielded cross-cutting, high-level recommendations equally applicable to all of the domains that make up the Canadian Smart Grid.

The most critical cross-cutting finding relates to the Task Force's recommendation for SCC to establish a *Smart Grid Standards Steering Committee*. This committee would continue supporting strategic oversight of managing the domestic and regional deployment of this roadmap, and further development of Canadian expert participation at the appropriate international policy management committees, such as IEC SMB-SG3 for Smart Grid, SMB-SG6 for Electric Vehicle Mobility, and the new *Advisory Committee on Electricity Transmission and Distribution (ACTAD*). In addition to key stakeholder representatives, it should also include representatives from the relevant Canadian national mirror committees to the International Electrotechnical Commission (IEC), the International Organization for Standardization (ISO), the International Telecommunications Union (ITU), the International Organization of Legal Metrology (OIML), etc. The *Smart Grid Standards Steering Committee* would champion and promote Canadian activities, filling identified gaps and periodic maintenance of the Smart Grid strategic roadmap.

Recommendation G1:

> The CNC/IEC should recommend the creation of a Smart Grid Steering Committee to coordinate and assist with the other recommendations contained in this Roadmap, work with other relevant standards policy bodies and technical committees, and periodically update the Roadmap.

The Task Force also found that Canada did not have a smart meter technical committee. Additionally, a few important technical committees are insufficiently resourced to undertake the effort; the continuity of the effort will need to be sustained over the foreseeable future.

Recommendation G2:

> The CNC/IEC should support the creation of a Canadian technical sub-committee for smart meters, and encourage greater participation and support funding to other important technical committees.

The Task Force members found that many of the potential standards to be used in the Smart Grid environment are not yet mature. There is no clear consensus of how suitable those standards will remain as the overall system strategy evolves. More research and pilot-scale demonstrations are important to gain experience with the applications of the standards required. Therefore, it is not recommended to enshrine any standards in regulation in the near term.

Recommendation G3:

> The CNC/IEC should recommend to governments and regulators to be very cautious about enshrining any standard in regulation in the near term, as some are not yet mature enough to have a proven track record. Also, forced early conversion to a new standard may prematurely render current infrastructure investments obsolete, unnecessarily adding cost burdens.

2 Smart Grid Policy, Legislation and Regulatory Overview

2.1 Overview of policy objectives

The Smart Grid is the application of technologies pioneered in the telecommunications sector, across the entire electricity supply chain, that enables better communications in real time–from generation to transmission and distribution, right down to the meter, and even inside customer premises by contract. One of the major factors empowering this transition is a growing recognition by government leaders of the potential of the Smart Grid to achieve a wide range of energy policy objectives. Certainly, this is the case for the Government of Canada, which sees Smart Grid technologies as key to a brighter, greener economic future.

The Government of Canada's approach toward the future for Smart Grid is focused on three core energy policy objectives: ensuring reliability (which includes security), adequacy, and environmental performance.[3] To meet the first objective, a Smart Grid will aim to improve real-time knowledge of what's happening on the system. The goal would be to avoid unplanned outages where possible, and improve response time when outages occur. Of course, a reliable system also has to be secure, which requires solid standards and operating protocols. The second energy policy objective, ensuring adequacy, means having sufficient infrastructure across all aspects of the electrical system, to meet customer loads. Smart Grid will enable increased use of renewable energy, allow improved demand management and therefore ensure that assets are used efficiently. Thirdly, by allowing customers to purchase cleaner, lower-carbon-emitting generation and manage their own energy consumption—and by helping to better integrate renewable energy sources at customer sites—a Smart Grid will contribute to our goal of improved environmental performance, by reducing greenhouse gas (GHG) emissions.

While much of the innovation to deploy the Smart Grid will be driven by industry, governments also have a clear role to play in facilitating research and development and in aiding the commercialization of promising new technologies. For example, the Government of Canada is taking steps to support promising demonstration projects under the Clean Energy Fund and ecoEnergy Innovation Initiative, to spur the kind of technological changes that will help deploy the Smart Grid as part of Canada's economic development strategy. For example, four Maritime utilities led by New Brunswick Power Corporation will integrate Smart Grid technologies, customer loads and the management of wind generation in a region with potentially significant renewable electricity capacity. Other provinces, such as Ontario—and, more recently, British Columbia, Manitoba and Quebec—have initiated projects to enable the Smart Grid evolution in Canada.

Policymakers have a role to play in removing barriers for new product and service offerings in areas such as Smart Home, demand response, distributed generation and electric vehicle management, in the domestic, regional and international arenas. Allowing not only traditional utility companies, but innovators from other sectors, to explore new business models and develop opportunities, that will help maximize value-creating activities around Smart Grid infrastructure. "Smart Regulation" can *significantly* boost the ability of national manufacturers to compete in the global market by providing input to international standards bodies to support emerging product development. A key role governments and regulators play in this strategy is helping the private sector develop and promote standards that open up the international market to Canadian companies, while not unintentionally hampering innovation.

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[3] NRCan minister speaking notes Canada-US Clean Energy Dialogue Smart Grids in the North American Context: A Policy Leadership Conference: http://www.nrcan.gc.ca/media-room/speeches/16/2011-01-25/clean-energy/1802.

2.2 The federal role

The federal government is contributing to this strategic planning process by leading standardization discussions with stakeholders. SCC manages and provides leadership for coordinating standardization input for Smart Grid activity. At the international level, Canadian experts, via SCC's *Accreditation Services*, are active participants in the International Electrotechnical Commission (IEC) Standardization Management Board Strategic Group 3 (SMB-SG3) for Smart Grid. In addition, other accredited Canadian experts are taking a leadership role in developing Smart Grid communications standards within IEC Technical Committees, such as TC57[4], or are active participants. Industry Canada participates at the International Telecommunications Union (ITU), representing government regulatory harmonization interests. Canadian experts also participate in a number of other relevant North American standards-setting bodies such as IEEE (Institute of Electrical and Electronics Engineers).[5] A major concern Task Force members have identified is the need for adequate funding of experts and their availability to participate in the development and harmonization of international standards.

Industry Canada manages the wireless spectrum allocation process that includes a spectrum identified for utilities, for Smart Grid communications requirements. Industry Canada[6] has identified the 1800-1830 MHz spectrum for various applications in support of the management of the electricity supply, including high-speed teleprotection, Supervisory Control and Data Acquisition (SCADA), telemetry and mobile radio, and Smart Grid development. The electricity sector continues to emphasize to Industry Canada the critical infrastructure nature of the industry and the need to protect and enhance existing spectrum resources, as well as ensure access to necessary bandwidth for Smart Grid applications.

Measurement Canada[7] is an Agency of Industry Canada, mandated to ensure the integrity and accuracy of trade measurement through the administration and enforcement of *the Electricity and Gas Inspection Act and Regulations and the Weights and Measures Act and Regulations*. The key elements considered for smart metering standardization is the requirement: that a meter must be approved; must be verified and sealed; must have a means of indication (display); and that any modifications to Advanced Metering Infrastructure (AMI) must not impact the meter's accuracy or integrity. Measurement Canada is recommending a pragmatic approach that separates the legal metrology verification from AMI applications and communications. This is allowed in the standard OIML-D31 (General requirements for software controlled measuring instruments Standard). Measurement Canada S-EG-05 Specifications for the Approval of Software Controlled Electricity and Gas Metering Devices, and S-EG-06 Specifications Relating to Event Loggers for Electricity and Gas Metering Devices are now effective and evaluated for compliance in test laboratories by Measurement Canada.

The Federal Public Security Technical Program (PSTP) is an initiative of Defence Research and Development Canada (DRDC). This program aims to enhance collaboration across government and deliver science and technology (S&T) solutions across many dimensions of public security. PSTP will mobilize resources to address challenges to public security and critical infrastructure protection, by integrating expertise across disciplines and departments. DRDC initiated a project

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[4] "Smart Home" is the term commonly used to define a residence that has appliances, lighting, heating, air conditioning, TVs, computers, entertainment audio & video systems, security, and camera systems that are capable of communicating with one another and that can be controlled remotely by a time schedule, from any room in the home, as well as remotely from any location in the world, by phone or Internet.
Refer to the IEC Smart Grid Strategic Framework available: http://www.iec.ch/zone/smartgrid/.

[5] Refer to the IEEE: http://www.ieee.org/index.html.

[6] Industry Canada Smart Grid and Digital Economy Strategy: http://www.ic.gc.ca/ic_wp-pa.htm.

[7] Measurement Canada: http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/home.

to review the cyber security issues related to the Smart Grid and SCADA communications systems.[8]

The National Energy Board (NEB) and several Canadian provinces have signed a Memorandum of Understanding with the North American Electric Reliability Corporation (NERC).[9] NERC is a regulatory authority established to evaluate reliability of the bulk transmission power system in North America. NERC develops and enforces reliability standards; assesses adequacy annually; monitors the bulk power system; and educates, trains and certifies industry personnel. A review of reliability requirements under Smart Grid is currently underway. NERC is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC). In Canada, NERC presently has memoranda of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Quebec and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity. Manitoba recently adopted legislation that sets out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the “electric reliability organization” under Alberta’s Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and Northeast Power Coordinating Council (NPCC) have been recognized as standards-setting bodies by the Régie de l’énergie of Québec, and Quebec has the framework in place for reliability standards to become mandatory. Nova Scotia and British Columbia[10] also have frameworks in place for reliability standards to become mandatory and enforceable. The National Energy Board and the Department of Natural Resources Canada (NRCan) are following the progress of the NERC Task Forces on bulk (wholesale) electricity reliability, including ongoing effort of its own Smart Grid Task Force.

2.3 The provincial role

Under the divisions of legislative responsibility of the Canadian constitution, electricity matters falling within the boundaries of a single province are within provincial jurisdiction.[11] This is already having a profound influence on the development of the Smart Grid in Canada, and we expect it will continue to do so. Over the course of its work, this Task Force has noted that there is a wide disparity from province to province in regards to both levels of Smart Grid development activity and the manner in which those activities are being carried out. These are, of course, heavily influenced by the widely varying industry structures between the provinces.

In some cases, we have seen the enthusiasm of early adopters of Smart Grid technology running up against the challenge of deploying such technologies in advance of established interoperability standards. One such prominent example is the Ontario Smart Metering Initiative, which was conceived and implemented before the development of emerging Advanced Metering Infrastructure Standards. For example, Ontario is now coping with how to enable data access for third-party service providers when common standards are not in place across the

[8] DRDC project results will be reported in 2012-2013 for two projects: PSTP 02-347eSec - Study in Cyber Security and Threat Evaluation in SCADA Systems; and PSTP 03-431eSec - Build a SCADA/Smart Grid Test Centre.
[9] North American Reliability Corporation (NERC): http://www.nerc.com/
[10] BC Hydro is a member of NERC and WECC. BC Ministry of Energy and Mines is a member WIRAB, that advises NERC and WECC:

- http://transmission.bchydro.com/transmission_system/reliability/
- http://www.empr.gov.bc.ca/EPD/Electricity/TD/Reliability/Pages/default.aspx

[11] Ref.: RSC, Consolidated Constitution Acts 1867 to 1982, section 92A

province. [12] Ontario's electricity industry recognizes the need to adopt widely used interoperability standards and is looking to groups such as this Task Force to make recommendations in that regard.

Consumers increasingly need access to information to allow them to use the Smart Grid more efficiently. Also, consumer products interfacing with the Smart Grid will need to follow internationally accepted equipment standards; typically, consumer equipment is drawn from the international market. That being the case, Smart Grid standards need to be harmonized and will fall into one of two general categories:

- standards that enable and/or enhance national and regional system/device <u>interoperability from a utility point of view</u>; or
- standards that provide <u>compatibility</u> between vendor equipment in the international marketplace.

The adoption and use of interoperability standards is at particular risk of being adversely affected by domestic disparities within Canada and across the border.

Some standards discussed in this report have the legislative backing of a standards body. Measurement Canada, for example, has the power to stipulate and enforce nationwide standards for various aspects of metering devices. However, the U.S. government does not have an equivalent agency. Also, decisions regarding how and when most standards discussed in this report will be used, ultimately reside with Canada's provincial and territorial authorities. There is also a recognized need for coordinating this effort within Canada and the United States. Canada's Federal, Provincial and Territorial (FPT) energy ministers initiated support for a collaborative approach to energy at their annual meeting, held in Kananaskis, Alberta[13] in July 2011. At that time, the reliability of this nation's Smart Grid and electricity network were identified as areas requiring collaboration. An FPT Energy Technology Working Group is preparing a Smart Grid Report, which will identify gaps and recommend opportunities to energy ministers at the their annual meeting in Prince Edward Island in September 2012.

Our Task Force has noted that discussions between FERC and National Institute of Standards and Technologies (NIST), in the United States, have resulted in the U.S. national regulator stepping back from legislating Smart Grid standards at the national level.[14] The U.S. regulator has, however, called for another national organization to lead in promoting and recommending Smart Grid standards for use across all U.S. states. The Task Force has followed the developments in the United States and believes that SCC and its nationally accredited standards development organizationsSDOs can continue to lead in promoting the adoption of harmonized standards in Canada. As a result, this Task Force is recommending a consolidated, national view of Smart Grid in Canada.

<u>Regulator Recommendation R1</u>:

> SCC's CNC/IEC should encourage Provincial, Territorial regulators and utilities, when developing business plans for Smart Grid initiatives, to ensure that systems migrate from proprietary technologies to open standards, and from their current architecture to the Canadian Smart Grid Reference Framework described in this report. This step will enable regulators and utilities to compare roadmaps and therefore identify areas of commonality, interoperability, deployment timing and possible technological risk.

[12] Ref.: Ontario Smart Grid Forum, "*Modernizing Ontario's Electricity System: Next Steps. Second Report of the Ontario Smart Grid Forum*," May 2011, Section 2-2 ("Third Party Access"), page 22

[13] The Alberta Utilities Commission (AUC), Alberta Smart Grid Inquiry, Proceeding ID No. 598, January 31, 2011. http://www.auc.ab.ca/items-of-interest/special-inquiries/Documents/smart_grid/Alberta_Smart_Grid_Inquiry_final_report.pdf

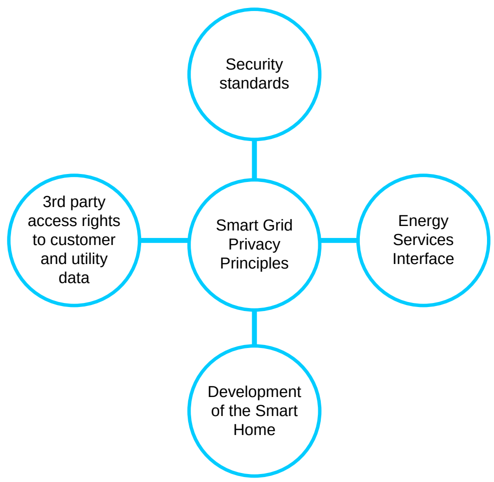
[14] U.S. Federal Energy Regulatory Commission, Docket No. RM11-2-000, "*Smart Grid Interoperability Standards*" (Issued July 19, 2011), page 1

3 Privacy and Security Requirements

Privacy has a close and complex interrelationship with a number of Smart Grid interoperability issues that are central to this report. There is a growing awareness of the need to develop first principles for consumer privacy that should be embedded in the architecture and standards of Smart Grid infrastructure. These issues have been at the forefront of the Task Force's examination of the various interoperability standards.

In Canada, the provincial privacy commissioners are tasked with responding to consumer complaints regarding possible infringements to the applicable privacy law.[15] At the heart of current Smart Grid privacy discussions is a set of core principles, which states that the consumer should have the ultimate authority over access and usage of their own energy-related data. Figure 1 identifies the four aspects linked to the *Smart Grid Privacy Principles*.

Figure 1: Interrelationships between Privacy, Security and Smart Grid



Perhaps nowhere in Canada are these *Smart Grid Privacy Principles* more explicitly linked to the Smart Grid's architecture than in Ontario. The Ontario Information and Privacy Commissioner has set out a series of "Privacy by Design" principles for the Smart Grid.[16] The Ontario Smart Grid Forum, an advocacy body for the development of smart grids, has formally recognized these principles as crucial to the development of the Smart Grid. Our Task Force notes that these principles broadly apply to developing Smart Grid across Canada. Legislators and regulators need to consider the precise instruments and mechanisms by which such principles should be applied and enforced.

These *Smart Grid Privacy Principles* include: the energy service interface, the development of the Smart Home, the third-party access to customer and utility data, and the cross-cutting security standards.

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[15] For example, British Columbia's privacy commissioner has launched an investigation into BC Hydro's Smart Meter program, after receiving complaints that the information collected by the device breaches personal privacy. The Commissioner's Office received complaints and correspondence from more than 600 British Columbians about the smart meter program, which prompted the investigation. The commissioner found that BC Hydro is complying with the *Freedom of Information and Protection and Privacy Act*, with regard to the collection, use, disclosure, protection and retention of the personal information of its customers. However, the crown Corporation was not in compliance with regard to the notification it provides to its customers about smart meters. Source: www.oipc.bc.ca

[16] Privacy by Design: http://www.ipc.on.ca/english/Resources/Discussion-Papers/Discussion-Papers-Summary/?id=967

<u>The Energy Services Interface and the Development of the Smart Home</u>: NIST has begun to conceptualize an Energy Services Interface (ESI) as a crucial meeting point in the Smart Grid between systems belonging to utilities, customers and third parties. The ESI is therefore one of the most crucial areas of the Smart Grid, where privacy issues will play out. This Task Force has considered how these functions should be enabled by available interoperability standards. The Task Force has made recommendations allowing Canadian homes to connect to the Smart Grid in a secure and private framework. The technical details of the Canadian *Smart Grid Advanced Metering Infrastructure Logical Architecture* and recommendations are described in Section 5 of this report.

<u>Third-Party Access to Customer and Utility Data</u>: Beyond the *Smart Grid Privacy Principles* are the detailed protocols and ground rules by which third-party service providers may access customer data and receive data on the customer's behalf from their local utility. In Ontario, this issue has risen to prominence; an emerging class of private-sector players has expressed interest in accessing real-time smart metering data to provide a burgeoning array of Smart Home products and services. Section 5 of this report also includes a technical approach to resolve this access issue in a safe and secure manner. The Task Force notes that the North American Energy Standards Board (NAESB) [17] has just concluded the development of a comprehensive set of detailed recommendations regarding the division of responsibility between third parties and utility companies that warrant a close examination by regulators and the Canadian electricity industry.

<u>The Need for Security Standards:</u> The application *Privacy Principles*, and ensuring the confidentiality and integrity of Smart Grid data, are enabled by applying a wide variety of security standards. Cyber security standards may use encryption to maintain data confidentiality and the integrity of data transmitted between Smart Grid system components. Other standards address the need to have the "trusted" equipment, system design, people and procedures in place to create and maintain the required secure environments.

For smart meter security, Measurement Canada's Software Security Joint Working Group has reviewed standard OIML-D31 General requirements for software-controlled measuring instruments. (Measurement Canada was represented within the TC5/SC2 OIML Working Group.) [18] Consequently, Measurement Canada developed, in collaboration with industry stakeholders, the S-EG-05 Specifications for the Approval of Software Controlled Electricity and Gas Metering Devices, and S-EG-06 Specifications Relating to Event Loggers for Electricity and Gas Metering Devices. These specifications are being used in Canada for meter-type approval, including for: Encryption, Authenticity Check (public keys and signatures), Integrity Check and Design Requirements. These specifications allow for software upgrades under certain conditions.[19]

The NERC Technical Committees (Operating, Planning, and Critical Infrastructure) for the North American transmission systems have begun to address the implications of reliability through five task forces. In addition to being staffed by industry experts, these task forces are supported by globally renowned U.S. and Canadian governmental agencies, scientists and subject matter experts.[20] As well, the Canadian Electricity Association representing utilities has signalled its commitment toward a pragmatic approach to the implementation of Smart Grid technologies in

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[17] North American Standard Energy Board: http://naesb.org

[18] OIML : International Organization of Legal Metrology or Organisation Internationale de Métrologie Légale

[19] Measurement Canada presentation: http://www.oeb.gov.on.ca/OEB/_Documents/EB-2011-0004/MC%20presentation%20-%20Ontario%20smart%20grid.pdf)

[20] In 2011, more than 75 industry and government partners participated in the North American Electric Reliability Corporation's (NERC's) first cyber security readiness exercise. The two-day exercise is part of NERC's ongoing security readiness program to assess NERC and the industry's crisis response plans, and to validate current readiness in response to a cyber incident.

Canada. Cyber security must be taken seriously, and customer privacy is of utmost importance.[21] [22]

The Task Force found significant Canadian participation and leadership in the development and the adoption of Smart Grid privacy principles and their promotion in Canada and the United States. However, the Task Force identified an urgent need to coordinate Canadian efforts regarding Smart Grid cyber security guidelines,[23] and makes the following recommendation:

Regulator Recommendation P&S1:

> The CNC/IEC should recommend that Canadian stakeholders participate in the specification of Smart Grid cyber security requirements and standards within NIST's Smart Grid Interoperability Panel (SGIP) and Cyber Security Working Group, to promote a harmonized North American approach to the extent possible. It is also recommended that the proposed National Smart Grid Steering Committee consider where and how Canadian positions on Smart Grid cyber security standards should be developed.

[21] THE SMART GRID: A PRAGMATIC APPROACH, A "State-of-Play" Discussion Paper by the Canadian Electricity Association, 2011.

[22] When planning comprehensive system security, the following factors need to be considered: resilience and access to both physical building and surrounding premises, electronic and cyber-attacks. In doing that it is essential to consider the overall architecture necessary to deal with 'all' security systems relating to fire & burglary protection and life safety systems for home, commercial, institutional premises, the access controls and surveillance equipment.

[23] NIST released an updated version of their document in February, 2012, which incorporates public comments into the NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0 . Chapter 6 is dedicated to Cyber security. The chapter includes an outline of the going-forward three-year strategy of NIST's SGIP Cyber Security Working Group (CSWG): http://www.nist.gov/smartgrid/framework-022812.cfm.

4 Transmission and Distribution Standards

4.1 Introduction

The Canadian Smart Grid Standard and Technology Task Force recognizes the value of the core IEC TC57 architecture presented in the IEC Technical Report 62357-1. The IEC Smart Grid Standardization Roadmap is based on the work of the IEC TC57. Canada is actively participating in the development of this international reference architecture and participates in the Standard Management Board Smart Grid Committee. The schematic in Figure 2 is adapted from the IEC 62357-1 and identifies the cross-cutting applications layers, services, and standards protocols that apply in the management of a power system and how they relate to each other within a Canadian context. The Task Force completed a detailed assessment and identified a number of priority standards and gaps in this section of the report. A description of the key layers presented in figure 2 includes the following key reference layers:

- application-to-application and business-to-business communications for energy markets, customers and other energy service providers;
- control centres for energy and distribution management system (EMS and DMS) using Common Information Model (CIM);
- SCADA communications between control centres and the field equipment using interfaces and mappings;
- field equipment communications for substations and feeder automation; and
- cross-cutting infrastructure requirements, including industry communications protocols, wide area network (WAN) and telecontrol communications media and services and security standards.

The goal of interoperable systems can be very hard to achieve in a diverse environment with different requirements, many different vendors, and a wide variety of standards. Fortunately, the industry can overcome these issues by:

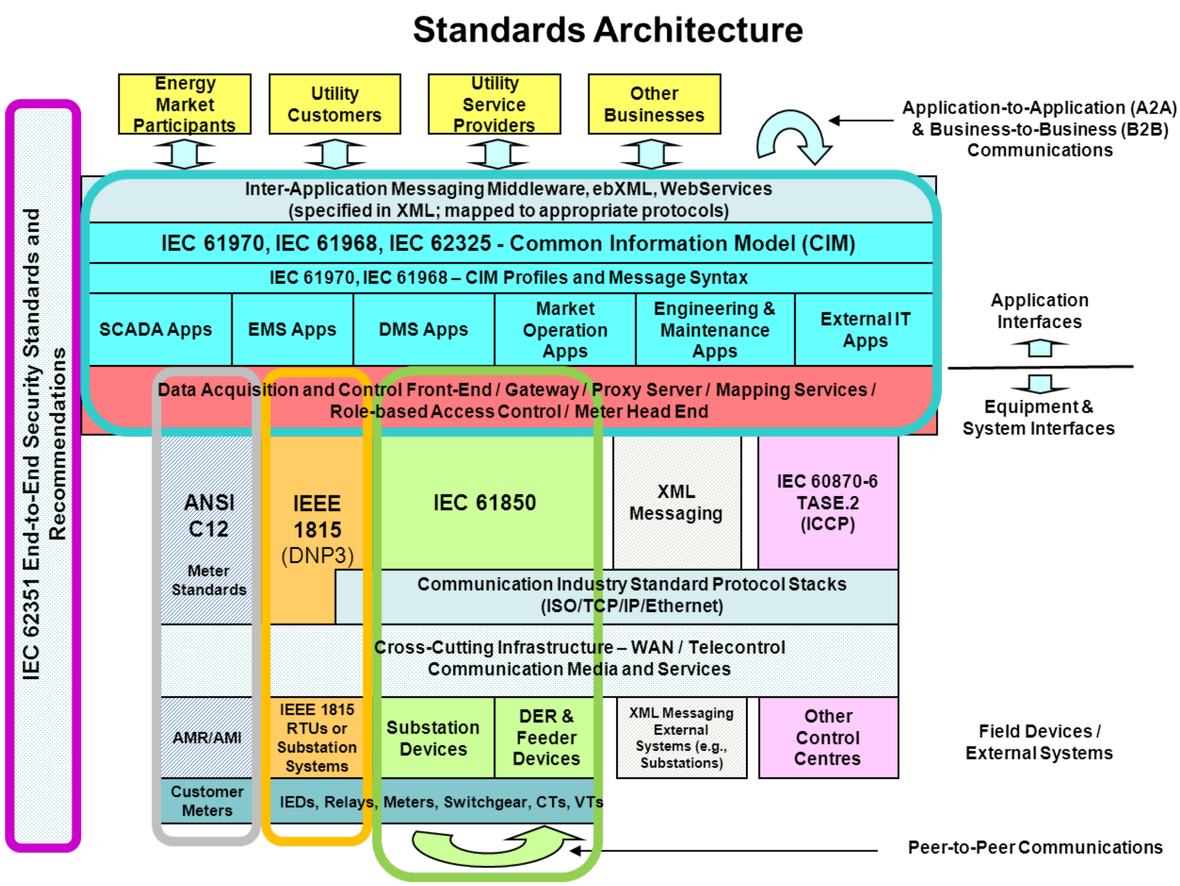
- using gateways and protocol converters to help the migration from legacy systems to modern Smart Grid technologies;
- using object modeling that represents the physical equipment; and
- using metadata[24] to facilitate information exchange between systems and applications.

The Task Force identified the key standards required to ensure interoperability for Canadian Smart Grids (Figure 2). The Task Force has taken a pragmatic view by recommending Canadian deviations from the IEC standards framework. This reflects the wide-scale adoption of ANSI C12 meter standards use in Canada and the necessary transition period required before migrating to the core IEC standards (IEC 61850 and CIM). The following subsections of the roadmap describe the findings of the Task Force for Canadian energy markets (4.2), control centres (4.3), Supervisory Control and Data Acquisition (SCADA) (4.4), field devices and distributed energy resources (4.5), and the cross-cutting communications network infrastructure (4.6). The Task Force recommendations considered the current status of the Smart Grid implementation in Canada and reports on the results of a utility survey conducted in 2011.

[24] Metadata: Information used by the utility systems to describe basic data sets. For example, Extensible Markup Language (XML) can be used to define metadata.

The Canadian reference architecture provides a framework for future standardization work to extend IEC core standards or develop new standards within the IEC. The architecture highlights, using colour lines, the key areas of focus for this Canadian Smart Grid Roadmap. The schematic allows Canadian stakeholders to compare current industry standards—as they apply to utility transmission and distribution infrastructure—with the evolving reference architecture being developed by the IEC working groups.

Figure 2: Canadian Smart Grid Standards Architecture adapted from IEC 62357-1



As the functionalities required by Smart Grid are deployed throughout the generation, distribution and delivery infrastructure, additional standards will be needed. Existing and emerging standards being developed in other industry sectors must be evaluated to determine their suitability, and must be incorporated into the proposed architecture, as appropriate. This approach will both minimize the overall proliferation of standards and avoid conflicting or redundant requirements. This evaluation will require good cross-sector knowledge of the standards being developed internationally. Creating a Canadian Smart Grid Steering Committee would serve as an ideal means to assemble the cross-sector experts needed.

4.2 Energy market communications

Energy market communications has historically been a relatively closed transactional environment, limited to: i) wholesale transactions controlled by an independent electricity system operator; and ii) to a very minor extent, utility-controlled interactions with customers (manual demand response). With the coming of the Smart Grid, both ends of the market, wholesale and retail, are expected to open up, to a large degree. New standards that can promote interoperability are required for both types of markets.

The Common Information Model (CIM) is an abstract model (published by the IEC TC 57) to represent all major *objects* in an electric utility enterprise typically needed to model the operational aspects of a utility. This standard should be understood as a tool enabling integration in any domain where a market system model must facilitate interoperability and plug-and-play compatibility between applications and systems independent of any particular implementation. CIM specifies the basis for the semantics for this message exchange. (Refer to Table 1.) The profile specifications, contained in parts of the IEC 62325 standards, currently only support European-style markets. A project within the IEC 62325 part 352, to support the North American-style market, is planned, with the collaboration of the Independent Regional Council (IRC). The IRC represents 10 regional transmission operators in Canada and the United States. These operators are characterized by *regional markets*, with day-ahead unit commitment by a market operator, intraday and real-time balancing through central dispatch, and settlement based on Locational Marginal Prices (LMP).[25]

Although Canada has not participated in the work done by the IEC TC57 Working Group 16 to develop these standards parts, several independent Regional Transmission Operators (RTO) are members of the North American Energy Standards Board (NAESB). NAESB has several active committees developing wholesale and retail electricity market standards. The NAESB Wholesale Electricity Quadrant (WEQ) standard was published with requirements for all information flows—from registration through to performance evaluation of demand resources and including deployment, with 33 exchanges in total. IRC members developed a flexible framework intended to cover local variations in market rules, while still standardizing the information payloads in these exchanges over time. Following the ratification of both the wholesale and retail electricity market requirements documents, the NAESB Working Group embarked on a more-detailed data requirements phase. In 2011, the wholesale and retail groups reconciled the processes and aligned their models. The project team was therefore able to deliver a common set of requirements.[26]

The Task Force identified a need to encourage participation of experts in the work of the IEC TC57 Working Group 16. The Working Group would develop profiles for the North American wholesale energy market (IEC 62325 part 352) and propose new work items for standardizing information exchanges for demand response electricity markets (NAESB WEQ and REQ standard market profile). The two energy market communications standards priorities are highlighted in yellow in the list of key standards in Table 1.

[25] Independent System Operator/Regional Transmission Operator Council (ISO/RTO), IRC 2009 State of the Markets Report: www.isorto.org.

[26] Scott Coe, CanmetENERGY report March 2011 : NAESB standard "covers the 290 data elements which are needed to build the 33 WEQ information flows and support the 31 REQ use cases, with indicators to applicability to wholesale and retail for each element." Refer to NAESB weblink : http://www.naesb.org/dsm-ee.asp.

Table 1: Energy Market Communications Standards

Standard	Title			
IEC 62325	**Framework for energy market communications**			
	Part	**Subtitle**	**Status**	**TC/SC/WG**
	102	Energy market example	Published	TC57 WG16
	301	Common information model (CIM) for markets	To be published	TC57 WG16
	351	Profile for European-style markets	To be published	TC57 WG16
	*352	Profile for North America wholesale energy markets (IRC ISO-RTO Council)	Planned	TC57 WG16 / NAESB
	450	Methodology	To be published	TC57 WG16
	451, 452	Document profiles	To be published	TC57 WG16
	501	General guidelines for use of ebXML	Published	TC57 WG16
	55X	Translations	New work	TC57 WG16
NAESB	*	Profile for North American wholesale and retail demand response markets (NAESB)	Gap	NAESB
*** priorities and gaps highlighted**				

4.3 Control centres—energy and distribution management systems

Canadian utilities are implementing the Common Information Model (CIM), CIM IEC 61970 and 61968 within their control centres.[27] [28] These standards cover both electric utility transmission and distribution business operations. The CIM is expressed in Unified Modeling Language (UML), which enables system integration and information exchange. CIM also defines a set of standard system interfaces for exchanging information between Information and Communications Technology (ICT) systems. The CIM can be extended to enable both the standard extensions for new functional areas and for private extensions for specific utility requirements, such as relevant geospatial data models**.** The CIM IEC 61970 standard defines the energy management system (EMS) Application Programming Interfaces. The CIM IEC 61968 standard defines the System Interfaces for Distribution Management.

The core models defined in the IEC 61970-301 Standard for Transmission Management System, and the models defined in the IEC 61968-11 Standard for Distribution Management System, complement the models defined in IEC 62325-301 for the energy markets. These models were presented in section 4.2 of this report.

CIM profiles are a standard part of the IEC 61968 and IEC 61970-4xx series of Component Interface Standards. These standards specify the functional requirements for interfaces that a component (or application) shall implement to exchange information with other components (or applications) and/or to access publicly available data in a standard way. The component interfaces describe the specific message contents and services that can be used by applications

[27] Hydro-Québec CIM implementation plan, presentation to the CEA, February 22, 2012; and Manitoba Hydro presentation to the CNC/IEC Smart Grid Task Force, 2011.

[28] Canadian Control centres will continue to use IEC 60870-6.2 TASE.2 (ICCP); finding a replacement is not a priority. There are few incentives to replace IEC 60870-6 with CIM technologies, but this could change in the future.

for this purpose. In tables 2 and 3, several CIM Profiles projects[29] have been highlighted as priority projects:

- The IEC 61970 part 452, CIM Static Transmission Network Model Profile, aims to rigorously define the subset of classes, class attributes, and roles from the CIM for executing state estimation and power flow applications. The North American Electric Reliability Council (NERC) Data Exchange Working Group (DEWG) Common Power System Modeling group (CPSM) produced the original data requirements, used as the basis for producing the CIM Profile. These requirements are based on prior industry practices for exchanging power system model data for use primarily in planning studies. However, the list of required data has been extended in part 452 to facilitate a model exchange that includes parameters common to breaker-oriented applications.[30] In addition, the IEC 61970 part 45X aims to provide additional profiles, including part 451 - CIM profile for SCADA Data Exchange and part 455 - CIM Model Population Profile.[31]
- The IEC 61968 Part 11 contains the CIM extensions for distribution. The standard is not complete, and several Canadian utilities have developed extensions of their own. There is an opportunity to include Canadian extensions in future editions of the standard.
- The IEC 61968 Part 14-2 is another highlighted project for mapping Multispeak 4.0 to the IEC 61968 parts 3 to 10. This project is a result of work done by the NIST Priority Action Plan (PAP) 8 to develop strategies for integrating and expanding IEC 61970-301, IEC 61968, Multispeak and IEC 61850 for Smart Grid applications.[32]
- The IEC 61968 Part 100 aims to define a set of implementation profiles for IEC 61968 using technologies commonly applied to enterprise integration. This document describes how message payloads defined by parts 3 to 9 of IEC 61968 are conveyed using web services and the Java Messaging System. Guidance is also provided for using Enterprise Service Bus (ESB) technologies. The goal is to provide details that would enable interoperable implementations of IEC 61968.[33]

Table 2: Control Centre Standards for Energy Management Systems

Standard	Title			
IEC 61970	**Energy management system (EMS) application program interface**			
	Part	**Subtitle**	**Status**	**TC/SC/WG**
	1	Guidelines and general requirements	Published	TC57 WG13
	301	Common information model (CIM) base	Ed.3 published	TC57 WG13
	*452	CIM model exchange specification	To be published	TC57 WG13
	453	CIM based graphic exchange	Published	TC57 WG13
	*45X	Additional profiles	New work	TC57 WG13
	501	CIM RDF Schema	Published	TC57 WG13
	502-8	Web Services mapping	New work	TC57 WG13
	50X	Additional message format	New work	TC57 WG13
*** priorities highlighted**				

[29] From IEC 61970-452, 57/1107/NP.
[30] From IEC 61970-452, 57/1107/NP.
[31] IEC TC 57 working group 13 report, Shanghai, 2011.
[32] Multispeak background found at : http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP08DistrObjMultispeak.
[33] IEC 61968-100 new proposal: reference IEC 57/1151/NP.

Table 3: Control Centre Standards for Distribution Management Systems

Standard	Title			
IEC 61968	**Application integration at electric utilities–System interfaces for distribution management**			
	Part	**Subtitle**	**Status**	**TC/SC/WG**
	1	Interface architecture and general requirements	Ed.2 to be published	TC57 WG14
	1-1	Enterprise Service Bus implementation profile	New work	TC57 WG14
	1-2	Web Services	New work	TC57 WG14
	3	Network operations	Published	TC57 WG14
	4	Record and asset managements	Published	TC57 WG14
	9	Meter reading and control	Published	TC57 WG14
	*11	Common information model extensions for distribution	Published	TC57 WG14
	13	CIM RDF Model exchange for distribution	Published	TC57 WG14
	*14-1	Mapping between Multispeak 4.0 and IEC 61968, parts 3 to 10	Planned	TC57 WG14
	*14-2	CIM profile for Multispeak 4.0 Profile for IEC 61968 3 to 10	Planned	TC57 WG14
	*100	ESB implementation profile	Planned	TC57 WG14

*** priorities highlighted**

4.4 SCADA communications between control centres and the field equipment

Supervisory Control and Data Acquisition (SCADA) systems are used to obtain data from the field or to exchange data between control centres. For control centres, the Task Force believes CIM should fulfill this role. Currently, SCADA servers acquire field data using IEEE 1815 (known as DNP3) and serve it to proprietary applications.

In the future, a SCADA system will use IEC 61850 standards to access data from substation and field devices. The SCADA system will act as a server using CIM IEC 61970 standards to exchange data with Control Centre EMS applications (e.g., Smart Grid State Estimator). The Task Force identified the need to resolve the differences in models between IEC 61850 and the CIM IEC 61970. The TC57 Working Group 19 effort will eliminate duplication through reuse of CIM classes by using IEC 61850 standards.

Legacy standards, such as IEEE 1815, implicitly assumed an "anonymous point-oriented model" to identify the values received and devices controlled. A data value source, such as an analog measurement, status, or accumulator (i.e., counter) value, is, therefore, a Remote Terminal Unit (RTU) point number or name. This is in contrast to the "device-oriented models" being developed in the TC57 Working Group 10 with the 61850 standards. For this Working Group, real-world substation and field devices are represented by object models. The value of the object is identified by a structured name identifying the device that supplies it and the object it contains.

Although adapters will always be required to translate proprietary data formats in legacy systems, a goal is to harmonize standards within TC57 so that a single representation of SCADA data is used in all standards. Single representation eliminates the need for translation in adapters. This would lead to a seamless architecture and is part of the vision of the future reference architecture. Table 4 lists the key standards for SCADA.

The Task Force has identified two high-priority projects that will help build this seamless architecture:

- *Communications between control centres and substations* crucial to allowing the free flow of data between field equipment and control centre applications. The possibility of using IEC 61850 for communications between substations and control systems is identified in the IEC TC57 reference architecture document (IEC 62375) without any specification of how it will be used. The issue was evaluated in 2002 by an IEC task force. The conclusion was that IEC 61850 is suitable, but may eventually require the following extensions:[34]
    - o a new mapping of the communications services on a protocol suitable for wide area communications. Bandwidth, latency and packet loss issues need to be considered;
    - o extensions of the data model to provide a control centre view of the substation. A further important benefit to users is the possibility of entering configuration information only once; and
    - o currently, substation configuration information is available in the SCL (substation configuration language). Control centre configuration information is available in the CIM. The models have been harmonized, so that an automatic transfer of the information from one model to the other should be possible. New work shall describe how that configuration information can be transferred between CIM and SCL.
- *Communication of synchrophasor information needed for advanced Smart Grid applications.* Synchrophasor data, as measured and calculated by Phasor Measurement Units (PMUs), are required for advanced Smart Grid applications. The synchrophasor and related message formats to transmit synchrophasor data over long distances are defined in IEEE C37.118. There is a need to ensure that PMU communications mechanisms comply with the IEC 61850. The IEC 61850 Part 90-5 Technical Report describes how this should be done.[35]

Table 4: Standards for Supervisory Control and Data Acquisition

Standard	Title			
IEC 61850	**Communications networks and systems for power utility automation**			
	Part	**Subtitle**	**Status**	**TC/SC/WG**
	1, 2, 3, 4, 5, 6, 8-1, 9-2, 10, 7-1, 7-2, 7-3, 7-4	Main parts – developed for substations	Ed. 2 under publication	TC57 WG10
	80-1 TS	Exchange of 61850 information using IEC 60870-5-101/105	Published	TC57 WG10
	*90-2 TR	Communications between control centres and substations	To be published	TC57 WG19
	*90-5 TR	Communication of synchrophasor information (IEEE C37.118-2005)	To be published	TC57 WG10 / IEEE C37.118
IEC 61970 CIM	451	CIM-SCADA Data Exchange	New work	TC57 WG13
IEEE 1815		Standard for data acquisition and control between SCADA and field equipment	Published	IEEE 1815
*** priorities highlighted**				

[34] From IEC 61850-90-2 draft R0-24.
[35] From IEC 61850-90-5, reference IEC 57/1144/DTR.

4.5 Field equipment communications for substations and distribution automation

Intelligent Electronic Devices (IEDs) will have applications critical to power system reliability within smart grids. For power system protection, field devices will communicate with other field devices, using peer-to-peer communications. This opens the door to decentralized networks, compared with existing centralized networks, in which a master relays and make decisions. These components enact *self-healing* procedures that cannot currently be monitored or controlled in real time by today's SCADA systems. IT and telecommunications best practices and technological advances will enable performance and security tools to monitor and manage the growing field area networks, substation local area networks and communications between them.

Areas where these differences need to be reconciled occur when information is shared between a system using one set of models (e.g., an EMS/SCADA system based on the CIM) with a system using the other models (e.g., an automated substation using the 61850 standards). Another example would be a fault location system or maintenance management system based on CIM network and asset models using data from a 61850-based automated substation to provide fault and asset data. Table 5 lists the main parts of the IEC 61850 required for substation automation and the Task Force has identified two standards projects that are highlighted as priorities:

- The IEC Technical Report entitled "Use of IEC 61850 for the communication between substations" should be promoted in Canada, as it will guide the implementation of advanced line protection schemes. When IEC 61850 was prepared, it was intended for the use of information exchange between devices of a substation automation system. However, the concepts can be used in other application domains of the power utility system. Therefore, IEC 61850 is on the way to becoming the foundation for a globally standardized utility communications network. With existing and new applications for power system operation and protection, the requirement to exchange standardized information directly between substations increases. The IEC 61850 shall be the basis for this information exchange. IEC 61850 provides the basic features to be used for that information exchange. However, some extensions to IEC 61850 may be required.[36]
- The IEEE1815 (Distributed Network Protocol (DNP3)) is the standard most frequently used by Canadian utilities, while IEC 61850 is making progress.[37] The IEEE 1815 committee is collaborating with IEC TC57 Working Group 10, to publish a specification describing how to implement gateways between IEC 61850 and IEEE 1815. Two primary-use cases are addressed: mapping between an IEEE 1815-based master and an IEC 61850-based remote site; and mapping between an IEC 61850 based master and an IEEE 1815-based remote site. Mapping aspects included in the standard are: conceptual architecture; general mapping requirements; the mapping of Common Data Classes, Constructed Attribute Classes and Abstract Communication Service Interface (ACSI); and the architecture of a gateway for translation and requirements for embedding mapping configuration information into IEC 61850 System Configuration Language (SCL) and an DNP3 Device Profile. This specification addresses a selection of features, data classes and services of the two standards.[38]

[36] Refer to IEC 61850-90-1; reference IEC 57/992/DTR.
[37] The IEEE 1815.1 (part 1) specifies the standard approach for mapping between IEEE 1815 and IEC 61850 (Communications Networks and Systems for Power Utility Automation).
[38] Refer to http://standards.ieee.org/develop/project/1815.1.html.

Table 5: Standards for Substation Automation

Standard	Title			
IEC 61850	**Communication networks and systems for power utility automation**			
	Part	**Subtitle**	**Status**	**TC/SC/WG**
	1, 2, 3, 4, 5, 6, 8-1, 9-2, 10, 7-1, 7-2, 7-3, 7-4	Main parts–developed for substations	Ed. 2 under publication	TC57 WG10
	9-2			
	80-1 TS	Exchange of 61850 information using IEC 60870-5-101/105	Published	TC57 WG10
	*IEEE 1815.1	Gateways between IEC 61850 and IEEE 1815 (DNP3)	New work	TC57 WG10 / IEEE 1815
	*90-1 TR	Communication between substations, including GOOSE messages	Published	TC57 WG10
	90-4 TR	Network engineering guidelines for substations	To be published	TC57 WG10
*** priorities highlighted**				

As a pillar of the Smart Grid, the scope of usage of IEC 61850 is expanding, especially in the fields of:[39]

- the integration of Distributed Energy Resources (IEC 61850-7-420);
- feeder automation and advanced distribution management systems; and
- the integration of active electricity consumers, such as electric vehicle charging stations, homes, buildings or industrial plants.

Table 6 highlights the priority projects of IEC 61850, including two new required work items:

- The IEC 61850 Part 7-4XX series for advanced distribution automation. As a first step, the IEC TC57 WG17 is planning to publish the IEC 61850-90-6 Technical Report. This report identifies the advanced distribution applications that require coverage by IEC 61850. The following Smart Grid applications have been identified by WG17:[40]
  - demand response
  - volt-var management
  - fault detection, localization, isolation and restoration (FDIR)
  - feeder reconfiguration
  - controlling dispatchable distributed generation units
- web services. The resulting IEC 61850-8-2 Smart Grid standard will offer[41]:
  - open-source communication stacks
  - low footprint implementation, to fit small device constraints
  - de facto LAN/WAN capabilities
  - easy convergence and interoperability with CIM
  - embedded cyber security capabilities, and firewall/security policies compatibility
  - connectivity to millions of communicating devices already supporting these mechanisms

[39] This is described in the IEC 61850-8-2, new proposal IEC 57/1181/NP.
[40] This is described in the IEC 57/1074/DC.
[41] This is described in the IEC 61850-8-2, new proposal IEC 57/1181/NP.

Table 6: Standards for Distribution Automation and Distributed Energy Resources

Standard	Title			
IEC 61850	**Communication networks and systems for power systems**			
	Part	**Subtitle**	**Status**	**TC/SC/WG**
	1, 2, 3, 4, 5, 6, 8-1, 9-2, 10, 7-1, 7-2, 7-3, 7-4	Main parts	Ed. 2 under publication	TC57 WG10
	*7-420	Distributed energy resources logical nodes	Published	TC57 WG17
	*7-4XX	Feeder automation	New work	TC57 WG17
		Communication for Distributed Resource Island Systems	**Gap	TC57 WG17 / IEEE 1547.4
	*8-2	Communication profile using web services	New work	TC57 WG17
	90-7 TR	Object models for DER inverters	New work	TC57 WG17
	90-8 TR	Electric vehicles	New work	TC57 WG17
	90-9 TR	Storage and batteries	New work	TC57 WG17
		Demand response for customer loads, based on IEEE 1547.3	**Gap	TC57 WG21 / IEEE1547.3
*** priorities and gaps highlighted**				

4.6 Cross-cutting infrastructure–communications media and services

A central tenet of Smart Grid development should be the extension of open standard field area networks with high bandwidth and low-latency service throughout the geography of Canada for largely last-mile connectivity purposes. (Refer to Table 7.) To this end, spectrum has been identified in Canada for electric utility applications by Industry Canada, in the 1.8 GHz band (1800-1830 MHz), as shown in Figure 3. This recognized the urgent need for Smart Grid communication solutions. It has been proposed that utilities could deploy Worldwide Interoperability for Microwave Access (WiMAX based upon IEEE 802.16 standard), Long Term Evolution (LTE) or other standardized technologies in this frequency range, to address some of the last-mile connectivity concerns.

Canada is a leader in the identification of Smart Grid spectrum; other countries may choose different bands for electricity management. This is not a significant problem, as long as similar amounts of spectrum and operating rules permitting similar technologies are adopted. For example, 1800 to 1830 is near the Global System for Mobile Communication (GSM) 1800 gap band (1785 to 1805 MHz), between the GSM[42]-1800 uplink and downlink. The 1785 to 1805 MHz band is used for time division industrial broadband networks in China. In the United States and other countries where electricity management spectrum is not yet allocated, the gaps between Advanced Wireless Services (AWS) and Personal Communication Services (PCS), or the GSM bands, are good opportunities.[43] Some U.S. utilities that cannot wait are purchasing spectrum from auction winners (e.g., 2.3 GHz or 700MHz). The United States is considering

[42] For mobile phone applications–GMS standard: Global System for Mobile Communications.

[43] U.S. spectrum broadband: http://www.broadband.gov/plan/5-spectrum/#s5-2; In Canada, the cellular mobile radio services (CMRS) were launched in the early 1980s, with licences for 40 MHz of spectrum in the cellular band. In response to tremendous growth in demand for mobile telephony services, additional spectrum was designated in 1989 (in the cellular band); in 1995 (in the PCS band); and in 2001 (additional PCS spectrum). The Advanced Wireless Service (AWS) auction in 2008 made available an additional 105 MHz to the commercial mobile industry in three different bands: AWS, PCS and 1670-1675 MHz. http://www.ic.gc.ca/eic/site/sd-sd.nsf/eng/home.

repurposing frequencies in the 700MHz range. Many utilities already have spectrum in the 700 to 900MHz range, which they use for analog and digital microwave radio. There is potential in this area for common Smart Grid spectrum to be identified. A disadvantage of not having direct harmonization with the United States is a potential for international frequency coordination challenges, as the bulk of the Canadian population is located near the U.S. border.

Table 7: List of Wireless Telecommunication Options for Metering, Middle Mile and Backhaul[44]

Component	Requirements	Possible Telecommunication Options
Smart Metering	• Short range connectivity • Low bandwidth, low duty cycle • Robust: Withstands interruptions • Must be low cost	➢ Wireline ➢ Wireless ➢ Licence-exempt ➢ Licensed
Middle Mile	• Connection to many collector stations/substations and small generation sources • Moderate cost is acceptable • Good reliability • Medium bandwidth	➢ Wireline ➢ Wireless ➢ Licensed
Backhaul	• Connect to fewer points • High bandwidth • High reliability • Low latency	➢ Wireline (Fibre/copper) ➢ Wireless ➢ Licensed

Figure 3: Industry Canada Wireless Spectrum 1800-1830 MHz Band for Point-to-Multi-point Backhaul for Fixed Electricity Management

WiMAX communication technology for wirelessly delivering service to large geographic areas—the choice of early utility networks—is a mature technology. The standard is well-established, and the WIMAX Forum promotes its interoperability.[45] With the emergence of LTE for mobile cellular services,[46] research and development investment in WiMAX technology has diminished. The future of WiMAX is in doubt among cellular telephony providers. Utilities may represent an alternate market for WiMAX technology because it can be deployed without dependency on an external telecom provider, which is appealing to some utilities. There is a precedent: the utility industry has managed to keep the 900 MHz analog radio equipment manufacturers in business as their primary market since 1990. However, it is not clear whether utilities and other niche markets will be sufficient to make WiMAX a healthy, growing technology. Canadian utilities have signalled to their suppliers that development roadmaps are required. One desirable roadmap

[44] Source: Miranda Kong, Spectrum Regulation, Presentation at ISACC 44th Plenary, Ottawa, Ontario, November 4, 2010.
[45] Worldwide Interoperability for Microwave Access (WiMAX) is a communication technology for wirelessly delivering service to large geographic areas. Its conformance is verified through certification by the WIMAX Forum: http://www.wimaxforum.org/certification/certification-overview.
[46] Long Term Evolution (LTE) is a standard for wireless communication of high-speed data for mobile phones and data terminals, also marketed as 4G LTE.

option is to enhance LTE to support utility operating conditions, allowing migration.[47] Some of the utility market-focused suppliers are already offering LTE products. In Canada, having spectrum policy for electricity management mitigates product development risk and allows the utility suppliers to develop communications solutions to meet the unique and stringent needs of electric utilities.

4.7 Cross-cutting security

Today, cyber security frameworks are an essential part of every utility's communications. There are numerous methods to secure communications. Therefore, each utility must assess how and to what extent their communication network should be secured. To help utilities in this task, a series of technical specifications was issued by IEC TC57 WG15 to describe security enhancement for key power systems communications standards. These enhancements are necessary, because, at the time the original standards were produced, security issues were not part of the scope. Three important projects are highlighted in Table 8 as priorities:

- IEC 62351 Part 5—Security for IEC 60870-5 and derivatives: IEC 60870-5, Part 101 and, particularly, Part 104, require security enhancements to ensure their implementation and use in non-secure environments. This technical specification also addresses security for IEEE 1815.
- IEC 62351 Part 6—Security for IEC 61850 profiles: The different communications profiles of IEC 61850 require security enhancements to ensure their implementation and use in non-secure environments.
- Security for CIM: There is currently no work under way to describe security enhancements for the CIM. Ideally, work being done on CIM communications profiles should include security aspects from the start, and should not require a separate security specification. However, WG13 and WG14 experts developing CIM profiles may not have the security expertise of their WG15 colleagues. Therefore, the situation has to be assessed as work progresses on CIM profiles, to evaluate the need for such a security specification.

Table 8: Standards for Security

Standard	Title			
	Data and Communications Security			
	Part	**Subtitle**	**Status**	**TC/SC/WG**
	3	Security for profiles including TCP/IP	Published	TC57 WG15
	4	Security for profiles, including MMS	Published	TC57 WG15
	*5	Security for IEC 60870-5 and derivatives	Published	TC57 WG15
IEC 62351	*6	Security for IEC 61850 profiles	Published	TC57 WG15
	7	Objects for Network Management	Published	TC57 WG15
	8	Role-Based Access Control	Published	TC57 WG15
	9	Key management	In progress	TC57 WG15
	10	Security architecture	In progress	TC57 WG15
	*	Security for CIM	Gap	TC57 WG15
*** priorities and gaps highlighted**				

[47] Electricity transmission and distribution utility decentralized operation—focused on security, but not accounting and hardened for industrial environments.

In addition, significant linkages need to be established with the Joint Technical Committee (JTC1/SC27), which develops security standards suitable for industrial application. The JTC1/SC27 has developed a series of base-security standards, originally addressing the ICT sector. Unlike the ICT sector, where the protection of information is typically most important, the industrial sector places the most emphasis on the protection of people, the environment and physical assets. Therefore, security standards must be tailored to meet Smart Grid and other critical infrastructure requirements. This is an evolving field, and additional work will be required to identify and promote the standards needed.[48]

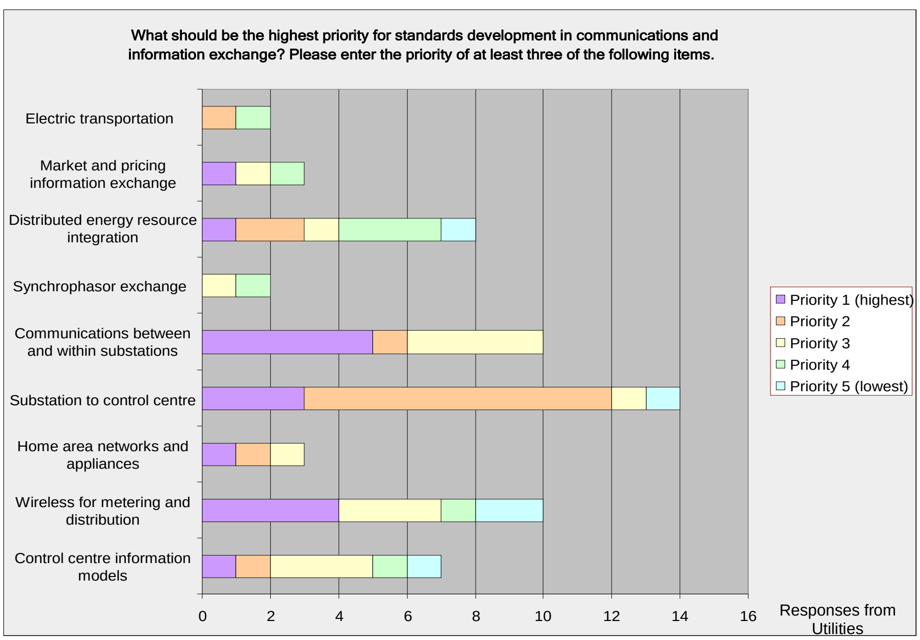
4.8 Survey results of Canadian implementation

The results of a cross-Canada utility survey conducted by Task Force Working Group 2 (WG2) is shown in Figure 4. The top three priorities for the industries are the following:

- communication between and within substations. The relevant standards for this priority area include IEC 61850 for substation, IEEE 1815 (DNP3) for SCADA and IEEE C37.118 for synchrophasors;
- wireless communications for metering and distribution. This priority reflects the need to develop cross-cutting, wide-area network infrastructure solutions needed to convey the information from the field equipment to the Distribution Management Systems; and
- communication between substations and control centres. This priority area requires a technical report describing how to transform IEC 61850 data into IEC 61970 CIM data.

The Canadian Task Force has included these top three priorities as part of its key transmission and distribution Smart Grid recommendations, as depicted in Figure 4.

Figure 4: Results of Survey to Identify the Top Three Priorities for Standards Development



[48] For example, work in IEC/TC65 WG10 *Security for industrial process measurement and control—Network and system security*, aims to develop a series of standards that targets the industrial sector.

4.9 *Recommendations for closing the T&D standards gaps*

The Task Force consolidated the following six key Transmission and Distribution (T&D) system recommendations:

Recommendation T&D1:

It is important for Canadian experts to participate in, or initiate work on, harmonization of NAESB energy market standards with the IEC TC57 WG16. This would support new work on harmonization of standards for the wholesale and retail electricity markets and demand response.

> The CNC/IEC should encourage Canadian experts' participation in IEC TC57/WG16 for developing the IEC 62325-356 profile for North American wholesale energy markets. As well, the CNC/IEC should become an active contributor to NAESB Demand Response standards.

Recommendation T&D2:

There is far too much variability in the current CIM projects, and multi-vendor CIM deployments are nearly non-existent. To achieve the advantage of interoperability, CIM standards must evolve to more closely resemble the application programming interface standards they were originally intended to be.

> The CNC/IEC should encourage the creation of standardized profiles for CIM implementations and the creation of mappings between Multispeak 4.0 and IEC 61968 CIM as a means to improve control centre systems interoperability.

Recommendation T&D3:

The future Smart Grid requires standards that will support improved situation awareness over a large geographic area, to help avoid large-scale blackouts.

> To support Smart Grid interoperability requirements, the CNC/IEC should encourage the adoption and application of IEC 61850 for the purpose of communication between substations, between substations and control centre and for the transfer of synchrophasor data.

Recommendation T&D4:

Although the IEC 61850 if one of the core standards identified, it still needs to reach greater maturity for field equipment, substations and Distributed Energy Resources.

> The CNC/IEC should encourage the development of guidelines and standards for utilities to migrate from existing, commonly used technologies to the architecture described in IEC 61850. At the same time, the CNC/IEC should recognize the large, existing investment by utilities in the older technologies. This will require gateway solutions and protocol converters during the initial transition period. In addition, the CNC/IEC should encourage the extension of this standard to distribution automation equipment and distributed energy resources.

Recommendation T&D5:

The dominance of proprietary solutions is blocking the creation of communication network solutions for distribution feeder automation.

> The CNC/IEC should encourage the standardization and adoption of high-bandwidth, low-latency, low-cost field communication networks; this area is often dominated by proprietary solutions and Canada's vast geography. In addition, the CNC/IEC should

encourage a dialog between the Canadian and U.S. policymakers regarding the use of a common spectrum.

Recommendation T&D6:

The CNC/IEC should encourage the development and use of the IEC 62351 standard that applies security controls to power-system-specific communications technologies. One specific area that needs to be addressed and monitored is the security for CIM.

5 Metering Systems Standards

5.1 Introduction

Canada's Smart Grid interoperability framework will need to account for the realities of existing infrastructure and systems that are already deployed across Canada (and the United States), having many years of useful service life left in them. This holds true for:

- meters
- metering and related communications systems between utility and customer
- metering head-end systems
- utility enterprise-side metering and data management systems (back office)

Collectively, the meters, the systems behind the meters, and those in front of the meters, manifest themselves across Canada's diverse mixture of generation, transmission, distribution and measurement assets. Today, for example, millions of customer locations across the province of Ontario implement various proprietary forms of Advanced Metering Infrastructure and attendant "smart meters" and related control devices. These items pre-date (at times by more than 10 years) emerging or contemporary interoperability standards, such as the ANSI [49] standard C12 and the IEEE [50] standard 1377 and the IEEE standard 170x series of standards. Utility stakeholders have developed and are actively developing additional conformance testing specifications, deployment management guidelines and accreditation requirements for the AMI. These include establishment of the North American End Device Registry Authority (NAEDRA)[51], AEIC[52] Guidelines 2.0 (AMI interoperability guidelines for meter communications and supporting enterprise networks), and the application of Measurement Canada's[53] specifications for the approval of both software-controlled electricity meters and event loggers.

5.2 Canadian Smart Grid advanced metering infrastructure standards

A list of key standards referenced in electricity metering requirements, or in Canadian legislation, is provided in Table 9. These standards are expected to be deployed in a manner consistent with the recommended *Smart Grid Advanced Metering Infrastructure Logical Architecture*. The logical flow and control of the information is shown in Figure 5. This logical schematic provides an expanded view of the AMI/AMR Customer Domain Field Area Network (FAN) and Premises Area Network (PAN). From a communications standpoint, the Customer AMI Domain (depicted in the top-left quadrant of Figure 5) is divided internally into three security perimeters:

- the utility-owned (or delegated) and controlled trusted Facility Area Network zone (**FAN trusted zone**) component of the AMI;
- the customer control and trusted Premises Area Network zone (**trusted PAN zone**); and

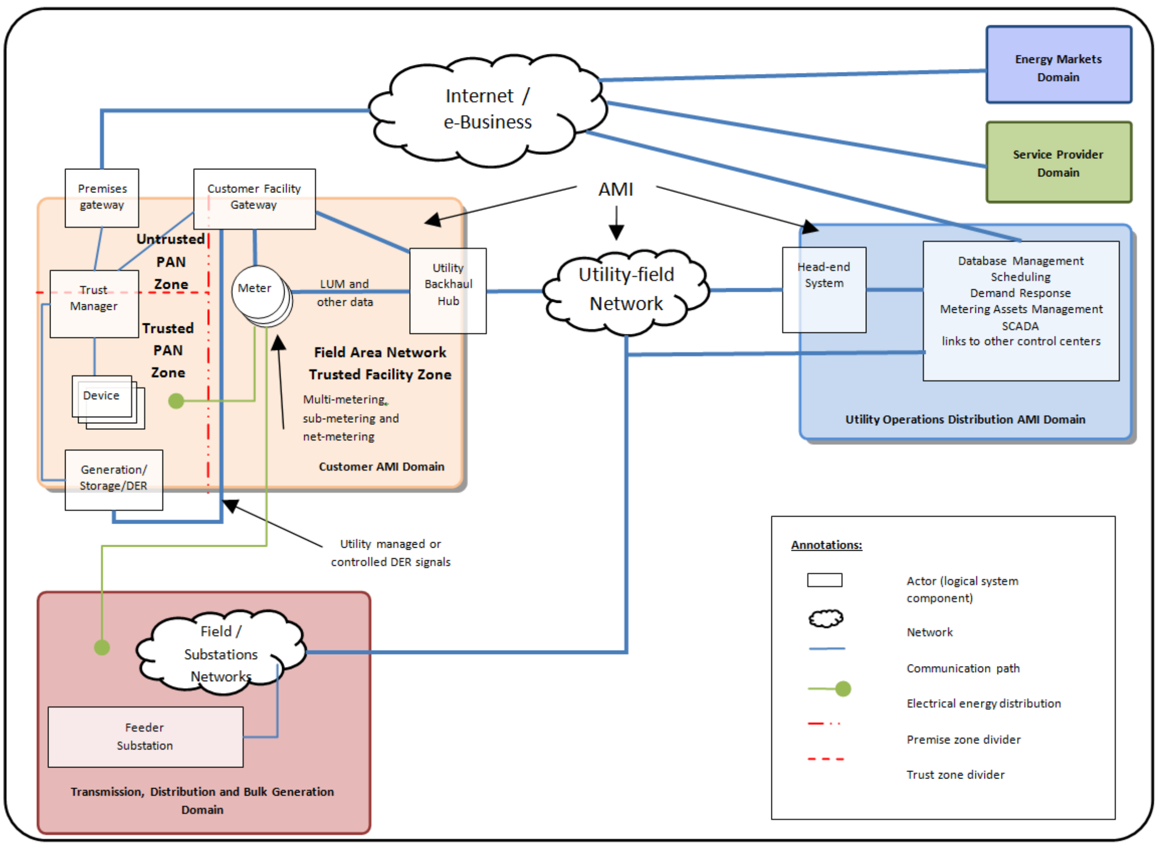
[49] ANSI: http://www.ansi.org/default.aspx.
[50] IEEE: http://standards.ieee.org/.
[51] NAEDRA: http://www.naedra.org.
[52] AEIC: http://www.aeic.org/meter_service.
[53] Measurement Canada's: http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm04528.html.

- the customer control and untrusted Premises Area Network zone (**untrusted PAN zone**)[54].

The *untrusted* segment of the Premises Area Network can communicate with energy markets, service providers and the utility operations domains via available channels—ideally through the premises gateway, using any network. Information and control messages may be exchanged between the utility Head End Systems and the utility-owned meters, customer-owned devices (such as home appliances, energy management systems, thermostats, electric pluggable vehicle, and electric storage) through the customer facility gateway and the customer facility *trust manager* (that acts both as a trust centre and a gateway or a bridge to the Premises Area Network).

When the customer domain devices act as Distributed Energy Resources (DER)—which allows the flow of energy to and from the electrical grid, depending on its size—the energy flow may need to be controlled by the utility (or its agents), as specified by existing or new regulations.

Figure 5: Smart Grid Advanced Metering Infrastructure Logical Architecture*



*Exhibited elements include only meters and the assets that are in front and behind the meter.

The equipment that may be co-located at the customer premise is separated and isolated using utility gateways. The gateways provide access to and separation from the utility backhaul networks (these include metering/AMI and T&D managed networks) from the PAN (including appliances, EMSs and consumer technologies). The gateways do so by using trust centres,

[54] An example of the *untrusted* PAN Zone is the wired Internet or wireless radio internet into the customer premise.

while maintaining the co-generation storage technologies (such as Plug-in Electric Vehicles), which should be connected through utility back-haul network. The AMI customer premises loose coupling to the utility network empowers the consumer, while mitigating the risk and concerns regarding information privacy, impact on reliability, accessibility, load control, load response and load management.

Typical logical architecture diagrams lay out only the communications pathways at the equipment interfaces. Figure 5 provides additional information. The blue lines represent communications paths; the thick blue lines correspond to reliable managed networks; and the thin blue lines represent customer domain unmanaged and less-reliable networks. The green lines provide an elementary indication of where in the customer domain the electrical power flows, where it is controlled and where it is measured (metered). The reason for indicating electrical energy flows is to show where the energy usage measurements take place (e.g., metering, net metering and sub-metering); the location of control points (e.g., service connect/disconnect switch, load control); and where information is needed to manage the facility and the grid loads (e.g., Distributed Energy Resources, Demand Response, Co-Generation).

The logical flow of information shown in Figure 5 addresses Home Area Networks (HAN) for home appliances and electrical vehicle charging that are within the scope of many HAN standards. One such standard is the Smart Energy Profile (SEP) 2.0 of the Zigbee Alliance.[55] The Task Force agreed more effort is required at the international level to harmonize those standards for the demand response functions required within the Smart Grid system components. For example, experts working on SEP 2.0 will be collaborating with the IEC TC57 WG21 to develop protocol and gateway interface to consumer applications. The goal is to address possible orphaned Smart Grid investments.

In addition, the Society of Automotive Engineers (SAE) has developed important Smart Grid standards, such as the SAE J2847 Recommended Practice. This practice establishes requirements and specifications for communications between plug-in electric vehicles and the electric power grid.

Similarly, the Task Force considered the importance of the migration from Internet Protocol version 4 (IPv4) to Internet Protocol version 6 (IPv6). This migration has a significant impact on the realization of the Smart Grid. BC Hydro is the first Canadian utility planning to deploy the new IPv6 private communication infrastructure for smart meters, and other grid-enabled devices, over a wireless mesh network.

Several advanced metering standards projects are identified in Table 9 as priority projects for the development of the Canada Smart Advanced Metering. Three of these standards are marked to indicate the conceptual gap between the AMI security and privacy-burden assumption protocols, and the AMI implementation of real-time processing requirements—as it applies to utilities' expectations for the use of NIST-approved cryptographic methods. In the context of the overall goals of the NIST *Cryptographic Toolkit*,[56] a gap exists where the immediate and practical demand for security and privacy are being excluded from the market because they are not yet approved by NIST. Stronger security techniques with more-efficient, key management approaches will be required. This is an area needing further study, and where

[55] Smart Energy Profile (SEP) version 2.0 is still under development, as the current standard is the SEP 1.1; refer to the Zigbee Alliance standards webpage http://www.zigbee.org/Standards/Overview.aspx

[56] "*NIST aims to approve a small set of strong cryptographic mechanisms to serve as standard building blocks for the development of secure applications and protocols. There is a recurring tension between demand for new features and the practical requirement to limit the size of the toolkit. This practical requirement stems primarily from industry needs for interoperability, reusability, and assurance (i.e., confidence in the security) of these algorithms, and motivates our preference for broadly applicable algorithms*" [ref. Tim Polk on NIST Determination regarding EAX', March 22, 2012].

the standards from the ICT sector within the ISO/IEC/JTC1/SC27 Working Group may be appropriate.

5.3 Smart metering infrastructure recommendations

As part of its strategic planning mandate, the Task Force identified six key recommendations regarding smart meter standards. The Task Force also recognized the development and use of open standards and the related call for interoperability as very important aspects for an effective multi-vendor environment of the Smart Grid.

Recommendation M1:

The recommended Canadian AMI architecture, shown in Figure 5, exposes the interfaces and the demarcation (separation) zones in a manner that will help regulators, utilities and implementers enact key requirements. These requirements include security, privacy of information, grid safety, interoperability and reliability. This Canadian AMI architecture is an overarching recommendation: it represents, at the highest level, the overall thrust of the Smart Grid standardization effort. This architecture also highlights the technology and service elements that need addressing, to reach the standards environment for supporting a fully functional Smart Grid.

> Therefore, the CNC/IEC should recommend to utilities and regulators the need for a clear and unambiguous separation (demarcation) between utility-owned and customer-owned equipment and services.

Recommendation M2:

Most smart meters today meet the necessary legislation and policies required to ensure Measurement Canada-approved smart meters communicate Legal Units of Measure (LUM) to the billing systems. However, currently there are smart meters that do not communicate LUMs, and that may require external calculations to yield LUMs, critical computation basis for accurate billing.

> The CNC/IEC should recommend to utilities and regulators that smart meters regulation and policies be established, as needed, to ensure that Measurement Canada-approved smart meters:
>
> - communicate LUMs to the billing systems, just as they do for their local meter display;
> - where the time of use is relevant to calculating customer billing: that Source Legal Unit of Measure (SLUM) is also tested for the accuracy of the start, end and duration of the time periods used to measure the SLUM communicated by the meter to the billing systems, for computing a Process Legal Unit of Measure (PLUM); and
> - communicated interval or period-based LUMs for demand measurement are tested for their accuracy of demand measurement and for accuracy of the start, end and duration of the demand interval time for the intervals or periods of the LUMs (where required for reporting by the meter to the billing systems).

Recommendation M3:

Currently, utilities and the authority having jurisdiction[57], set their own standards of practices. There is no harmonized federal or provincial policy, regulation or legislation that requires common and interoperable practice for uniform accountability, operation, reporting, and accuracy of billing and management of billing information that is computed by the utility enterprise back-end systems. These processes should be end-to-end traceable, directly and indirectly to information that is communicated by Measurement Canada-approved meters (LUMs) to the billing systems.[58]

> The CNC/IEC should recommend that Smart Grid regulation and policies be established to harmonize provincial, territorial and interprovincial, and interterritorial practices.
>
> In addition, the CNC/IEC should recommend that Smart Grid regulation and policies be established to prompt provincial and interprovincial practices that, ultimately, shall result in uniformity of practice and standards-based interoperability of processing by the back-office billing data processing technologies—in a manner that also increases transparency of operations for the benefit of consumers and the utility for Canada.

Recommendation M4:

To provide support for DER integration (distributed generation–micro-grid and storage, including electric vehicle-to-grid), sub-metering and multi-metering may be necessary for payments and credits; otherwise, different billing rates may apply. It is known that many of the Smart Grid standards support such capabilities; however, these have yet to be enacted or implemented in the meters and in the head-end systems. A common strategy to address acceptable solutions has not been established.

> The CNC/IEC should recommend to utilities, regulators, Measurement Canada and meter manufacturers, that they develop strategies and requirements related to sub-metering and multi-metering applications for distributed generation at the customer's domain, where LUMS, SLUMS and PLUMS are required.

Recommendation M5:

Electric vehicle standards are still at the final stages of being published as tri-national standards. Initially, these standards focus on charging stations, physical connections to the vehicle, and safety. In some other areas, such as communications—competing standards or protocols developed by Special Interest Groups (SIG) are being debated. The possible implications of those discussions are presently far from clear. However, over the longer term, emerging standards may unlock the potential for fleets of electric vehicles or buses to be used, in effect as storage devices, providing ancillary services to the Smart Grid.

The concept of PEV charging and different payment scenarios, while roaming within or between different service provider locations, also applies to PANs. Application exists where the home or facility owner opts to have the utility charge the "guest" vehicle owner directly for electrical load consumed at the PAN. The infrastructure assumed for this is the existing and emerging Smart Grid AMI (metering infrastructure and protocols) that communicate through the facility gateway with the utilities. These infrastructure and protocols already have the design framework to carry on the task in published standards.

[57] In the United States, the AHJ is known as the Public Utility Commission.

[58] Refer to Audit Trail Implementation Guide for ANSI C12.19 / IEEE 1377, Utility Industry Standards Tables. A Guide for implementing Measurement Canada "Interim Specifications (/ Procedures) Relating to Event Loggers for Electricity Metering Devices and Systems" , IS-E-01-E / IP-E-01-E and PS-EGMVXX-E, for re-programming ANSI C12.19 / IEEE 1377 standard based metering devices, which operate an event logger or event counters.

The CNC/IEC should recommend to utilities to deploy AMI and metering communications networks for the Smart Grid in a manner that does not operate in isolation and does permit energy usage retrieval billing and roaming Plug-in Electric Vehicle capabilities that span multi-utility networks across the entire Smart Grid. Such billing and credit capability will be the basis for utility-to-utility roaming operations, communications, micro-grid and resource usage settlement agreements.

Recommendation M6:

There is a need for Canadian experts to coordinate their efforts and promote the Smart Grid Advanced Metering Infrastructure (AMI) architecture. Canadian experts are members of the IEEE SCC31 and ANSI ASC12 SC17 and participate in the effort of the North American End Device Registry Authority (NAEDRA). In addition, Canada should enhance its participation in the international standards on interconnection of information technology (IT) equipment being led by the ISO/IEC JTC 1/SC 25. This committee has a new focus on home and building energy management, and a connection to the Smart Grid. The committee produces international standards for home electronic system, including the control of equipment for heating, lighting, audio/video, telecommunications, security, residential gateways (customer premises cabling and relevant ICT communication interfaces) and the internal Home Electronic System network and external wide-area networks, such as the Internet. The committee also looks at similar building management functions in commercial buildings. Currently, there is no Canadian national committee to the IEC on smart meter. To promote harmonization, participation at alternative standards organizations relevant to North America(for example, ANSI, IEEE and NAEDRA), has been insufficient.

The CNC/IEC should recommend the creation and funding of a Canadian harmonized national Technical Committee (CSC/TC13) on Electricity Metering Standards be formed within the Canadian National Standards System. This committee should also bring Canadian interests to metering-related standards and activities of IEEE, ANSI and NAEDRA.

Table 9: List of Standards Used in North American Electricity Metering (highlight the gaps)**

Standard	Title	Status	TC/SC/WG
S-EG-05	Measurement Canada Specifications for the Approval of Software Controlled Electricity and Gas Metering Devices	Published 2012 **Priority**	Measurement Canada WG
S-EG-06	Measurement Canada Specifications Relating to Event Loggers for Electricity and Gas Metering Devices	Published 2012 **Priority**	Measurement Canada WG
ANSI C12.18	Protocol Specification for ANSI Type 2 Optical Port [same as IEEE 1701]	V2.0 Pub. 2006 **Priority**	ASC12 SC17 WG4*
ANSI C12.19	Utility Industry End Device Data Tables [same as IEEE 1377]	V2.0 Pub. 2008 **Priority**	ASC12 SC17 WG2*
ANSI C12.21	Protocol Specification for Telephone Modem Communication [same as IEEE 1702]	V2.0 Pub. 2006	ASC12 SC17 WG4*

Standard	Title	Status	TC/SC/WG
ANSI C12.22	Protocol Specification For Interfacing to Data Communication Networks [same as IEEE 1703]	V1.0 Pub. 2008 **Priority**	ASC12 SC17 WG2*
IEEE 1377	Standard for Utility Industry Metering Communication Protocol Application Layer (End Device Data Tables) [same as ANSI C12.19]	V2.1 Approved Ballot 2010 **Priority**	IEEE SCC31 P1377 WG*
IEEE 1701	Standard for Optical Port Communication Protocol to Complement the Utility Industry End Device Data Tables [same as ANSI C12.18]	V2.0 Pub. 2010 **Priority**	IEEE SCC31 P1701/P1702 WG*
IEEE 1702	Standard for Telephone Modem Communication Protocol to Complement the Utility Industry End Device Data Tables	V2.0 Pub. 2010	IEEE SCC31 P1701/P1702 WG*
IEEE 1703	Standard for Local Area Network/Wide Area Network (LAN/WAN) Node Communication Protocol to Complement the Utility Industry End Device Data Tables [same as ANSI C12.22]	V1.0 published 2012 **Priority**	IEEE SCC31 P1703 WG*
XML-2008	*Extensible Mark-up Language (XML) Recommendation (Fifth Edition) [used by ANSI C12.19 / IEEE 1377 for enterprise data exchange language, configuration management and Table model Definition Language]*	V1.0 Pub. 2008	W3C
XHTML	XHTML 1.0 The Extensible HyperText Markup Language (Second Edition) *) [used by ANSI C12.19 / IEEE 1377 for configuration management documentation of Table model Definition Language]*	E2.0 Pub. 2002	W3C
ISO/IEC 62056-62	Electricity metering—Data exchange for meter reading, tariff and load control—Interface classes. OBIS/COSEM [incorporates the ANSI C12.19 / IEEE 1377 Data (Tables) Model]	Pub. 2006	IEC/TC13
ISO/IEC 15955 **X.237 bis**	Information Technology—Open Systems Interconnection—Connectionless Protocol for the Application Service Object Association Control Service [defines the message format used by ANSI C12.22 / IEEE 1703]	Pub. 1999 **Priority**	ITU X
ISO/IEC 10035-1, X.237 / Amendment 1	Information Technology—Open Systems Interconnection—Connectionless Protocol for the Association Control Service Element: Protocol Specification	Pub. 1995	ITU X
ISO/IEC 8824-1 / ITU-T X.680	Information technology – Abstract Syntax Notation One (ASN.1): Specification of basic notation [defines the abstract syntax notations used by ANSI C12.22 / IEEE 1703]	Pub. 1995	ITU-X

Standard	Title	Status	TC/SC/WG
ISO/IEC 8825 / ITU-T X.690	Information technology—ASN.1 encoding rules: Specification of Basic Encoding Rules (BER), Canonical Encoding Rules (CER) and Distinguished Encoding Rules (DER) [defines the payload encoding rules used by ANSI C12.22 / IEEE 1703]	Pub. 2003 **Priority**	ITU-X
RFC 6142	ANSI C12.22, IEEE 1703, and MC12.22 Transport Over IP	Pub. 2011 **Priority**	IETF
AEIC Interoperability Guidelines	Smart Grid/AEIC AMI Interoperability Standard Guidelines for ANSI C12.19 / IEEE 1377 / MC12.19 End Device Communications and Supporting Enterprise Devices, Network and related accessories.	V2.0 Pub. 2010 **Priority**	AEIC / AMTI , and NIST/SGIP PAP5/ Measurement Canada WG
FIPS PUB 180-2	Secure Hash Signature Standard (SHS) FIPS PUB 180-2). [used by ANSI C12.19 / IEEE 1377 logger hash function]	Pub. 2002	NIST
**FIPS Pub 197	Advanced Encryption Standard (AES), Federal Information Processing 28 Standards Publication 197 [used by ANSI C12.22 / IEEE 1703 logger hash function]	Pub. 2001 Gap	NIST
**SP800-38A	Recommendation for Block Cipher Modes of Operation; Methods and 32 Techniques [used by ANSI C12.22 / IEEE 1703 logger hash function]	Pub. 2001 Gap	NIST
**NIST SP 800-38B	Recommendation for Block Cipher Modes of Operation: The CMAC Mode for 38 Authentication [used by ANSI C12.22 / IEEE 1703 logger hash function]	Pub. 2005 Gap	NIST

* Developed jointly with the Measurement Canada Task Force on Data Communications Protocol for EMD.

6 Conclusion

We hope that this Smart Grid Standards Roadmap report has provided you with insight into the broad range of related standards activities. Our ongoing goal is to encourage provincial regulators and utilities—when developing business plans for Smart Grid initiatives—to support the migration from proprietary technologies to open standards, and from their current architecture to the recommended Canadian Smart Grid Reference Framework described in this report.

The Smart Grid will enable customers to manage their electricity consumption; a wide range of smart devices for these applications will be available. An important aspect of advanced smart metering is a guiding principle that the consumer should have ultimate authority over access and usage of their energy-related data. In some cases, customers will enter into a contract with third-party energy services providers, to help them participate in the electricity market. From legal and technical points of view, a clear demarcation needs to be identified, to understand the responsibility and bi-directional flow of information between the customer premises (zones) and the utility and/or third-party energy service providers.

As mentioned in this report, the Task Force recommends the promotion of Smart Grid Privacy Principles, as they are broadly applicable across Canada. This report has described the logical flow of information and security boundaries for the *Smart Grid Advanced Metering Infrastructure Logical Architecture*. The Task Force has identified the priority areas for smart meter standards and the need to bridge the gap on security standards. The complex nature of this effort will require a plan to recruit experts knowledgeable in this emerging field. The Task Force has recommended the establishment of a Canadian National Sub-committee on Electricity Metering Standards.

The most critical cross-cutting finding of the Task Force is its recommendation for SCC to establish a Smart Grid Steering Committee. The committee would continue managing the domestic and regional deployment of this roadmap, and further development of Canadian expert participation at the appropriate international policy management committees. Furthermore, the steering committee would champion and promote key standards activities—filling identified gaps, reporting on progress, or suggesting steps to address delays or conflicts.

To strengthen harmonization with the IEC, a Canadian work program, with a list of priority projects, was identified for IEC TC57 working groups (WGs). These projects included: WG10, tasked to prioritize electricity substation automation; WG13 and WG14, tasked with priority projects for control centres for energy management and distribution management systems; WG15, for cross-cutting security standards; and WG17, for addressing the integration of distributed energy resources, through several projects. Canada is fairly well represented in the key IEC TC57 WGs; however, there is a need for Canadian experts to be accredited to participate in WG16 on energy markets and WG21 on standards protocols and gateways for consumer applications. These two WGs are important because of the need to promote open standards for the wholesale and retail electricity markets. In addition, the steering committee could address the need to promote cross-cutting requirements on wireless spectrum harmonization standards and low-cost access to necessary bandwidth for Smart Grid applications.

The Task Force has followed the developments in the U.S. NIST Smart Grid Initiative, and believes SCC—and the Canadian national Standards Development Organizations—can continue to lead in promoting the adoption of harmonized standards in Canada.

Annex A: Summary List of Recommendations

Recommendation G1:

The CNC/IEC should recommend the creation of a Smart Grid Steering Committee to coordinate and assist with the other recommendations contained in this roadmap; work with other relevant standards policy bodies and technical committees; and periodically update the roadmap.

Recommendation G2:

The CNC/IEC should support the creation of a Canadian technical subcommittee for smart meters, and encourage greater participation and funding for other important technical committees.

Recommendation G3:

The CNC/IEC should recommend to governments and regulators to be very cautious about enshrining any standard into regulation in the near term. Some of these standards are not yet mature enough to have a proven track record. Also, forced early conversion to a new standard may prematurely make obsolete current infrastructure investments, unnecessarily adding cost burdens.

Recommendation R1:

The CNC/IEC should encourage provincial regulators and utilities, when developing business plans for Smart Grid initiatives, to ensure systems migrate from proprietary technologies to open standards, and from their current architecture to the Canadian Smart Grid Reference Architecture described in this report. This step will enable regulators and utilities to compare roadmaps and therefore identify areas of commonality, interoperability, deployment timing and possible technological risk.

Recommendation P&S1:

The CNC/IEC should recommend Canadians stakeholders participate in the specification of Smart Grid cyber security requirements and standards within NIST's SGIP and CSWG, to promote a harmonized North American approach to the greatest extent possible.

It is also recommended that the proposed Smart Grid Steering Committee consider where and how Canadian positions on Smart Grid cyber security standards should be developed.

Recommendation T&D1:

The CNC/IEC should encourage Canadian expert participation in IEC TC57/WG16 for development of the IEC 62325-356 profile for North American wholesale energy markets, and should become an active contributor to NAESB Demand Response standards.

Recommendation T&D2:

The CNC/IEC should encourage the creation of standardized profiles for CIM implementations and the creation of mappings between Multispeak 4.0 and IEC 61968 CIM, as a means to improve control centre systems interoperability.

Recommendation T&D3:

To support Smart Grid interoperability requirements, the CNC/IEC should encourage the adoption and application of IEC 61850 for the purpose of communications between substations, between substations and control centre, and for transferring synchrophasor data.

Recommendation T&D4:

The CNC/IEC should encourage the development of guidelines and standards for utilities to migrate from existing, commonly used technologies, to the architecture described in IEC 61850. At the same time, the CNC/IEC should recognize that the large, existing investment by utilities in the older technologies will require gateway solutions and protocol converters during the initial transition period.

- In addition, the CNC/IEC should encourage extending this standard to distribution automation equipment and distributed energy resources.

Recommendation T&D5:

The CNC/IEC should encourage the standardization and adoption of high-bandwidth, low-latency, low-cost field communications networks; this area is often dominated by proprietary solutions and is vital to Canada's broad geography.

- In addition, the CNC/IEC should encourage a dialog between the Canadian and U.S. policymakers regarding the use of a common spectrum.

Recommendation T&D6:

The CNC/IEC should encourage the development and use of the IEC 62351 standard that applies security controls to power-system-specific communications technologies. One specific area that needs to be addressed and monitored is the security for CIM.

Recommendation M1:

The CNC/IEC should recommend to utilities and regulators the need for a clear and unambiguous separation (demarcation) between "utility-owned" equipment and services, and "customer-owned" equipment and services.

Recommendation M2:

The CNC/IEC should recommend to utilities and regulators that smart meter regulation and policies be established, as needed, to ensure that Measurement Canada-approved smart meters:

- communicate LUM to the billing systems, just as they do for their local meter display;
- where the time of use is relevant to calculating customer billing: that SLUM is also tested for the accuracy of the start, end and duration of the time periods used to measure the SLUM communicated by the meter to the billing systems, to compute a PLUM; and
- communicated interval or period-based LUM for demand measurement is tested for the accuracy of the demand measurement and for accuracy of the start, end and duration of the demand interval time, for the intervals or periods of the LUMs—where required for reporting by the meter to the billing systems.

Recommendation M3:

The CNC/IEC should recommend that Smart Grid regulation and policies be established to harmonize provincial and interprovincial practices.

In addition, the CNC/IEC should recommend that Smart Grid regulation and policies be established to prompt provincial and interprovincial practices that initially will increase and ultimately shall result in uniformity of practice and standards-based interoperability of processing by the back-office billing data processing technologies, in a manner that also increases transparency of operations for the benefit of the consumer and the utility for Canada.

Recommendation M4:

The CNC/IEC should recommend to utilities, regulators, Measurement Canada and meter manufacturers, that they develop strategies and requirements related to sub-metering and multi-metering applications for distributed generation at the customer's domain, where LUMs, SLUMs and PLUMs are required.

Recommendation M5:

The CNC/IEC should recommend to utilities that they deploy advanced metering infrastructure and metering communications networks for the Smart Grid in a manner that does not operate in isolation and does permit energy usage retrieval billing and roaming Plug-in Electric Vehicle capabilities that span multi-utility networks across the entire Smart Grid. Such billing and credit capability will be the basis for utility-to-utility roaming operations, communications, micro-grid and resource usage settlement agreements.

Recommendation M6:

The CNC/IEC should recommend a Canadian harmonized national Technical Committee (CSC/TC13) on electricity metering standards be formed within—and funding come from—Canada's national standardization network. This committee should also bring Canadian interests to metering-related standards and activities of IEEE, ANSI and NAEDRA.

Annex B

Table 10: List of Abbreviations

AEIC – Association of Edison Illuminating Companies AMI – Advanced Metering Infrastructure AMR – Automated Meter Reading ANSI – American National Standards Institute APPs – Applications AWS – Advanced Wireless Services CSA – Canadian Standards Association CEA – Canadian Electricity Association CIM – Common Information Model CNC/IEC – Canadian National Committee of the International Electrotechnical Commission CSWG – Cyber Security Working Group CT – Current Transformer DA – Distribution Automation DER – Distributed Energy Resources (Wind, Solar PV, Storage, etc.) DMS – Distribution Management System DNP – Distributed Network Protocol DR – Demand Response EMS – Energy Management System FAN – Facility Area Network and/or Field Area Network (managed by the utility) FERC – Federal Energy Regulatory Commission FPT – Federal, Provincial, Territorial GOOSE – Generic Object-Oriented Substation Event GSM – Global System for Mobile Communications HUB – A bridge or data concentrator that links the utility's metering head-end system to meters and facility gateways IC – Industry Canada ICCP – Inter-Control Center Communications Protocol IEC – International Electrotechnical Commission IED – Intelligent Electronic Devices IEEE – Institute of Electrical and Electronic Engineers IRC – Independent Regional Council IP – Internet Protocol ISO – International Organization for Standardization ISO – Independent Systems Operator ICT – Information and Communications Technology ITU – International Telecommunications Union JTC1 – Joint Technical Committee 1 LAN – Local Area Network LTE – Long Term Evolution	LUM – Legal Unit of Measure (defined by *Electricity and gas Inspection Act* and managed by Measurement Canada) MC – Measurement Canada NEB – National Energy Board, Canada NAEDRA – North American End Device Registry Authority NAESB – North American Energy Standards Board NRCan – Natural Resources Canada NEMA – National Electrical Manufacturers Association NERC – North American Electric Reliability Corporation NIST – National Institute of Standards and Technology NP – New Proposal NPCC – Northeast Power Coordinating Council OIML – International Organization of Legal Metrology PAN – Personal Area Network / Premises Network (managed by the customer) PCS – Personal Communication Services PEV – Plug-in Electric Vehicles PMU – Phasor Measurement Unit PSTP – Public Security Technical Program P&S – Privacy and Security RDF – Resource Description Framework REQ – Retail Electricity Quadrant RTO – Regional Transmission Operator RTU – Remote Terminal Unit SAE – Society of Automobile Engineers SC – Sub-Committee SCADA – Supervisory Control and Data Acquisition SCC – Standards Council of Canada SCL – Substation Configuration Language SDO – Standards Development Organization SEP – Smart Energy Profile SGIP – NIST Smart Grid Interoperability Panel SGTS – Smart Grid Technology and Standards Task Force TASE – Theoretical Aspects of Software Engineering TC – Technical Committee TCP – Transmission Control Protocol T&D – Transmission and Distribution TR – Technical Report U.S. – United States UL – Underwriters Laboratories ULC – ULC Standards VT – Voltage Transformer WAN – Wide Area Network WEQ – Wholesale Energy Quadrant WIMAX – Worldwide Interoperability for Microwave Access WG – Working Group XML – Extensible Markup Language

Solution Overview

Cisco GridBlocks Architecture: A Reference for Utility Network Design

In today's rapidly transforming energy industry, utilities are focused on modernizing the electrical grid with an integrated communications infrastructure. However, interoperability concerns, legacy networks, disparate tools, and stringent security requirements all add complexity to the transforming grid.

To address these challenges, the Cisco GridBlocks™ Architecture provides a forward-looking view into how the electrical grid can be integrated with digital communications across the entire power delivery chain. The model is a starting point for creating utility-specific designs, and offers guidance on deployment of grid-specific applications. It also lays out a framework for designing and deploying comprehensive management and security solutions across the grid. This will help utilities to lower the total cost of ownership of their communication infrastructure, as well as create additional value by helping to enable new utility services.

Addressing the Challenges of Utility Architecture Design

Many of today's utilities still rely on complex environments formed of multiple application-specific, proprietary networks. Information is siloed between operational areas, substations, and regulatory authorities. This prevents utility operators from realizing the operational efficiency benefits, visibility, and functional integration of operational information across grid applications and data networks. The key to modernizing grid communications is to provide a common, multi-service network infrastructure for the entire utility organization. Such a network serves as the platform for current capabilities while enabling future expansion of the network to accommodate new applications and services.

A platform based on the Cisco® GridBlocks Architecture integrates utility networks into a single, highly secure and reliable communications infrastructure across the various levels of utility operations. By supporting multiple applications on a converged network, it also provides a framework for integrating new technologies and utility-specific applications. At the same time, its modular approach enables implementation of projects over time, allowing utilities to plan their investments and flexibly adapt to rapidly changing business circumstances. This extends the life of existing infrastructure investments as part of a grid modernization roadmap.

The Cisco GridBlocks Architecture Suite

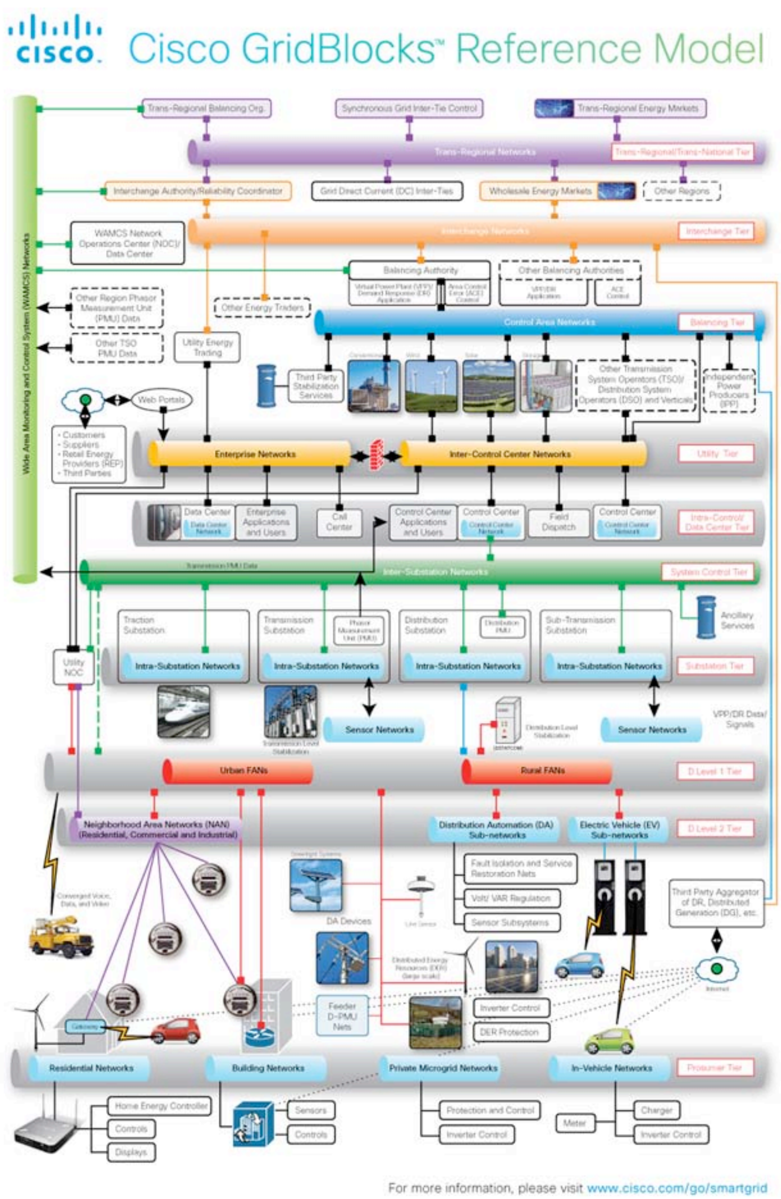
To support utility planners and operation teams, Cisco provides a complete suite of technical architecture offerings from the reference model to design and implementation guidance. This architectural approach is consistent with industry and standards organizations (e.g., NIST, EPRI), but provides a finer level of granularity to support design and implementation across multiple tiers of electric power operations. The Cisco GridBlocks Architecture suite comprises:

- GridBlocks reference model:
- GridBlocks reference architecture
- Solution architecture and designs
- Implementation designs
- Connected Grid services

The GridBlocks Reference Model

The Cisco GridBlocks reference model partitions the electrical power communications infrastructure into 11 logical tiers, which support networking the entire power delivery chain and define interaction across the tiers. This design provides a finer level of granularity than is available in other models to support unique tier requirements. It also supports tiers that represent networks owned and managed by different utility entities, while maintaining the necessary convergence and interoperability between them. This helps utilities understand the scope of upgrading a specific tier without impacting the others. Figure 1 displays the tiered approach of the reference model.

Figure 1. Cisco GridBlocks Reference Model



This tiers-based model facilitates segmentation of all capabilities and functional areas within a single, converged architecture. The tiers, from the bottom to the top of Figure 1, include:

Prosumer Tier—The prosumer tier (combining the concepts of energy producer and consumer) encompasses all third-party elements that impact the grid. This tier includes devices and systems that are not part of the utility infrastructure, but which interact with the utility. These may include networks managing distributed generation and storage, responsive loads in residences or commercial/industrial facilities, onboard electric vehicle networks, and so on.

Distribution—Networks at the distribution level—between primary distribution substations and end users—are broken into two levels:

- **Distribution Level 2 Tier**—The lower Level 2 tier is composed of purpose-built networks that operate at what is often viewed as the “last mile” or neighborhood area network (NAN) level. These networks may service metering, distribution automation, or public infrastructure for electric vehicle charging.
- **Distribution Level 1 Tier**—The upper Level 1 distribution tier supports multiple services that integrate the various Level 2 tier networks and provide backhaul connectivity directly back to control centers using the system control tier (see below) or directly to primary distribution substations to facilitate distributed intelligence. This tier also provides peer-to-peer connectivity for field area networks (FANs).

Substation Tier—This layer includes all internal substation networks. These can have wide-ranging requirements, from relatively uncomplicated secondary stations to complex primary substations that provide critical low latency functions such as teleprotection. Within the substation, networks may comprise from one to three buses (system, process, and multi-service). Primary distribution substation networks may also include distribution (field area network) aggregation points.

System Control Tier—This tier includes all of the wide area networks (WANs) that connect substations with each other and with control centers. Their high-end performance requirements can be stringent in terms of latency and burst response. In addition, these networks require flexible scalability and at times, due to geographic challenges, mixed physical media and multiple aggregation topologies as well. System control tier networks provide networking for SCADA, SIPS, event messaging, and remote asset monitoring telemetry traffic, as well as peer-to-peer connectivity for teleprotection and substation-level distributed intelligence.

Intra-Control Center/Intra-Data Center Tier—This tier encompasses networks inside utility data centers and control centers. Both are at the same logical tier level, but control centers have very different requirements for security and connection to real-time systems, compared to enterprise data centers that do not connect directly to grid systems. Both provide connectivity for systems inside the facility and connections to external networks in the system control and utility tiers.

Utility Tier—This tier encompasses enterprise or campus networks, as well as networks that link control centers to each other. Since utilities typically operate multiple control centers and campuses across a wide geographic area, this tier includes both metro and regional networks.

Balancing Tier—This tier includes networks that connect generation operators and independent power producers with balancing authorities, and balancing authorities with each other. In some cases, balancing authorities may also dispatch retail-level distributed energy resources or responsive load.

Interchange Tier—The networks at this tier connect regional reliability coordinators with transmission operators and power producers, and wholesale electricity markets with market operators, providers, retailers, and traders. In some cases, bulk markets are being opened up to small prosumers so that they have a retail-like aspect, impacting networking for the involved entities.

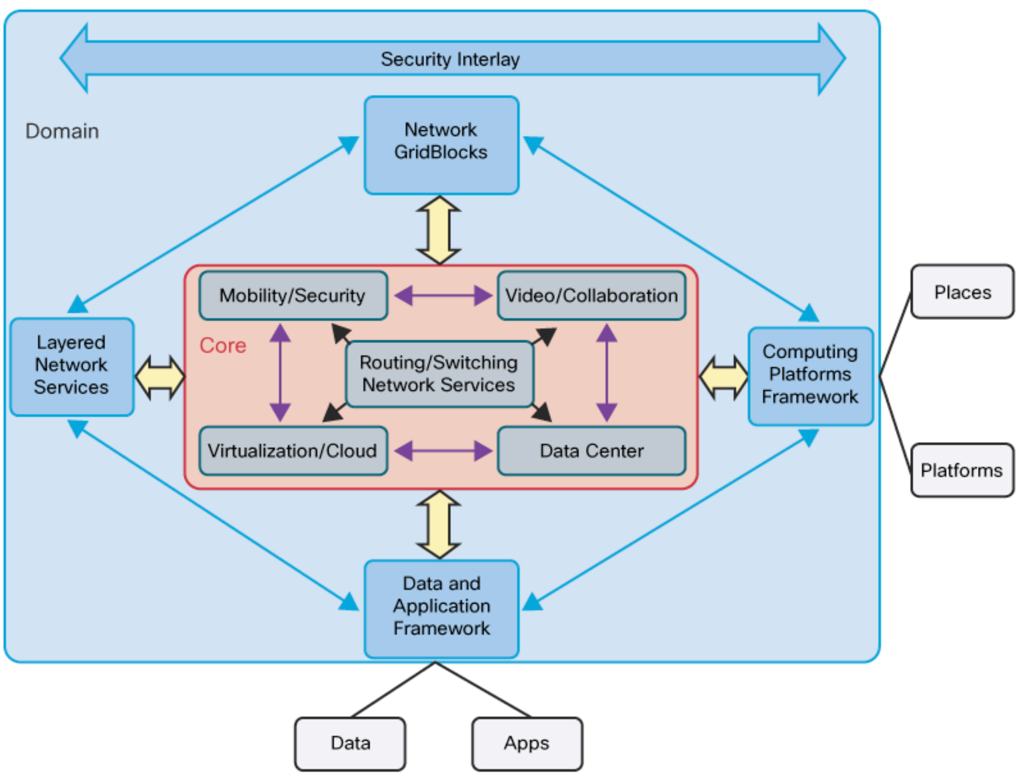
Trans-Regional or Trans-National Tier—This tier includes networks that connect synchronous grids for power interchange, as well as emerging national or even continental networks for grid monitoring, inter-tie power flow management, and renewable energy markets.

WAMCS Tier—This tier encompasses the networks of power management units (PMUs) known as Wide Area Measurement and Control Systems (WAMCS), Wide Area Measurement Systems (WAMS), or Wide Area Measurement, Protection, and Control System (WAMPACS). This tier must inherently connect to entities at other tier levels, but will typically do so through special network arrangements. In cases of wide area, low-latency networking, the owner of the network may not necessarily be one of the entities using it to share PMU data.

The Cisco GridBlocks Reference Architecture

The reference architecture consists of five sets of capabilities built into the network platform (see Figure 2). This fundamental structure supports deployment of a wide range of technologies and services that support grid automation solutions, information exchange, and management, including operational systems and extension of communications to reporting authorities.

Figure 2. Cisco GridBlocks Reference Architecture



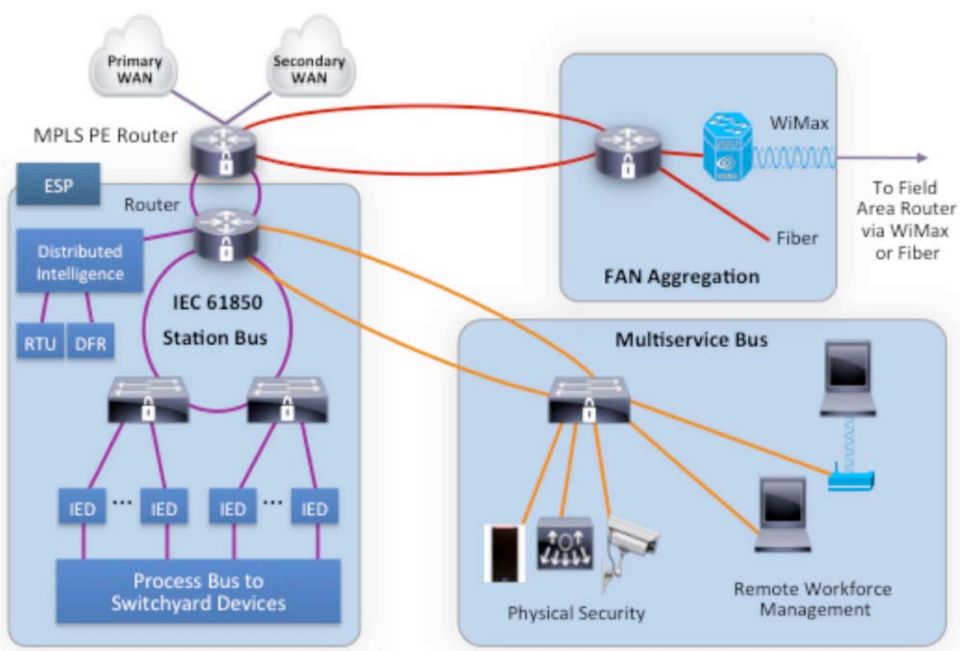
The five sets of capabilities include:

- **Network GridBlocks**—Uses the reference model and provides more detailed views of the specific architectures within each of the 11 utility tiers, as well as the interconnections between them. Examples include, the System Control GridBlock, Primary Substation GridBlock, or Field Area Network GridBlock.
- **Layered Network Services**—Offers a series of network layers that include both traditional network services and specific utility functions such as distributed intelligence, core functions, and discrete applications.
- **Computing Platforms Framework**—Provides a platform to unify grid-level elements and control and data centers using the network. The computing platform supports centralized, distributed, and hybrid intelligence models that can be extended beyond utility assets to field and external devices.
- **Data and Application Framework**—Enabled by connectivity, services, and computing capabilities, utilities run the business based on applications and their data. The GridBlocks model provides flexible, open standards-based applications support that encompasses requirements from traditional and mobile workforces, administration of large data sets, and regulatory audits to mergers, expansions, and new technology rollouts.
- **Security Interlay**—Provides pervasive security throughout the architecture, which includes multiple layers of access control, data confidentiality and privacy, threat detection and mitigation, and device and platform integrity.

Solution Architecture and Designs

Solution architectures are specialized versions of the reference architecture for a specific set of utility use cases or deployment scenarios, for example, a Substation GridBlock that has been customized for a primary substation automation deployment (see Figure 3). These solution designs provide a plan for building the solution and may include specifications, diagrams, bill of materials (BOM), etc. They also identify ecosystem vendor elements needed.

Figure 3. Primary Substation GridBlock with Ring Network



Implementation Designs

Implementation designs are detailed design plans that provide the implementation and configuration information needed to build and deploy the solution. Validated designs incorporate a set of products and technologies that have been tested as a complete system and are fully documented to support faster, more reliable, and predictive customer deployments, such as the substation network design implementation guide.

Connected Grid Services

Cisco Services has architected some of the world's largest industrial networks, offering architecture services to help utilities every step of the way from concept to completion. Cisco teams also provide a thorough analysis of use cases for current and future environments, and customize each service to specific needs for generation, transmission, and distribution. Built on extensive experience, they help utilities create a roadmap for highly secure, scalable, multi-service communications architecture. Specific services offered include:

- Network Architecture Discovery Service
- Network Architecture Assessment Service
- Network Architecture Planning and Design Service
- Cisco Network Optimization Service

Business Benefits

The Cisco GridBlocks Architecture offers significant benefits as a starting point for communications and smart grid initiatives to the utility:

- Provides a flexible, modular approach that supports incremental utility transformation
- Helps enable integrated system integration and security, increasing access to required information in and outside of the organization
- Offers an open standards-based vision of power delivery chain connectivity based on IPv6 convergence
- Lowers the total cost of ownership and creates value through new services and functional integration
- Provides a framework for developing custom grid modernization roadmaps for utilities well into the future

Cisco in the Utility Industry

Cisco provides one of the industry's most comprehensive portfolios of communications infrastructure solutions, spanning production, distribution and consumption of energy based on an end-to-end open standards network. By delivering multiple applications over a single, intelligent, and highly secure platform, electric utilities benefit from lower total cost of ownership as well as creating value from new services and functional integration well into the future. To learn more about the Cisco GridBlocks Architecture, please visit http://www.cisco.com/go/smartgrid

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OpenWay®

CENTRON® Meter

The OpenWay system delivers a truly smart meter for the residential mass market. Itron engineers have built upon our proven CENTRON solid-state platform to deliver an advanced meter that provides a cornerstone technology for the smart grid.

Featuring open-standards architecture, modular design for flexibility in communications, and extensive features and functionality, the OpenWay CENTRON supports the most demanding smart grid business requirements today and well into the future.

A key component of any advanced metering or smart grid initiative, the OpenWay CENTRON meter is a truly smart device used to collect, process and transmit vital energy information to utility systems. Rather than simply inserting a network communication card into a standard meter, Itron developed an advanced meter where calculations and usage data are calculated within the meter itself, allowing utilities to leverage time-based rates, demand response, home networking and many other smart grid applications.

The OpenWay CENTRON system provides enhanced security and a reliable approach to data collection and communications between the meter and the network. Storage and transport of register data are provided through ANSI C12.19 and C12.22 open standards technology. In addition, each OpenWay CENTRON meter comes factory-equipped with a ZigBee® radio to provide a built-in communications pathway into the home for data presentation, load control and demand response. ZigBee also provides a communication channel with 2.4GZ OpenWay Gas Modules.

The OpenWay CENTRON also provides robust data storage capability to support time-of-use pricing, load profile data and other data-intensive applications, as well as the most advanced feature set available to support smart grid requirements. These features include full two-way communication, a load-limiting remote disconnect and reconnect switch, positive outage detection and restoration notification, voltage monitoring, automatic tamper and theft detection, as well as the ability to reprogram the meter remotely and upload new firmware via the network.

The OpenWay CENTRON meter is the smart meter for the smart grid.

FEATURES

Time-of-Use and Critical Peak Pricing

» The OpenWay CENTRON supports four TOU rates as well as CPP

» TOU registers may be displayed on the meter's display

Load Profile

» Four channels of configurable load profile data are available in the following default parameters: (1) single channel 30-minute data 753 days; (2) two channels 30-minute data 501 days

» Modified parameters are available via configuration download

» The OpenWay CENTRON module provides over one year of 15-minute load profile data storage

OpenWay RFLAN Module

» Two-way, unlicensed RF module

» Adaptive-tree RFLAN architecture provides easy installation and self-healing capabilities

Home Area Network (HAN)

» Every OpenWay CENTRON meter includes a ZigBee radio for interfacing with the HAN, in-home displays and load control devices

» The OpenWay CENTRON can store consumption from 2.4GZ OpenWay gas modules utilizing the ZigBee radio

Bi-Directional Metering

» The OpenWay CENTRON measures and displays active energy (kWh) delivered, received, uni-directional and/or net or apparent energy (kVAh) delivered and/or received

Disconnect/Reconnect with Load Limiting

» The OpenWay CENTRON forms 1S, 2S, 12S network, and 25S is available with a 200 amp remote disconnect/reconnect switch as an optional feature. The switch can be operated on demand, or automatically as part of a service-limiting configuration

Tamper Detection

» Tamper indications can be communicated regularly through the OpenWay system

» Tampers include: inversion, removal and reverse power flow

» SiteScan Diagnostics (advanced polyphase register only)

Non-Volatile Memory

» All programming, register, TOU and load profile data are stored in the EEPROM during a power outage. A battery maintains just the clock circuitry during a power outage

Voltage Monitoring

» Instantaneous voltage

» Voltage monitoring system

Standard Features

» Electronic LCD display

» Polycarbonate cover

» Optical tower

» Test LED

Register Capabilities

» 4 energies, 1 demand:

- Wh (delivered, received, net, uni-directional)
- VAh (delivered arithmetic, received arithmetic, Lag)
- W (max delivered, max received, max net, max uni-directional)

» Configurable event log

» All programming, register, TOU and load profile data are stored in the EEPROM during a power outage. Battery maintains the clock circuitry during a power outage

Option Availability

» Identification/accounting aids

» Remote disconnect/reconnect

» Multiple WAN options including GPRS and CDMA

» Option slot for additional communications options

Technical Data

Meets applicable standards:

» ANSI C12.1 - 2008 (American National Standard for Electric Meters - Code for Electricity Metering)

» ANSI C12.18 - 1996 (American National Standard - Protocol Specification for ANSI Type 2 Optical Port)

» ANSI C12.19 - 2008 (American National Standard - Utility Industry End Device Data Tables)

» ANSI C12.20 - 2002 for Hardware 2.0 and 3.0 (American National Standard for Electricity Meters - 0.2 and 0.5 Accuracy Classes)

» ANSI C12.20 - 2010 for Hardware 3.1 (American National Standard for Electricity Meters - 0.2 and 0.5 Accuracy Classes)

» ANSI C12.22 - 2008 (consult Section 9 of the standard)

» ANSI/IEEE C62.41.1-2002 (Characterization of surges on Low-Voltage AC Power Circuits)

» ANSI/IEEE C62.41.2-2002 (Characterization of surges on Low-Voltage AC Power Circuits)

» IEC 61000-4-2

» IEC 61000-4-4

Reference Information

» OpenWay CENTRON Technical Reference Guide

» Hardware Specification Form

SPECIFICATIONS

Product Availability

Volts / Service	Meter Class	Test Amps	Kh (Pulse/Wh)	Meter Form	Register Descriptions
120 V	200	30	1.0	1S	OpenWay RF with or without Disconnect
240 V	200	30	1.0	2S	OpenWay RF with or without Disconnect
240 V	320	50	1.0	2S	OpenWay RF
120 V	20	2.5	1.0	3S	OpenWay RF
240 V	20	2.5	1.0	3S	OpenWay RF
240 V	20	2.5	1.0	4S	OpenWay RF
120 V	200	30	1.0	12S/25S	OpenWay RF with or without Disconnect

Specifications

Power Requirements	Voltage Rating: 120 V, 240 V Frequency: 60Hz Operating Voltage: ± 20% (60Hz) Operating Range: ± 3 Hz Battery Voltage: 3.6 V nominal Battery Operating Range: 3.6 V nominal; 3.4 V - 3.8 V Carryover: 12-year continuous usage or 20-year shelf life
Operating Environment	Temperature: -40° to +85°C Humidity: 0% to 95% non-condensing
Transient / Surge Suppression	IEC 61000-4-4-2004-07 ANSI C62.45-2002
Accuracy	ANSI C12.20 0.5 accuracy class
General	Demand interval lengths: Programmable: 5, 6, 10, 12, 15, 20, 30 and 60 min. Demand calculation: Peak Energy calculation: Basic: Wh and VAh
Time	Line sync: Power line frequency Crystal sync: +0.01% @ 25°C; +0.025% over full temperature range Battery: +0.005%@25°C; +0.005% to -0.02% over full temperature range
Display	Nine-digit liquid crystal display Six-digit data height: 0.4" Annunciator height: 0.088" Display duration: 1-15 seconds Three-digit code number height: 0.24" 3-segment electronic load indicator
Characteristic Data	Starting Current: 20 mA (Class 200), 5 mA (Class 20)
Register Burden	0.66W

Burden Data (C2S0D) (United States)

Form	Watt Loss	VA Loss	Test Voltage
1S	2.796	6.759	120
2S	3.773	12.357	240
3S	2.123	7.068	120
3S	2.350	14.255	240
4S	2.535	14.619	240
12S	2.861	6.751	120

Burden Data (C2S0D) (Canada)

Form	Watt Loss	VA Loss	Test Voltage
1S	2.686	6.999	120
2S	3.203	11.89	240
3S	2.123	7.068	120
3S	2.350	14.255	240
4S	2.535	14.619	240
12S	2.831	7.393	120

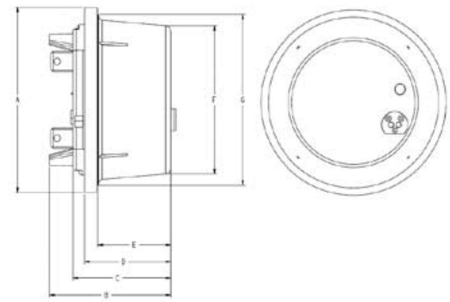
Service Switch (Optional)	200A; can be programmed as service (load) limiting Service Switch is available in Forms 1S, 2S, and 12S/25S
Modules	Standard OpenWay Register
Additional Base Functionality	Cell Relay (available in Form 2S only)

SPECIFICATIONS

Dimensions

C2S0/C2S0D - Forms 1S, 2S and 12S						
A	B	C	D	E	F	G
6.95"	5.27"	4.37"	3.97"	3.47"	5.68"	6.30"
17.66 cm	13.39 cm	11.10 cm	10.08 cm	8.82 cm	14.43 cm	16 cm
C2S0/C2S0D - Forms 3S and 4S						
A	B	C	D	E	F	G
6.95"	4.56"	3.66"	3.23"	2.73"	5.56"	6.42"
17.66 cm	11.59 cm	9.30 cm	8.21 cm	6.94 cm	14.13 cm	16.31 cm

C2S0/C2S0D Dimensions



Shipping Weights

Polycarbonate C2S0/C2S0D		
	Pounds	Kilograms
4 Meter Cartons	11 lbs	5 kg
96 Meter Pallets	280 lbs	127 kg

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FORTISBC

DECEMBER 17, 2010

FORTISBC INC

ADVANCED METERING INFRASTRUCTURE

SYSTEM & SERVICES

LISD10005

Request for Proposal

Close

3:00 pm Pacific Daylight Time, February 4, 2011

Contents

1 Background

1.1 Introduction

FortisBC Inc. (“FortisBC”) is the oldest utility in British Columbia, reaching back to the late 1890's when mining was the driving force in the Kootenays and Rossland was its focal point. At that time, the mines required an abundant and inexpensive source of electric power and so the development of hydroelectric power began.

FortisBC’s service area stretches more than 17,000 square kilometers, from the rugged and mountainous West Kootenay region of British Columbia, to the growing urban area of Kelowna on the shores of Lake Okanagan, to the hot and semi-arid south Okanagan and Similkameen regions. The Company generates and distributes electricity to approximately 159,000 customers (111,000 direct customers and 48,000 through municipal wholesalers) through a network of some 7,000 kilometers of distribution and transmission lines and four regulated hydroelectric generating plants on the Kootenay River.

Figure 1: FortisBC service area

Fortis Inc., FortisBC’s parent company, is the largest investor-owned distribution utility in Canada, serving approximately 2,100,000 gas and electricity customers. Its regulated holdings include electric utilities in five Canadian provinces and three Caribbean countries & a natural gas utility in British Columbia. It owns non-regulated hydroelectric assets across Canada and in Belize & Upper New York State. It also owns hotels & commercial real estate in Canada.

1.2 FortisBC's Smart Grid Vision

FortisBC's vision of a smart grid is to build upon the foundation of existing infrastructure to ensure a reliable, cost-effective, safe and environmentally friendly electrical system which can facilitate active customer participation, meet future demands and support public policies and standards. Figure 2 below shows the major components of FortisBC's smart grid vision.

Figure 2: FortisBC's Smart Grid Vision

The vision can be further categorized into short, medium and longer term plans. The short term plans are well defined, whereas the longer term plans are less certain and will be undertaken at some point in the future if and when it becomes prudent to do so. The following plans are subject to change at the sole discretion of FortisBC and subject to regulatory approval.

Short Term (1 – 3 Years)

- Two-way communication between FortisBC and the customer premise via Advanced Metering Infrastructure which will provide:
  - o more outage diagnosis tools to improve restoration times and operational efficiency;
  - o enhanced outage reporting;
  - o feedback on power quality in case of customer concerns or issues; and
  - o near real time consumption information for customers via the consumer's method of choice to effectively manage their energy costs.
- Streamlined metering and billing processes for all rates including conservation and net metering rates;
- Streamlined billing processes for vacant sites, customer moves, off-cycle billing, consolidated billing, etc.

- Offering further incentives for new technologies through the PowerSense Demand Side Management ("DSM") program;
- Monitoring power quality via substation automation;
- Creating an infrastructure of IT systems and interfaces to make effective use of existing information as well as infrastructure and information created through Smart Grid enhancements; and
- Implementation of Smart Grid security standards in coordination with provincial government and other BC Utilities as required.

Medium Term (4 – 7 years)

- Conservation rates (including time-based rates) which reflect pricing signals that match FortisBC's unique energy and demand challenges;
- Enhanced DSM and marketing programs to support customers in being able to respond to pricing signals;
- Gaining the ability to integrate smaller, green generation more cost-effectively;
- Finding generation options for areas that are less cost effective such as those along radial lines;
- The integration of community energy systems;
- Enabling advanced technologies including prepayment, load control and communication with smart home appliances and other devices;
- Re-configuring and optimizing the distribution system infrastructure to more closely align load requirements; and
- Reducing system losses (both technical losses and losses from theft).

Long Term (7 – 10 years)

- Establish coordinated control of distributed generation, existing generation and transmission & distribution resources;
- Monitor and explore alternate storage options;
- Promotion of cost effective distributed generation through DSM (as defined in section 1.3) programs and customer education;
- Providing services for PHEV (as defined in section 1.3) including charging stations if and when customer demand materializes;
- Active control of voltage regulators, capacitor banks, and inverter-based distributed generation and storage to manage voltage and volt-amperes reactive ("VAR");
- Coordinated integration of micro-grids;
- Adding localized, available distributed generation when required to support peak loads and coordinated integration of smart grid components so that better and more automated decisions can be made in regards to the operation of the electrical grid.

1.3 Glossary of Terms

Unless otherwise expressly stated, the following terms are hereinafter defined as:

1) **95% coverage:** means that 95% of the meters in the proposed AMI solution are connected to the AMI network with all technical requirements as described in Section 5 being met and the AMI solution meeting the Service Level Agreement requirements detailed in section 5.1.1 AMI Network Service Level Agreement for 95% of the meters in the FortisBC Service Territory
2) **100% coverage**: means that 100% of meters in the proposed AMI solution are connected to the AMI network with all technical requirements as described in Section 5 being met and the AMI solution meeting the Service Level Agreement requirements detailed in section 5.1.1 AMI Network Service Level Agreement for all meters in the FortisBC Service Territory
3) **Achilles Certification:** Means a program that provides a benchmark for the secure development of the applications, devices and systems found in critical industrial infrastructure.
4) **ACL:** Means Access control list and is a list of permissions attached to an object and specifies which users or system processes are granted access to objects, as well as what operations are allowed on given objects.
5) **AMI:** means Advanced Metering Infrastructure
6) **Approved Vendor List:** refers to a company that, in the sole discretion of FortisBC, has met certain criteria, including but not limited to; technical capability, safety and environmental compatibility, financial stability and insurance coverage to perform services for FortisBC
7) **BCUC:** means the British Columbia Utilities Commission and is also referred to as the "Commission"
8) **CHAP:** Challenge-Handshake Authentication Protocol - authenticates a user or network host to an authenticating entity.
9) **Closing Time**: has the meaning ascribed to it in section 1.4 Key Dates;
10) **Collector**: means the field device which aggregates telecommunication traffic from multiple meters and other end point devices, and interfaces them, via the WAN to the Head End System
11) **Commission:** means the British Columbia Utilities Commission and is also referred to as the "BCUC";
12) **Company Representative**: the person that will receive the Proponents' inquiries or comments with respect to any matter under dispute and whose decision shall be final and binding
13) **Contract:** the binding agreement(s) which may be negotiated between FortisBC and chosen Proponent(s)
14) **CPCN:** means the Certificate of Public Convenience and Necessity. This is the application that will be made to the BCUC for approval of the implementation of all elements for the AMI project;
15) **DA**: means Distribution Automation and in this document refers to the various elements of a distribution automation program that can be communicated with and controlled by the proposed AMI solution. Distribution Substation Automation references a project recently undertaken at FortisBC

16) **DHCP**: means Dynamic Host Configuration Protocol an auto-configuration protocol used on internet protocol networks
17) **Disaster Recovery:** the process, policies and procedures related to preparing for recovery or continuation of technology infrastructure critical to FortisBC
18) **DSM:** means Demand Side Management and refers to a program in place at FortisBC which helps customers manage their electricity bills through energy efficiency improvements
19) **End Device: means** the meter including the communication module
20) **Feeder Meters:** means an end point device that registers bi-directional, energy flow, at a point on the distribution system feeder
21) **FortisBC Service Territory:** means the geographical area in which FortisBC has active customers as shown in Figure 1.
22) **Fully Compliant:** has the meaning ascribed to it in section 2.2.1(3) Submission of Proposal;
23) **GIS:** means FortisBC's Geographic Information System
24) **HAN:** means Home Area Network
25) **HES:** means Head End System and is the component that manages the customer meters and other end point devices
26) **IHD:** means In Home Display
27) **IT:** means Information Technology
28) **LAN:** means AMI Local Area Network communication of the AMI system is the secure two way communication of the Meter Modules with other Meter Modules or directly with the Collectors.
29) **MAC Address filtering:** is a security access control methodology whereby the 42-bit address is assigned to each network card is used to determine access to the network
30) **MDMS:** means Meter Data Management System
31) **Metering End Device:** referred to in this document also as AMI End Device and End Device Means customer meters including communication module, and any other future measurement and/or control devices that may use the same network as the customer meters, to communicate to the Head End System.
32) **MV-90:** is software used for interval data collection, management and analysis from commercial and industrial (C&I) metering devices
33) **MV-RS:** is a PC-based meter reading software system for data collection and route management
34) **NAT:** means network address translation - the process of modifying network address information in datagram (IP) packet headers while in transit across a traffic routing device for the purpose of remapping one IP address space into another
35) **Not Compliant:** has the meaning ascribed to it in section 2.2.1(3) Submission of Proposal;
36) **PAP:** password authentication protocol is an authentication protocol that uses a password and validates users before allowing them access to server resources.
37) **Partially Compliant:** has the meaning ascribed to it in section 2.2.1(3) Submission of Proposal;
38) **PLC:** means power line carrier
39) **Price Submission:** refers to the separate envelope that is to be provided as part of the Proposal and that contains the Pricing Spreadsheet. A further description can be found in Section 2.2.1(3) Submission of Proposal;
40) **PHEV:** means Plug-In Hybrid Electric Vehicle is a hybrid vehicle with rechargeable batteries that can be restored to full charge by connecting a plug to an external electric power source
41) **Project Compliant:** has the meaning ascribed to it in section 2.2.1(3) Submission of Proposal;
42) **Proponent:** shall refer to the party submitting a Proposal in response to this RFP;

43) **Proposal:** is the Proponent's response to this RFP and all associated forms, documents and attachments. Section 2.2.1(3) Submission of Proposal further contains a complete list and description of each of the documents that must be submitted as part of the Proposal.
44) **Proposal Number:** means LISD10005.
45) **RFP:** means this Request for Proposals.
46) **RFP Documents:** are the documents provided by FortisBC to each of the Proponents and contain the submission instructions and background information upon which Proposals should be based. A complete list of each of the RFP Documents is located in section 2.1 RFP Documents
47) **RFP Process:** means the three stage process through which FortisBC seeks to find a Proponent or several Proponents to complete the Work. This process is further described in section 2.2 RFP Process and Instructions to Proponents;
48) **SCADA:** means Supervisory Control and Data Acquisition system in use at FortisBC and further described in section 3.2.6
49) **Service Level Agreement ("SLA")**: has the meaning ascribed to it in section 5.1.1 AMI Network Service Level Agreement (CI);
50) **Submission Forms:** includes the Intention to Reply Form and the RFP Submission Form located in Section 2.4 Submission Forms
51) **Time to Live:** means the amount of time a message is allowed to stay alive in a mesh environment to help control noise levels in the network.
52) **Transformer Meter:** means an endpoint device that registers bi-directional flow, on the secondary voltage side of a distribution transformer.
53) **Use Cases: are** formal documents developed to identify, clarify and organize system and business requirements for an MDMS and AMI Technology
54) **UOM:** means Unit of Measure as described in the Functionality Spreadsheet
55) **Vendor:** shall refer to the successful Proponent or Proponents. The term Vendor will be used when stating future requirements, to be performed only by the successful Proponent or Proponents.
56) **WAN** means Wide Area Network and is a secure 2 way telecommunications network between the collectors and the Head End System
57) **WSBC:** means WorkSafeBC which is the Worker's Compensation Board of British Columbia.
58) **Work:** means the scope of work described in Section 3.3 Scope of Work

Please note that the definitions for several of the technical terms are noted within the text of this document and primarily in section 3 Project Overview.

1.4 Key Dates

Below is the expected timeline that FortisBC will be following during the evaluation of available AMI solutions. FortisBC reserves the right to adjust these dates as required in FortisBC's sole discretion. All Proponents will be notified if any of the following dates are altered.

Dates of Significance

RFP released by FortisBC:	**December 17, 2010**
Submission of Intention to Reply and Confidentiality Agreement:	**January 4, 2011 10:00 am Pacific Time**
Final Questions Due:	**January 14, 2011**
Answers to Questions:	**January 21, 2011**
Closing Time (Proposal Due):	**February 4, 2011 3:00 pm Pacific Time**
Proponent Presentations:	**March 28, 2011 to April 7, 2011**
Decision:	**April 29, 2011**

Implementation is not expected to begin until regulatory approval of the CPCN is received. Please see Section 3.1.8 Expected Regulatory Process.

2 Instruction to Proponents

2.1 RFP Documents

This RFP establishes the system products and services that FortisBC wishes to acquire. This set of documents is the basis upon which FortisBC seeks Proposals from selected Proponents and upon which Proposals may be evaluated.

Please ensure that you have received a complete copy of the RFP Documents as each one will assist you in preparing and submitting your Proposal. The RFP Documents are as follows:

1. RFP (a .pdf document), which includes the following seven sections and one appendix:
   i. Section 1 – Background
   ii. Section 2 – Instructions to Proponents – this section includes the following two forms:
      a) Intention to Reply Form
      b) RFP Submission Form
   iii. Section 3 – Project Overview
   iv. Section 4 – Proponent Company Information
   v. Section 5 – AMI Solution Technical Requirements
   vi. Section 6 – Price Submisssion Requirements
   vii. Section 7 – Required Contract Terms and Conditions
   viii. Appendix A – Confidentiality Agreement

2) Meter Functionality Sheet (hereinafter referred to as the "Functionality Spreadsheet")- a Microsoft Excel workbook. This document allows for confirmation of compliancy with the functionality requested, providing detailed information on product capabilities.

3) Pricing Spreadsheet (hereinafter referred to as the "Pricing Spreadsheet") - allows the Proponent to enter their pricing information in a standard format. As per Section 2.2.1(3) Submission of Proposal, any hard copies of the pricing submission should be submitted in a separate envelope, marked "PRICE SUBMISSION".
   The following tabs are included within the Pricing Spreadsheet:

   1) Pricing_Option1_95%: This tab represents pricing for coverage for 95% of the meters (as defined in the Glossary) in FortisBC territory and requires completion by the Proponent.

   2) Pricing_Option1_100%: This tab represents pricing for coverage for 100% of the meters (as defined in the Glossary) in FortisBC territory and requires completion by the Proponent.
   3) Pricing_Option2_95% and Pricing_Option2_100%: These tabs are optional. If the Proponent provides the services to operate the AMI network on behalf of the utility with the infrastructure owned by the utility then these tabs are to be completed. **NOTE: In the event that the Proponent chooses to complete Pricing Option 2, the utility will still require a completed Option 1 tab.**

2.2 RFP Process and Instructions to Proponents

The RFP Process is a three stage process that involves various steps which are described throughout this section 2.2.

2.2.1 Stage 1 – Submission of Intention to Reply, Confidentiality Agreement and Proposal

(1) Submission of Intention to Reply and Executed Confidentiality Agreement

Recipients of this RFP must inform FortisBC of their intention to reply by completing the template form found in Section 2.4 Submission Forms, and by submitting this form by the date shown in Section 1.4 Key Dates.

The Proponent is also required to sign the Confidentiality Agreement as part of their intention to reply to this RFP in order to receive the FortisBC data required to complete this proposal. Failure to submit either document by the date noted in Section 1.4 Key Dates may result in the Proponent's submission not being considered.

Recipients that express an intention to reply will be included in all correspondence (if any) during the RFP Process. Please provide full contact information and expression of intention via the provided form to FortisBC contact as per instruction in Section 2.4 Submission Forms. If the Proponent is partnering with any other suppliers or vendors, their contact information must be provided as well.

(2) Proponent Access to Background Information

Once a Proponent states their intention to reply to this RFP and signs the required Confidentiality Agreement (as described in Section 2.2.1(1) Submission of Intention to Reply and Executed Confidentiality Agreement), they will be provided access to a library of background information in relation to FortisBC's AMI project.

The Proponent is asked to provide information (full name and email address) for one contact person who will be provided with access to this library.

Information within that library currently includes the following documents:

Table 1: Listing of Background Information

Document Title	Description
Meter_Detail_Listing	A listing of all active meters for FortisBC direct customers.
Meter_Detail_Listing_Legend	A description of what each field means in the Meter_Detail_Listing report.
Meter_Inventory_By_Type	A listing of all active meter types currently installed in the field.

Substation_Detail_Listing	A detailed listing of FortisBC's substations.
FBC_Buildings	A listing of all FortisBC buildings
FortisBC Meter Pricing Sheet	Pricing spreadsheet required to be completed for the RFP.
FortisBC Meter Functionality Sheet	Proponent compliance spreadsheet listing functionality within AMI system
FortisBC infrastructure.kmz	Google Earth format file containing: service area, districts, substations, business offices, transmission lines, fibre-optic links, repeater sites and licensed radio sites
Kootenay Comm Block Diagram.pdf	Block diagram showing Kootenay-area substation (intra and inter-site) communications
Mountain-top repeater site list.pdf	Mountain-top repeater listing with latitude, longitude, site elevation and call sign
Okanagan Comm Block Diagram.pdf	Block diagram showing Okanagan-area substation (intra and inter-site) communications
Planning single-line diagram.pdf	Simplified diagram of the FortisBC transmission system
Service area map – substations – repeaters – fibre optic.pdf	Geographic map intended for printing on D or E-size paper Substations are represented by yellow dots Radio repeater sites are represented by blue dots Existing fibre-optic links are shown by red lines Planned fibre-optic links are shown by blue lines
Substation site list.pdf	Detailed substation listing with geographic coordinates
System single-line diagram.pdf	Detailed transmission system single-line diagram
Terasen Gas radio sites.kmz	Google Earth format file containing locations for Terasen Gas radio sites (FortisBC sister company)
Transmission lines – master list.pdf	List of all FortisBC transmission lines showing connected substations, operating voltage and line length

Although every attempt has been made to ensure the above documents contain accurate information, the information within these documents is not guaranteed.

(3) Submission of Proposal

Proponents must submit their Proposal on or before the Closing Time as noted in Section 1.4 Key Dates. A complete Proposal will consist of an original, two (2) hard copies and one (1) soft copy on CD of each of the following:

a) RFP Submission Form – this form can be found in Section 2.4 Submission Forms.
b) Substantive Portion of the Proposal - where information has been requested in the RFP Documents, the Proposal should clearly indicate the RFP section number that the particular portion of the Proposal pertains to. The Proposal should be organized according to the following sections:
    i. Section 1 of the Proposal will contain the Proponent's executive summary, no more than two pages in length that introduces the Proponent and highlights key features of the Proposal.
    ii. Section 2 of the Proposal **should be provided in a separate envelope which has been clearly marked "PRICE SUBMISSION".** This section will contain the summary pages pertaining to the Price Submission, contained within the Pricing Spreadsheet. The Proponent's detailed itemized pricing information for all goods or services is to be contained within the Pricing Spreadsheet. Any alternative pricing submissions may also be included within the Pricing Spreadsheet, by adding tabs as needed. All pricing shall be expressed in Canadian currency, exclusive of taxes. If your originating currency is not Canadian dollars, the currency exchange rate that was used to calculate the price in Canadian currency is to be provided.
    iii. Section 3 of the Proposal will contain the functionality statement that is included within the Functionality Spreadsheet.
    iv. Section 4 of the Proposal will contain all the information regarding the Proponent that is requested in Section 4 - Proponent Company Information of the RFP Document. Please submit the requested Proponent information in the same order and using the same numbering as that noted in Section 4 of the RFP Document.
    v. Section 5 of the Proposal will contain the required information sought in Section 5 - AMI Solution Technical Requirements of the RFP Document. Please submit the requested information in the same order and using the same numbering as that noted in Section 5 of the RFP Document. Further explanation of how to respond to this section is located directly after this list in the subsection titled "Proposal Format Example: Section 5".
    vi. Section 6 of the Proposal will contain any additional documentation or alternative Proposals that the Proponent may decide to include regarding their submission. Any additional information or any unsolicited value-added alternatives may, in FortisBC's absolute discretion, be given due consideration, or not.
    vii. Section 7 of the Proposal will contain any changes to the Required Contract Terms and Conditions that the Proponent requests. Please note that it will be considered a negative if the Proponent suggests terms which are significantly different from those identified in Section 7 Required Contract Terms and Conditions.

viii. Section 8 of the Proposal will contain any information relating to the commercial 'off-the-shelf' software that is to be utilized. The Proponent should include the software license agreement, the software maintenance agreement and all additional material information with respect to the relationship between the Proponent and the software manufacturer.

Proposal Format Example: Section 5

Within Section 5 AMI Solution Technical Requirements of the RFP, an indicator has been included with the subsection heading to indicate the requirement of the Proponent to provide information pertaining to the functionality of their product (with regards to the section requirements), or a statement of compliancy AND information pertaining to the functionality of their product with respect to the requirement of the section.

(I)	When an (I) has been included with the section heading, FortisBC requires information regarding the proposed system's functionality, and the methodology utilized to satisfy the RFP requirement.

(C)	When a (C) has been included with the section heading, FortisBC requires a statement of compliancy from the Proponent. Within the submission documentation, the Proponent is required to state the proposed product's compliancy with the requirement by stating Fully Compliant, Project Compliant, Partially Compliant, or Not Compliant. In instances where the product is Partially Compliant, or Not Compliant, the Proponent is required to state their plans (complete with development time line) to bring their product into compliancy.

(CI)	When a (CI) has been included with the section heading, FortisBC requires both a statement of compliancy, and information regarding the proposed system's functionality, and the methodology utilized to accommodate the RFP requirement.

The method with which the Proponent provides information and compliancy statements is detailed within the individual sections, as well as within the Functionality Spreadsheet.

Fully Compliant - Proponent confirms that the functionality required is currently in their product in a live environment with other customers.

Project Compliant – Proponent confirms that the functionality required is in beta testing with another customer and scheduled to be part of the base product in a specified future version OR Proponent intends to build the functionality in the product to meet the specifications.

Partially Compliant - Proponent confirms that some of the functionality required is in their current product in a live environment but may be missing a portion of the required functionality.

Not Compliant - Proponent confirms that this functionality is not part of their current product in a beta or live environment with other customers.

SAMPLE of response for Section 5*.1.1 AMI Network Service Level Agreement*, demonstrating that the section numbering from this document is to be retained, and that each section should be included, and shall include within it a statement of compliance (which is also included in spreadsheet form in the Functionality Spreadsheet).

5.1.1 AMI Network Service Level Agreement (CI)

AMI Vendor will design FortisBC's network with the Service Level requirements as stated above and supports the performance requirements for meter readings. All information and pricing included with this Proposal is outlined with these requirements in mind. We expect that we will be able to cover 100% of FortisBC's service territory with the proposed design

Proponent's declaration of compliance: **Fully Compliant**

(4) Submission Requirements and Guidelines

a) The original hard copy of the complete Proposal shall be clearly identified as "ORIGINAL"; the remainder (i.e. two copies) shall be marked as "COPY". In the event of discrepancy between any of the copies (hard or soft) of the documents provided as part of the proposal, the hard copy marked "ORIGINAL" shall prevail. Each Proposal shall consist of the required documents with the required number of copies of all commercial information, including pricing, terms and conditions and exceptions (if applicable).

b) Faxed or late Proposals may not be accepted.

c) Proposals must be sealed and marked clearly quoting the Proposal Number referred to on the cover sheet of the Proposal. The use of any means of delivery of a Proposal shall be at the risk of the Proponent.

d) FortisBC shall not be liable for, nor shall it reimburse any Proponent for costs incurred in the preparation of Proposals, or any other services or samples that may be requested as part of the evaluation process.

e) The Proposal shall be signed by a duly authorized signing officer of the Proponent.

f) By submitting a Proposal the Proponent acknowledges that they have carefully examined, and understand the RFP Documents and make their Proposal in accordance with the submission requirements identified herein.

g) If a Proposal is not withdrawn in accordance with Section 2.2.1(8) Withdrawal of Proposal then such Proposal shall remain valid for a period of one hundred and eighty (180) days from the RFP Closing Time whether or not FortisBC is in the process of negotiating with any other Proponent or entity.

h) Where functionality (as noted in the Functionality Spreadsheet) has been misrepresented, FortisBC reserves the right to disqualify the Proponent from further evaluation of the RFP.

i) Failure to maintain confidentiality (as per Section 2.3 Confidentiality) shall be cause to reject a Proposal and remove the Proponent from FortisBC's Approved Vendor List.

(5) Adjustments / Substitutions

a) A Proposal may be altered by a Proponent only by submitting another Proposal at any time up to the Closing Time. Adjustments by telephone, facsimile, email or letter to a Proposal already submitted will not be considered. The last Proposal received by FortisBC's Company Representative shall supersede and invalidate all Proposals previously submitted by the Proponent for this RFP.

b) During the period prior to the Closing Time, changes made by FortisBC to the RFP Documents will be issued by FortisBC to the Proponents as written addenda. The Proponent shall list in its Proposal all addenda that were considered in the preparation of its Proposal.

c) No substitutions or deviation from the RFP Process, submission format, forms or required documentation shall be permitted without the prior written consent of FortisBC.

(6) Complete Proposal

The Proponent is requested to submit a Proposal that is complete and unambiguous without the need for additional explanation or information. FortisBC reserves the right to make a final determination as to whether a Proposal is acceptable or unacceptable solely on the basis of the Proposal as submitted, and proceed with Proposal evaluation (or not) without requesting further information from any Proponent. If FortisBC deems it desirable and in its best interest, FortisBC may, in its sole discretion, request from any Proponent or Proponents additional information clarifying or supplementing any submitted proposal.

(7) Clarifications

Upon the issuance of this RFP to Proponents, and continuing until the Closing Time, all questions or other communications with FortisBC shall be by email only, with FortisBC's Company Representative at:

amiprocurement@fortisbc.com

It is the responsibility of the Proponent to obtain clarifications in writing:

a) Should any details necessary for a clear and comprehensive understanding be omitted; or
b) Should any error appear in the RFP Documents; or
c) Should the Proponent note facts or conditions, which in any way conflict with the letter or spirit of the RFP Documents.

FortisBC may respond to the question in writing, with both the question and response provided, to each Proponent that has declared intention to make a proposal. No response will be made to questions submitted after January 14, 2011.

(8) Withdrawal of Proposal

Proponents will be permitted to withdraw their Proposal unopened after it has been submitted if such a request is received by the FortisBC Company Representative by email to ***amiprocurement@fortisbc.com***, prior to the Closing Time as stated in Section 1.4 Key Dates. No other methods of withdrawing Proposals shall be accepted.

(9) Post Proposal Meeting

FortisBC reserves the right to invite any or all Proponents to make an in-person presentation regarding the proposed AMI solution. FortisBC may also request Proponent's assistance in arranging visits to other installations where Proponent has deployed the solution.

(10) Information Accuracy

While FortisBC has made efforts to ensure an accurate representation of information in this RFP, the information contained in this RFP is supplied solely as a guideline for Proponents. The information is not guaranteed or warranted to be accurate by FortisBC, nor is it necessarily comprehensive or exhaustive. Nothing in this RFP is intended to relieve Proponents from forming their own opinions and conclusions in respect of the matters addressed in this RFP. Each Proponent must examine the RFP Documents before submitting a Proposal and by submitting a Proposal; the Proponent agrees that it has relied on its own analysis and interpretation of matters addressed in this RFP.

(11) No Contract

By submitting a Proposal and participating in this RFP, the Proponent expressly acknowledges and agrees that no contract of any kind is formed under, or arising from this RFP. Specifically, without limiting the provisions of this RFP, a Proponent submitting any Proposal does so, on the basis that neither this RFP, or anything contained in the Proposal, shall constitute a legal offer of, and is not to be construed as, an agreement to purchase goods or services. The RFP, the RFP Documents and the Proposal are only an invitation for Proponent to submit a Proposal to FortisBC.

FortisBC shall not be bound to accept any Proposal, or to enter into any agreement with any Proponent submitting a proposal.

FortisBC shall not, in any event, be liable to any Proponent for costs incurred in preparing a proposal.

FortisBC may, at any time, even after reviewing all properly submitted Proposals, in their sole discretion and without liability to the Proponent, for any or no reason, and with or without notice to each Proponent, terminate this RFP Process and not enter into any contract(s) for the Work as described in Section 3.3 Scope of Work. FortisBC reserves the right to negotiate with any one or more Proponents for the completion of the Work with or without reference to the Proposals submitted and for certainty, without obligation of any kind to any Proponent having submitted a proposal.

2.2.2 Stage 2 – Proposal Evaluation

(1) Evaluation Criteria

FortisBC will evaluate Proposals using an internal scoring method that considers various parameters to give FortisBC insight into the strengths of each Proposal relative to FortisBC's needs. Criteria which may be used by FortisBC in evaluating Proposals and selecting Proponent(s) and the weight, if any, to be given to the criteria are in FortisBC's sole and absolute discretion and, without limiting the generality of the foregoing, may include one or more of the following:

1. General AMI system requirements
2. Performance service levels
3. Scalability
4. Security
5. Price

2) Rights of FortisBC

By submitting a Proposal the Proponent acknowledges that they have read, understand and agree with the following sections regarding the evaluation of Proposals.

1) All Proposals shall be opened after the Closing Time in the presence of the FortisBC Company Representative or another individual designated to open the Proposals by FortisBC. The opening will not be public.
2) The evaluation criteria used in this RFP Process are in the sole and absolute discretion of FortisBC.
3) The lowest Proposal will not necessarily be accepted, and FortisBC reserves the right to accept or reject any or all Proposals, in total or in part, in its sole and absolute discretion.

4) FortisBC will review Proposals and may then carry out interviews with or request that presentations be made by selected Proponents for clarification as required.

5) FortisBC reserves the right, privilege, entitlement and absolute discretion, and for any reason whatsoever to:

   a) Cancel this RFP at any time and for any reason (reasonable or not), either before or after the Closing Time;

   b) Move forward to the negotiation stage of this RFP Process with one or more Proponent's;

   c) Substantially alter the limits or scope of Work in the process of any negotiations with any Proponent(s), without obligation to any other Proponent;

   d) Change the dates, schedules and deadlines in the RFP Documents and to issue addenda;

   e) Accept a Proposal which is not the highest scoring Proposal, or reject a Proposal that is the highest scoring Proposal even if it is the only Proposal received;

   f) Accept the Proposal deemed most favourable to the interests of FortisBC or that may provide the greatest value advantage and benefit to FortisBC based upon but not limited to price, ability, quality of work, service, past experience, past performance and qualification and any other criteria that FortisBC in its sole and absolute discretion deems relevant;

   g) Accept or reject Proposals that comply or do not comply with the submission requirements and guidelines set out in this RFP;

   h) Accept or reject any and all Proposals, whether in whole or in part;

   i) Accept or reject any unbalanced, irregular, incomplete or informal Proposals.

6) FortisBC reserves the right, at its sole discretion, to negotiate with the manufacturer to modify any provision of the software license agreement or software maintenance agreement, provided that the Proposal is compliant with the administration, performance, delivery and contractual requirements of the RFP. If negotiations do not result in modification of the software license agreement or software maintenance agreement acceptable to FortisBC, the Proposal will be rejected.

7) FortisBC will evaluate Proposals using an internal scoring method which includes various criteria which FortisBC in its sole and absolute discretion deems relevant, even though such criteria may not have been disclosed to the Proponent.

8) The Proponent acknowledges FortisBC's rights under this RFP and absolutely waives any right, or cause of action against FortisBC and its consultants, by reason of FortisBC's failure to accept the Proposal submitted by the Proponent or the decision of FortisBC to accept a Proposal submitted by any other Proponent or entity, whether such right or cause of action arises in contract, negligence, or otherwise.

2.2.3 Stage 3 – Notification of Successful Proponent(s) and Contract Negotiations

The third stage of the RFP Process involves FortisBC choosing a successful Proponent or Proponents and then negotiating a contract for the Proponent(s) to complete all of or a portion or the Work. The following sections describe this stage of the RFP Process in more detail and notify the Proponent of FortisBC's rights within this stage of the RFP Process:

1) The successful Proponent(s) will be notified in writing by FortisBC of their selection as a party with whom FortisBC wishes to negotiate an agreement based on the RFP Documents.

2) FortisBC may substantially alter the Work in the process of any negotiations with any Proponent(s), without obligation to any other Proponent.

3) FortisBC may, in its sole and absolute discretion, terminate negotiations with the Proponent(s) and either negotiate a contract with another Proponent or choose to terminate the RFP Process and not enter into a contract with any of the Proponents.

4) There will be no valid or binding agreement between the Proponent(s) and FortisBC, and no Proponent will acquire any legal or equitable rights or privileges, relative to the Work or this RFP until a written contract between the Proponent(s) and FortisBC is executed by both parties.

5) The contract that is to be negotiated shall include those terms that are identified in Section 7 Required Contract Terms and Conditions of this RFP. Proponents should examine these provisions carefully as it will be considered a negative if the Proponent suggests terms which are significantly different from those identified in Section 7 Required Contract Terms and Conditions.

6) The parties agree that any contract that is agreed upon between FortisBC and the Proponent(s) shall be subject to approval of the project by the BCUC and if such project is not approved by the BCUC the contract shall immediately terminate without liability for loss or damage to either party.

7) Once a successful Proponent(s) has been chosen, FortisBC will provide such Proponent(s) with a copy of FortisBC's proposed additional contract terms and conditions to commence negotiations.

8) Proponents whose Proposals have been rejected by FortisBC will be notified within thirty (30) days of the RFP Decision Date.

9) The successful Proponent(s) shall provide FortisBC with a designated representative. Any queries, comments and discussions with respect to the contract negotiations will be directed to the "Proponent Representative", whose decisions with respect to the contract negotiations shall be final and binding.

2.3 Confidentiality

Proposals submitted to FortisBC become the property of FortisBC and shall be used solely for the purpose of evaluation of the proposal.

All information contained in the Proponent's Proposal may be released to the regulator. If requested by the Proponent, FortisBC may request that the regulator keep any and all information confidential recognizing that ultimately it is in the sole discretion of the regulator to make an order of confidentiality.

Proponents shall maintain strict confidentially with respect to this RFP Process and the RFP Documents in accordance with this Section 2.3 and the Confidentiality Agreement. Failure to maintain this confidentiality shall be cause to reject a Proposal and remove the Proponent from FortisBC's Approved Vendor Lists. No publicity or discussions of the Proponent's involvement in the Work will be made until a formal Contract is executed by both parties.

2.3.1 Information Ownership

All information, including without limitation, drawings, specifications, calculations, instructions, notes and memoranda, provided at any time or times by FortisBC or its agents or contractors, to the Proponent, or to employees, agents or contractors of the Proponent, or prepared or obtained at any time or times by the Proponent, or by employees, agents, or contractors of the Proponent, in connection with the performance of Work or in connection with the RFP Documents shall be and remain at all times the sole and absolute property of FortisBC.

2.4 Submission Forms

Within this section, there are two forms required for submission.

2.4.1 Intention to Reply Form

This form should be copied and pasted into an email and then submitted to the following email address:

amiprocurement@fortisbc.com

in accordance with the process described in Section 2.2.1(1) – Submission of Intention to Reply and Executed Confidentiality Agreement and according to the timeline established in Section 1.4 – Key Dates.

INTENTION TO REPLY FORM

PROPOSAL NO. LISD10005

Intention to Propose:

Please allow this email to represent "__Insert Company Name Here (including any partners)__" intention to respond to FortisBC Proposal No. LISD10005.

Intention to Decline

Please allow this email to represent "____Insert Company Name Here__________" intention to decline to respond to FortisBC Proposal No. LISD10005. (Please state reason)

Contact for communication regarding proposal: ______________________________

Contact phone number: ______________________________

Contact email address: ______________________________

List any partners by name here:

____

____

We acknowledge the requirement for our AMI solution to meet the minimum functional requirements as outlined in the RFP Documents. Our Proposal will include the required compliance statements and documents to properly express our ability to meet these requirements. We also acknowledge the Submission Deadline is 3:00 PM Pacific Time on February 4, 2011.

I understand that if I do not submit a Proposal, this will not affect our company's status as a potential supplier to FortisBC in the future. I understand that if I do not return this form our company will not receive any further notices with regard to this Invitation for a Proposal.

2.4.2 RFP Submission Form

To submit this form, print the following pages to be included with the Proposal, which should be addressed to:

Lucy McMahan
FortisBC
Suite 100, 1975 Springfield Road
Kelowna, BC V1Y 7V7

in accordance with the process described in Section 2.2.1(3) – Submission of Proposal and according to the timeline established in Section 1.4 – Key Dates.

FortisBC

Proposal Number: LISD10005

FOR: ADVANCED METERING INFRASTRUCTURE SYSTEM & SERVICES

THIS PROPOSAL IS SUBMITTED BY: ______________________________

ADDRESS: ______________________________

____

____

TELEPHONE: ____________________ FAX NO.: ______________________

PROPONENT H.S.T. No.: ______________________________

PERSON(S) SIGNING ON BEHALF: ______________________________ (print)

POSITION(S) OF THE PERSON(S): ______________________________ (print)

I/WE ____ the undersigned declare:

1. THAT I/WE have read and understand the RFP Documents and hereby acknowledge FortisBC's rights as identified throughout Section 2 – Instructions to Proponents and throughout the remainder of the RFP Documents.

2. THAT I/WE do hereby propose to enter into negotiations to come to an agreement on the terms and conditions of a contract (with the exception of those terms identified in Section 7

- Required Contract Terms and conditions which shall be required to be included in any contract between the Proponent and FortisBC unless otherwise agreed to by the parties).

3. THAT this proposal shall remain valid for a period of one hundred and eighty (180) days from the RFP Closing Time. Once FortisBC chooses a Proponent(s) to negotiate with, the parties shall enter into negotiations to determine the terms and conditions of the contract. If the parties cannot come to an agreement on the terms and conditions of the contract, then no party shall have any further obligation to one another and there shall be no liability to either the Proponent(s) or FortisBC.

The undersigned affirms that he/she is duly authorized to execute this proposal.

PROPONENT'S SIGNATURE:

NAME: ______________________ ______________________
(Please Print) (Signature)

POSITION: ______________________

WITNESS
NAME: ______________________ ______________________
(Please Print) (Signature)

POSITION: ______________________

(documentation should be witnessed)

DATED AT THE ______________________ THIS ______________
(City/Town) (Day)

DAY OF ______________________ 20____.
(Month)

3 Project Overview

3.1 AMI Program Overview

3.1.1 Application History

On December 19th, 2007, FortisBC submitted an application to the BCUC for implementation of AMI throughout its service territory. In order to provide regulatory certainty, FortisBC's approach to the application was to obtain funding approval prior to proceeding with technology selection. The application was amended in March 2008 to include hourly readings and home area network capabilities. Subsequently, there were three rounds of information requests exchanged between FortisBC, the BCUC and registered interveners. Final arguments and replies were completed in June 2008.

On December 3rd, 2008 by order G-168-08, the BCUC denied FortisBC's AMI application.

"The Commission Panel acknowledges the initiative of FortisBC in developing plans and applying for a CPCN for the AMI project. The Commission Panel is also cognizant of the government's goal of having advanced meters and associated infrastructure in place for all utilities in British Columbia in the future. However, in summary, the Commission Panel is of the view that the Application and the Amended Application are incomplete and premature."

The following points summarize the main reasons cited in order G-168-08 Reasons for Decision.

The application was **incomplete** as:

- It did not have enough detail on the long term vision for AMI including the costs and benefits of future initiatives that could result from the installation of the AMI infrastructure. Those initiatives may include:
    - Remote disconnection
    - Time of Use ("TOU") rates (or other innovative rates)
    - Load control
    - In-home display;
- It did not have enough detail on whether or not AMI would be used to read gas and water meters and whether or not this would offset costs or produce revenue;
- It did not have enough detail about the costs of the components within the AMI system for the BCUC to ensure that the chosen infrastructure will enable FortisBC to make effective use of the AMI system; and
- The scope, plan and overall cost estimates of AMI project were not sufficiently complete and advanced to determine if they were cost-effective or appropriate.

The application was **premature** as:

- Government regulations related to BC Hydro's smart meter initiative has not yet been defined. Although these regulations, when issued, will not apply to FortisBC, the Commission believed it would be prudent to review them prior to approval of FortisBC's application; and
- FortisBC had not done any official analysis on what the impact of AMI enabled DSM measures would be in the future.

The Commission also discussed several positive points about the future of the AMI project including the following:

"The Commission panel encourages FortisBC to continue its efforts to develop, and in due course, reapply for approval of a comprehensive and complete program for the implementation of AMI."

3.1.2 Program Environment

During 2010, British Columbia's energy objectives as defined in section 2 of The Clean Energy Act S.B.C. 2010, c. 22 (the "Clean Energy Act") were issued which include the following:

> (a) to achieve electricity self-sufficiency;
>
> (b) to take demand-side measures and to conserve energy, including the objective of the authority [BC Hydro] reducing its expected increase in demand for electricity by the year 2020 by at least 66%;
>
> (d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources; and
>
> (g) to reduce BC greenhouse gas emissions.

In addition, section 17 of the Clean Energy Act, provided general guidance on advanced metering:

> (6) If a public utility, other than the authority, makes an application under the Utilities Commission Act in relation to smart meters, other advanced meters or a smart grid, the commission, in considering the application, must consider the government's goal of having smart meters, other advanced meters and a smart grid in use with respect to customers other than those of the authority.

For the purposes of the development of an advanced metering strategy, the following are FortisBC's understanding of the applicable objectives of the BCUC:

- Lowest possible costs and impacts on rates;
- Avoiding of duplicate infrastructure if possible; and
- Delivering consistent customer experience within the province of BC.

The latter two objectives were further outlined within the reasons for FortisBC's denial (order G-168-08) of the first AMI application as follows:

"The Commission Panel is of the view that it is important to the public interest that there be minimal duplication of infrastructure necessary for data reading, gathering, transmission and storage, and that utilities consider a coordinated approach where there is potential to avoid duplication of costly infrastructure…"

"The Commission Panel considers that FortisBC has not been sufficiently proactive in conducting consultations and research to determine the extent to which its AMI project can or will be coordinated and / or compatible with other utilities, including BC Hydro, the distribution utilities within FortisBC's service area and with its own sister utilities in the natural gas distribution sector…"

The Commission Panel encourages FortisBC to continue to develop and, in due course, reapply for approval of a comprehensive and complete program for the installation and implementation of Advanced Metering Infrastructure and related technologies. The Commission Panel further encourages FortisBC to coordinate its efforts with those other utilities."

It is FortisBC's understanding that BC Hydro has already begun to proceed with its procurement process for implementation of an advanced metering infrastructure as required by the Clean Energy Act.

3.1.3 Re-Application Approach

Approval of the AMI project will be sought by submitting a CPCN application that addresses the issues discussed in order G-168-08 Reasons for Decision and shows the benefits for FortisBC's customers.

In order to accomplish this, FortisBC will create a comprehensive CPCN including technology choice and a study of the expected costs and benefits of future programs enabled by AMI (such as conservation rates). The CPCN will also address collaboration with other BC utilities, focusing primarily on the customer experience.

Specifically, the FortisBC AMI project team will:

- work with operational supervisors to define detailed AMI requirements, by documenting AMI "Use Cases" to be included within the procurement and project management processes;
- complete the necessary RFP processes to select the most appropriate Vendor(s) based on the documented requirements and evaluation criteria defined by the project stakeholders;
- perform acceptance testing of the AMI system through a technology proof of concept or site visits;
- compile detailed estimates on the cost of the AMI system for use in the business case and CPCN Application;

- o commission a conservation potential study on the possible benefits of future programs that are supported by AMI technologies;
- o document a long term AMI program plan which will describe the functions and features that will be available day one as well as those that will be available and used in the future;
- o create a revised business case for AMI based on the long term program plan and AMI Use Cases; and
- o establish a preliminary scope, schedule and budget for the implementation of AMI.

3.1.4 AMI Program Objectives

The following are FortisBC's key objectives with respect to the implementation of AMI:

a) Improve operational efficiencies by reducing operating costs;
b) Improve customer service by increasing the accuracy and timeless of bills;
c) Support conservation and efficiency objectives by enabling conservation rates and providing customers with more information on consumption;
d) Protect revenue by identifying and resolving system losses; and
e) Support customer in-home automation by providing usage information and price signals into the customer's home.

3.1.5 AMI Program Scope

The scope of the AMI program at FortisBC is expected to include:

Meters & Modules

As part of its AMI program, FortisBC intends to install AMI-enabled meters for all approximately 110,000 of its direct customers over a two year period beginning in 2013. These meters will be capable of two-way communications and provide hourly interval data. There may also be a future inclusion of all or a portion of the 48,000 electric meters serviced by municipal wholesalers in FortisBC's service area, approximately 55,000 gas meters which are on the same premises as the electric meter, approximately 900,000 stand alone gas meters and an unknown number of water meters. The scope and timing of these inclusions is not known at this time.

Communications Infrastructure

The AMI communications infrastructure is expected to collect and transfer readings, alarms and other meter data from the metering end points into the system's Head End System ("HES"). It will also be responsible for providing communications to any other downstream devices such as in-home displays or other smart grid devices.

There may also be a future inclusion communications infrastructure required to include the 48,000 meters serviced by municipal wholesalers as well as gas and water meters within FortisBC's service area.

IT Infrastructure

The AMI System implementation will include a Meter Data Management System ("MDMS") that will be the central repository for all meter related data. The MDMS will integrate with the AMI Head End System. The Head End System will manage the communications, operations, and diagnostic monitoring of the electric meters and field devices.

3.1.6 Coverage of the AMI System

To ensure a consistent level of service amongst FortisBC customers, it is the preference of FortisBC that the AMI system reach as many customers as possible with a consistent offering of services. However, 100% coverage of the service area is not required at any cost.

In order to obtain an understanding of the cost in servicing the most remote customers, FortisBC is asking Proponents to provide two prices; one for 100% coverage of the service area and another for 95% coverage. The final decision on the actual coverage that will be required is expected to be part of contract negotiations.

3.1.7 Planned Uses of the AMI System

The following grid describes FortisBC's planned uses of the AMI system. A more detailed scope of each area is included below.

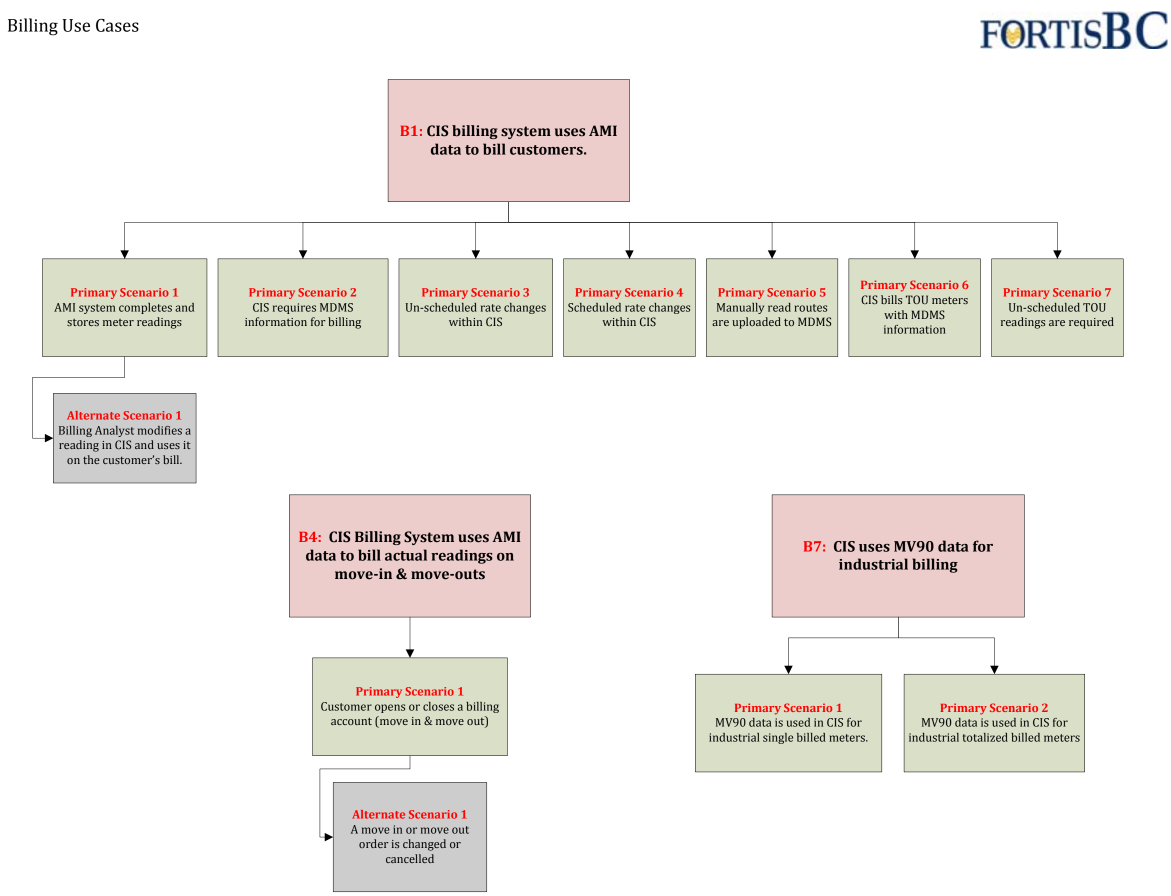
Figure 3: Use Case Grid

Billing	Customer Service	Field Operations Services	AMI Installation & Maintenance	Future Uses
B1 CIS billing system uses AMI data to bill customers	C1 Customer has access to readings, recent energy usage and cost Information	O1 Distribution operator locates outage using AMI data and restores service	I1 Utility installs, provisions and configures AMI system	F1 External clients use the AMI system to interact with customer DSM devices
B4 CIS billing system uses AMI data to bill actual readings on move-in and move-outs.	C3 Customer provides distributed generation via net metering	O2 AMI system recovers after power outage, communications or equimpment failure	I4 Utility manages overall health of the AMI system.	F2 Contract meter reading for other utilities (incl gas and water)
B7 CIS uses Mv-90 system for industrial billing	C4 TCC uses AMI data to provide support to customers for common questions and concerns	O3 Utility uses AMI to replace physical disconnection with virtual disconnection.		F6 Utility upgrades AMI system to address future requirements
	C5 Customer has access to consolidated billing options and flexible billing dates.	O5 Distribution operators optimize network based on data collected by the AMI system		F7 Customer Pre-Pay
	C7 CSR uses AMI system to gain an on-demand reading.	O6 Operations completes meter related service requests post AMI.		
	C8 Utility detects possible tampering or theft at customer site	O7 Security Requirements		**Finance and Reporting** R1 Utility uses AMI data for Reporting
		O8 Utility remotely limits or connects / disconnects customer		

A. Billing

The following diagram outlines the billing processes expected to be affected by the implementation of AMI:

Figure 4: Billing Use Cases



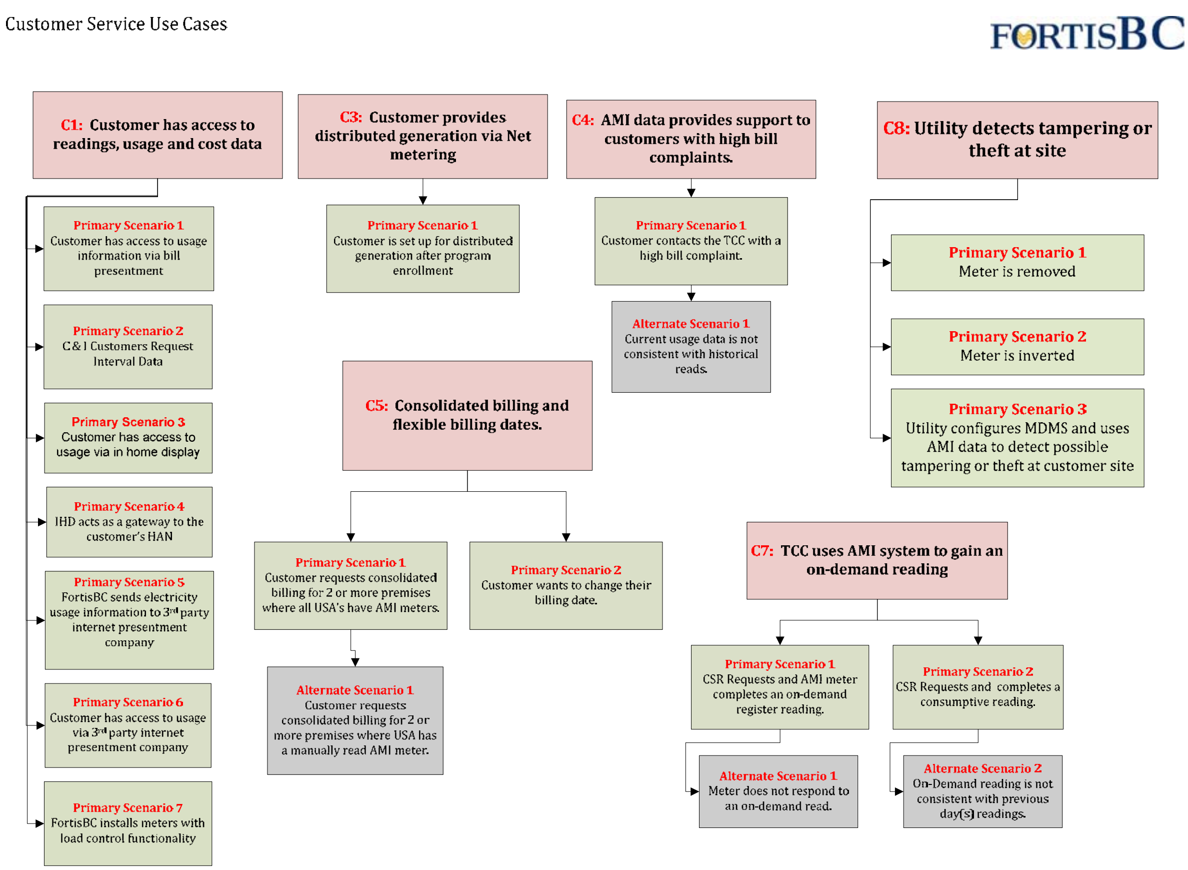
Some important considerations related to billing processes are:

- The AMI system must have daily register readings and interval data available to the MDMS upon request of this information from CIS. This may include reads for regular billing cycles or unscheduled readings for moves or to correct a bill error.
- The AMI system must support two way communication to allow for:
  - Maintenance of reading schedules between the meter and HES. Rate information is to be provided to customer portals and devices
- The AMI system must be able to accommodate the different time zones in the FortisBC service territory so that the correct data is used for customer billing.
- FortisBC intends to keep the CIS billing system as the system of record for customer information, service orders and rating processes while the MDMS will be the system of record for readings.
- The AMI system will be required to support consistency between meter reading data on any external displays as compared to the consumption data shown on the customer's bill.

B. Customer Service

The following diagram outlines the customer service processes expected to be affected by the implementation of AMI:

Figure 5: Customer Service Use Cases



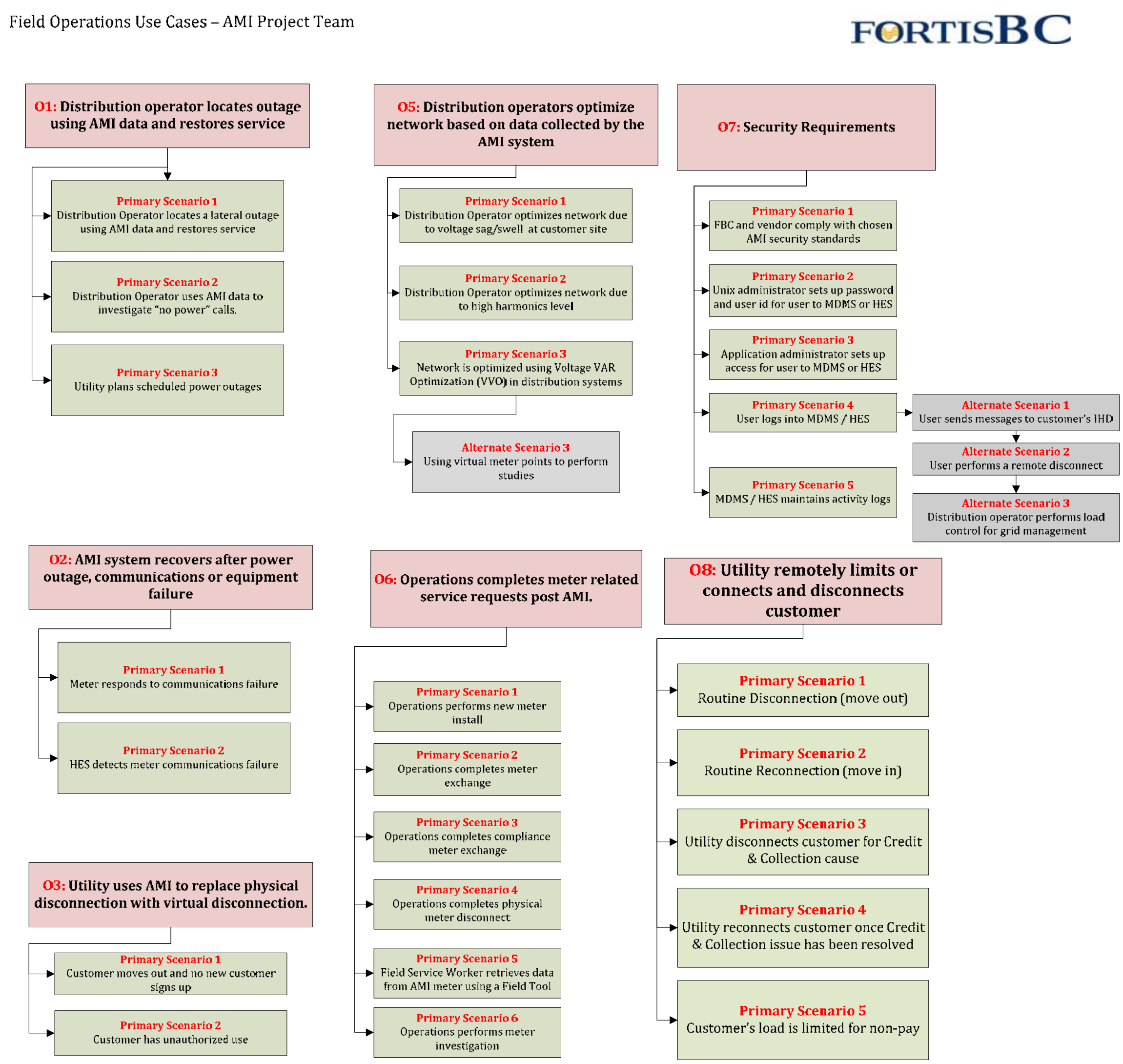
Primary objectives and important considerations related to customer service functions are:

- To provide all customers with enhanced feedback via AMI;
- To provide customers with choices on how they receive that feedback;
- Ensure, as much as possible, a consistent level of service for all FortisBC customers and;
- To provide FortisBC employees with the information and tools needed to complete research and analysis of all data from the AMI system to support customers.

C. Field Operations Services

The following diagram outlines the field operations processes expected to be affected by the implementation of AMI:

Figure 1: Field Operations Use Cases



Primary objectives and important considerations related to field operations processes are:

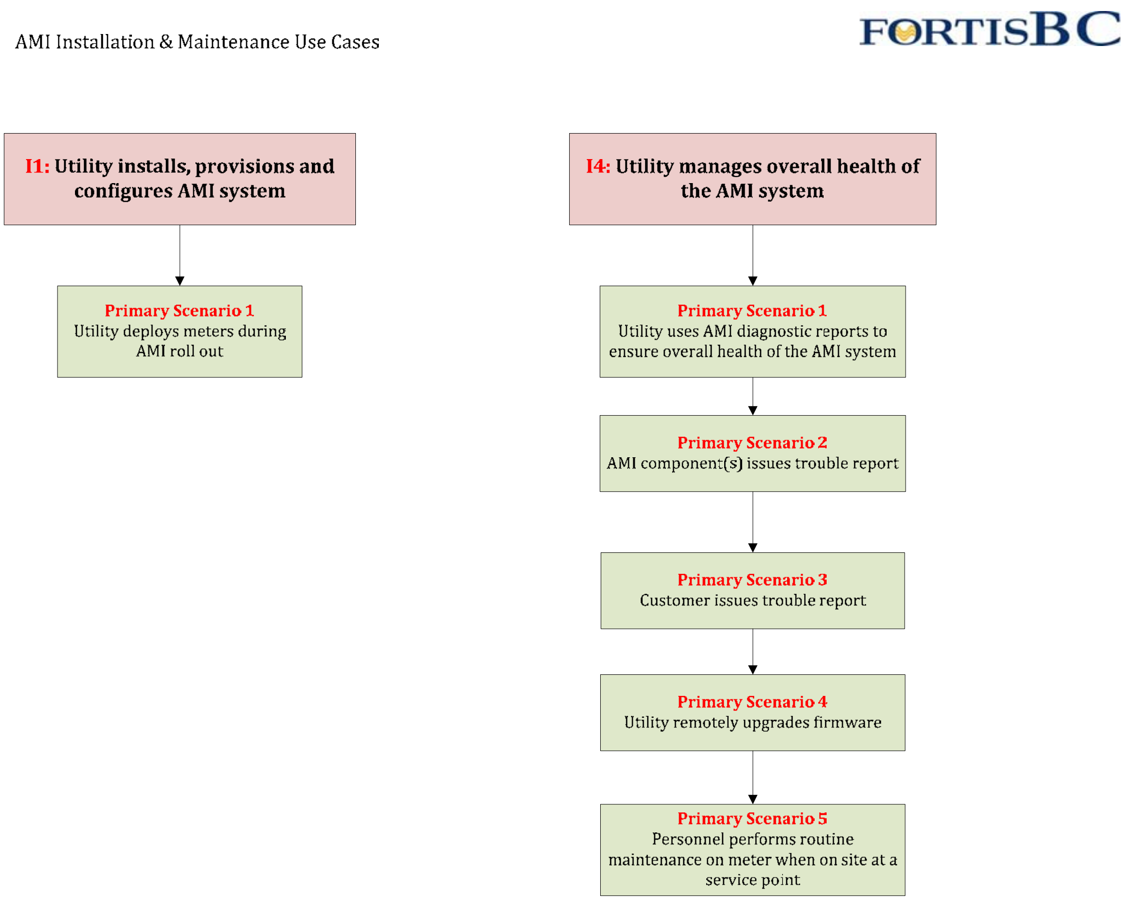
- The AMI system will be expected to work with the data provided by the MDMS and CIS to provide accurate alerts to ensure smooth flow of field processes such as meter installations, removals and exchanges.

- FortisBC expects to use outage and restoration data from the AMI system in order to manage primarily small and medium sized outages. Restoration information will be important in assisting with large scale outages;
- To provide FortisBC employees with the information and tools needed to complete research and analysis of all data (such as Voltage Var Optimization ("VVO"), voltage sags and swells and harmonics) from the AMI system in order to optimize the FortisBC network;
- To ensure that industry security standards are followed in each aspect of the AMI system from the meter to the HES; and
- To provide the option of remote connect/disconnect and load limiting

D. AMI Installation & Maintenance

The following diagram outlines the installation and maintenance processes expected to be affected by the implementation of AMI:

Figure 2: AMI Installation & Maintenance Use Cases

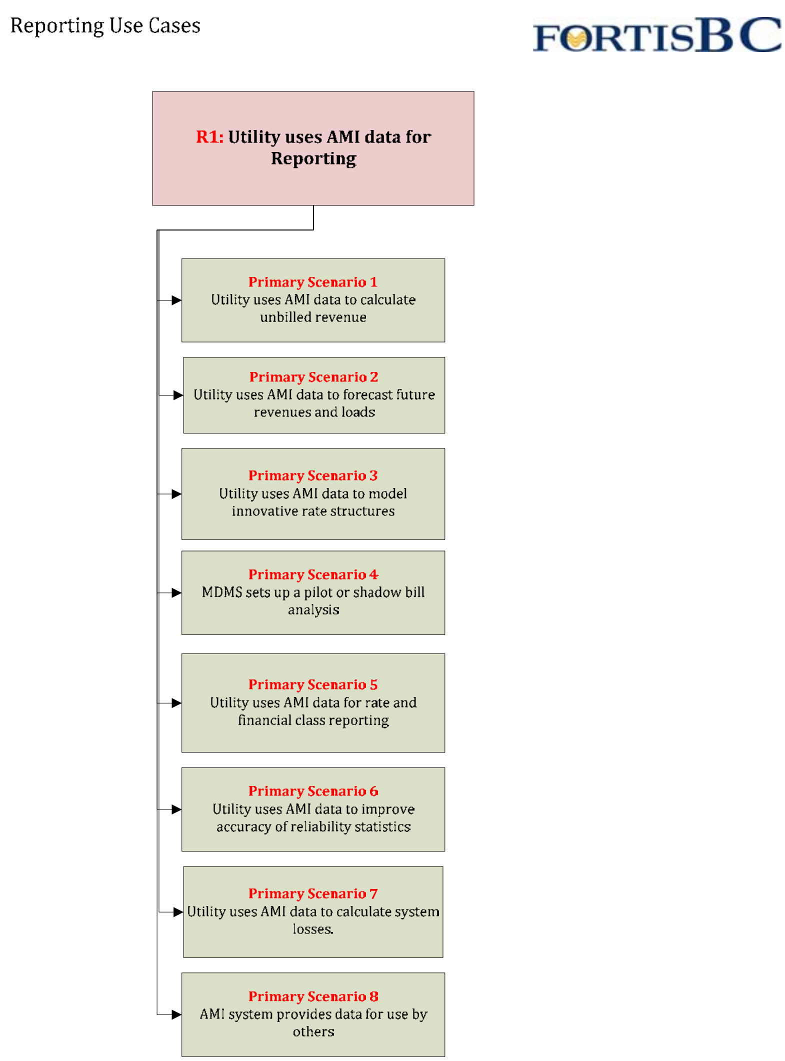


The primary objectives related to AMI installation and maintenance processes is that the AMI system must provide accurate and timely data that can be used to ensure the overall health of the system

E. Finance & Reporting

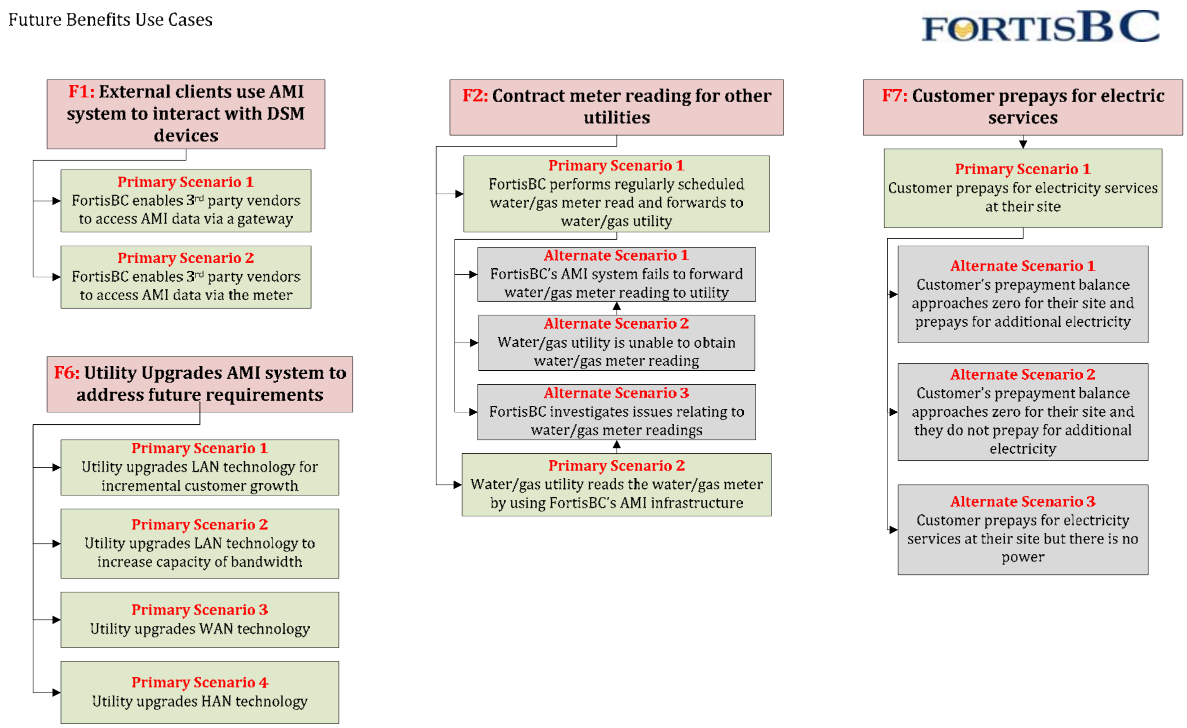
The following diagram outlines the finance and reporting processes expected to be affected by the implementation of AMI:

Figure 3: Reporting Use Cases



F. Future Uses

Figure 4: Future Benefits Use Cases



Primary objectives and important considerations related to future benefits are:

- To ensure that the AMI system is able to accommodate potential growth. The customer base may grow due to the inclusion of Terasen Gas meters or other power and water municipalities.
- To ensure that the ability to provide customers with new types of services is available such as prepay or load limiting; and
- To provide customers with more options to access their consumption data.

3.1.8 Expected Regulatory Process

Once RFP's have been completed for all components of the AMI system, then the business case will be updated and CPCN will be written. The following schedule is only approximate at this time and may be amended by FortisBC or the BCUC:

CPCN Application:	July 1, 2011
Rounds of IR's and Responses:	Mid June to Mid August 2011
Final Submission:	End of August 2011
Reply Submission:	Beginning to Mid September 2011
Decision:	4-6 months from application filing

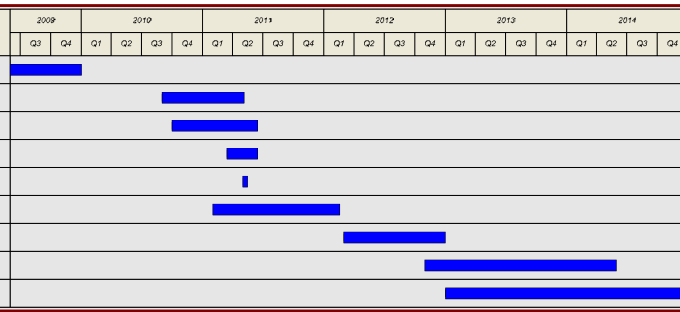
All information contained in the Proponent's Proposal may be released to the regulator. This may be limited to a certain level of detail for public view but all may be made available on a confidential basis to the BCUC.

Implementation of the AMI System is not expected until after regulatory approval is obtained.

3.1.9 Implementation Timelines

A final implementation schedule cannot be completed until regulatory approval has been obtained. However, based on information available at this time, FortisBC expects that the AMI system implementation will follow the timeline below:

ID	Task Name	Start	Finish
1	Complete Use Cases and Requirements	01/06/2009	01/01/2010
2	MDMS RFP Process	01/09/2010	05/05/2011
3	AMI RFP Process	01/10/2010	15/06/2011
4	Implementation Planning	15/03/2011	15/06/2011
5	Consultation	02/05/2011	16/05/2011
6	CPCN Creation & Regulatory Process	01/02/2011	17/02/2012
7	IT Systems Implementation	01/03/2012	31/12/2012
8	Communications Deployment	31/10/2012	30/05/2014
9	Meter Deployment	01/01/2013	31/12/2014

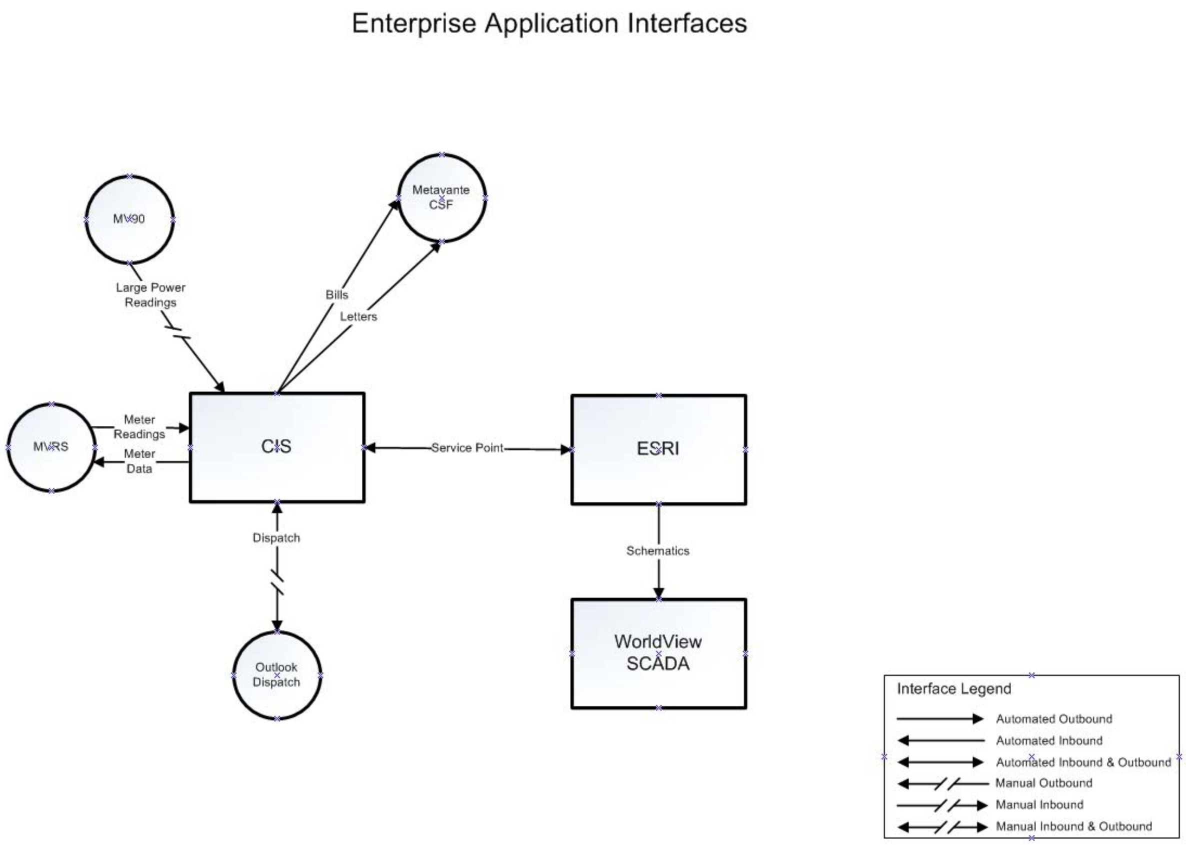


3.2 FortisBC Systems in Use

3.2.1 System Architecture Overview

FortisBC's system architecture involves 4 core systems (including SAP which is used by the finance department and is not expected to have an impact on the AMI deployment). These systems are detailed in the following sections below.

Figure 5: Enterprise Application Interfaces



3.2.2 Customer Information System (CIS)

FortisBC's billing system is CISPlus 2.5.1 from SAG / Oracle was implemented in 2000.

> <u>Technical Specifications:</u>
> Platform: AIX 5.2
> Database: Oracle 9.2.0.6
> GUI Client: 2.5.1.0071

CIS+ is integrated with MV-RS to accept meter readings in order to bill customers on a monthly and bi-monthly basis. Customer, premise and service point information is stored in CIS. Other integration points are with Metavante CSF Designer and ESRI ArcFM.

There is a project currently underway to convert the CIS to a web services based application with a thin client web style front end and to migrate to Linux environment. This is expected to be completed in the first quarter of 2011.

3.2.3 Handheld Metering

FortisBC's meter reading software is currently MV-RS Version 7.8 from ITRON. It is a PC-based meter reading software system for data collection and route management for ITRON handheld computers and mobile collection systems. The MV-RS system provides an interface to the FC200 ITRON handheld computers used by FortisBC.

The main server is housed in Trail, B.C. and interfaces with CIS+ via a daily custom file transfer that delivers meter reading route detail and reads based on the CIS billing schedule. CIS uses this information to generate customer invoices. FortisBC anticipates that MV-RS and the ITRON handhelds will be retired upon a completed AMI implementation but that there will be a flow through of data from MV-RS to the MDMS during the transition period.

3.2.4 C&I Interval Metering

MV-90xi V2.0 is the software FortisBC uses for interval data collection, management and analysis from commercial and industrial (C&I) metering devices. It is currently hosted by FortisAlberta and monthly text files of 15 minute interval and demand data are emailed to FortisBC to use for manual billing. Upon request additional files can be sent by FortisAlberta if further analysis of certain meter data is required.

Currently, FortisBC manually bills approximately 60 C&I meters with MV-90 data received from FortisAlberta. This manual process could either remain in place or be incorporated into a permanent process once an MDMS has been installed and can receive MV-90 file formats of interval data to use for billing.

3.2.5 GIS

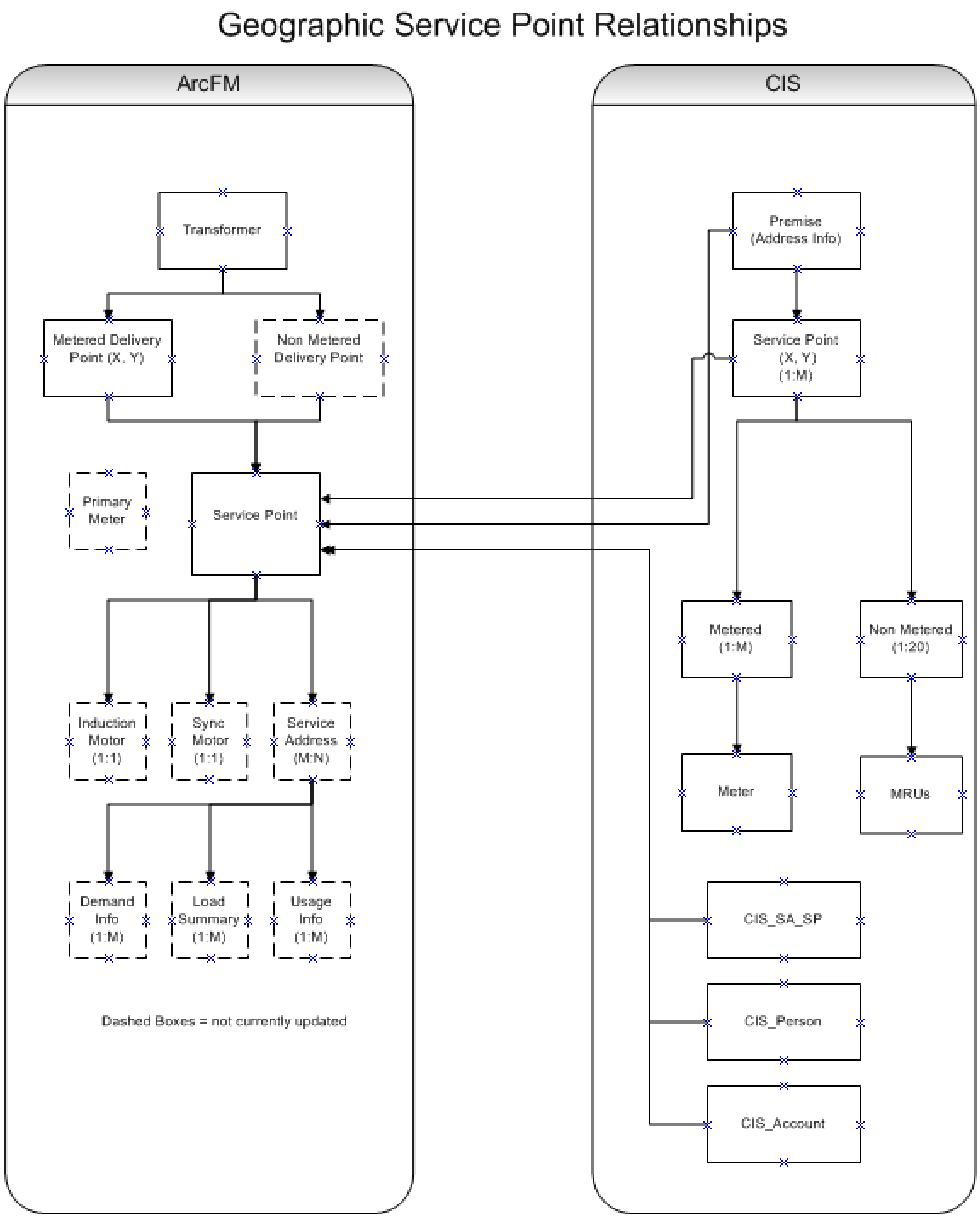
FortisBC's GIS software is currently ArcGIS 9.3.1sp1 and ArcFM 9.3sp1. ArcGIS allows the business user to view and analyze data from a geographic perspective. ArcFM allows the business user to model, design and manage critical infrastructure. It was implemented in the spring of 2008 and an upgrade is being considered for the next release in 2011.

> Technical Specifications:
> Vendor: ESRI and Telvent
> O/S Application: Microsoft Windows Server 2003 Enterprise Edition SP2
> Database: AIX 5.3 / Oracle 10.2.0.2

FortisBC has integrated ArcFM to CIS for service point and meter information. CIS information is sent to GIS daily. Any updated CIS information will be updated in the GIS 'service point' table when it is sent.

The following diagram shows FortisBC's integration between CIS and GIS. The CIS service point information is sent to the GIS daily as well as correlating customer information. This is done to ensure that any new meter information that is added to CIS for installations or removals is updated in GIS.

Figure 6: Geographic Service Point Relationships



3.2.6 SCADA

Survalent Technologies provides the SCADA system currently used at FortisBC.

Technical Specifications

SCADA Software on protected LAN (firewalled from corporate WAN)

Master Station software: SmartSCADA suite (formerly known as Windows SCADA)
Operator workstation software: WorldView Graphical User Interface
Licensed protocols: DNP3 serial, DNP3 over TCP/IP, ICCP, QUICS IV, MultiSpeak

SCADA Software on the corporate WAN:

Database replicator and web server: SCADA WebSurv
- Version: SCADA Replicator 4.3.2.1
- OS: Microsoft Server 2003 Enterprise Edition SP2
- Database: SQL Server 2005 SP4

Two Master Station servers (hosts) are installed in separate locations and operate in a redundant hot-standby configuration. The host machines are responsible for interrogating devices at remote locations and storing received information in a local database. The database is continuously synchronized on both hosts to ensure that if either machine fails there is no interruption in SCADA system operations. Multiple client workstations connect to the host machines and provide a graphical user interface to the power system dispatchers who are responsible for operating the electrical system. Some client machines have editing capabilities that are used to configure the SCADA database and to develop the graphical screens for the dispatchers' graphical interface. The hosts, workstations and communications equipment are connected via a redundant, protected LAN which is firewalled from the FortisBC WAN. To provide corporate access to the SCADA database, the SCADA WebSurv application is installed on separate server which is connected to the corporate WAN. This server uses a secure connection to the hosts in order to provide a replicated copy of the host database.

At remote sites (generating plants and substations) FortisBC uses IEDs (intelligent electronic devices) from a number of manufacturers (SEL, GE, Cooper, etc.). The SCADA system communicates with these devices using serial and Ethernet protocols over fibre optic, satellite, cellular and leased-line connections. Currently, FortisBC has complete visibility and control over all generating stations and transmission substations. A Distribution Substation Automation Program is also underway which will provide complete visibility and control of all distribution substations by the end of 2011.

At the present time, FortisBC has no remote control or monitoring of any distribution system field devices (i.e. devices which are not located within a substation sites). Investigations are currently underway to determine if there is sufficient cost-benefit justification to support this level of field equipment monitoring.

FortisBC has also recently completed the installation of a data historian solution. The data historian is based on the eDNA product supplied by InStep Software, LLC. The data historian collects real-time information from the FortisBC SCADA system and the FortisBC power-quality monitoring system (Schneider ION Enterprise). The collected information is archived in proprietary database which is integral to the eDNA software. System interfaces are provide for user access (via thick and thin clients) and for database connections to the data sources. The eDNA system resides on the corporate WAN.

3.2.7 Bill Designer Software

FortisBC uses CSF Designer from Metavante as the software to create and deliver customer communications; including statements, notices and direct mail campaigns.

Version 6.0 was implemented on April 1st, 2007 and a recent upgrade was done to Version 9.0 in March 2010.

In the future FortisBC may want the MDMS to provide data to CSF Designer for the purpose of providing customers more information on their interval usage.

Technical Specifications
Version: CSF Designer 9.0.21
VM Server: Windows 2008 Server R2
Database: SQL Server 2005 SP4 on Windows Server 2003 SP2

Version: CSF Batch MCCD 9.0.21
O/S: Windows Server 2003 SP2

3.2.8 Dispatching (Work Order) System

Microsoft Outlook 2007 client running on Microsoft Exchange 2010 using Public Folders is currently used at FortisBC for dispatching and work order management. Dispatchers along with various other departments create work orders through dispatch orders and form templates that attach to dispatch orders. These orders are accessed through different views that can be set up depending on the user's role or need.

All work is captured by a dispatch order and field and office personnel add information and change the status of the order based on the work that was done.

3.2.9 Web Portal for Customers

FortisBC currently does not have a Web Portal for customers.

3.3 Scope of Work

FortisBC, through this RFP, is seeking a cooperative and mutually beneficial relationship with a Vendor which will allow FortisBC to deliver on the objectives set out in Section 3.1.4 AMI Program Objectives.

The Vendor shall supply all required components of an AMI system as well as the necessary project management, system design, installation, commissioning and training in order to successfully implement the AMI system at FortisBC. Specifically, the scope of work includes the following components described in further detail below:

I. Meters & Modules
II. Communications Infrastructure
III. Head end system (HES)
IV. Implementation Services
V. Ongoing services

FortisBC intends to undertake a separate RFP for meter installation services once the AMI CPCN application has been approved by the BCUC. Once implementation begins, it is expected that the AMI and installation contractors will work together to carry out the deployment of AMI and resolve any issues that arise during that process.

3.3.1 Meters & Modules

Deployment Supply & Delivery

FortisBC requires that the Vendor supply approximately 110,000 meters as part of the AMI deployment. An example of meter breakdown by region is as follows:

Table 2: Summary of Meter Volumes

4	Residential Meters	C&I Meters	Total Meters
Kelowna	43,490	4,735	**48,225**
South Okanagan	20,800	3,290	**24,090**
Kootenay	33,190	4,495	**37,685**
Total	**97,480**	**12,520**	**110,000**

Meter count and location is in the Meter Detail Listing described in Section 2.2.1(2) Proponent Access to Background Information. Current styles of meters used at FortisBC are described in Table 3 below:

Additional meters are required to support future growth and ongoing operations. For the purposes of this RFP, the Proponent should assume an average of 2% growth per year.

All meters are required to meet the specifications outlined in Section 5 AMI Solution Technical Requirements.

The delivery schedule and locations will be determined once the AMI deployment plan has been finalized. However, for purposes of this proposal, the Proponent should assume a delivery schedule of every two weeks beginning in January 2013 and ending

December 2014. Each bi-weekly shipment should contain no more than 7,000 meters and will need to be delivered to the following location:

Table 3: Warehouse Locations

Region	Warehouse Location
All Areas	Terasen Measurement 444 Okanagan Ave East Penticton, BC V2A 3K3

Once approved for implementation, it is the expectation of FortisBC that the Vendor will supply warehouse locations in strategic areas around FortisBC's service area.

Ongoing Supply & Delivery

Once deployment has completed, the Vendor will be required to deliver meters to the central meter shop located at Terasen Measurement, 444 Okanagan Ave East, Penticton BC, V2A 3K3

3.3.2 Communications Infrastructure

Network Design & Configuration

In Section 5.1 General AMI Requirements, FortisBC has outlined the required performance specifications, redundancy requirements and scalability of the AMI system. FortisBC requires that the Vendor provide the necessary equipment and infrastructure to meet the stated requirements.

FortisBC has provided meter locations for active, installed meters as described in Section 2.2.1(2) Proponent Access to Background Information.

FortisBC has also provided a listing of all substations, buildings and other infrastructure that could be used to support the communications infrastructure. It is the preference of FortisBC that existing structures be used to support the communications infrastructure (rather than building new) and that company owned assets be considered before any others. In the event that the Proponent utilizes an alternative building or structure in their design plan, the necessary approvals and costs must be included in the proposal.

It is the responsibility of the Vendor to provide a system design that will meet all specifications within this document. Privacy and security should be designed into the system. All network design documents will be subject to review and approval by FortisBC.

Deployment Supply & Delivery

FortisBC requires that the Vendor supply all equipment required to implement the communications infrastructure as designed.

The delivery schedule and locations will be determined once the AMI deployment plan has been finalized. However, it is the expectation of FortisBC that the Vendor will supply warehouse locations in strategic areas around FortisBC's service area.

Ongoing Supply & Delivery
Once deployment has completed, the Vendor will be required to deliver any required equipment to a FortisBC run central warehouse the location of which will be determined at some point in the future.

3.3.3 Head End System (HES)

Design:
The Vendor shall perform the initial design for the HES and IT infrastructure required to support the proposed solution. This includes:

I. Identifying the system infrastructure requirements for all production and test environments.
II. Developing the system architecture plan that will meet the requirements set out in Section 5 AMI Solution Technical Requirements.
III. Ensuring the system design meets the security standards set out in Section 5.15 AMI System Security.

The final design will be subject to review and approval by FortisBC.

Implementation & Configuration
The Vendor shall configure the HES (in all environments) once it has been installed at FortisBC. This includes:

I. Reviewing FortisBC's Use Case documentation to determine what system configuration is required.
II. Following established FortisBC change management processes in completing this configuration and providing documentation of all configurations performed.
III. Identifying any integration points within the HES and completing the integration work as required.

Testing
FortisBC requires that the Vendor provide detailed HES test plans for review and approval by FortisBC. Once approved, the Vendor is expected to perform functional and performance testing to prove that the HES meets the requirements identified within this RFP document. FortisBC may also choose to complete independent testing of the system.

3.3.4 Implementation Services

Project management

FortisBC requires that the Vendor provide the necessary project management resources and tools to deliver on the stated scope of work. Project management activities completed by the Vendor should include:

i. Providing detailed implementation plans including a work breakdown structure, scope and schedule for the Vendor's scope of work to be included in FortisBC's integrated project plan.
ii. Providing a detailed project plan and updating that plan as required;
iii. Providing status reports including variance reporting, issues reporting and any risk management items to FortisBC's project management team.
iv. Participation by Vendor personnel in status meetings which are expected to be held on a regular basis in conjunction with FortisBC's project team.

Operation of the Network

FortisBC requires that the Vendor operate the AMI system until such time as network stability and system acceptance testing has been completed and approved by FortisBC.

Meter Deployment

The Vendor is responsible for ensuring that all meters are properly registered or activated to the network.

FortisBC will undertake a separate RFP to procure meter installation services once regulatory approval has been achieved. However, the Vendor is expected to support the meter deployment process by:

i. Participating in deployment planning with FortisBC and the deployment contractor;
ii. Coordinating with FortisBC and the deployment contractor in ensuring meters are delivered to the correct locations when required (as per the deployment schedule);
iii. Providing technical support to the deployment contractor in case of issues during deployment; and
iv. Providing the meter and network tools (field programming devices etc) required to deploy the AMI meters.

Testing

The completed end to end AMI system will be subject to FortisBC acceptance, which will occur after System Acceptance Testing (SAT) has been completed to FortisBC's satisfaction. The Vendor will provide SAT test cases for FortisBC to review and approve prior to the completion of phase of testing listed below. The testing will be completed primarily by the Vendor with support from FortisBC as required. FortisBC and / or its consultants will audit and approve the results of this testing and also may complete their own, independent tests.

The following phases are expected to make up the required system acceptance testing:

i. **Factory acceptance testing** which includes a review of the manufacturer's accreditation documentation review and FortisBC audits of manufacturing and sealing facilities;
ii. **Functional acceptance testing** of meters which will occur at a FortisBC determined meter shop or some other location;
iii. End to end **System acceptance testing** and **field validation** once each area is substantially deployed; and
iv. **Final acceptance testing** once all areas are deployed.

Training

FortisBC requires that the Vendor to provide training in all areas of the proposed AMI solution as described in Section 5.13 Training.

3.3.5 Ongoing services

Technical support & updates

FortisBC requires the Vendor to provide technical support as described in Section 5.14 Support for all software solutions for a period of no less than ten years and for all other components for a period of fifteen years. This support is expected to include:

i. **Software updates** for all components of the AMI system including patches and major releases.
ii. **Technical assistance** with the operation of the end to end metering system including troubleshooting issues and providing resolutions to those issues.
iii. **Firmware management** for all components of the AMI system.
iv. **Network optimization and planning** in the event of performance issues or customer growth.

4 Proponent Company Information

4.1 Financial / Business Stability (I)

The Proponent is asked to answer the following questions intended to help FortisBC evaluate the stability of the Proponent's business:

a) What is the current number of employees and the, turnover rates for last three (3) years?

b) What is the location(s) of the Proponent's company?

c) Please provide the number of employees assigned to development and support for the AMI system solution proposed.

d) What is the current financial condition of the Proponent's company? Describe the financial conditions for the AMI system division within the company. Provide supporting documentation and annual reports for the last three years. If the company is privately held, supply sufficient information to document the company's financial status.

e) Please provide your corporate roadmap specific to your AMI products and their development within your organization.

4.2 Experience Providing Same or Similar Products & Services (I)

The Proponent is asked to answer the following questions intended to help FortisBC evaluate the Proponent's experience providing the scope of services included in this RFP:

a) How many years has the Proponent been in business?

b) How long has the Proponent been providing AMI system solutions?

c) What is the number of AMI endpoints currently installed and what number are under contract?

d) What is the current number of utilities using the AMI system solution and the number of endpoints deployed at each? Proponent to also provide number of utilities using version of technology being proposed.

e) Provide a description of clients with similar terrain and/or topography as FortisBC using the AMI system.

f) What is the number of clients using the solution to collect and manage hourly interval data for all customers and what is the number of endpoints at each?

g) How long has the proposed solution been deployed and implemented in the field excluding any period of time for which it was in a beta test status?

h) Describe the Proponent's primary line of business and the percentage of its business derived from the sale of AMI products and associated services.

4.3 Contract Manager (I)

The Proponent is asked to acknowledge the requirement to designate a contract manager, who shall have the authority to handle and resolve any technical issues, disputes or contractual issues in a timely manner. The Proponent is asked to describe the contract manager's experience with managing projects of a similar size and scope, including timelines, and results if applicable. Response should include the contract manager's and any other related team member's Curriculum Vitae (CV).

The Proponent is to also provide information regarding a backup contract manager in case a change is required throughout the life of the contract. The Proponent should describe the backup contract manager's experience with managing projects of a similar size and scope, including timelines, and results if applicable. Response should include the backup contract manager's Curriculum Vitae (CV).

The Proponent will designate a project manager whose role will be to coordinate operational and technical activities within the proponent's company and will have the authority to handle and resolve disputes or contractual issues with FortisBC. The project manager is expected to spend sufficient time on the project and project site to identify and resolve areas of concern.

4.4 Perspectives Expressed by References (CI)

To ensure long-term viability and maintenance of the system, the selected Proponent must be a proven Vendor in the area of AMI products and services. Therefore, the Proponent is requested to provide a list of at least three (3) references (contact names and phone numbers) for companies using the Proponent's proposed system to perform the same or similar function(s) as the one(s) described in this RFP for the past three (3) years.

4.5 Health & Safety Record (I)

FortisBC Inc. believes in an incident and injury free work place. We are committed to managing our business in a safe and responsible manner by taking accountability for personal safety. We place no greater importance on what we do above accomplishing it safely.

In every part of our operations we will:

- Make the safety of our employees, customers and the public our first priority, regardless of the type of work or the situation.
- Continually improve our safety performance by reporting, analyzing and taking action based on incident experiences.
- Incorporating safe management principles in all phases of our business including design, operations, and purchasing.
- Proactively complying with safety legislation and regulations in all of the jurisdictions we operate.
- Ensure that our employees and contractors understand the consequences of their actions and have the knowledge and skills to make the right decisions.
- Communicate our goals and progress with regulatory agencies, customers and other stakeholders regarding our performance in relation to those safety targets.

Although the successful Proponent will be an independent contractor of FortisBC, it is imperative that the Proponent puts the same value and importance on environment, health and safety as has been noted above. The Proponent is to provide data to support their safety record such as corporate safety statistics, internal safety record, WSBC rating, injury rate or injury severity. In addition, the Proponent must provide documentation supporting their commitment to safety within their manufacturing facilities and design of products.

4.6 Subcontractors (C)

The Vendor shall take responsibility for all subcontractors. FortisBC reserves the right to approve any subcontractors.

The Proponent shall submit a list of subcontractors including name and explanation of the work to be performed by the subcontractor.

4.7 Privacy (C)

Protection of our customer's personal information is very important to FortisBC and we require the successful Proponent to be in compliance with the Personal Information Protection Act, S.B.C. 2003, C.63; the Personal Information Protection and Electronic Documents Act, S.C. 2000, c. 5; and all other applicable privacy legislation.

The Proponent is asked to acknowledge this requirement and to provide a copy of their privacy policies and any other descriptions and documentation showing how the Proponent collects, uses, discloses, secures and retains personal information.

5 AMI Solution Technical Requirements

5.1 General AMI Requirements (I)

The following section is intended to provide FortisBC with an overview of the network architecture and the components which comprise the vendor's AMI system.

a) The Proponent is asked to provide a summary overview of the proposed system architecture and system functionality (from HES to in-home communications). This overview should be no more than five pages long and should include the following:

   i. Information on installation requirements;
   ii. Information on expected labour requirements (for installation as well as ongoing maintenance);
   iii. Preferred LAN configuration and ideal relay/hop settings;
   iv. Information on the limitation of the number of hops/relays to transmit information in the LAN;
   v. "Time to Live" restrictions to messages in the LAN to control network traffic and noise levels;
   vi. If each level of the network operates on a push, pull or combination method of transmitting data. (i.e. Meter to collector, collector to HES);
   vii. What configuration options are available to control the LAN in urban environments where noise can be an issue; and
   viii. What configuration options are available in rural settings where maximizing distance will be important to FortisBC.

As described in Section 3.3.2 Communications Infrastructure, FortisBC prefers that existing structures be utilized in the network design wherever possible.

b) The Proponent is asked to provide for the 95% coverage option:

i. A copy of the electric only propagation study used to price the Proposal for 95% coverage;
ii. The location of all collector devices and number of meters allocated to each collector;
iii. Maps showing LAN and WAN coverage;
iv. The precise location of any new or "Greenfield" sites being proposed as part of their solution.

c) The Proponent is asked to provide for the 100% coverage option:
   i. A copy of the electric only propagation study used to price the Proposal for 100% coverage;
   ii. The location of all collector devices and the number of meters allocated to each collector;
   iii. Maps showing LAN and WAN coverage;
   iv. The precise location of any new or "Greenfield" sites being proposed as part of their solution.

d) The Proponent is asked to provide:
   i. An alternate propagation study to help FortisBC to understand the requirements for an electric and gas deployment. For ease of this exercise, the Proponent is to assume a gas meter for every electric location from the propagation study provided in (c)(i) above;
   ii. The location of all collector devices and the number of electric and gas meters allocated to each collector;
   iii. Maps showing LAN and WAN coverage; and

e) The Proponent is asked to provide:
   i. An alternate propagation study to help FortisBC to understand the requirements for an electric, gas and water deployment. For ease of this exercise, the Proponent is to assume a gas and water meter for every electric location from the propogation study provided in (c)(i) above;.
   ii. The location of all collector devices and the number of electric, gas and water meters allocated to each collector;
   iii. Maps showing LAN and WAN coverage; and

f) The Proponent is to complete the functionality matrix supplied by FortisBC in the Functionality Spreadsheet. This spreadsheet details what components the AMI system are compliant with and if the functionality is included in the base product or what the cost would be to include these enhancements.

g) The Proponent is asked to describe in detail the pricing for the systems proposed in the Pricing Spreadsheet. Include any communication charges that FortisBC will incur in operating the system. Detail any assumptions made in the proposed solution and pricing. All of this information should be included within the Pricing Spreadsheet.

5.1.1 AMI Network Service Level Agreement (CI)

a) FortisBC requires that the Proponents state their acceptance with the following Service Level Agreement (SLA) requirements. These requirements are to demonstrate the AMI vendor's ability to acquire the readings that were missed in 24 hours and over the subsequent time periods and will be included within the future contract:

- Percent of interval readings captured:
  - 98% in 24 hours
  - 99% in 72 hours (rolling statistic)
  - 99.5% in 30 days (calendar static)
- Percent of daily (register) readings captured:
  - 98% in 24 hours
  - 99% in 72 hours (rolling statistic)
  - 99.5% in 30 days (calendar static)
- Percent of meters communicating within 24 hours: 99.9% (This statistic is to track that a meter is alive and has been heard on the network).

NOTE: the Proponent's network design and pricing being proposed must be designed to accommodate these SLA requirements.

b) The Proponent is asked to provide the calculated and demonstrated Mean Time Before Failure (MTBF) for each meter / module combination being proposed.

5.1.2 AMI Network Redundancy Design (I)

FortisBC's preference is for a redundant configuration in all areas.

a) Proponent is to declare the main LAN redundancy ratio used in their network design (i.e. each meter can access 2 collectors being a 1:2 ratio). The documentation should describe how, in the event of a fail-over, peripheral and communication equipment operates. The information provided should detail whether these operations (including, but not limited to, crash tolerances, restart/recovery procedures, integrity check, and file protection) are automatic, or require manual intervention.
b) Proponent is asked to provide the ratio of collectors to meters they have incorporated in the design proposed to FortisBC to achieve the SLA described in Section 5.1.1 AMI Network Service Level Agreement.

5.1.3 AMI Compliance with Health Canada Regulations (CI)

It is essential that all systems and installations meet or exceed all relevant regulations pertaining to the safe implementation of radio frequency radiating devices and systems as directed by Health Canada within their publication entitled: Limits of Human Exposure to Radiofrequency Electromagnetic Fields in the Frequency Range from 3 kHz to 300 GHz – Safety Code 6 (2009).

Note: This document is posted electronically on Health Canada's website at URL: http://www.hc-sc.gc.ca/ewh-semt/pubs/radiation/radio_guide-lignes_direct-eng.php

a) Proponent is to declare their compliancy with this specification and to provide documentation showing their compliancy.

To the extent that it may apply, products proposed shall also be designed to meet or exceed the installation standards for mounting RF systems on poles, towers and structures as set forth in CSA Standard S37-01, Antennas, Towers, and Antenna-Supporting Structures. Furthermore, grounding of these RF systems shall occur as required and set forth in CSA Standard C22.1-02, Canadian Electrical Code, Part I (19th Edition) - Safety Standard for Electrical Installations.

b) Proponent is to declare their compliancy with this specification and provide supporting material to this statement.

5.1.4 AMI Communication Standards / Protocols (I)

FortisBC requires an understanding of the protocols that the vendor supports in their product today. For each of the standards listed below, the Proponent is to describe:

a) Which are currently supported in the Proponent's products;
b) In what layer in the network (Meter End Device, Collector, HES, HAN devices, DA devices) the protocol is supported;
c) If the protocol is following the true industry standard or if the vendor is performing any manipulation/mapping at their HES to accommodate the standard;
d) Proponent is to provide details on what standards are part of their network design and the effects on the network if available standards not implemented are turned on at a later date; and
e) If the current vendor hardware/processors will be able to accommodate current known upgrades to the standards listed below.

1) ANSI C12.18
2) ANSI C12.19
3) ANSI C12.22
4) IPv4
5) IPv6
6) ZigBee 1.0
7) ZigBee 1.1
8) ZigBee 2.0
9) Modbus
10) DNP3

5.1.5 AMI System Warranty (CI)

FortisBC desires a warranty for equipment, materials and workmanship.

a) The Proponent is asked to provide information detailing the standard warranties that are provided with the AMI system proposed. Should the Proponent's warranty statement be greater than one page in length, please include a summary highlighting the following items:
   i. Term - term of warranty by product: meter and communication modules, collectors, head-end system, (hardware and software), and possible pro-rated scenarios;

ii. Cost coverage and obligations depending on whether deficiency is attributed to manufacture/workmanship, or some fault of FortisBC's;

iii. Are labour costs covered by the AMI Provider if a fault is found in the product after the endpoints have been deployed;

iv. The procedure which would be required by FortisBC when defects in materials and/or workmanship are found. Proponent's response should include descriptions of the Proponent's obligations, as well as the obligations of FortisBC.

b) If applicable, the vendor should also describe any optional warranties that can be procured and that are not part of the base warranty (i.e. Additional warranties for extended periods – 3 or 5 years).

With regards to warranty, it is FortisBC's assumption that the proposed AMI hardware, software, and communication infrastructure will function as an integrated system, as represented in the Proponent's Proposal document. If this assumption is incorrect,

c) Proponent to provide details on any component on their AMI network that is not covered by the warranty.

d) What is the warranty?

5.1.6 AMI Test Environment (I)

At minimum, FortisBC anticipates a requirement to have both a Production and Test environment. There are two options that FortisBC may consider:

I. Test HES with a test collector and meter farm:

a) The Proponent is asked to recommend how a full test AMI environment can be set up for FortisBC which utilizes a test HES with a test collector and meter farm.

b) The Proponent should describe their license policy for this second environment and if any functionality differences would exist between the Test and Production systems. Any standard form licensing agreements that may apply should be provided.

c) The Proponent is to address if the same hardware specifications and service levels would apply to the test environment as to the live environment.

II. Test HES only:

d) The Proponent should describe their license policy for a test HES and if any functionality differences would exist between test and production. Any standard form licensing agreements that may apply should be provided.

e) The Proponent is asked to provide details on how a test HES can be utilized with the production infrastructure. How will the data from the Production environment be migrated or replicated in the test HES?

f) The Proponent is to address if the same hardware specifications would apply to the test HES as to the live HES.

5.2 Meters and Communication Modules (Metering End Device) (CI)

The metering end device must be permanently labeled with manufacturer's name, model number, "FortisBC", ID number, required Industry Canada / Measurement Canada labeling, input/output connections, and date of manufacture.

a) The Proponent is asked to attach a copy of the standard label(s) in the appendix of their response. All metering end devices must also have a tamper / theft warning applied to each end device. Final text for the warning to be specified by FortisBC.
b) The Proponent must state what industry standards the metering end device complies with.

The meter must have barcoding to assist in the installation and inventory process.

c) The Proponent must state what information is provided on the barcode.

Each metering end device must have a unique, permanent ID number.

d) The Proponent must describe how and if the identifier denotes the make, model, version and production run of the specific device.
e) The Proponent must state if the identifier is transmitted with the meter read and identify any other information within the ID number or in addition to the ID number that is a part of the physical and/or virtual metering end device identification.
f) The Proponent must state how the end device ID and meter number are linked and if this is performed during end device programming or the HES or both.
g) The Proponent must state required field and digit length for the ID number and how FortisBC is assured that all devices are part of a unique numbering plan.
h) The Proponent must state if the metering end device identification number and meter badge number are visible without breaking the seal, and if not, the Proponent should note how FortisBC will be able to determine what metering end device number is under the meter glass without breaking the seal.

5.2.1 Compatibility with Multiple Meter Manufacturers (I)

FortisBC requires a comprehensive understanding of the impact on AMI system functionality when the communications module is utilized with different meter manufacturers. It is the preference of FortisBC that the communications module be compatible with multiple meter manufacturers.

a) The Proponent is to provide a detailed listing of the meter manufacturers they are currently integrated with that have received Measurement Canada approval. In the event that integration has not yet been completed for multiple meters, the Proponent is requested to provide their anticipated timeline for development and approval of additional combinations.

   When providing the information on integration with other meter manufacturers, any functionality differences resulting from use of the communication board in conjunction with another metering product shall be noted (i.e. last gasp, voltage, etc).

b) The Proponent is requested to provide information regarding meter functionality by completing the spreadsheet "FortisBC Meter Functionality Sheet" that is provided. One column should be completed for each meter manufacturer that their product is compatible with, by specifying S (Standard), O (Optional), or NA (Not Available). If the optional functionality is available only at an incremental cost, this pricing must be specified.
c) The Proponents must provide details on each meter type including if the metering information is being accessed via the meter's ANSI tables or if the information is stored and accessed via the Proponents communication module. For each meter vendor supported, the Proponent is to declare the number of meters sold/deployed with the proposed module installed.
d) The Proponent must state whether Measurement Canada approvals have been acquired and if new metering end devices can be factory sealed and delivered "installation ready" to FortisBC.

5.2.2 Ability to Supply all Utility Meter Forms (I)

As per the Functionality Spreadsheet, FortisBC requires certain meter forms for their deployment. Proponents should state the meter forms that are available for all meters that are included in the pricing table that has been completed for Section 5.2.1 Compatibility with Multiple Meter Manufacturers.

5.2.3 Metering End Device Power Supply & Draw (I)

FortisBC would like to understand the power supply requirements of the metering end device.

a) Proponent must provide details on the forecasted annual power consumption for each type of metering end device based on the vendor read transmission/schedule to achieve the SLA listed in Section 5.1.1 AMI Network Service Level Agreement.
b) The Proponent must also describe the transmission distance from the metering end device to the collector and what wattage is used for this transmission. The Proponent should also state if higher wattage devices are available and when it is recommended that they be used.
c) The Proponent must state the power output from each metering endpoint and if the power setting is configurable in the meter (i.e. higher setting for rural environments and lower setting for denser urban environments).
d) For each proposed unique combination of meter manufacturer and meter model type describe the potential impact, on meter shop test boards as a result of the meter power supply, i.e. reactive loading.
e) The Proponent to confirm the comm module will be able to operate at same voltage as meter (i.e. accommodating auto-ranging meters)

The Proponent must state if the metering end device requires a battery.

If the metering end device requires a battery:

f) Provide a description of the battery;
g) Describe the anticipated life expectancy of the battery under both normal and extreme temperature conditions;
h) Describe the anticipated life expectancy of the battery when the meter is energized and when it is de-energized, i.e. the metering end device is in storage;
i) Provide copies of test reports supporting the anticipated battery life expectancy under various conditions and frequencies of transmission;
j) Describe the process for replacing the battery and for recycling the meter at end-of-life;
k) Describe the time accuracy or drift when the meter clock is powered from the battery only; and
l) Describe the battery life status reporting that is available through the HES; and
m) Describe any features that would indicate the remaining power left in the battery.
n) Provide data on lab battery tests, battery failures and battery life from significant installations where the proposed AMI end device has been installed.

If the meter does not have a battery:

o) Describe the power outage duration that the meter can experience before the clock and / or the meter become non-functional.

In addition to transient, short duration line surges, energized metering end devices may be exposed to 60 Hz power frequency overvoltage, across their line side terminals, for several seconds. This is typically due to distribution transformer insulation failure or accidental contact between transmission voltage, primary voltage or secondary voltage circuits.

p) For each proposed manufacturer and model of metering end device, Proponents are asked to provide the maximum per unit 60 Hz overvoltage magnitudes and time durations, applied across the line side terminals, which an energized metering end device can sustain without:
    i. Impacting accuracy; or
    ii. Failing catastrophically to the extent that personnel or property could be jeopardized.
    iii. Describe the metering end device design features that will minimize, and contain, the impact of a catastrophic overvoltage failure, e.g. due to a sustained 60 Hz overvoltage incident, the protective surge arrestors' rupture and considerable energy is dissipated within the meter case.

5.2.4 End Device Surge Protection (I)

a) Proponents are asked to provide details around the layering of surge protection devices/solutions that are provided with the proposed solution.

5.2.5 Metering End Device Functionality

FortisBC would like to understand what functionality is available with the metering end device.

5.2.5.1 Visual Meter Display (I)

FortisBC requires some information be visible to customers and field staff on site at the meter location. This information includes:

- Meter readings - all UOM on meter (i.e. kWh, KW, voltage)
- Error messages
- Visual indicator that the communication board is operational
- Disconnect / reconnect status (if the meter is equipped with remote disconnect capability).

a) The Proponent is asked to confirm that this information is visible on the meter display and to describe what other information is visible once the meter has been installed.
b) Describe any health check and diagnosis tests are available through the meter either on-demand or at a pre-configured frequency (e.g. metrology, memory, and communications issues)?

5.2.5.2 Meter Registers / Functionality (CI)

The AMI System must provide all meter reads to a minimum of ten (10) Watt hours (0.01 kWh) resolution in order to define electricity consumption for billing purposes in hourly intervals.

The AMI meter must store, at a minimum, one register read for each channel of data as of 12 midnight every day.

a) The Proponent is asked to confirm their compliancy with this statement.

FortisBC currently has a net metering program that the AMI system will need to support.

b) The proponent is asked to provide an overview of net metering options available within the end device and AMI system to be able to support this program.

FortisBC would like to understand the flexibility available for changing read intervals once the end device has been installed.

c) The Proponent is asked to describe the process by which the meter could be remotely programmed to record intervals as small as fifteen minutes in order to complete load research for specified customer.

5.2.5.3 Demand Reset Process (I)

a) FortisBC requires that Proponents provide detailed information as to the process by which the AMI system performs the demand reset of a meter. Details should include
   a) The process to change a demand reset schedule;
   b) What information is included in the confirmation to the AMI head-end system upon the demand reset; and
b) The exception management process to notify FortisBC if the action failed.
c) Proponents are asked to describe their experience with demand reset in their AMI network including the numbers of meters deployed today currently using this functionality.
d) Proponents are to confirm if the demand reset schedule is maintained within the meter, communications module or performed on demand by the HES.
e) If the meters are configured with a default demand reset schedule, Proponents are asked to confirm if the schedule can be modified over the air.

5.2.5.4 Load Profile Data (I)

a) Proponents are to provide information explaining how they measure load profile data, specifically addressing if it is stored on the communications module or if they access the ANSI C12.19 tables of the meters. Proponents are to address the following in their response:
   i. How many load profile channels are available with the meters currently supported?
   ii. What are the units of measurement available to be recorded to these channels?
   iii. What interval lengths can be configured in the module?
   iv. Once the interval length has been programmed can it be changed over the air or does the meter seal have to be broken to change the configuration?

5.2.5.5 Information Brought Back Over the Network (I)

a) The Proponent must indicate whether all data being recorded in the meter is transmitted back through the AMI network. Proponent to identify if there is information recorded in any of their meters that will not be available to be transmitted over the AMI network.
b) Specify if information in the load profile channels can all be brought back to the HES or if this is restricted to the limitations of the communications module (i.e. 8 channel meters can bring back all 8 channels, or any restricted to 2 or 4 of the channels?).
c) Provide details as to the method by which the data is transmitted, specifically if it is included with regular scheduled readings or if the data (i.e. load profile channels) is transmitted on a separate schedule at a specific time each day.

5.2.5.6 Metering End Device Dimensions (CI)

a) The Proponent must describe the physical characteristics of the meter including height, length, width and weight.

b) The Proponent must confirm the meter operates within a temperature range of –35 °C (-31 °F) to 65 °C (149 °F), and a humidity range of 0% to 100% non-condensing.
c) The Proponent must state if or when an external device is required to connect to the electric meter to enhance or augment data transmission to the collector.
d) The Proponent must describe features of the meter that prevent corrosion or degradation of mechanical or electrical performance (e.g. encapsulation or coating).
e) What is the flammability rating of the meter, e.g. UL94 rating V-0?

5.2.5.7 KYZ Pulse Outputs and Load Control Contacts

FortisBC has a few customers currently on TOU rates that have invested in equipment that utilizes the KYZ pulse output contacts on their existing meter to operate energy efficient systems.

a) The Proponent to provide details on pulse output options available with their meters, and what meter forms support this option.
b) The Proponent to provide details on what data is available through the pulse outputs.

If the Proponent has additional options that would support these customers (other than physical contacts on the meter):

c) Please describe the options available; and
d) Please outline the work that would be required by the customer in order to accommodate this change in technology.

5.2.6 Firmware Upgradability (CI)

FortisBC requires that the proposed AMI system be capable of over-the-air firmware upgrades to the meter in the event that there are programming upgrades required post installation.

a) The Proponent is asked to provide an overview of the AMI system's ability in this regard. The overview should include the following:
   i. A description of upgrade procedures including backwards compatibility/rollback for all components being proposed;
   ii. A listing of reporting available on firmware version (i.e. version control processes);
   iii. A description of the Proponent's process for firmware version quality and version control;
   iv. Whether or not the system provides an acknowledgement of a completed upgrade;
   v. An estimate of the expected time required for 100% of the meter population to be upgraded; and
   vi. A description of what performance impacts to daily network processes as a result of mass firmware upgrades.

In light of Measurement Canada sampling plans, the Proponents are to notify FortisBC of any firmware enhancements that may affect the homogeniety of the purchase lots.

b) The Proponent is asked to describe the firmware upgrade process including at what point the meter begins to use the new version of firmware and how firmware upgrade attempts, failure, successes, reversions, etc are logged within the meter or HES.
c) The Proponent is also asked to describe how rollback to a previous version of firmware could be accomplished.

FortisBC understands that Measurement Canada does not currently allow firmware upgrades to meter metrology in Canada.

d) The proponent is asked to describe the process to "unlock" metrology firmware in the meter should this change in the future. Would it require a site visit or meter exchange to do so?
e) Proponents are asked to describe their experience with firmware upgradability including the numbers of firmware upgrades they have performed on networks deployed including the names of utilities, numbers of meters, numbers of firmware revisions performed, and time to complete the entire upgrade process.

5.2.7 Reliability, Adaptability and Fail-Over Design (I)

Meters shall be able to determine that the provisioned communication link has failed and shall select alternate redundant links, or a new link if available.

a) The Proponent must provide details if their meter maintains preferred routing paths and if multiple redundant paths are stored in case of failure in communications.
b) The Proponent is to describe in detail the steps performed if communication failure occurs and time required for the meter to establish a new communication path.
c) Proponent to identify how often the meter is evaluating its communication links to identify if they are optimized.
d) The Proponent must indicate any restrictions when installing meters in close proximity to each other. This includes proximity issues with water and gas devices as well as any combination of the two.

5.2.8 Licensed and Unlicensed Frequencies(I)

FortisBC would like to understand the LAN frequency being proposed by the Proponent.

a) The Proponent is asked to provide detail as to whether the proposed system is utilizing a licensed or unlicensed radio frequency to send data through the network. Information should include:
    i. theoretical and actual data throughput of communication network;
    ii. the frequency range;
    iii. the number of frequencies utilized for both transmission and receipt of data;
    iv. the bandwidth of each frequency;
    v. the modulation method used; and

vi. the power output.

b) The Proponent must state whether the frequency being proposed is available for use in FortisBC service territory as well as in surrounding areas, should FortisBC territory expand or options to read meters in neighboring territories emerge over time.
c) Proponents are to provide a description of the key benefits of the spectrum used in their AMI network.

5.2.9 Outage Notification (Last Gasp Messages) (CI)

FortisBC requires that the proposed AMI system be capable of certain outage management functions (i.e. outage notification or restoration confirmation). In order to ensure maximum value of the system, FortisBC is requiring the following SLA related to outage message success. Using the AMI network to assist with outage notification and help manage crews in the field during restorations is a potential benefit FortisBC hopes to achieve. Proponents are to provide details in the following sections to help FortisBC understand how their network can help achieve the following values in the tables below.

Table 4: Outage Message SLA's

Success Rate Based on a 300 second Latency After a Programmable Delay of 120 seconds to Filter out Momentary Outages		Number of Power Failures Under a Single Collector				
	1	10	100	500	1,000	2,000
Expected Success Rate	95.0%	95.0%	95.0%	90.0%	85.0%	80.0%

Restoration events:

Table 5: Restoration Message SLA's

Success Rate Based on a 300 second Latency After a Programmable Delay of 120 seconds to Filter out Momentary Restorations		# of Power Restorations Under a Single Collector				
	1	10	100	500	1,000	2,000
Expected Success Rate	99.0%	95.0%	95.0%	90.0%	85.0%	80.0%

a) The Proponent is asked to confirm that the proposed system can meet these requirements.

For a metering system with “last gasp” functionality, the Proponent is asked to address the following questions pertaining to meter detected outages:

b) The Proponent is requested to provide an explanation as to how the meter end device transmits information during outages, how many outage messages in a system wide outage are expected to be received by the HES and how long it will take to get there. The explanation should include any steps used to prevent data collision to maximize the information collected, and if any specific communication channels or prioritization in traffic is used for these event messages.

c) The Proponent is to provide in seconds the length of time individual meters have to provide “last gasp” communications capability after an outage.
d) Do meters receive and relay “last gasp” outage messages from other meters?
e) What information is included in a last gasp or outage notification message (i.e. power fail, register reads, voltage, etc.)?
f) Understanding not all outage data will successfully be transmitted through the last gasp process, the Proponents are to describe how outage data is sent through the regularly scheduled read events after the network is up and operational again. Are all outage events logged and transmitted? Is this part of the regular HES daily read file?
g) The Proponent must describe how the AMI System logs momentary outages (blinks) at the meter.
h) The Proponent must define what constitutes a blink and if this definition is user configurable. The Proponent must state how blinks are reported and if they can be tracked at the HES.
i) The Proponent is asked to describe how and when restoration messages will be received and what information is included in the restoration message.
j) For full restoration, the Proponent is asked to describe details and how long it will take, for the metering system to:
    i. Re-configure itself
    ii. Re-optimize itself
    iii. Re-synchronize time

5.2.10 Automatic Registration (I)

FortisBC would like to understand the registration process that takes place when a new meter is installed into the AMI network. FortisBC prefers that the proposed AMI allows for automatic registration of the meter upon installation in the field, and that there is the capability for visual confirmation of successful (or not) communication while installers are at the residence.

a) Describe how the metering system will automatically detect, validate and register, provision, commission, and report newly installed meters. How long will this take?
b) What information is transmitted during the registration process from the meter to the HES?
c) How will the installer on site know that the meter and module are communicating via the AMI network before leaving the site? What tools are available to support this process?
d) What “health checks” does the meter perform upon initial installation?

5.2.11 Meter Memory and Storage (I)

FortisBC would like to understand the memory capabilities of the end point.

a) The Proponent is asked to provide detailed information about the memory capabilities of the metering endpoint, as well as the process by which data can be accessed and/or extracted from the metering endpoint (i.e. data which may have been missed during normal data collection process). The Proponent should also explain whether or not this recovery process is manual or if it can be automatically initiated.

Additionally, if power is interrupted the AMI meter must maintain all reads that were collected but not yet transmitted (for transmission at a later date).

b) The Proponent is asked to describe what information can be stored within the meter, including:
   i. Readings;
   ii. Alarms and messages; and
   iii. Communications events.
c) The Proponent is asked to provide the maximum number of days of interval and register readings that can be stored within the meter, assuming:
   i. For residential meters:
      - Two Channels of Hourly interval data
   ii. For C&I meters:
      - Four Channels of Hourly interval data
      - Four Channels of 15 minute interval data
d) The Proponent is asked to provide the maximum number of days of readings, diagnostic, outage and tamper related events/errors that can be stored within the meter.
e) Provide details as to what logic is built into the system to determine what data has not yet been received at the HES.
f) Describe the process by which data can be accessed and/or extracted from the metering endpoint (i.e. data which may have been missed during normal data collection process) and whether or not this process is manual or can be automatically initiated.

5.2.12 Billing Information (Register & Interval Data) (I)

a) The Proponent is asked to provide detailed information on the read collection schedules that are maintained within the AMI system. This information should detail the following;
   i. Whether the meter reports register and interval data together or separately;
   ii. What the respective schedules are;
   iii. Whether the schedules are configurable; and
   iv. If configurable, what the options are.
b) The Proponent is asked to provide their recommendations for best practices in regards to data collection schedules.

The Proponent is also asked to provide details on:

c) How often the meter stores a register reading for each channel of data and if this frequency is configurable.
d) How the AMI meter acknowledges receipt of, sets up and/or changes a read schedule in a manner that the event can be logged and stored within the HES. If so, provide a description of how long this process will take.
e) In the event of a failed scheduled reading, how does the meter send the reading back to the HES once communication is re-established?
f) Describe if the meter is capable of transmitting different data types according to multiple read schedules.

5.2.13 Operational Information

Using the AMI network to collect and feed operational data into analytical systems is of interest to FortisBC. Proponents are to provide details in the following sections to help FortisBC understand how their network can help achieve this value.

5.2.13.1 Voltage (CI)

FortisBC requires that the proposed AMI network, at a minimum, provide daily max/min/average voltage values, as well as acquire instantaneous voltage information from an on demand reading.

a) Proponents are instructed to provide documentation regarding voltage information available from the meter and communication module.
b) The Proponent is to confirm if the end device is capable of retaining and returning event based power quality information upon query for a minimum of 60 days for C&I meters and 30 days for residential meters after the data is captured, even if there is no communications with the meter over the 60/30 day period.

The Proponent is asked to describe the following;

c) How the meter differentiates between sags, swells and momentary outages and longer outages.
d) Are alarms sent on Hi/Lo voltage events? Are the parameters for these events configurable?
e) Are the events date and time stamped?
f) Is there a hold off on Hi voltage events due to power restorations?
g) Are maximum/minimum/average voltage values provided per phase?
h) Are the values for date and time stamps recorded for maximum/minimum/average values?
i) What are the configurable periods for the maximum/minimum/average values (i.e. 1 hour, 6 hours, 12 hours, 24 hours, etc)?
j) Does the meter provide instantaneous voltage data? Is this available on the meter display?
k) Does the meter monitor the voltage continuously in order to detect an RMS variation?

5.2.13.2 Current & Line Frequency (I)

a) Proponents are to provide information as to which of their products are able to monitor line frequency, current, and current/voltage harmonics, including:
   i. whether they are residential or commercial applications;
   ii. whether it is an instantaneous reading or if it is profiled; and
   iii. if the products are in use in current implementations or are not yet deployed.

5.2.13.3 Tamper (I)

FortisBC would like to understand how the AMI system can prevent and identify tampering with meters out in the field.

a) The Proponent is asked to describe the ability of the metering system to identify and locate stolen meters.
b) Describe what methodology the meter uses to detect tampering such as physical inversions (i.e. tilt alarm).
c) What are the options to deal with reverse energy flow? How are these events handled by the network?

For each tamper and outage event the meter must be able to detect, transmit and locally log the following information about the event:

- timestamp
- tamper status (event type)
- meter ID

Upon meter reinstallation, any unsent tamper events must be sent to the HES including the reinstallation event.

d) The Proponent is asked to describe how their system accommodates this requirement.

5.2.13.4 Hot Socket Detection (I)

a) The Proponent is asked to describe how their product detects hot sockets (over temperature) and reports this information to the HES. Specifics should include:
   i. what metering products include this feature;
   ii. whether the threshold level for detection is configurable; and
   iii. whether the event is reported instantaneously as an alarm or transmitted with a normal reading schedule.

5.2.14 End Device Time Synchronization (I)

The Proponent is asked to describe:

a) How the end device validates its time upon installation.
b) How and how often the end device validates and synchronizes its clock and how it corrects itself should it find any deviations. Are these changes logged somewhere or reported to the HES for future review if required?

c) Describe how the system can identify meters with constant drift or large drifts that may be due to a default and should be replaced.
d) At what threshold of deviation does the end device reset itself and is this threshold configurable?
e) Are all found deviations corrected with a hard synch or are these configurable with larger drifts being able to be identified to an operator instead?
f) If the meter "loses time" during a power outage, describe the time re-synchronization process and the expected duration for re-synchronization to occur.
g) Following restoration of an outage, how does the end device ensure its time is synchronized prior to sending its first transmission?
h) Describe how load profile intervals, generated prior to or during time re-synchronization, are "adjusted" once time re-synchronization has occurred.

5.2.15 End Device Roadmap (I)

a) The Proponent is to provide detailed information as to the product roadmap vision and planned releases over the next 24 months. Details should include:
   i. What functionality is going to be added or enhanced?
   ii. What are the planned hardware and firmware releases?

5.2.16 End Device Trouble Shooting Process (I)

a) The Proponent is asked to describe the troubleshooting tools and processes that are available to help resolve communication or meter issues. Specifically,
   i. The ability of the meter to detect and log a communications failure.
   ii. The ability of the meter to determine internal data inconsistencies.
   iii. The ability to initiate a meter health and communications self check that can be using a tool on site, through the HES or by the meter itself.
   iv. The ability to check that network coverage exists in the event of a communication failure at the point of meter installation.

5.2.17 End Device Spare Equipment Recommendation (I)

Proponents shall provide recommendations for on-site spares and test equipment needed to support the level of system availability required to meet the SLA's as outlined in Section 5.1.1 AMI Network Service Level Agreement. These costs will be separately itemized within the worksheet provided.

5.3 Gas Modules

As part of its AMI program, FortisBC is considering a future inclusion of all or a portion of the 55,000 gas meters that overlap with electric meters as well as the remaining 900,000 gas meters in joint FortisBC/Terasen Gas territory.

5.3.1 Overview of Gas Solution (CI)

a) The Proponent is asked to specify if their gas module products can utilize the AMI network.

b) The Proponent is asked to provide an overview of how the gas module operates within the AMI network including:

i. If the devices are one-way or two-way modules;
ii. If the module communicates with collectors directly or with other modules within the network;
iii. How many gas modules are deployed today and where they are deployed.

5.3.2 Physical Dimensions & Environmental Tolerances of the Gas Module (I)

a) The Proponent is to describe the physical characteristics of the module including height, length, width and weight.

b) The Proponent to confirm if the module operates within a temperature range of –30 °C (-22 °F) to 66 °C (150.8 °F), and a humidity range of 0% to 100% non-condensing with unlimited exposure to rain, snow, fog and ice.

c) The Proponent to confirm if the module is capable of withstanding storage temperature ranges of –40 °C (-40 °F) to 75 °C (167 °F), for up to 1000 hours.

d) The Proponent to state if or when an external device is required to connect to the gas module in order to enhance or augment data transmission to the collector.

e) The Proponent is to confirm if the gas module can be submersed and not receive any damage to the unit.

f) The Proponent is to confirm if the module is resistant to various chemical products and is the module sealed to keep out dust, humidity and water.

g) The Proponent is to describe features of the module that prevent corrosion or degradation of performance (e.g. encapsulation or coating).

h) The Proponent is to confirm that the gas module shall not impair the ability for the meter to be visually read.

i) The Proponent is to confirm that the module labeling can visibly display the following items as per Measurement Canada regulations:

i. Manufacturer's name
ii. Model number
iii. Serial number
iv. Input/output connections
v. Date of manufacture
vi. Bar Coding

5.3.3 Compatibility with Multiple Meter Manufacturers (I)

a) Proponents are asked to list all gas meters supported by the Measurement Canada approved gas module. With each gas module listed, please provide:

i. Details on available retrofit options.
ii. Measurement Canada approval numbers.

5.3.4 Module Power Supply and Draw (I)

FortisBC would like to understand the power supply requirements of the gas module.

a) The Proponent is asked to state the power requirements of the module and if there is a variation in power setting in the module. Proponent must also provide details on the forecasted annual power consumption for each available type of gas module.

b) The Proponent is asked to state the power output from each module and if there is a variation in power setting in the module. If this option is available, Proponent is asked to provide details on the effect on battery life.

In regards to the battery within the gas module, Proponents are to:

c) Provide a description of the battery;

d) Describe the anticipated life expectancy of the battery under both normal and extreme temperature conditions;

e) Describe the anticipated life expectancy of the battery when the meter is energized and when it is de-energized, i.e. the metering end device is in storage;

f) Provide copies of test reports supporting the anticipated battery life expectancy under various conditions and frequencies of transmission;

g) Provide details of the warranty as it relates to the battery;

h) Describe the process for replacing the battery and for recycling the module at end-of-life;

i) Describe the battery life status reporting that is available through the HES;

j) Describe any features that would indicate the remaining power left in the battery; and

k) Provide data on battery tests, battery failures and battery life from significant installations where the proposed module has been installed.

5.3.5 Gas Module Billing Information (Register & Interval Data) (I)

a) The Proponent is asked to provide detailed information on the read collection schedules that are maintained within the gas modules. This information should detail the following;
   i. Whether the module reports register and interval data together or separately;
   ii. Options for interval lengths (i.e. 5 min, 30 min, 1 hr);
   iii. Options for register reads (i.e. daily, with every transmission) and if the values are time stamped;
   iv. What the respective schedules are;
   v. Whether the schedules are configurable; and
   vi. If configurable, what the options are.

b) The Proponent is asked to provide their recommendations for best practices in regards to data collection schedules.

The Proponent is also asked to provide details on:

c) How often the gas module stores a register reading for each channel of data and if this frequency is configurable.
d) How the gas module acknowledges receipt of, sets up and/or changes a read schedule in a manner that the event can be logged and stored within the HES. If so, provide a description of how long this process will take.
e) In the event of a failed scheduled reading, how does the module send the reading back to the HES once communication is re-established?
f) Describe if the module is capable of transmitting different data types according to multiple read schedules.

5.3.6 Gas Module Functionality (I)

a) The Proponent is to provide information on the types of alarms such as meter tampering and low battery that are available from the gas module and if they are transmitted with the regular read transmission or instantaneously.

b) Proponent to provide details on the following functionality or technical requirements of the gas module.

   i. Proponent to confirm if the gas module has the ability to be initialized or programmed during field installation and also if there is the ability for this to be performed before they are installed in the field.
   ii. Proponent to confirm that the gas module meter reads received by the HES should contain the same information as that collected by all gas modules deployed and comply with SLA's noted in Section 5.1.1 AMI Network Service Level Agreement.
   iii. Proponent to provide details of the on-demand read functionality related to gas modules. This explanation should include the average response time to perform this function.

5.3.7 Gas Module Time Synchronization (I)

a) Is time stamped at the module or at the collector?

b) If at the module, the Proponent is to describe how the time accuracy is maintained with the gas module;

   i. How the module validates its time upon installation.
   ii. How and how often the module validates and synchronizes its clock, with the clock accuracy not to exceed a +- 1.5 minutes variance, and how it corrects itself should it find any deviations. Are these changes logged somewhere or reported to the HES for future review if required?
   iii. Describe how the system can identify modules with constant drift or large drifts that may be due to a default and should be replaced.

iv. At what threshold of deviation does the module reset itself and is this threshold configurable?

v. Are all deviations found corrected with a hard synch or is this configurable with larger drifts being able to be identified to an operator instead?

vi. If the module "loses time" during a power outage, describe the time re-synchronization process and the expected duration for re-synchronization to occur.

vii. Following restoration of an outage, how does the module ensure its time is synchronized prior to sending its first transmission?

viii. Describe how load profile intervals, generated prior to or during time re-synchronization, are "adjusted" once time re-synchronization has occurred.

c) If time is only maintained at the collector, the Proponent is to describe how this is performed and provide details on how the intervals are time stamped. Also describe how the collector deals with gaps in communication or down time due to power outages at a collector.

5.3.8 Module Memory and Storage (I)

FortisBC would like to understand the memory capabilities of the gas module.

a) The Proponent is asked to provide detailed information about the memory capabilities of the gas module, as well as the process by which data can be accessed and/or extracted from the gas module (i.e. data which may have been missed during normal data collection process). The Proponent should also explain whether or not this recovery process is manual or if it can be automatically initiated.

b) The Proponent is asked to describe what information can be stored within the gas module, including:

i. Readings;
ii. Alarms and messages; and
iii. Communications events.

c) The Proponent is asked to provide the maximum number of days of interval and register readings that can be stored within the module, assuming:

i. For residential meters:
   - Hourly interval data

ii. For C&I meters:
   - Hourly interval data
   - 15 minute interval data

d) Describe the process by which data can be accessed and/or extracted from the gas module (i.e. data which may have been missed during normal data collection process) and whether or not this process is manual or can be automatically initiated.

5.3.9 Gas Module Firmware Upgradeability (I)

a) If two-way gas modules are available, Proponent to provide additional details on the modules ability to support Measurement Canada approved remote firmware upgradeability.

b) The Proponent is asked to provide an overview of the gas module's ability in this regard. The overview should include the following:
   i. A description of upgrade procedures including backward compatibility/rollback for all components being proposed;
   ii. A listing of reporting available on firmware version (i.e. version control processes);
   iii. A description of the Proponent's process for firmware version quality and version control;
   iv. Whether or not the system provides an acknowledgement of a completed upgrade;
   v. An estimate of the expected time required for 100% of the gas module population to be upgraded; and
   vi. A description of what performance impacts to daily network processes as a result of mass firmware upgrades.

5.3.10 Gas Module Security (I)

a) Proponent is to provide details on the level of security used (i.e. encryption) on these devices and if there is any difference in security between their one-way and two-way modules and outline any differences with security used with their electric network.

5.3.11 Alternate Reading Methods for Gas Modules (I)

Within its service area, FortisBC has customers with electric-only service, gas and electric service and gas-only service (serviced by an electric utility other than FortisBC). FortisBC is interested in understanding what options are available to collect reading data for gas-only customers.

a) The Proponent is asked to describe what alternatives to reading via the electric AMI network are available. This may include:
   i. Drive-by solutions;
   ii. Walk-by solutions;
   iii. Fixed network solutions.

b) For each alternative described, information should be provided on the following:
   i. Details of the flexibility available to migrate between these alternative solutions and the electric AMI network.
   ii. Which alternatives can be accommodated using the same module and communications protocol and which will require a module change.
   iii. If a change is required, Proponent to describe how this transition works and if a site visit is required to reprogram devices to complete this migration if it is performed remotely.

5.3.12 Gas Module Roadmap (I)

a) The Proponent is asked to provide a general description of planned releases in the next 24 months related to gas modules.

5.4 Water Modules

As part of its AMI program, FortisBC would like to ensure the ability to include water meters in conjunction with local municipalities in the FortisBC service territory.

5.4.1 Overview of Water Solution (CI)

a) The Proponent is asked to specify if their water module products can utilize the AMI network.

b) The Proponent is asked to provide an overview of how the water module operates within the AMI network including:

   i. If the devices are one-way or two-way modules;
   ii. If the module communicates with collectors directly or with other meters within the network;
   iii. How many water modules are deployed today and where they are deployed.

5.4.2 Physical Dimensions & Environmental Tolerances of the Water Module (I)

a) The Proponent is to describe the physical characteristics of the module including height, length, width and weight.

b) The Proponent to confirm if the module operates within a temperature range of –30 °C (-22 °F) to 66 °C (150.8 °F), and a humidity range of 0% to 100% non-condensing with unlimited exposure to rain, snow, fog and ice.

c) The Proponent to confirm if the module is capable of withstanding storage temperature ranges of –40 °C (-40 °F) to 75 °C (167 °F), for up to 1000 hours.

d) The Proponent to state if or when an external device is required to connect to the water module in order to enhance or augment data transmission to the collector.

e) The Proponent is to confirm if the water module can be submersed and not receive any damage to the unit.

f) The Proponent is to confirm if the module is resistant to various chemical products and if it is sealed to keep out dust, humidity and water.

g) The Proponent is to describe features of the module that prevent corrosion or degradation of performance (e.g. encapsulation or coating).

h) The Proponent is to confirm that the water module will not impair the ability for the meter to be visually read.

i) The Proponent is to confirm that the module labeling can visibly display the following items as per Measurement Canada regulations:

i. Manufacturer's name
ii. Model number
iii. Serial number
iv. Input/output connections
v. Date of manufacture
vi. Bar Coding

5.4.3 Compatibility with Multiple Meter Manufacturers (I)

a) Proponents are asked to list all water meters supported by the Measurement Canada approved water module. With each water meter listed, please provide:

i. Details on available retrofit options and with each type provide details on the retrofit options such as requiring a two of three wire connection when replacing the outside remote with the water module device.

ii. Measurement Canada approval numbers.

5.4.4 Module Power Supply and Draw (I)

FortisBC would like to understand the power supply requirements of the water module.

a) The Proponent is asked to state the power requirements of the module and if there is a variation in power setting in the module. Proponent to also provide details on the forecasted annual power consumption for each available type of water module.

b) The Proponent must state the power output from each module and if there is a variation in power setting in the module. If this option is available, Proponent is asked to provide details on the effect on battery life.

In regards to the battery within the water module:

c) Provide a description of the battery;

d) Describe the anticipated life expectancy of the battery under both normal and extreme temperature conditions;

e) Describe the anticipated life expectancy of the battery when the meter is energized and when it is de-energized, i.e. the metering end device is in storage;

f) Provide copies of test reports supporting the anticipated battery life expectancy under various conditions and frequencies of transmission;

g) Proponent to provide details of the warranty as it relates to the battery;

h) Describe the process for replacing the battery and for recycling the module at end-of-life;

i) Describe the battery life status reporting that is available through the HES;

j) Describe any features that would indicate the remaining power left in the battery; and

k) Provide data on battery tests, battery failures and battery life from significant installations where the proposed AMI end device has been installed.

5.4.5 Water Module Billing Information (Register & Interval Data) (I)

a) The Proponent is asked to provide detailed information on the read collection schedules that are maintained within the water modules. This information should detail the following;
   i. Whether the module reports register and interval data together or separately;
   ii. Options for interval lengths (i.e. 5 min, 30 min, 1 hr);
   iii. Options for register reads (i.e. daily, with every transmission) and if the values are time stamped;
   iv. What the respective schedules are;
   v. Whether the schedules are configurable; and
   vi. If configurable, provide details.

b) The Proponent is asked to provide their recommendations for best practices in regards to data collection schedules.

The Proponent is also asked to provide details on:

c) How often the water module stores a register reading for each channel of data and if this frequency is configurable.
d) How the water module acknowledges receipt of, sets up and/or changes a read schedule in a manner that the event can be logged and stored within the HES. If so, provide a description of how long this process will take.
e) In the event of a failed scheduled reading, how does the module send the reading back to the HES once communication is re-established?

5.4.6 Water Module Functionality (I)

a) The Proponent is to provide information on the functionality listed below as well as any additional functionality available. For any events, indicate if they are transmitted with the regular read transmission or instantaneously.
   i. Back flow detection;
   ii. Tamper detection;
   iii. Cut wire detection;
   iv. Leak detection;
   v. Broken Pipe detection;
   vi. Low battery; and
   vii. Assistance with detection of losses in distribution network.

b) Proponent to provide details on the following functional or technical requirements of the water module.

   i. Proponent to confirm if the water module has the ability to be initialized or programmed during field installation and also if there is the ability for this to be performed before they are installed in the field.
   ii. Proponent to confirm that the water module meter reads received by the HES should contain the same information as that collected by all water modules deployed and comply with SLA's noted in Section 5.1.1 AMI Network Service Level Agreement.
   iii. Proponent to provide details of the on-demand read functionality related to water modules. This explanation should include the average response time to perform this function.

5.4.7 Water Module Time Synchronization (I)

a) Is time stamped at the module or at the collector?

b) If at the module, the Proponent is to describe how the time accuracy is maintained with the water module;

   i. Describe how the module validates its time upon installation.
   ii. Describe how and how often the module validates and synchronizes its clock, with the clock accuracy not to exceed a +- 1.5 minutes variance, and how it corrects itself should it find any deviations. Are these changes logged somewhere or reported to the HES for future review if required?
   iii. Describe how the system can identify modules with constant drift or large drifts that may be due to a fault and should be replaced.
   iv. At what threshold of deviation does the module reset itself and is this threshold configurable?
   v. Are all deviations found corrected with a hard synch or is this configurable with larger drifts being able to be identified to an operator instead?
   vi. If the meter "loses time" during a power outage, describe the time re-synchronization process and the expected duration for re-synchronization to occur.
   vii. Following restoration of an outage, how does the module ensure its time is synchronized prior to sending its first transmission?
   viii. Describe how load profile intervals, generated prior to or during time re-synchronization, are "adjusted" once time re-synchronization has occurred.

c) If time is only maintained at the collector, the Proponent is to describe how this is performed and provide details on how the intervals are time stamped. Also describe how the collector deals with gaps in communication or down time due to power outages at a collector.

5.4.8 Water Module Memory and Storage (I)

FortisBC would like to understand the memory capabilities of the water module.

a) The Proponent is asked to provide detailed information about the memory capabilities of the water module, as well as the process by which data can be accessed and/or extracted from the water module (i.e. data which may have been missed during normal data collection process). The Proponent should also explain whether or not this recovery process is manual or if it can be automatically initiated.

b) The Proponent is asked to describe what information can be stored within the water module, including:
   i. Readings;
   ii. Alarms and messages; and
   iii. Communications events.

c) The Proponent is asked to provide the maximum number of days of interval and register readings that can be stored within the module, assuming:
   i. For residential meters:
      - Hourly interval data
   ii. For C&I meters:
      - Hourly interval data
      - 15 minute interval data

d) Describe the process by which data can be accessed and/or extracted from the water module (i.e. data which may have been missed during normal data collection process) and whether or not this process is manual or can be automatically initiated.

5.4.9 Water Module Firmware Upgradeability (I)

a) If two-way water modules are available, Proponent to provide additional details on the modules ability to support remote firmware upgradeability.

b) The Proponent is asked to provide an overview of the water module's ability in this regard. The overview should include the following:
   i. A description of upgrade procedures including backward compatibility/rollback for all components being proposed;
   ii. A listing of reporting available on firmware version (i.e. version control processes);
   iii. A description of the Proponent's process for firmware version quality and version control;
   iv. Whether or not the system provides an acknowledgement of a completed upgrade;
   v. An estimate of the expected time required for 100% of the water module population to be upgraded; and
   vi. A description of what performance impacts to daily network processes as a result of mass firmware upgrades.

5.4.10 Water Module Security (I)

a) Proponent to provide details on the level of security used (i.e. encryption) on these devices and if there is any difference in security between their one-way and two-way modules and outline any differences with security used with their electric network.

5.4.11 Alternate Reading Methods for Water Modules (I)

a) The Proponent is asked to describe what alternatives to reading the water module via the electric AMI network are available. This may include:
   i. Drive-by solutions;
   ii. Walk-by solutions;
   iii. Fixed Network solutions.

b) For each alternative described, information should be provided on the following:
   i. Details of the flexibility available to migrate between these alternative solutions and the electric AMI network.
   ii. Which alternatives can be accommodated using the same module and communications protocol and which will require a module change.
   iii. If a change is required, Proponent is to describe how this transition works and if a site visit is required to reprogram devices to complete this migration if it is performed remotely.

5.4.12 Water Module Roadmap (I)

a) The Proponent is asked to provide a general description of planned releases in the next 24 months related to water modules.

5.5 Collector

5.5.1 Collector Hardware Design (I)

The Proponent is responsible for determining the number of regional collector units required to achieve access to all meters in FortisBC's service territory as required to support the service levels described in Section 5.1.1 AMI Network Service Level Agreement in each coverage option..

a) The Proponent must provide a description of the equipment within the proposed network design along with the function which each serves;
b) If more than one device is proposed within the design, the Proponent should describe each model offered including storage capacity, power requirements and the ability to mount in various terrains and locations. The main benefits of each model should also be described.
c) The Proponent must state how the collector complies with the necessary safety regulations for all mounting options available.
d) The Proponent is asked to provide the number of WAN take-out points within each collector option.

5.5.2 Collector Dimensions and Layout (I)

For all types of collector equipment being proposed:

a) The Proponent must provide the physical characteristics of the collector including height, length, width and weight. Please also attach pictures in the appendix with the response and describe the major advantages of the physical design.
b) The Proponent must state how the collector complies with the necessary safety regulations for all mounting options available.
c) The Proponent is asked to provide mechanical drawings of the interior of the collector device.

5.5.3 Frequency of Transmissions (Collector to HES)

In the following sub-sections, the Proponent is to describe what types of messages are communicated and how often the communications occur.

5.5.3.1 Transmission of Scheduled Readings (I)

a) The Proponent is to describe how frequently the meter communicates regularly scheduled readings to the collector and how often the collector transmits these files to the HES.
b) The Proponent is asked to describe if this frequency of transmission is configurable and if so, how.
c) The Proponent is asked to provide the maximum number of times per day the transmission can occur.

5.5.3.2 Transmission of Event Data (I)

a) The Proponent is to describe how the collector device manages event data and to describe how often the collector transmits these events to the HES.
b) Describe the ability of the collector to throttle (or aggregate) a high volume of events to help manage traffic to the HES.
c) The Proponent is asked to provide the maximum number of times per day the transmission can occur and if the frequency is configurable by the utility.

5.5.4 Collector Equipment Capacity (I)

a) The Proponent is to provide details on the number of meters that a collector can manage and the optimal meter to collector ratio taking redundancy requirements into consideration.
b) Proponent to specify if the capacity differs for electric, water, HAN and distribution automation points.

5.5.5 Collector Daily Management (I)

a) The Proponent should describe the expected daily procedural tasks that are required in order to properly manage the collector.
b) Standard operating procedures during instances of WAN failure as well as standard operating procedures during normal operation should be clearly explained.
c) The Proponent must describe all programmable options, features and procedures for the collector.

d) The Proponent must state if the collector can be remotely programmed and if not, what process is used to update the equipment and how this has been addressed in the past.
e) The Proponent must state the maintenance procedures and any equipment required to complete these procedures.
f) The Proponent is required to provide details on estimated number of annual collector field reboots/power cycles.

5.5.6 Collector Reliability, Adaptability and Fail-Over Design (I)

FortisBC understands that occasionally, the AMI system may experience difficulty in transmitting 100% of the daily data to the HES (as is reflected in the proposed SLA's). However, the Proponent must take into consideration FortisBC's SLA requirements when planning redundancy measures.

a) The Proponent is asked to explain how "redundancy" has been planned for within the system architecture for the following scenarios;
   i. Power Failure;
   ii. Collector Hardware Failure (how do meters link to other collector devices deployed); and
   iii. WAN temporarily not available but LAN operational.

b) The Proponent is asked to provide detailed information on the available hardware options used for LAN and WAN communication in the collector.
c) Are there multiple LAN interface cards to manage network communications?
d) Proponents to confirm all applicable components are Industry Canada licensed and approved for use in Canada.

5.5.7 Collector Surge Protection (I)

Proponents are asked to provide details of surge protection devices/solutions that are provided with the proposed solution.

5.5.8 Collector Memory and Storage (I)

FortisBC would like to understand the memory capabilities of the collector.

a) The Proponent must describe how many reads can be stored in the collector and if capacity is reached what procedure takes place in order to ensure reads are not lost.
b) The Proponent must describe how long event data and meter reads can be maintained in the data collection unit during a power outage.
c) If there is no memory within the collector, please describe how when there is a collector failure that data is retrieved from the network.
d) In the event of a seven day WAN failure how do you restore data and how far back can data be retrieved (assuming hourly interval data)?

5.5.9 Collector Battery Backup (I)

FortisBC would like to understand any battery utilized within the collector.

a) The Proponent must describe primary options for powering the collector and relay devices, as well as alternate and/or back up methods.
b) The Proponent must provide detailed information on the standard backup battery that is provided for the collector and the expected battery life.
c) The Proponent must describe whether the backup battery that is provided with the product performs only clock management functions, or whether the battery powers the collector for the purpose of allowing communications to continue.
d) The Proponent must state if a battery is present in the collector and what purpose it serves.
e) The Proponent must describe the lifespan of the battery and on-going maintenance required.
f) The Proponent is asked to describe if a battery life monitor exists.

5.5.10 Collector Installation Requirements (CI)

The Proponent is required to manage contractual logistics for mounting locations, and include the estimated costs of mounting and any continuing rental costs in the Proposal. This includes pricing of additional poles, and structures necessary for mounting collectors in appropriate locations in order to acquire reads as per the topology provided in this proposal.

Prior to implementation, the Proponent is to submit mechanical installation drawings which will be reviewed and approved by FortisBC.

a) The Proponent should explain the preferred method of installing the collector infrastructure, and best ensure the AMI Service Level Agreements outlined in 5.1.1 are met as quickly as possible. Any required personnel qualifications (safety training, specific tools, etc) should also be explained.
b) The Proponent must describe all mounting locations required to support the proposed solution design.
c) For each different mounting option, provide a typical mechanical drawing.
d) The Proponent must indicate the level of skill sets that will be required to maintain and service this equipment.
e) The Proponent must explain all options available for mounting collectors, and the recommended configuration. Indicate minimum required height for each location.
f) The Proponent must provide differences in collection capacity, ability to transmit and receive reads, etc from the various collector models using various mounting options.
g) The Proponent must explain the range of how far the collector can be located from the end device including the receiving/transmitting power of the collector units and the AMI end devices.
h) The Proponent must specify if the collector must be programmed prior to or during field installation.

5.5.11 Firmware Upgradability of the Collector (CI)

FortisBC requires that the proposed AMI network's functionality include two-way firmware upgradeability to the collector in the event that firmware changes are required post-installation.

a) The Proponent is asked to explain the upgrade procedures including backwards compatibility of software for all components.
b) The Proponent is also asked to comment on:
   i. If there is reporting on firmware version (i.e. version control process);
   ii. What the Proponent's process for QA and version releases are;
   iii. Whether the system provides an acknowledgement of an upgrade or not;
   iv. What the expected time requirement is for 100% of the meter population to be upgraded;
   v. What the expected performance impacts to the networks daily processes are if upgrades are being done.
   vi. Whether it is possible to upgrade the collector software/firmware remotely and at the site.
c) Proponents are asked to describe their experience with firmware upgradability including the numbers of firmware upgrades they have performed on networks deployed including the numbers of collector devices, numbers of firmware revisions performed, and time to complete.

5.5.12 Collector Environmental Operating Range (Including all components) (I)

Due to the weather conditions within its service area, FortisBC would like to understand the environmental conditions that the collection devices can operate within.

a) The Proponent must confirm the collector operates within the temperature range of -35 ºC to 65 ºC.
b) The Proponent must explain how the collector is protected against electrical surges such as lightning.
c) Describe any heating and cooling options are available with the collector.
d) The Proponent is asked to describe if any heaters are being recommended in the proposed design to deal with temperature or condensation issues.

5.5.13 Redundant WAN on Collector (I)

a) Proponent is to provide information outlining if their solution provides a redundant WAN option within the collector. If this is available, details should include how the switchover is performed, what downtime is involved and an approximate number of sites that they have implemented this at.

5.5.14 Repeater Options (I)

a) The Proponent is asked to describe what types of repeaters are offered with the Proponent's solution. This description should include information on:
   i. Limitations as to how many meters a repeater can manage;
   ii. Limitations of the number of repeaters that can report into a collector;
   iii. What the backup power supply is within the repeater;
   iv. What communication method is used between the repeater and the collector;

v. Mounting options (include hardware configuration); and
vi. The geographic area / distance that a repeater can cover.

5.5.15 Collector Time Synchronization (CI)

FortisBC needs to ensure the accuracy of the data from the AMI System in regards to time and date stamping. A major component of this is time synchronization at the collector. FortisBC is also in a unique situation where there are multiple times zones in their service territory. The data needs to accurately reflect these different time zones.

The Proponent is asked to describe:

a) How and how often the collector validates and synchronizes its clock and how it corrects itself should it find any deviations.
b) How the collector performs time synchronization with the devices in the field;
c) Is the source of the master time via a GPS time synchronization methodology or is it done through the HES?
d) Are these time synch changes logged somewhere or reported to the HES for future review if required?
e) At what threshold of deviation does the collector reset itself and is this threshold configurable?
f) How are the exceptions reported to assist in the identification of faulty devices?
g) How more than one time zone is accommodated.
h) How time is synchronized after a time change (i.e. daylight savings).

5.5.16 Collector Roadmap (I)

a) The Proponent is to provide detailed information as to the product roadmap vision and planned releases over the next 24 months. Details should include:
    i. What additional or enhanced functionality is planned; and
    ii. What hardware and firmware releases are planned.

5.5.17 Collector Trouble Shooting Process (I)

a) The Proponent is asked to describe the troubleshooting tools and processes that are available to help resolve communications or meter issues.
b) Proponent to provide details on the collector's ability to perform a self diagnostic test on-demand and/or at a preconfigured frequency.
c) What is the procedure to replace the collector and what is the proper set-up and configuration required from the HES for communication to resume with the meters?
d) How long does it take for the network to stabilize once a new collector is implemented?

5.5.18 Collector Spare Equipment Recommendation (I)

a) Proponents shall provide recommendations for on-site spares and test equipment needed to support the system uptime required to meet the SLA's as outlined in Section 5.1.1 AMI Network Service Level Agreement. These costs will be separately itemized within provided worksheet.

5.6 WAN Solution Technical Requirements

FortisBC's expectation is that the flexibility and functionality of the chosen AMI WAN Solution will enable the chosen AMI Solution to meet the SLA's outlined in Section 5.1.1 AMI Network Service Level Agreement as outlined in this RFP.

An important component of the AMI infrastructure is the Wide Area Network (WAN). The WAN solution should ensure that the information collected is able to reach the HES. Proponents are to provide details in the following sections to help FortisBC understand the robustness of the WAN solution proposed and so that it can meet FortisBC needs.

Please ensure the current functionality of your product is clearly explained for each of the following subsections.

5.6.1 WAN Solution Overview (I)

a) Proponents shall provide a work/data flow diagram and comprehensive explanation demonstrating how the communications will work between the collector and the HES.
   i. What is the WAN solution proposed at each collection point?
   ii. Outline any performance differences at each of the WAN points.

b) In addition, the Proponent is asked to provide the following technical information as it pertains to the proposed AMI WAN Solution:
   i. Technical descriptions of all equipment in the proposed solution, including size, shape and weight of all proposed devices;
   ii. Confirmation proposed equipment has been tested and certified to the WAN provider's standards;
   iii. A description of how the equipment is mounted;
   iv. The power requirements and source of voltage for all equipment; and
   v. Technical details of the equipment proposed to enable communication between the collector and the HES.

c) The Proponent is asked to provide any alternative WAN options available for use with the AMI system being proposed.

d) The Proponent shall provide all information regarding which of these options they have secured province-wide in relation to contract pricing.

If a public carrier is being recommended, the Proponent shall have contacted the service providers to determine availability.

Wireless options must comply with Industry Canada regulations and have frequency allocations available in FortisBC service territory and will be assessed based on cost to acquire and maintain those licenses. Wireless systems must not impede frequencies already being utilized within the FortisBC's service territory.

5.6.1.1 Current WAN Options including Throughput (I)

a) The Proponent is requested to provide detailed information (including throughput) on the recommended WAN options to connect the collector.

b) The Proponent is also asked to provide any alternative WAN options.

c) The Proponent must state if collector is Internet Protocol (IP) addressable.

5.6.2 WAN Solution Roadmap (I)

The AMI solution chosen by FortisBC is expected to have a 15 year life. As a result, FortisBC requests that Proponents identify the development roadmap for the proposed WAN solution.

a) Proponents should describe how the product will maintain backward compatibility for hardware, software, and any other required network components.
b) In the event that hardware and/or software upgrades are required, and/or if over-the-air firmware or software upgrades are possible, the Proponent should provide policies and procedures for these upgrades to demonstrate that FortisBC's system uptime will be minimally affected.

5.6.3 WAN Solution Security

a) For each WAN solution proposed, describe what standards the WAN provider complies with for the physical layer of security.
b) Provide security audit reports for each WAN provider being proposed.

5.6.3.1 WAN Intrusion Detection and Notification (I)

FortisBC is interested in understanding the monitoring processes, as well as notification and corrective measures that are utilized by each of the WAN solution providers proposed in the event that the WAN solution is breached.

a) The Proponent is asked to provide a description of how each of the proposed solutions supports this requirement.
b) Additionally, Proponents should discuss for each WAN solution proposed, examples of past breaches, how they were handled, and the measures that were implemented to minimize risk of future occurrences.

5.6.4 WAN Unwanted Traffic (I)

a) Proponents should explain how the network protects against unwanted traffic (i.e. text messaging, spamming, etc). If Proponents have addressed this through Service Level Agreements in the past with other customers, FortisBC is interested in any information that can be provided in this regard.

5.6.5 WAN Bandwidth and Data Plans (I)

FortisBC intends to explore the possibilities of incrementally expanding use of the AMI network to include other applications such as Smart Grid (i.e. transmission/distribution monitoring equipment) as well as multi-commodity data collection, etc.

a) Proponents are asked to provide details around the amount of bandwidth being proposed with the AMI solution, as well as the flexibility and any incremental costs to expand the solution should that be required in order to accommodate additional functions.

b) The Proponent is asked to describe if the data plan(s) to be utilized protects FortisBC from data overage charges as a result of unwanted traffic as described in Section 5.6.4 WAN Unwanted Traffic.

c) The Proponent is asked to describe if the data plan(s) to be utilized has the ability to pool data volume. For example, if one collector's transmissions exceed the monthly data allowance, can its usage be consolidated with another collector's data allowance to avoid overage charges?

d) Proponent is asked to describe the solution for accommodating nominal bandwidth increases in cases of electric utility acquisition or water/gas utilities contracting meter reading services through FortisBC.

FortisBC has an average of 2% percent growth per year for electric meters.

e) The Proponent is asked to describe how the WAN solution proposed will expand over the fifteen (15) year projected life to accommodate additional electric meters as the service territory grows

f) Proponent is asked to describe the solution to accommodate extreme growth scenarios on WAN (eg. doubling bandwidth).

5.6.6 WAN Performance and Recovery (I)

a) The Proponent is asked to provide comprehensive information around disaster recovery. The explanation should include disaster recovery plans for equipment in the field, equipment at the service provider's facility, and any equipment which is intended to reside at any of FortisBC's facilities.

b) Proponents are asked to explain the capacity within the proposed solution for remote fault resolution due to device malfunction.

c) Proponents should include a description of technical services available to ensure the AMI WAN solution maintains an acceptable level of performance.

d) The Proponent is asked to discuss how proactive, real time WAN network surveillance, alarming and trouble ticketing would be accomplished. If there are any network elements provided by the Proponent that cannot or will not be monitored remotely, this should be clearly explained.

5.6.7 WAN Equipment Configuration and Installation (I)

It is important that FortisBC understand the configuration of the equipment such as hardware settings, software settings and all known optional user configuration parameters.

a) The Proponent is asked to provide details in regards to the configuration of the equipment.

It is FortisBC's preference that in the vast majority of instances, equipment could be remotely restarted and reset.

5.6.8 WAN Surge Protection (I)

a) Proponents are asked to provide details around surge protection devices/solutions that are provided with the proposed solution.

5.6.9 WAN System Updates (I)

FortisBC acknowledges that the WAN solution will require upgrades to system components.

a) The Proponent is asked to describe the capabilities to do this remotely, the anticipated frequency with which this will occur, and the actual impact to system uptime.

5.6.10 WAN Certifications (I)

a) Proponents are asked to identify all applicable Health Canada and Industry Canada requirements and CSA certifications that pertain to the proposed solution. Information should include all manufacturing approvals that might be required. Response to this section should include a description of safety standards used in the manufacturing of equipment as well as safety standards that must be met for the installation of the proposed solution.
b) Documentation demonstrating the Proponent's license to operate on the proposed frequencies should be included.

5.6.11 WAN System Support (I)

a) The Proponent is asked to describe the process by which WAN software is maintained and upgraded. Included in this description should be information pertaining to any 3rd party software licenses and the associated costs, and any recurring costs associated with maintenance (software or otherwise) or upgrades.
b) The Proponent is asked to describe any one-time or recurring licenses, keys, restrictions of use, or limitations and all associated costs that may in any way restrict FortisBC's full and open use of the AMI system.
c) The Proponent is to provide details on the number of upgrades/releases that are standard per year.
d) FortisBC requires access to support from the WAN provider(s) proposed and requests that the Proponent provide the following details on product and network support:
    i. Provide hours that support is available.
    ii. Provide details on priority levels, support ticketing system, support process, escalation path.
    iii. Provide the definition of critical updates vs. enhancements.
e) FortisBC requests that the vendor provide a sample of standard release notes for a version upgrade. If a users group exists, please describe its structure, purpose and governance. Proponents are also asked to describe if the users group has an informal or formal role in submitting or disseminating software upgrades.

5.7 Head End System (HES)

5.7.1 HES Scalability (CI)

As outlined in Section 3.3.1 Meters & Modules, the intent is to deploy approximately 97,480 residential and 12,520 commercial endpoints.

a) The Proponent should demonstrate through documentation that the HES is capable of this volume.

Depending on future growth, or the addition of other commodities to the AMI network(i.e. water, gas), there is the potential for more than 1 million endpoints to be deployed. As such, FortisBC requires that the proposed HES have demonstrated, through actual deployments, or documented testing, scalability for one million plus endpoints.

b) The Proponent should describe their largest deployments and provide any documented testing in order to demonstrate scalability to meet this requirement.

c) In addition, the Proponent shall provide details regarding the HES storage capability. The HES should allow for 60 days of data storage capability. The Proponent should detail what information is stored in the HES database for how long and how the information is accessed.

5.7.2 User Interface Design - Network Health Management (I)

FortisBC requires that the proposed AMI network contain tools for identifying programming problems, validating proper installation and initialization of endpoints, measuring overall performance, identifying the communication path, providing time synch verification as well as identifying communication issues such as congestion, signal deterioration, signal loss and changing environments.

a) The Proponent is asked to provide information regarding the available network health management tools to assist in ensuring that a successful state of the network is maintained over time.
b) The Proponent is requested to describe the ability to query the HES for exceptions to find new meter installations, hardware, or communications problems.
c) The information provided should specify if access to the head end software is web based and if an interactive Graphical User Interface (GUI) is available to list exceptions and quickly isolate problems. If available, the associated programming language should be described and screenshots provided.

5.7.2.1 HES Operator Tools (I)

a) The Proponent should describe the toolset available within the HES specific to network health management. To clearly demonstrate the features and functionality available, the response should include detailed information and screen shots from the user interface that illustrate how the operator would utilize the tool to resolve network health issues.

5.7.2.2 Scheduling (I)

a) The Proponent should describe the toolset available within the HES specific to scheduling. To clearly demonstrate the features and functionality available, the response should include detailed information and screen shots from the user interface that illustrate how the operator would utilize the tool to adjust AMI schedules such as:

i. Time synch
ii. Read schedules
iii. Default read schedules

5.7.2.3 LAN Performance and Network Analysis Tools (I)

a) The Proponent should describe the toolset available within the HES specific to LAN performance and network analysis tools. To clearly demonstrate the features and functionality available, the response should include detailed information and screen shots from the user interface that illustrate how the operator would utilize the tool to monitor LAN performance and identify/troubleshoot communication paths.

5.7.2.4 Exception Management Tools (I)

a) The Proponent should describe the toolset available within the HES specific to exception management. To clearly demonstrate the features and functionality available, the response should include detailed information and screen shots from the user interface that illustrate how exception management features would aid the operator in managing the network health.

5.7.3 User Interface Design - Meter Information

FortisBC is interested in the options available to users in order to view endpoint information such as events/alarms, consumption history, and on demand read capabilities.

5.7.3.1 HES Operator Tools (I)

a) The Proponent should describe the toolset available within the HES specific to accessing meter information. To clearly demonstrate the features and functionality available, the response should include detailed information and screen shots from the user interface that illustrate how the AMI operator would be able to access information on the meter such as alarm/event data, consumption history.

5.7.3.2 CSR Support Tools (I)

a) The Proponent should describe the toolset available within the HES for use by CSRs. To clearly demonstrate the features and functionality available, the response should include detailed information and screen shots from the user interface that illustrate how CSRs would be able to access information on the meter such as graphical views of consumption history, last known outages and voltage concerns. How users would query specific meter information should also be described as well as the speed at which CSRs would be able to access information.

5.7.3.3 On Demand Read Capabilities (I)

a) The Proponent should describe the information that is reported back through the network when an on demand read is performed. Details should address the following:
   i. What operational data is brought back with an on demand read?
   ii. Are both register reads and interval data brought back with an on demand read?
   iii. Are there limitations to the number of load profile channels brought back with an on demand read?

5.7.3.4 Exception Management Tools (I)

a) The Proponent should describe the toolset available within the HES for dealing with exception management. To clearly demonstrate the features and functionality available, the response should include detailed information and screen shots from the user interface that illustrate how the data is presented and what tools are provided to the user to troubleshoot the exceptions.

5.7.4 AMI System Reporting (I)

a) The Proponent is asked to provide examples of daily, weekly and monthly reports to convey the capabilities of the AMI system. Specifically of interest are reports that:
   i. Report on exceptions for system management; and
   ii. Report on statistics to ensure Service Level Agreement is being met.

b) The Proponent is asked to provide a listing of reports that are offered out-of-the-box.

5.7.4.1 Dashboard: AMI Performance Levels (I)

A dashboard tool is considered a type of summary reporting which allows the management team to quickly identify and act on critical issues. A dashboard might report real-time on such items as meters not communicating, alarms, system read interval statistics, etc.

a) The Proponent is to describe their ability to meet the above requirements and to provide screen shots of their dashboard functionality related to the requirements described above.

b) If a dashboard function as described above is not available, the Proponent should provide information on what other functions and features within the system could be utilized for this purpose.

5.7.4.2 Dashboard: Operational Data, Indicators and Events (I)

It is FortisBC's preference that the events produced by the AMI system such as outage notification, restoration notification, tamper information, hi/lo voltage indicators etc, can be displayed graphically, within an interactive dashboard. In the event that the AMI network is encountering problems, the user should be able to click on the interactive dashboard function and be provided with additional information to explain the problems being encountered.

a) The Proponent is to describe their ability to meet the above requirements and to provide screen shots of their dashboard functionality related to the requirements described above.

b) If a dashboard function as described above is not available, the Proponent should provide information on what other functions and features within the system could be utilized for this purpose.

5.7.4.3 Reporting: Graphing (I)

It is expected that the HES will provide the ability to produce data graphs and reports for all metered and calculated channels. All graphs and reports shall be viewed within the HES application user interface, as well as contain the functionality to enable data export to spreadsheets, or be transportable to other electronic file format, and saved as images for use in external reports, etc. Reports may be required to be run in either online or batch mode.

a) The Proponent is to describe their ability to meet the above requirements and to provide screen shots of their dashboard functionality related to the requirements described above.

5.7.4.4 Reporting: Ad-hoc Reporting (I)

a) The Proponent is asked to provide detailed information as to the capability for ad hoc reporting from the HES.

5.7.4.5 Export Capabilities (I)

a) The Proponent is asked to provide detailed information as to the capability to export report data to a file that can be utilized by a 3rd party system.

5.7.4.6 HES Client Access (I)

FortisBC prefers that the HES be accessible via web client so that FortisBC and other potential future users (i.e. water municipalities) can access and view filtered data and have a means to export data for ad hoc analysis, both based upon the commodity that the user has rights to.

a) The Proponent should provide detailed information pertaining to the flexibility and functionality of the proposed solution in this regard.

5.7.5 System Integration (I)

Integrating the AMI network with FortisBC applications will be critical to get the value from the AMI product.

a) The Proponent is to provide information around integration standards used (i.e. MultiSpeak) or on the roadmap to assist with this activity.

5.7.5.1 Transmission of Scheduled and Real-time Read Files (I)

a) The Proponent is to describe all the interface options in real time and in batch mode for making scheduled read files available to other systems.
b) The Proponent should provide details on the preferred methodology and format to transfer this information and the timing around when it will be available.

5.7.5.2 Transmission of Event Files (I)

a) The Proponent is to describe all the interface options in real time and in batch mode for making event files available to other systems.
b) The Proponent should provide details on their preferred methodology and format to transfer this information and the timing around when it will be available.

5.7.5.3 Transmission of Operational Data (Voltage, Current, etc)

a) The Proponent is to describe all the interface options in real time and in batch mode for making operational data available to other systems.
b) The Proponent should provide details on their preferred methodology and format to transfer this information and the timing around when it will be available.

5.7.5.4 Integration with MDMS (CI)

It is the intent of FortisBC to use an MDMS to independently audit the AMI system to ensure it meets the agreed upon SLA's, as well as aid in back office integration and the storage of operational information.

a) The Proponent is asked to provide a listing of all interfaces available that will accommodate the transmission of all the data collected from the AMI network to the MDMS.
b) The Proponent is asked to detail if all data is in one file or if multiple files are transmitted to accommodate both reading and operational data.
c) The Proponent is asked to describe the options for the frequency of data transmission from the HES to the MDMS.
d) The Proponent to provide a listing of the MDMS providers that they have integrated with to date.

5.7.5.5 Integration with CIS (CI)

The proposed HES will be required to interface with FortisBC's billing system for synchronization processes, mass rollout coordination, and asset management.

a) The Proponent is asked to provide documentation of how the HES integrates with CIS.
    - If a direct database connection is provided as a method of interfacing with the CIS, describe how accuracy and integrity of the extracted data would be assured.

- If application programming interface (API) access is provided as a method of interfacing, provide details of the programming languages and/or development environments that are supported for use with the API.
- If a process of data export/import via files is provided as a method of interfacing, provide details of file format(s) available and how the import/export process is automated.

For all system interface methods provided by the proposed system, the Proponent should state the type of data accessible via the interface and indicate whether the interface is guaranteed to remain compatible with future system enhancements or upgrades.

5.7.5.5.1 Incremental Synchronization (I)

Incremental synchronization should provide changes to relevant systems and occur at a minimum of once per day or more frequently (hourly). It is the preference of FortisBC that this is a batch based file process. This file will be passed amongst the various systems via FortisBC web services.

a) Proponents are asked to describe their experience with and methodologies used for incremental synchronization including the size of utilities they currently perform this with.

5.7.5.5.2 Periodic Synchronization (I)

The process to perform a full synchronization between all systems will be referred to as periodic synchronization. This will be a file based process whereby all existing relationships are provided to interfacing systems. It is the intent of FortisBC to perform a Periodic Synchronization more frequently at the early stages of this project (e.g. Bi-Weekly), moving to a more standard approach of a quarterly periodic update. This file will be passed amongst the various systems via FortisBC web services.

a) Proponents should describe their experience with this process including the size of utilities they currently perform this with and describe methodologies which have been successfully utilized in the past.

5.7.5.6 Integration with OMS (I)

FortisBC currently does not utilize an OMS but does intend to implement one in the future.

a) The Proponent is requested to provide a listing of interfaces available to integrate the proposed HES with OMS applications such as Responder, Survalent and Milsoft DisPatch.
b) Proponent is asked to provide some details regarding past implementations and a list of references with regards to the integration of OMS.

c) The Proponent is to describe the functionality available to perform group pinging functions in the AMI system to allow OMS systems to call a geographic area to help verify restoration status.

5.7.5.7 Integration with GIS (I)

a) The Proponent is to describe the functionality available to perform read request for individual or groups of meters to assist with GIS load analysis.

5.7.6 HES Environments (CI)

At minimum, FortisBC anticipates the following requirement for the HES environments:

- Production HES
- Test HES

a) The Proponent should describe their license policy for these multiple environment scenarios and if any functionality differences exist between the systems. Any standard form licensing agreements that may apply should be provided.
b) The Proponent should address the following items in their documentation:
   - Will the test environment be configured as a mirror of the live environment, or will FortisBC be required to configure different synchronization processes for the test environment?
   - Will the same service levels apply to the test environment as to the live environment?
   - What hardware (if any) does the Proponent recommend for the test environment?

5.7.7 Release Note Documentation (CI)

Release Notes are expected to be provided by the AMI Vendor prior to release of new functionality. The documentation should be complete and sufficiently detailed to allow the utility to create appropriate test scripts to allow testing of the new functionality in the test environment prior to upgrades being performed on the live environment.

a) The Proponent is to provide a sample of their release notes to allow FortisBC to understand the quality of this documentation process.

5.7.8 Ongoing Resource Requirements (I)

FortisBC expects that the AMI solution will be fully implemented by the end of 2014.

a) Proponents should indicate to FortisBC, the level of resources that will be required for ongoing operation and maintenance of the proposed HES solution.
b) The Proponent should provide reference materials such as a description of a “day in the life” of the AMI operator
c) Assuming a meter population growth resulting from the implementation of gas and/or water AMI, the Proponent should explain how the required resources would be expected to change (or not), beyond 2014.

5.7.9 HES Configuration (CI)

5.7.9.1 HES Storage (CI)

It is important to FortisBC to be able to handle its current customer base as well as the growth of its own electrical customers into the future. The system should be designed for a minimum of 1 million customers, assuming 60 days of storage.

a) The Proponent is asked to provide information as to the impact (such as hardware and licensing) and costs associated with this growth in data.

5.7.9.2 Preferred Hardware Configuration (I)

FortisBC has implemented a virtual server environment using VM Ware 4 running on virtual server farms. The primary virtual server farm is made up of 6 DL386 G6 servers with dual quad core processors and 72 gigabytes of memory in each unit in the primary data centre. The secondary virtual server farm is made up of 6 DL386 G6 servers with dual processors and 72 gigabytes of memory in each unit in the backup data centre. The two farms are connected via dedicated 10 gigabyte fibre link and are set-up for load balancing. Both data centres have IBM N6040 SANs each with 11 terabytes of drive space, scalable to 400 terabytes each.

a) The Proponent is asked to provide confirmation that their system can run on the hardware configuration described above and/or to provide details on alternate options.

5.7.9.3 Preferred OS and DB Configuration (I)

FortisBC's preferred operating systems are 64 bit Microsoft 2008 R2 and 64 bit Oracle Redhat Linux 5.5 running in the virtual environment described above. The preferred database is Oracle Database Oracle 11g Enterprise Edition Release 11.2.0.1.0 - 64 bit but previous as well as the most current versions of Microsoft SQL 2007 are also supported.

a) The Proponent is asked to provide written acknowledgement of this requirement and/or to provide details on alternate options.

With the possible inclusion of multi-commodity data, FortisBC would like to gain an understanding of what database options (eg. data partitioning) may be available to isolate viewing or reporting of each commodity's data, other than through user rights or roles.

b) The Proponent is asked to provide details on the options to utilize database tables or different options for configuration which are available to meet this requirement.

5.7.9.4 HES System Disaster Recovery Planning (CI)

FortisBC DR Environment

FortisBC has a Disaster Recovery (DR) site at the data centre in their System Control Centre (SCC) in Warfield. Recovery environments for SAP, CIS, Domain Controller and exchange server are available there in the event of a failure of any of the identified systems at the Trail Data Centre. Infrastructure at the DR site is equal in performance and capabilities to the primary site.

Tape backups for the Trail Data Centre are done directly to the DR site at SCC and vice versa, backups at the DR site are done directly to tapes at the Trail Data Centre. This eliminates the need to find tapes in the event of an emergency cut over.

Routers are configured to enable all FortisBC offices to connect to the DR site in the event that the Trail data centre was lost.

DR Procedure

Steps to be taken:

1. Determine type of outage
2. Estimate duration of outage
3. Contact the business with the type and duration of outage
4. Follow disaster recovery process flow

Network Failure

If the network failure is isolated to one or more FortisBC locations, then alternate FortisBC sites that are still connected can be occupied by key business users. If all FortisBC locations become disconnected from the wide area network then any site with a high speed internet connection can be used to work via VPN connection through the internet.

In the event of a Telus wide area network failure, a Shaw internet connection will be used from Springfield, Benvoulin and Enterprise offices. Key users will connect through a Citrix session to access critical applications.

In the event of a complete wide area network and Internet failure the Trail, Warfield and South Slocan offices are not subject to wide area network failure, as the data centre is connected directly to a local area network for these locations. Therefore, all key users would be relocated to any of these offices.

In the event that the key business people (as identified in individual business continuity plans where available) are moved to the Trail, Warfield or South Slocan offices due to an extended wide area network failure, all empty offices will be made available. PCs and phones will be provided where possible, but anyone coming into these offices will be encouraged to bring their own systems and phones.

Connecting to Backup Data Centre in System Control Data Centre

In the event of a partial or complete loss of any or all systems in the Trail data centre, the recovery systems in the System Control data centre in Warfield will be promoted to production status with approval from the identified application owners.

a) The Proponent is asked to confirm how their product can be incorporated in FortisBC's DR process.
b) The Proponent is asked to provide information on any additional costs involved with implementing a DR process.

5.7.9.5 Data Archival Requirements (I)

Regular automated backup procedures are in place to back up electronic data on the Company's server infrastructure. Documentation is maintained outlining server backup timeframes, rotation and retention of backed up data.

All FortisBC corporate data and applications are backed up using Legato backup software. All backups are automated and managed by the Technical Analyst responsible for backups.

In the FortisBC backup environment, full server backups commence during server commissioning with incremental backups carried out daily for an indefinite period. Data backed up is retained according to versions and age. By default, the last 14 versions or 60 days old (the lesser of the two) are kept in backup. Database backup retentions are designed such that any database can be restored to the last 6 weeks. If database transaction logging is enabled, the database can be restored to any point in time within the last 6 weeks.

a) The Proponent is asked to provide information as to how their system can be incorporated into this backup and data archival process.
b) The Proponent is asked to provide their preferred backup process if there are other important considerations to note.

5.7.9.6 Data Restoration Requirements (I)

Disaster Recovery processes and procedures are in place for critical applications as described in the Section 5.7.9.4 HES System Disaster Recovery Planning.

a) The Proponent is asked to describe how data can be restored from a system backup and what processes have been utilized at other utilities.

5.8 Quality Assurance & Change Management (I)

5.8.1 Quality Assurance of the HES (I)

At FortisBC, the objectives of change management to the systems are to:

- Ensure that all changes represent an acceptable balance of risk, disruption to users and resource effectiveness;
- Ensure that all changes are processed and communicated in a timely and efficient manner; and
- Ensure that the changes are processed in a manner, which minimizes the impact of change related problems.

The change management function ensures that the following items are in place for each change:

- Appropriate documentation;
- An appropriate level of testing;
- Proper approvals;
- Timely notification to users;
- Adequate training for clients and IS staff where necessary;
- Back out procedures;
- An integrated schedule with other changes;
- Lessons learned documentation to be used the next time this type of change is implemented.

a) The Proponent is asked to describe their change management methodology and how it meets FortisBC's requirements.
b) If available, the Proponent is also asked to provide details on the percentage breakdown of ongoing support costs vs. costs for support to apply major releases.

5.8.1.1 HES Patch and Major Release Process (I)

The HES should allow for proper change management practices. A separate environment will be provided to allow testing of new functions prior to releasing the version to the live environment.

a) The Proponent should describe their anticipated frequency of releases, and the suggested manner in which this schedule can be managed by the utility.
b) The Proponent is asked to advise a recommended upgrade process, testing process and how versioning roll back occurs.

5.8.1.2 HES Quality Assurance Process (I)

Quality assurance plans should identify documents, standards and practices governing the product development and identify measures and procedures for problem reporting and corrective action.

a) The Proponent is asked to provide details on the company's quality assurance plan or process for the HES including details on how your company responds to:
   i. Service/Support related problems

ii. Software quality problems

5.8.2 Quality Assurance of the Metering End Device (I)

a) The Proponent is asked to describe the quality management structure for inspection and sampling of the meters being proposed. It shall outline how quality will be achieved, controlled, assured, demonstrated and managed. The structure shall be in compliance with Measurement Canada and other applicable requirements during the course of this project. The description is expected to address at least the following:

i. Examples of Corporate communication regarding the Quality Management system

ii. Responsibility and authority of personnel performing work affecting conformity to the requirements. Including receiving, inspection, sampling, testing, auditing, approving and shipping of meters.

iii. Competency and training of personnel performing work affecting conformity to the requirements (including receiving, inspection, sampling, testing, auditing, approving and shipping of meters).

iv. Control of documents and records pertaining to the end points, including control of external suppliers documentation and how this is incorporated into the Quality Management System

v. Identification and traceability of the end points, and demonstrate the ability to track devices throughout the production cycle, up to and including delivery of the product to FortisBC

vi. Infrastructure (planned maintenance) and work environment

vii. Control of monitoring and measuring devices, including certification and calibration of test consoles.

viii. Control of Non-Conforming product and dealing with non-conforming meters and shipments. Unacceptable shipments shall be marked, segregated and reported. Offloading of any unaccepted shipment shall be subject to former confirmation.

ix. Auditing, including internal and supplier audits, include information on training of Auditors and storage of Audit records

x. Corrective and preventative action system

Information regarding the details of FortisBC's meter acceptance test plans is included in the background information in Section 2.2.1(2) Proponent Access to Background Information.

5.8.3 Quality Assurance of all other components

a) The Proponent is to describe the quality management structure for inspection and sampling of all other components being proposed. It shall outline how quality will be achieved, controlled, assured, demonstrated and managed.

5.9 Home Area Network (HAN) (I)

FortisBC would like to understand the product offering and functionality available from the Proponent as it relates to their Home Area Network.

5.9.1 HAN Communication Standards, Protocols and Pairing (I)

FortisBC is interested in understanding the protocols the vendor supports in their product today.

a) Proponent to provided details on the standards listed below regarding if they are currently supported in their products, and if the protocol is following the true industry standard or if the vendor is performing any manipulation/mapping at their HES to accommodate the standard.
   i. ZigBee 1.0
   ii. ZigBee 1.1
   iii. ZigBee 2.0
b) Proponent is to provide details on any other standards supported.
c) Proponent to provide details of how HAN devices are paired and authorized to communicate on the network.

5.9.2 HAN Module in the Meter (I)

Proponent to provide details on the current memory size of the HAN module and its current capacity utilized.

a) Proponent to provide details regarding if their current HAN module processor and memory can accommodate known changes to the ZigBee standard going to 2.0.

5.9.3 HAN Module Firmware Upgradability (CI)

FortisBC requires that the proposed AMI network's functionality include two-way firmware upgradeability to the HAN device, in the event that firmware changes are required post-installation. Firmware upgradeability should be able to be completed without resealing of the meter.

a) The Proponent is asked to comment on the following items:
   i. What upgrade procedures are in place - including backward compatibility of software for all components?
   ii. Is there reporting on firmware version (i.e. version control process)?
   iii. Provide a description of the process for QA and version releases.
   iv. Does the system provide an acknowledgement of any upgrade?
   v. What is the expected time required for 100% of the HAN population to be upgraded?
   vi. If a system-wide firmware upgrade is done, what are the expected performance implications to the networks daily processes? Please also provide any available performance statistics in this regard.
b) Proponents are asked to describe their experience with firmware upgradability including the numbers of firmware upgrades they have performed on networks

deployed including the names of utilities, numbers of HAN devices, numbers of firmware revisions performed, and time to complete.

5.9.4 Gateway Devices(I)

a) FortisBC would like to understand the product offering and functionality available from the Proponent as it relates to Gateway devices. Proponents are asked to provide an overview and include information on the following areas of interest:

   i. Product functionality
   ii. Number of products or 3rd party vendor products supported
   iii. The communication options/standards available
   iv. How often the meter end device will communicate on average daily to this HAN device
   v. Effects this device will have on the network performance
   vi. The number of these products currently deployed

5.9.5 Thermostats (I)

FortisBC would like to understand the product offering and functionality available from the Proponent as it relates to thermostat products.

a) Proponents are asked to provide an overview and include information on the following areas of interest:

   i. Product functionality
   ii. Number of products or 3rd party vendor products supported
   iii. The communication options/standards available
   iv. How often the meter end device will communicate on average daily to this HAN device
   v. Effects this device will have on the network performance
   vi. The number of these products currently deployed

5.9.6 In-Home Displays (I)

FortisBC would like to understand the product offering and functionality available from the Proponent as it relates to in-home display products.

a) Proponents are asked to provide an overview and include information on the following areas of interest:

   i. Product functionality
   ii. Number of products or 3rd party vendor products supported
   iii. The communication options/standards available
   iv. How often the meter end device will refresh the data to this HAN device (i.e. 30 secs, 1min, hourly, etc).
   v. Effects this device will have on the network performance
   vi. The number of these products currently deployed
   vii. Details on what information is presented to the customer on an in-home display

FortisBC is concerned with privacy issues associated with new customers moving into a home where the in-home display has been left behind by the previous owner.

b) Proponent to provide details on the ability to control the range of historical information displayed in order to address these privacy concerns.

5.9.7 Water Heater Controls (I)

FortisBC would like to understand the product offering and functionality available from the Proponent as it relates to water heater control products.

a) Proponents are asked to provide an overview and include information on the following areas of interest:
   i. Product functionality
   ii. Number of products or 3rd party vendor products supported
   iii. The communication options/standards available
   iv. How often the meter end device will communicate on average daily to this HAN device
   v. Effects this device will have on the network performance
   vi. The number of these products currently deployed

5.9.8 Heat Pump Controls (I)

FortisBC would like to understand the product offering and functionality available from the Proponent as it relates to heat pump products.

a) Proponents are asked to provide an overview and include information on the following areas of interest:
   i. Product functionality
   ii. Number of products or 3rd party vendor products supported
   iii. The communication options/standards available
   iv. How often the meter end device will communicate on average daily to this HAN device
   v. Effects this device will have on the network performance
   vi. The number of these products currently deployed

5.9.9 Other Controls or Devices(I)

FortisBC would like to understand the product offering and functionality available from the Proponent as it relates to other in-home automation products.

a) Proponents are asked to provide an overview and include information on the following areas of interest:
   i. Product functionality
   ii. Number of products/ or 3rd party vendor products supported
   iii. The communication options/standards available
   iv. How often the AMCD will communicate on average daily to this HAN device
   v. Effects this device will have on the network performance
   vi. The number of these products currently deployed

5.9.10 Customer HAN Portal (I)

FortisBC would like to understand the product offering and functionality available from the Proponent as it relates to customer HAN Portals.

a) Proponents are asked to provide an overview and include information on the following areas of interest:
   i. Product functionality
   ii. Number of products or 3rd party vendor products supported

iii. How often the HES will make data available to the Portal
iv. The number of deployments of this product.
v. Proponent to provide screenshots

5.9.11 HAN Repeater Options (I)

FortisBC would like to understand the product offering and functionality available from the Proponent as it relates to repeater to amplify signals to HAN products.

a) Proponents are asked to provide an overview and include information on the following areas of interest:
   i. Product functionality
   ii. Number of products/ or 3rd party vendor products supported
   iii. The communication options/standards available
   iv. How often the AMCD will communicate on average daily to this HAN device
   v. Effects this device will have on the network performance
   vi. The number of these products currently deployed

5.9.12 HAN Time Synchronization (I)

The Proponent is asked to describe:

a) How the HAN device validates its time upon installation
b) How and how often the HAN device validates and synchronizes its clock and how it corrects itself should it find any deviations. Are these changes logged somewhere or reported to the HES for future review if required?
c) How the HAN devices with constant drift or large drifts that may be due to a default and should be replaced.
d) At what threshold of deviation does the HAN device reset itself and is this threshold configurable?
e) Are all deviations a hard synch or is this configurable with larger drifts identified to an operator?
f) If the HAN device "loses time" during a power outage, describe the time re-synchronization process and the expected duration for re-synchronization to occur
g) Following restoration of an outage, how does the HAN device ensure its time is synchronized prior to sending it first transmission?

5.9.13 HAN Roadmap (I)

a) The Proponent is to provide detailed information as to the product roadmap vision and planned releases over the next 24 months. Details should include:
   i. Planned functionality; and
   ii. Planned hardware and firmware releases.

5.10 Distribution Automation (DA)

5.10.1 DA Device Firmware Upgradability (CI)

FortisBC requires that the proposed AMI network's functionality include two-way communication to facilitate firmware upgradeability to the DA device, in the event that firmware changes are required post-installation.

a) The Proponent is asked to provide a description of their system's capability, focusing on the following:
   i. What upgrade procedures are in place - including backward compatibility of software for all components?
   ii. Is there reporting on firmware version (i.e. version control process)?
   iii. Provide a description of the process for QA and version releases.
   iv. Does the system provide an acknowledgement of any upgrade?
   v. What is the expected time required for 100% of the HAN population to be upgraded?
   vi. If a system-wide firmware upgrade is done, what are the expected performance implications to the networks daily processes? Please also provide any available performance statistics in this regard.

b) Proponents are asked to describe their experience with firmware upgradability including the numbers of firmware upgrades they have performed on networks deployed including the number of DA devices, number of firmware revisions performed, and time to complete these revisions.

5.10.2 Communication Channels (I)

a) With the time sensitivity and critical up time requirement of DA devices the Proponent is to describe how these devices are treated on their network to assure they have a high availability and throughput on the network.

5.10.3 Load Fault Indicators (I)

FortisBC would like to understand the product offering and functionality related to load fault indicator products.

a) Proponents are asked to provide an overview of available products and include information on the following areas of interest:
   i. Product functionality;
   ii. Number of products or 3rd party vendor products supported;
   iii. The communication options/standards available;
   iv. Impact this device will have on network performance; and
   v. The number of these products currently deployed;
   vi. What information is measured and available within the product; and
   vii. What information is brought back over the network and what is the frequency of transmission of that information.

5.10.4 Remote Terminal Units (RTUs) (I)

FortisBC would like to understand the product offering and functionality available from the Proponent as it relates to RTU products.

a) Proponents are asked to provide an overview and include information on the following areas of interest:
   i. Product functionality;
   ii. Number of products or 3rd party vendor products supported;
   iii. The communication options/standards available;
   iv. Impact this device will have on network performance; and
   v. The number of these products currently deployed;
   vi. What information is measured and available within the product; and

vii. What information is brought back over the network and what is the frequency of transmission of that information.

5.10.5 Reclosers and Switching Devices (I)

FortisBC would like to understand the product offering and functionality available from the Proponent as it relates to switches.

a) Proponents are asked to provide an overview and include information on the following areas of interest:
   i. Product functionality;
   ii. Number of products or 3rd party vendor products supported;
   iii. The communication options/standards available;
   iv. Impact this device will have on network performance; and
   v. The number of these products currently deployed;
   vi. What information is measured and available within the product; and
   vii. What information is brought back over the network and what is the frequency of transmission of that information.
   viii. With the product supported what information is available within the product; and
   ix. What information is brought back over the network.

5.10.6 Primary Metering (I)

FortisBC would like to understand the product offering and functionality available from the Proponent as it relates to feeder metering.

Feeder meters must be capable of measuring power flows in two directions, reading the same interval length as customer meters and remote configuration.

a) Proponents are asked to provide a description of how their product meets these requirements.

b) Proponents are asked to provide information on the following areas of interest:
   i. Product functionality;
   ii. Number of products or 3rd party vendor products supported;
   iii. The communication options/standards available;
   iv. Impact this device will have on network performance; and
   v. The number of these products currently deployed;
   vi. What information is measured and available within the product; and
   vii. What information is brought back over the network and what is the frequency of transmission of that information.

5.10.7 Transformer Metering (I)

FortisBC would like to understand the product offering and functionality available from the Proponent as it relates to transformer metering.

a) Proponents are asked to provide an overview and include information on the following areas of interest:
   i. Product functionality;

ii. Number of products or 3rd party vendor products supported;
iii. The communication options/standards available;
iv. Impact this device will have on network performance; and
v. The number of these products currently deployed;
vi. What information is measured and available within the product; and
vii. What information is brought back over the network and what is the frequency of transmission of that information.

5.10.8 DA Time Synchronization (I)

The Proponent is asked to describe:

a) How the DA device validates its time upon installation.
b) How and how often the DA device validates and synchronizes its clock and how it corrects itself should it find any deviations. Are these changes logged somewhere or reported to the HES for future review if required?
c) Describe how the system identifies DA devices with constant drift or large drifts that may be due to a default and should be replaced.
d) At what threshold of deviation does the DA device reset itself and is this threshold configurable?
e) Are all deviations a hard synch or is this configurable with only larger drifts identified to an operator?
f) If the DA device “loses time” during a power outage, describe the time re-synchronization process and the expected duration for re-synchronization to occur.
g) Following restoration of an outage, how does the DA device ensure its time is synchronized prior to sending it first transmission?

5.10.9 DA Roadmap (I)

a) The Proponent is to provide detailed information as to the product roadmap vision and planned releases over the next 24 months. Details should include:
   i. Planned functionality; and
   ii. Planned hardware and firmware releases

5.10.10 DA Integration

a) The Proponent to provide listing of the standards used today to accommodate the integration with DA systems.
b) The Proponent is to provide a listing of DA systems they currently are integrated with i.e. SCADA/OMS vendors.

5.11 Miscellaneous Tools and Functions

FortisBC is interested in the Proponent providing information on the availability of the following miscellaneous products.

5.11.1 Remote Disconnect Capabilities (I)

FortisBC would like to understand the product offering and functionality available from the Proponent as it relates to Remote Disconnect Capabilities.

a) Proponents are asked to provide an overview and include information on the following areas of interest:
   i. Product safety features, including those at installation and what is displayed on the meter to visually indicate that the meter is in the disconnect position.
   ii. If the meter can be prevented from reconnecting when there is voltage on the load side to prevent equipment damage or personal injury;
   iii. Details on the type of switch used to perform reconnection by the customer and information on the expected life of these switches;
   iv. Details of the reconnection process and if the product has Cold Load Diversity pickup;
   v. Once disconnected, if the HES provides exception reports on any consumption by the meters (customer tamper);
   vi. Details on what is logged in the HES with all disconnections and reconnections performed and attempted;
   vii. Details on if a register reading is collected and transmitted to the HES upon disconnection;
   viii. Details on what service limitation functionality is available;
   ix. Details on what components of this functionality are configurable;
   x. If the HES provides confirmation of successful remote service disconnect switch operations. Where confirmation is not received, within a configurable time, is an alarm initiated and / or a configurable number of retry attempts automatically initiated;
   xi. If the service disconnect switch is capable of local operation by authorized personnel via a metering system tool.
   xii. The number of remote disconnection and load limiting products currently deployed.

5.11.2 Pre-payment Capabilities (I)

FortisBC would like to understand the product offering and functionality available from the Proponent as it relates to Pre-payment services.

a) Proponents are asked to provide an overview and include information on the following areas of interest:
   i. Product functionality overview (including hardware and software);
   ii. Details on what information is presented to the customer on an in-home display;
   iii. Details on how the client is informed of their remaining balance and options available to alert them when they go below a set threshold.
   iv. What system(s) is used (i.e. HES or separate third party system) to perform the ongoing billing calculations and manage the remittance process;
   v. Details on how current balance information is presented and calculated and how frequently this process is done;
   vi. What is typically the master system for these calculations?
   vii. Details on if there is a resetting process for in-home displays in the event that errors with payment processing occur at the HES (cancel payment and reapply due to operator error);
   viii. Details around if there are any limitations to number of rates that can be managed;

ix. How often this information is transmitted to the HES to manage the reconciliation process;
x. What audit tools related to pre-payment are available within the product;
xi. Does the product allow users to go over on a balance by a configurable threshold before a disconnection or load limitation is initiated?
xii. The number of products related to prepayment currently deployed including the names of utilities using this product.

5.11.3 Field Programming and Investigation Tools (I)

FortisBC would like to understand what field programming / investigation tools are available and / or required.

a) Proponents are asked to provide an overview and include information on the following areas of interest:
   i. Provide a product functionality overview;
   ii. The Proponent must indicate unit weight and dimensions of field programming devices and attach a picture of the portable device;
   iii. The Proponent is asked to indicate the maximum distance at which a portable interrogator will reliably receive the complete meter reading signal from an AMI end device;
   iv. The Proponent must describe if the field programmer can program the AMI end device and if so, how it is protected against unauthorized use and what type of security has been instituted to ensure protection.
   v. Proponent to describe how the field tool is able to manage the key once encryption is enabled within the AMI network.
   vi. What functionality in the meter and communication module can be modified by these products when it is sealed in the field while still complying with Measurement Canada standards?
   vii. What functionality in the meter and communication module can be modified by these products when in the meter shop when the meter is in an unsealed state?
   viii. Proponent to provide details on if the field tools can download the register reading, load profile tables and event load data. Description should include the options available to perform these tasks including using the communication board or optical cables.
   ix. Proponent to provide details on if the field tool can force a reading from a meter device through the network with confirmation this information has been received by the HES.
   x. Details on if the field tools are capable of operating the service disconnect within the meter and if so, how this is performed.
   xi. Proponent to provide details on how the field tools indicates the LAN signal strength and provide other metrics to assist with LAN diagnostics and trouble shooting.
   xii. Proponent to provide details on how the field tools can assist with trouble shooting HAN devices.

xiii. Proponent is asked to provide the number of these products currently deployed.

5.12 System Implementation (I)

FortisBC requires the services of a company with an exemplary track record in implementing AMI solutions on time and on budget. The Vendor must show strong skills in the areas of managing project resources, documenting project timelines, assessing risk and identifying project gaps. Not only must the qualified candidate have strong implementation skills, but they will also need to have a solid training and educational team that can teach FortisBC's staff how to get the most out of their AMI system.

At a minimum, the methodology utilized by the Vendor while implementing the AMI system for FortisBC should consist of the following:

- Processes, checklists and matrices that define project resources and timelines.
- Key milestone deliverables that are clearly identified and require FortisBC sign-off.
- A communication strategy to keep all members informed on the status of the project.
- A change management process.
- The use of software tools and assets that can easily be shared, interpreted, and leveraged to produce defined outputs.

Key criteria that will be evaluated as part of the selection process include the following:

- Discovery Process
- Implementation Plan
- Implementation Timelines
- Implementation Resource Requirements

It is expected that the selected Vendor will be fully accountable for the implementation and system integration project plan.

a) The Proponent is asked to provide information regarding the implementation methodology for the AMI system being proposed.

5.12.1 Discovery and Design Process (I)

The initial phase of the AMI project is considered the "Solution Definition Phase". During this phase FortisBC will work with the Vendor team on Use Case refinement. This activity is where the vendor team and the FortisBC team explore FortisBC's current business processes from all aspects utilizing the Use Cases already developed. This exploration is to be as in-depth as possible in order for both parties to fully understand how best to implement the system.

Use Cases will be refined as required to record the various business processes as described by FortisBC. Our expectation is that the Vendor will review and determine how their AMI system can be incorporated into these business processes and how the features and functionalities of the system can be utilized.

a) The Proponent is asked to provide their experience with utilizing Use Cases as well as an overview of the information that is gathered during this critical kick-off phase of the implementation.
b) The Proponent is asked to provide information pertaining to the cost of this discovery/design process to the AMI project.
c) The Proponent is also asked to include key FortisBC personnel that are recommended to be included in this process, as well as the timelines required to complete a full Use Case refinement process.

5.12.2 Implementation Plan (CI)

The Proponent is asked to provide sample implementation plans that outline the key steps involved in integrating the AMI into FortisBC's production environment. The qualified Proponent must have strong implementation processes, effective planning skills, and experience. It is required that the Proponent assign full time project managers that have completed similar implementations in size and scope to the one for FortisBC. The project manager is expected to be onsite as much as is required during strategic points in the project.

FortisBC insists on a stable and experienced project management team who are dedicated to their needs. Proponents must commit to keeping their implementation team in place for the duration of the project and not switch out resources mid-stream. Any changes to the project team must be approved by FortisBC.

The use of Gantt charts, MS Project and other planning tools are also recommended when tracking and planning these types of implementations.

It is expected that the selected Vendor will be fully accountable for the system integration project plan.

a) The Proponent is asked to describe their approach and organizational model for overall project governance. This description should include expectations of what FortisBC staff's responsibilities are within this model.
b) The Proponent is asked to provide a sample project plan and other documents that provide an overview of the project and that address the above requirements.
c) The Proponent is asked to explain what project status reporting they have used with other similar sized utility AMI projects including, but not limited to, project timelines, hardware delivery updates and network performance updates.
d) The Proponent is asked to describe their approach to risk management in general and any specific risks which may be applicable to FortisBC's AMI project.

5.12.3 Implementation Timelines (I)

Based on the timelines outlined in Section 3.1.9 Implementation Timelines:

a) The Proponent is asked to provide projected implementation timelines. Timelines should include all aspects of the project from Use Case Refinement process, installation of the hardware, configuration of the software, user training, testing, and cut-over to live.

5.12.4 Implementation Resources Requirements (I)

FortisBC needs to fully understand the resource requirements that the implementation of the AMI system will place on their internal staff.

a) Proponents should indicate in their response which resources are expected to be key members of the implementation and what subject matter experts from various departments will be needed to participate in the implementation.

The project timelines should also take into consideration the key resources required from FortisBC and the appropriate effort that will be required from these resources during the implementation. The plan should accurately reflect the number of resources expected to participate on behalf of FortisBC during this engagement, as well as build in some contingency time to deal with any issues.

b) The Proponent is asked to indicate when resources will be required during certain stages of the implementation. These resource requirements should be clearly defined in the response to allow FortisBC to evaluate the impact of the implementation on their utility.

5.12.5 System Acceptance Testing (I)

The completed AMI system will be subject to FortisBC acceptance, which will occur after System Testing has been completed to FortisBC's satisfaction. The Vendor will provide test cases for FortisBC to review and approve prior to the completion of phase of testing listed below. The testing will be completed primarily by the Vendor with support from FortisBC as required. FortisBC and / or its consultants will audit and approve the results of this testing.

The following phases of are expected to make up the required system acceptance testing:

i. **Functional acceptance testing** of meters which will occur at a FortisBC determined meter shop or some other location;
ii. End to end **System acceptance testing** and **field validation** once each area is substantially deployed; and
iii. **Final acceptance testing** once all areas are deployed.

a) The Proponent is requested to suggest suitable tests to demonstrate end to end functionality of the AMI system and describe a methodology and plan for system acceptance testing.

5.13 Training (I)

FortisBC requires that the Proponent provide detailed training at utility-provided facilities for various levels of personnel of FortisBC and FortisBC's contractors who will be involved with:

- Installation of meter/Smart Meter customer premises equipment.
- Installation of communications infrastructure not at customer premises.
- Routine operation and required maintenance of the installed system.
- Troubleshooting, diagnosis and repair of the installed system.
- Training on test equipment needed to maintain the system.

a) The Proponent is asked to provide a course syllabus and any other sample materials to illustrate the training involved with the above topics.
b) The Proponent is asked to identify the various positions recommended to be trained on the AMI System.

5.13.1 Up Front Training (I)

FortisBC requires the following of all AMI training:

i. The Vendor must provide to the trainees workbooks, training aids and system technical manuals prior to or during the training session. Proponent is asked to supply a sample training course outline (i.e. Course syllabus) and material.
ii. Training Testing - The Vendor's training must include evaluation of trainees to ensure that they have learned the course content and can perform all necessary functions on the system. The Vendor must notify FortisBC of any employees who fail this evaluation, and provide them with additional training.
iii. Training Aids - The Vendor must provide a detailed outline including any equipment and software requirements of each training session's objectives and content at least two (2) weeks prior to the training session.
iv. The Vendor must restore, repair or replace any FortisBC equipment damaged in training. It must restore any hardware or software modified in training.
v. The Vendor must provide trained and experienced instructor(s), and ensure that they do not perform other duties during the training period that will interrupt instruction. The Proponent is asked to provide instructor(s) background and resume(s).
vi. FortisBC may require the Vendor to videotape training sessions for internal use. The Vendor must cooperate with FortisBC to ensure quality video records of training sessions.

a) The Proponent is asked to describe how their training processes support the above requirements.
b) The Proponent is also asked to describe the major sessions of training available and required including duration and number of trainees for each of these training sessions.
c) The Proponent is asked to describe what materials they provide for training.

5.13.2 On Going Training (I)

Following implementation, FortisBC requires that formal refresher training take place at a FortisBC designated location. Training should address FortisBC specified topics. It is expected that the Vendor will supply a qualified, knowledgeable instructor(s).

In addition, the Vendor must repeat a training session at no additional cost to FortisBC if a majority of the trainees lack the skills or fail the evaluation at the end of the training.

a) The Proponent is asked to provide information to indicate their understanding of this requirement and any details on best practices that have been utilized with other utilities.
b) The Proponent should declare if they offer webinar sessions to users and if there is a cost for these sessions.
c) The Proponent is asked to describe any training available with new releases or upgrades.

5.14 Support (I)

a) Proponent should provide description of their intended support for the AMI system, including the following:
    i. Location(s) of support personnel
    ii. Hours of support
    iii. Organizational structure of support team(s)
    iv. Support escalation process.

It is anticipated that support will follow a tiered structure whereby the utility will describe a support item complete with priority (e.g. High, Med, and Low).

b) The Proponent should describe their tiered structure and the guaranteed time to respond to and resolve issues within the different levels of priority.

5.15 AMI System Security (CI)

FortisBC requires that the AMI system have, as a minimum, end-to-end protection against cyber attack and unauthorized intrusions.

a) The Proponent should describe its organization's approach to security throughout the company - how it is managed, operated, continuously monitored and assured, and how it responds to issues.
b) The Proponent should describe how its AMI solution supports a segmented network infrastructure, where the solution as a whole is firewalled off from the corporate network or within the AMI environment itself.
c) FortisBC requires that periodic architecture reviews be conducted to ensure that no cyber risks are introduced as the AMI project progresses. The Proponent should describe any security architecture reviews completed by a third party security audit firm within the last 12 months. Please identify the scope of each assessment and how your organization is responding to the results.

d) The Proponent should describe any cyber risk assessment of the AMI system (within 12 months on the AMI system being proposed). Please identify the scope of each assessment and how your organization is responding to the results.
e) FortisBC requires that all vendors align with our Corporate Management and Protection policies and standards and applicable industry standards and regulatory requirements. Are there any concerns with meeting our policies and standards and how does your organization prepare and respond to regulatory impacts?
f) The Proponent should describe how its AMI systems support the following standard security practices:
    i. Encryption at rest and in transit for sensitive information, including key management and speed of key distribution.
    ii. User access to head end and network communication devices.
    iii. User and system access for field devices.
    iv. Role-based access control and support for centralized user management with active directory.
    v. Patch Management process and assurance for updating all system devices; provide testing information of time and validation for all device patching/updates.
    vi. Device event logging and how logging can be utilized for response processes.
g) The Proponent should describe how its AMI ensures against loss or tampering of data including:
    i. Data integrity so that the reading on the meter, ID numbers, and other data are always correct,
    ii. Data security in the transmissions of Meter Reads and customer data such that it cannot be intercepted or accessed by unauthorized parties,
    iii. Immunity from outside electromagnetic interference as well as from fading and other forms of signal degeneration or attenuation,
    iv. Data encryption capabilities,
    v. MAC address filtering,
    vi. DHCP (dynamic host configuration protocol),
    vii. NAT (network address translation),
    viii. Built-in firewall protection,
    ix. User authentication (CHAP) capabilities,
    x. Password access (PAP) functionality,
    xi. Centralized password repository (global, regional, cluster or unit remote updates),
    xii. Bandwidth restrictions (limited data rate per unit),
    xiii. Traffic analysis restrictions (watch for irregular traffic flows),
    xiv. Automatic “call home” modems,
    xv. ACL (access control lists),
    xvi. Traffic logging.
h) The Proponent is asked to:
    i. Identify what AMI security work groups that they are involved in.
    ii. Provide documentation of security and vulnerability testing in their AMI network.
    iii. Describe knowledge and experience pertaining to AMI security testing, regulations, and guidelines.
    iv. Provide details on security platform which has been proposed and is implemented at a utility today.
    v. Describe what security standards that the product complies with.
    vi. Describe what security certifications that the product complies with (eg. Achilles Certification).

6 Price Submission Requirements

Please note that all documentation must reflect current capabilities. Any future capabilities must be stated as such, and a development schedule outlined.

Describe in detail the pricing for the systems proposed. Detail any assumptions made in the proposed solution and pricing. All of this information should be included within the Pricing and Compliancy Spreadsheet. **As per Section 2.2.1(3) Submission of Proposal, any hard copies of the pricing submission should be submitted in a separate envelope, marked "PRICE SUBMISSION".**

6.1 Pricing Submission

The Pricing Spreadsheet allows for the Proponent to provide two options for the proposed AMI Infrastructure:

1) Within the tab labeled "Pricing_Option1_95%", the Proponent is required to submit pricing (Capital and 15 year Operating costs) for the proposed AMI Solution, as per the requirements of this RFP document (i.e. Licensed model, with capability to accept AMI network data, perform AMI audit, etc.). This tab represents pricing for coverage for 95% of the meters in FortisBC territory.
2) Within the tab labeled "Pricing_Option1_100%", the Proponent is required to submit pricing (Capital and 15 year Operating costs) for the proposed AMI Solution, as per the requirements of this RFP document (i.e. Licensed model, with capability to accept AMI network data, perform AMI audit, etc.). This tab represents pricing for coverage for 100% of the meters in FortisBC territory.
3) Within the tabs labeled "Pricing_Option2", Proponents have the option to provide pricing alternatives to that provided through Option 1. **NOTE: Pricing Option 1 is required, Pricing Option 2 is optional.** These tabs are to be completed if the Proponent will provide the services to operate the AMI network on behalf of the utility with the infrastructure owned by the utility.
4) The Proponent is also asked to provide pricing on any additional costs under each option above for a test environment as outlined in Section 5.1.6 AMI Test Environment.

All pricing must be in Canadian dollars. If the Proponent has priced this as a foreign currency and used an exchange rate please provide the exchange rate utilized to convert to Canadian dollars.

6.2 Pricing and Compliancy Statement

In addition to the Pricing Options described in Section 6.1 Pricing Submission, Proponents are required to submit the incremental cost for any functionality that is discussed in their Proposal which does not come standard with their product. If an incremental cost is not provided, it is assumed that the functionality comes standard with the product being proposed.

6.3 Pricing Qualification

In addition to the Pricing Options described in Section 6.1 Pricing Submission, Proponents are required to submit any discounts that would be available to FortisBC based on the following;

- Contract is signed and the project is started ahead of the proposed schedule; or
- If the terms for payment is shortened to Net 10 days.

6.4 Pricing Estimation

In addition to the Pricing Options described in Section 6.1 Pricing Submission, the Proponent is required to submit a level of confidence with the pricing they have provided (e.g. + / - 10%) or a statement of the pricing as a range. Include any key assumptions that have been made in developing the estimate and identify any factors that would cause the estimate to be altered. Price is only one of the factors that will be considered in the evaluation of Proposals.

6.5 Risk Items

The Proponent shall describe how the Proponent intends to allocate risk for the Work, both risks to be borne by the Proponent and risks to be borne by FortisBC – and how the risk allocation factors into the estimated lump sum price for the Work. Unless a risk is specifically accepted by FortisBC during the negotiation stage, all risks whether or not they are noted or discussed within this RFP shall be entirely borne by the Proponent. Please provide a price allocation for each of the following risks if they were considered in the estimated lump sum price:

- Network Failure as described in Section 6.5.1
- Network Security
- All other risks that may have been included in the estimated lump sum price for the Work.

6.5.1 Network Failure

Should the network fail to a degree that meter data cannot be communicated or retrieved, leading the utility to revert back to collecting data manually, the Vendor will be required to cover any utility costs incurred, at the sole discretion of FortisBC, which are associated in manually obtaining the meter data for billing.

6.5.2 Security Audits

The Vendor is expected to perform independent, third party security audits of all Vendor products (of all Vendor products commercially available, not just those installed at FortisBC) annually at their own cost and provide the audit results to FortisBC or its agents.

6.5.3 Performance Requirements & Remedies

FortisBC requires that the AMI vendor state their acceptance with the following Service Level Agreement requirements and that these requirements are included in the contract:

- Percent of interval readings captured:
  - 98% in 24 hours
  - 99% in 72 hours (rolling statistic)
  - 99.5% in 30 days (calendar static)
- Percent of daily (register) readings captured:
  - 98% in 24 hours
  - 99% in 72 hours (rolling statistic)
  - 99.5% in 30 days (calendar static)
- These requirements will demonstrate the AMI vendor's ability to acquire the readings that were missed in 24 hours; over the subsequent time periods (i.e. continued commitment to acquire as many readings as possible).
- Percent of meters communicated within 24 hours: 99.9% (while it is conceded that some meters may be difficult to communicate with, and therefore acquire 100% of the readings 100% of the time, the aim of this statistic is to show that 99.9% of meters can be reached on a daily basis).

If these SLA's are not met, the Vendor is responsible to provide and install additional infrastructure at no cost to FortisBC in order to make up for any deficiencies and to achieve the SLA.

If the performance issues are not corrected within 30 days of identification, performance remedies in the amount of liquidated damages are estimated to be between $1,000 and $2,500 per day.

After 4 consecutive months with 4 or more failures FortisBC has the option to terminate the agreement for cause.

6.5.4 Late Meter Deliveries

Should delivery of the meters not meet the delivery date as scheduled and there are insufficient meters in the FortisBC's stock to accommodate the installation schedule, the Vendor will be required to pay a $10.00 per late meter per day to FortisBC which is the estimated liquidated damages as a result of internal costs and standby charges which may be owed to the installation contractor.

6.5.5 Meter Initialization Tools

If any required meter registration tools provided by the Vendor result in meter failures, any resulting liquidated damages to FortisBC must be paid by the Vendor (i.e. site visit costs etc).

6.5.6 Price Escalation

Any price escalations or de-escalations used in the Proponent's price needs to be identified within the Pricing Spreadsheet.

6.5.7 Warranties

The Vendor must provide detailed pricing warranty options with regards to standard warranties and extended warranties on their meters and network equipment.

6.5.8 Time and Materials

The Vendor shall declare their time and materials rates for any services or products that may be required above what is contemplated within this RFP.

7 Required Contract Terms and Conditions

The following terms and conditions shall be part of any contract that is agreed to by the parties pursuant to this RFP. These terms are non-negotiable and all Proponents should consider these required terms when preparing and submitting their Proposals.

7.1 Condition Precedent

FortisBC's obligation to carry out any of the transactions contemplated in this contract are subject to FortisBC receiving regulatory approval by the British Columbia Utilities Commission to proceed with the Work and the AMI Project as a whole on the terms and conditions satisfactory to FortisBC in their sole and absolute discretion (the "Condition"), which Condition is for the sole and absolute benefit of FortisBC and which may be waived by FortisBC in whole or in part, in its sole discretion. If the Condition is not satisfied or waived by FortisBC then FortisBC may deliver notice to the Vendor that the Condition has not been satisfied and this contract shall be null and void, without liability between FortisBC and the Vendor, and neither FortisBC or the Vendor will be under any obligation to the other to complete the transactions contemplated by this contract.

FortisBC and the Vendor each acknowledge that if either party elects to undertake any work or incur any costs with respect to this contract prior to the waiver or satisfaction of the Condition, that party will be solely responsible for all costs incurred and shall not claim for any reimbursement from the other party.

7.2 Confidentiality

The Vendor agrees to maintain confidentiality with regard to secret, confidential or restricted matters that are disclosed or developed in connection with this Agreement, and, when so advised by FortisBC, agrees to execute the Confidentiality Agreement in form and content as determined by FortisBC forthwith upon FortisBC' request therefore and shall require a similar agreement of all employees, sub-Vendors and agents of the Vendor to whom any work or duty relating to this Agreement may be allotted.

APPENDIX "A"

CONFIDENTIALITY AGREEMENT

(the "Confidentiality Agreement")

THIS CONFIDENTIALITY AGREEMENT, made as of the day of , 2010.

BETWEEN:

FORTISBC INC., a corporation incorporated under the laws of the Province of British Columbia

("**FortisBC**")

AND:

____________________________________, a corporation incorporated under the laws of the Province of British Columbia

(the "**Proponent**")

WITNESSES THAT WHEREAS:

A. FortisBC has released a Request for Proposal (Proposal Number LISD 10005) – FortisBC Advanced Metering Infrastructure System & Services dated December ___, 2010 (the "RFP") to various parties including the Proponent;

B. The Proponent wishes to submit a proposal in response to the RFP (the "Proposal");

C. To facilitate the Proponent's ability to submit a Proposal, FortisBC expects to provide to the Proponent certain information of a confidential nature regarding FortisBC and its undertaking; and

D. FortisBC requires that the Proponent accept and use, and the Proponent has agreed to accept and use, all such information on a confidential basis, in accordance with the terms and conditions of this Confidentiality Agreement.

NOW THEREFORE in consideration of the mutual covenants herein contained and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged by each of the parties hereto, the parties agree as follows:

1. <u>Confidential Information</u>. "**Confidential Information**" as used in this Confidentiality Agreement means all information disclosed to the Proponent by FortisBC in connection with the Proponent's submission of a Proposal, including any business, technical, engineering, financial or other information, whether in electronic, oral or written form, and all memoranda, summaries, notes, analyses, compilations, studies or those portions of other documents prepared by the Proponent to the extent they contain or reflect such information. Confidential Information shall also include any 'personal information' as defined under the Personal Information Protection Act, S.B.C. 2003, C.63 ("PIPA") and the Personal Information Protection and Electronic Documents Act, S.C. 2000, c. 5 ("PIPEDA") regarding an individual. Confidential Information shall not include information that:

(a) is or becomes part of the public domain other than as a result of disclosure by the Proponent;

(b) becomes available to the Proponent on a nonconfidential basis from a source other than FortisBC, provided that such source is not prohibited from transmitting such information by a contractual, legal, or other obligation;

(c) as shown by reasonably documented proof, was in the Proponent's possession prior to disclosure of the same by FortisBC; or

(d) is authorized in writing by FortisBC to be released or is designated in writing by FortisBC as no longer being confidential.

2. Non-Use: Protection and Dissemination of Confidential Information. The Proponent will not use any Confidential Information for any purpose other than to assist in preparing the Proposal. The Proponent will not disclose any Confidential Information to any other person and will use its best efforts to protect the confidentiality of such information; provided, however, that the Proponent may furnish Confidential Information to its directors, officers and employees (collectively, the "**Representatives**" of the Proponent) who need to have access to such Confidential Information to enable the Proponent to submit a Proposal. As a condition to such disclosure, the Proponent shall inform its Representatives of the confidential nature of the information and shall be responsible for any breach of this Confidentiality Agreement by any such Representatives.

3. Ownership and Return. All Confidential Information shall be and remain the property of FortisBC, and no right or license is granted to the Proponent with respect to any Confidential Information. Upon the expiry or termination of this Agreement, the Proponent agrees immediately to return to FortisBC or destroy all Confidential Information provided to the Proponent, including all copies of the same. Upon request, the fact of any such destruction shall be certified in writing by an officer of the Proponent. All internal memoranda, summaries, notes, analyses, compilations, studies or those portions of other documents prepared by the Proponent to the extent they contain or reflect such information, will remain in the possession of the Proponent and continue to be treated as Confidential Information. Nothing in this Confidentiality Agreement obligates FortisBC to disclose any information to the Proponent or creates any agency or partnership relation between FortisBC and the Proponent.

4. Compelled Disclosure. If the Proponent is requested or required by legal or administrative process to disclose any Confidential Information, the Proponent shall promptly notify FortisBC of such request or requirement so that FortisBC may seek an appropriate protective order or other relief. In any case, the Proponent will:

(a) disclose only that portion of the Confidential Information which its legal counsel advises is required to be disclosed;

(b) use its best efforts to ensure that such Confidential Information is treated confidentially; and

(c) notify FortisBC as soon as possible of the items of Confidential Information so disclosed.

5. Remedies. Both parties acknowledge that remedies at law may be inadequate to protect FortisBC against any actual or threatened breach of this Confidentiality Agreement by

the Proponent, and, without prejudice to any other rights and remedies otherwise available to FortisBC, the Proponent agrees to the granting of injunctive relief in favour of FortisBC without proof of actual damages. In the event of litigation between the parties concerning an alleged breach of this Confidentiality Agreement, the non-prevailing party shall be responsible for the prevailing party's costs and expenses in such litigation, including costs on a solicitor client basis.

6. No Representations by FortisBC. No representation or warranty is made by FortisBC as to the accuracy or completeness of any information provided to the Proponent as contemplated hereunder.

7. Term. This Confidentiality Agreement will terminate;

(a) two (2) years after the date of expiry or termination of any agreement subsequently executed between FortisBC and the Proponent as a result of the RFP; or

(b) if there is no subsequently executed agreement between FortisBC and the Proponent as a result of the RFP this Confidentiality Agreement will terminate two (2) years after the date this Confidentiality Agreement was signed.

8. Notices. Unless agreed to otherwise by the parties, in writing, all notices, requests or demands relating to this Confidentiality Agreement will be in writing and will be sufficient in all respects if delivered, or if sent by facsimile, or if sent by prepaid registered mail in British Columbia to the parties at the following addresses, respectively:

a) to the Proponent:

Attention:

Fax No.:

b) to FortisBC:

FortisBC Inc.
#100 – 1975 Springfield Road
Kelowna, B.C.
V1Y 7V7

Attention: Contracts Department

Fax No.: 1-866-875-7369

Either party will have the right at any time to change its address by notice in writing sent to the other party at the address in effect hereunder.

9. Time of Delivery. Any notice, request, demand or other instrument will be deemed to have been received on the following dates:

(a) if sent by facsimile, on the business day next following the date of transmission;

(b) if delivered, on the business day next following the date of delivery; or

(c) if sent by registered mail, on the seventh day following its mailing, provided that if there is at the time of mailing or within seven (7) days thereafter a mail strike, slowdown, lockout or other labour dispute which might affect delivery, then any notice, direction or other instrument will only be effective upon actual delivery.

10. Miscellaneous.

(a) This Confidentiality Agreement shall enure to the benefit of and shall be binding upon the parties' respective successors and assigns.

(b) In the event that any one of the provisions contained in this Confidentiality Agreement should be found to be invalid, illegal or unenforceable in any respect by a court of competent jurisdiction, the validity, legality or enforceability of the remaining provisions contained in this Confidentiality Agreement shall not in any way be affected or impaired by such a finding.

(c) No waiver of any provisions of this Confidentiality Agreement shall be valid unless the same is in writing and signed by the party against whom such waiver is sought to be enforced. A waiver or consent given by either party on any one occasion is effective only in that instance and will not be construed as a bar to or waiver of any right on any other occasion.

(d) This Confidentiality Agreement contains the entire agreement of the parties, supersedes any and all prior agreements, written or oral, between them relating to the subject matter hereof, and may not be amended unless agreed to in writing by each party.

(e) This Confidentiality Agreement shall be governed by and interpreted in accordance with the laws of the Province of British Columbia and the laws of Canada applicable therein.

11. Counterparts/Electronic Transmission. This Confidentiality Agreement may be executed in one or more counterparts and delivered by electronic transmission or facsimile, each of which when so executed shall constitute an original and all of which together shall constitute one and the same agreement.

IN WITNESS WHEREOF, the parties have executed this Confidentiality Agreement as of the date first above written.

FORTISBC INC.

Per: ____
Authorized Signatory

THE PROPONENT:

____

Per: ____
Authorized Signatory

Request for Expression of Interest

In-Home Feedback Devices (RFEI #1089)

ISSUE DATE

December 2, 2011

CLOSE DATE/TIME

Dec 21, 2011

11:00:00 AM

Pacific Standard Time (PST)

Contact Person

| Laura Silva |

| Tel 778.452.6672 |

| laura.silva@bchydro.com |

TABLE OF CONTENTS

SECTION 1 - INTRODUCTION

Company Information

BC Hydro is one of North America's leading providers of clean, renewable energy, and the largest electric utility in British Columbia, serving approximately 95 per cent of the province's current population and approximately 1.8 million customers (expected to grow to 1.93 million by 2013). BC Hydro's vision is "powering B.C. with clean, reliable electricity for Generations."

As a provincial Crown Corporation established in 1962 under the British Columbia Hydro and Power Authority Act, BC Hydro reports to the Minister of Energy, Mines and Petroleum Resources, and is regulated by the British Columbia Utilities Commission (BCUC).

BC Hydro's various facilities generate between 43,000 and 54,000 gigawatt hours (GWh) of electricity annually, depending on prevailing water levels.

Electricity is delivered through a network of 18,336 kilometres of transmission lines and 55,705 kilometres of distribution lines. The transmission and telecom assets are owned and operated by BC Hydro.

BC Hydro is in the process of deploying advanced metering infrastructure, including smart meters. This document relates directly to that program. More information about that program is available here:

http://www.bchydro.com/energy_in_bc/projects/smart_metering_infrastructure_program.html

Additional information about BC Hydro is available at: www.bchydro.com

Executive Summary

This RFEI is designed to inform in-home energy feedback device (IHD) vendors of device requirements for operational compatibility with BC Hydro smart meters, as well as eligibility for potential future BC Hydro marketing programs. These preliminary requirements are outlined in the product requirements document (PRD) – please see section 6 of this document.

This PRD is not intended to be prescriptive and inflexible. Rather, BC Hydro hopes to open a dialogue with vendors and retailers to assure that the specifications and suggestions contained therein reflect industry best practices, leverage the ability of these devices to affect conservation behavior, and best seed a nascent industry.

Specifically, BC Hydro will host a series of workshops to engage manufacturers in finalizing these requirements and to discuss the overall home-area network (HAN) strategy, including testing and qualification. We encourage active participation as part of a community striving to create a vibrant energy insight industry. A final revised version of the PRD will be released following these workshops and industry consultations.

SECTION 2 - THE PROJECT

BC Hydro is mandated by the provincial government to provide customers with the ability to provision a home area network off of their smart meters by December 31, 2012, and ultimately launch an in-home device program under the Power Smart banner to encourage residential customers to conserve energy by providing them with detailed and timely information about how and when they use electricity in their home.

Potential solutions may include:

- Stand alone display devices (IHDs), or
- Gateway solutions, which are bundled software and hardware devices designed to connect a customer's smart meter to home networks and PCs. Gateway devices themselves may be Wi-Fi devices, wired (Ethernet) devices, or USB dongles.

The product requirements document (please see section 6 of this document) outlines a minimum set of requirements identified as necessary to be compatible with BC Hydro's current systems and future marketing efforts.

SECTION 3 - REQUEST FOR EXPRESSIONS OF INTEREST

As this document is a request for expressions of interest, suppliers are encouraged to provide as much information as possible; however BC Hydro understands that not every question will be applicable to each respondent.

Section No.	Title	Contents
1.	**Introduction**	
1.1	**Company Name** Provide the legal name of the Respondent.	
1.2	**Contact Information** Provide the name and contact details for the Respondent's Representative. Respondent's Representative: Name Mailing/courier addresses Telephone number Mobile number (optional) Email address Website address	
2	**Overall Solution**	
2.1	**Please describe your company's products and/or services**	
3	**PRD Comments**	
3.1	**Comments on the PRD laid out in Section 6**	
3.2	**Please provide any other notes or comments here**	

SECTION 4 - RESPONSE PROCESS

Submission Guidelines:

Timelines:

Any potential supplier who has interest in the PRD program should complete Section 3 and return it as described below by December 21 at 11:00:00 PST.

Format:

Submission should consist of one bound hardcopy not exceeding ten (10) pages double sided in length, and one (1) soft copy on a USB drive in Portable Data Format (PDF).

Delivery Location:

BC Hydro Bid Station

535 Hamilton Street

Vancouver, B.C.   V6B 2R1

RE: RFEI 1089

SECTION 5 - FREEDOM OF INFORMATION AND PROTECTION OF PRIVACY ACT BC "FOIPPA"

All documents and other records in the custody of, or under the control of, BC Hydro are subject to the Freedom of Information and Protection of Privacy Act (FOIPPA) and other applicable legislation. Except as expressly stated, and subject to FOIPPA or other applicable legislation, all documents and other records submitted in response to this RFI 1017 will be considered confidential.

SECTION 6: PRODUCT REQUIREMENTS DOCUMENT (PRD)

1.1 TECHNOLOGY

BC Hydro will enable a HAN in residential smart meters based on ZigBee Smart Energy Profile version 1.1 (SEP 1.1) technology.

1.2 DEFINITIONS

Compatible Devices means any device that is:

- certified by the ZigBee Alliance as an in-premises device1 using SEP 1.1, and
- approved by the meter vendor (Iron) to work with the BC Hydro meter that

will be able to securely connect to the HAN and receive near real-time information from the meter. This document refers to such devices as "Compatible" devices.

Eligible Devices describes how BC Hydro intends to partner with retailers to sell HAN devices in their stores, and connect these devices at the store. In addition, BC Hydro anticipates the ability to offer a rebate to customers towards this purchase. Devices sold in this manner are referred to as "**Eligible**" devices, as they are eligible for inclusion in the planned rebate program.

1.3 DEVICE REGISTRATION

Activation (pairing) of these devices will take place:

1. On the BC Hydro website
2. Over the phone with BC Hydro Customer Representatives, and possibly
3. At the retailer through a BC-Hydro provided and connected application

A document describing this process will be provided under separate cover.

1.4 COMPATIBLE DEVICES

Compatible devices must satisfy the following requirements, and be fully tested according to BC Hydro testing policy, which will follow under separate cover.

[1] In-Premises Device is defined in the ZigBee Smart Energy Profile specification.

1.5 FUNCTIONAL REQUIREMENTS

REQ 1. ZigBee Smart Energy 1.1 Certification

The HAN device must support all mandatory SEP 1.1 functionality, as certified by the ZigBee Alliance and deemed necessary to operation on a SEP 1.1 HAN. Main operational features include tiered pricing (known in BC as Residential Incline Block rates), and fast polling. Other details outlining exactly which clusters and functions are to be included are to follow under separate cover.

REQ 2. Compliance with the BC Safety Standards Act

If applicable (e.g. mains powered), the device must bear an appropriate certification mark as evidence of meeting BC safety standards. Refer to the British Columbia Safety Authority for details on the certification or approval marks and labels that are acceptable in BC.

REQ 3. Industry Canada Certification of Radio Equipment

The device must satisfy Industry Canada requirements for compliance with radio standards specifications and bear the appropriate labelling.

REQ 4. Provincial and Federal Legislation

The device must comply with any other BC or Canadian legislation, as appropriate.

1.5.1 PERFORMANCE REQUIREMENTS

REQ 5. Device Pairing with BC Hydro Meters

The device must successfully pair with the HAN module in BC Hydro meters using BC Hydro device pairing systems and methods.

When the device is de-paired from the meter, the relationship is released from the device side (via the release command).

1.6 ELIGIBLE DEVICES

Eligible devices must satisfy the requirements stated above for compatible devices, as well as the specific requirements outlined below.

1.6.1 FUNCTIONAL REQUIREMENTS

REQ 6. ZigBee Smart Energy 1.1 Requirements

The HAN device must support all mandatory SE 1.1 functionality (as outlined above under sec 2.5.1) as well as the following functionality.

a) Device must be certified as a ZigBee SEP In-Premises Display device

b) Device must support the ZigBee SEP 1.1 clusters, attributes, and commands listed in Appendix B.

REQ 7. Price Display

The device must determine the current active price (note that BC Hydro has tiered pricing called RIB or Residential Incline Block rates) and display this in $/kWh, rounded to 3 or more decimal places for cents. Note that this includes tracking billing date and storing thresholds. Price, or a visual indicator of price (see REQ 12), must be shown on the default, or primary, screen of the display.

REQ 8. Manual Price Entry Not Allowed

The device must not allow price of energy to be manually entered into the device.

REQ 9. Power and Cost of Power

The device must display power in kW and $/hr (with at least 2 decimal places for cents) for the current moment in time.

REQ 10. Energy and Cost of Energy

The device must display cumulative energy consumed in kWh and $ (to at least 2 decimal places for cents) for at least the following time periods:

- Current Day (since midnight) or 'past 24 hours'
- Current Bill Period (stated clearly that this is an estimate).

REQ 11. Block Period Dates

When inclining block rates are in effect, the user must be able to view the start and stop dates for the current block period (i.e. the billing dates).

REQ 12. Meter Register

The device must display the current meter register reading for the cumulative energy in kWh.

REQ 13. Text Messages

The device must receive and display text messages of as long as 80 ASCII characters that are sent via the HAN gateway in the meter. The device must send a signal when the message is

REQ 14. Text Message Waiting Indicator

The device must display an indication that a new message has been received. For example, this may be an envelope icon or a special LED light display.

REQ 15. Pairing Process Result and Signal Strength Indicator

The device must display its pairing status. This may be led, text, or an icon on the display. In addition, the device must display wireless signal strength at all times, and indicate when there has been a loss of connectivity to the HAN. For example, this may be in the form of text on the display stating no signal, or zero bars in a signal strength icon.

REQ 16. Battery Level Indicator

If battery operated, the device must display the level of battery charge remaining. For example, this may be text on the display stating 'battery full/med/low', or by bars in a battery icon.

REQ 17. Time of Day

The device must display the correct time of day (HH:MM) using the correct time zone. The time should be set automatically and synchronized with BC Hydro (i.e. not user-settable).

REQ 18. Device Labelling

The device must have a label specifying it has been certified with ZigBee SEP 1.1 and must include the MAC address and installation code in both human-readable and bar code formats (details to be determined during the development process). Also, it must have vendor contact information for product support purposes (i.e. phone number).

REQ 19. Product Documentation

The device must be packaged to include installation instructions, a user manual, support information, and company contact information (phone and web). This documentation must be easy to understand for a non-technical user. In addition, the documentation must include a statement that the costs indicated on the device may not match the bill from BC Hydro and that BC Hydro's bill is the authoritative source for billing information. BC Hydro will provide such information under separate cover.

REQ 20. Firmware Upgrades

The device must have the ability to be upgraded by the consumer.

REQ 21. Reset Capability

The device must have the ability to be reset to factory default settings by the user. This reset must include erasing all text message, energy, cost, and price information on the device and must also de-pair and re-pair the device from the HAN (requiring the device to go through the pairing process to reconnect to the HAN).

REQ 22. Operational Information

a) The device must display operational information including MAC address, installation code, RF Channel, PAN ID, Short Address. In addition, firmware version and model number must be displayed or clearly identified on the product itself. Optionally, this could also display EPAN and Key.

b) The device must identify itself by providing the following information to the meter:

   i. Hardware version

   ii. Firmware version

   iii. Serial number

c) The device must provide on-screen diagnostics with (at minimum) latest error code and time of error.

1.6.2 PERFORMANCE REQUIREMENTS

REQ 23. Device Pairing – Performance

After using BC Hydro systems (online registration or CSR), customers must be able to pair their device to their meter in no more than 2 additional steps. For example, after providing the device MAC address and Installation Code to BC Hydro systems and after this information is sent to the meter by BC Hydro, the 2 additional steps may be as follows: step 1 would be the customer powering on the device, and step 2 (if needed) would be the customer pressing a button on the HAN device to initiate pairing.

REQ 24. Near Real-Time Display of Information

When viewing cumulative consumption information, the device shall update every 30 seconds.

REQ 25. Fast-Polling Display of Information

The device shall utilize a ‘fast polling’ mode that persists for 15 minutes when the device is put into consumption display mode. While in this mode, the device shall display updated power (energy per hour in kW and $) information every 2 seconds.

REQ 26. Reconnect After Power Loss

The device must reconnect to the home area network without requiring human intervention after the device has lost power (e.g. battery replacement, unplugged from power outlet), the meter has lost power, or any other event causes the device to drop from the network (such as interference). All device settings history data, text messages, etc. must persist through a power loss or any other loss of network connectivity.

REQ 27. Operational Distance

The device must operate at a distance of two hundred feet (200') from the meter in unobstructed space.

1.6.3 BUSINESS REQUIREMENTS

The device vendor must provide a written agreement that they will implement and maintain the following business requirements.

REQ 28. Environmental Considerations

The device vendor must take into account environmental responsibility for hardware, software, installation of components, packaging, energy consumption, and disposal of components. The device should support the following:

A. Average power consumption less than 1W (for gateway devices see requirement #34)

B. Environmentally friendly production (from raw materials to manufacturing processes and retail packaging)

C. Environmentally friendly disposal, with the preferred method of disposal explained in the documentation.

REQ 29. Safety

Any safety hazards related to the device must be documented with the device packaging. For example, documenting a choking hazard exists if batteries are included.

REQ 30. Packaging and Labelling

The packaging must be labelled, in a legible font, with the following information:

A. Installation code in hexadecimal format and bar code format

B. Caveat that the cost displayed may not equal the bill and does not replace the bill

C. Disposal instructions

D. Manufacturer support contact information, including a phone number and website address

E. All necessary regulatory labeling and BC Hydro terms and conditions sheet.

REQ 31. Product Warranty

The device vendor must provide a minimum of one (1) year of warranty for the device.

REQ 32. Product Support

The device vendor must commit to provide support for their products for a minimum of five (5) years from the date of the first sale of their device in BC. Support must include:

A. Toll-free phone support

B. f-serve support available 24 hours a day, that should include:

   i. Online access to all documentation included with the device

   ii. Troubleshooting steps

   iii. Answers to frequently asked questions (FAQs)

1.6.4 ADDITIONAL REQUIREMENTS FOR GATEWAY SOLUTIONS

In addition to the above requirements for eligible devices, additional requirements exist for gateway solutions. Gateway solutions are described in section 1 as:

“Gateway solutions. These solutions will be bundled software and hardware devices to connect the smart meter to home networks and PCs. The gateway devices themselves may be Wi-Fi devices, wired (Ethernet) devices, or USB dongles. “

Essentially gateway solutions are thus defined as hardware/software packages that enable users to view real-time energy feedback on connected smart devices either directly or through a home area network. The software may be provided separately or embedded in the device itself (for example if a web server is being run and connected devices ‘hit’ the gateway with a browser).

Actual embedded devices (such as ZigBee radios embedded in other consumer devices such as routers or set-top TV boxes) would not qualify for a rebate under this program.

REQ 33. Requirements for Wi-Fi devices

Maximum power consumption: 2W (average over a 24 hour period)

Must incorporate Wi-Fi sleep mode.

Must be Wi-Fi certified.

REQ 34. Power consumption for other gateway devices

If the hardware component of the gateway solution is a removable device such as a USB dongle, wired Ethernet device, or network card, only incremental power consumption is considered and must be less than 1W as specified in REQ 31.

REQ 35. Status Indicators

Must indicate status of the connection to the meter (pairing status) and to the network. Where applicable (such as in Wi-Fi access point mode), must indicated that the network is enabled and traffic is active.

REQ 36. Security

At minimum, 128-bit encryption must be present on the computer/LAN side of the gateway. A more detailed specification of security will follow.

REQ 37. Upgrade

Must be user-upgradeable. When SEP 2.0 is certified, must be upgradeable to that standard.

REQ 38. Registration and Pairing

See REQ 24. In addition, gateway devices must complete Zigbee Han registration to the meter upon the user connecting to the gateway through the client device (merely turning the device on is not sufficient).

REQ 39. Compatibility

In order for devices to be eligible for a rebate, they must be test-able in the BC Hydro lab, as per our eligibility program. BC Hydro supports most common platforms (Android, Mac, PC). A more detailed list of platforms and operating systems will be provided under separate cover.

Smart Grid Standards for Residential Customers

February 3, 2012

Smart homes can enhance the effectiveness of smart grids in the following ways:

- Reduce energy consumption by using energy more efficiently.
- Provide the inhabitants of homes with tools and user interfaces to increase energy efficiency, comfort and security.
- Automatically align energy consumption with energy availability.
- Provide an infrastructure that supports the integration of energy management with other home system applications.

ISO/IEC JTC 1 SC 25/WG 1[1] is the international standards body writing information technology (IT) standards for interconnecting home electrical and electronic equipment and consumer products since 1983. WG 1 standards are being deployed in products that have been certified in compliance with these standards. The JTC 1 Study Group *Green by ICT* has identified energy management topics that are being addressed by WG 1 standards and projects.

The mission of WG 1 is to develop standards for a home network that allows consumer electronic products, networks and services to interoperate or to operate, where feasible, as a single coherent system. This systems approach benefits all stakeholders including manufacturers, developers, service providers, installers, utilities and consumers.

To fulfil this mission, WG 1 is writing standards and technical reports specifying the Home Electronic System (HES) supporting applications such as entertainment, lighting, comfort control, life safety, health and energy management. HES consists of a network of networks that enables interoperation among consumer products, sensors, control devices and user interfaces in the house with the potential for access to external services.

WG 1 standards specify IT infrastructures for homes that address the following aspects of smart grids:

- Smart grid application specifications for demand response, distributed energy resources and local storage (ISO/IEC 15067-3).

[1] IEC/ISO JTC 1 – Joint Technical Committee: Information Technology;
SC 25 – Subcommittee 25: Interconnection of Information Technology Equipment;
WG 1 – Working Group 1: Home Electronic System.

This standard specifies a framework for methods that can align residential needs for electricity with available supplies. These supplies may be provided by a public utility plus local generation and storage.

- Communications for energy efficient devices (ISO/IEC 14543-3-10, ISO/IEC 29145).

  Many methods for energy management in homes require communications among sensors, appliances, user interfaces, controllers and a gateway. Wireless communications may be chosen for communications and is a preferred medium for smart grid applications by some utilities. WG 1 is writing standards for efficient wireless communications.

  ISO/IEC 14543-3-10 is a communications protocol tailored to short data packets produced by wireless devices that function with a minimal amount of energy. This includes devices that operate by harvesting energy from the environment (such as heat, motion, and light) without mains power or batteries.

  ISO/IEC 29145 specifies a method for efficient mesh networking among devices communicating using radios that conform to IEEE 802.15.4.

- Gateway to link a home network and an external network including smart grid communications (ISO/IEC 15045).

  The residential gateway is the interface between a public smart grid and a home network. This gateway may also be applied to other home services that interact with external service providers. The gateway translates between different communication protocols and has options for enhancing consumer privacy, safety and data security.

- Product interoperability to provide seamless operation of home system products including energy management complying with a diversity of communication protocols (ISO/IEC 18012).

  Customer energy management may involve devices designed for a variety of communications protocols. This standard allows these products to exchange messages and data within the house and with energy management service providers. This protocol may be implemented in an ISO/IEC 15045 gateway to interconnect networks running different protocols.

- Residential communication architecture, protocols, network configuration and network management that could carry smart grid signals (ISO/IEC 14543 series).

  This series of standards specifies a generic interface architecture for connecting devices to a home network. Specific communication protocols for command, control and discovery are included in this series.

The functions specified in these WG 1 standards are essential for smart grids to interoperate with customers and customer equipment. The participants in WG 1 are experts in home systems, consumer electronics and utility customer services. Among the WG 1 experts are members of key national and regional smart-grid programs in Asia, Europe and North America. Therefore, WG 1 is the best-positioned standards body to write standards essential for the customer aspects of smart grids.

The WG 1 perspective on smart grids is explained in the next section. This is followed by a listing of WG 1 standards published or under development that are related to smart grids.

WG 1 aspect of smart grids

This section provides background on the aspects of smart grids addressed by WG 1

Electricity power grid generation, transmission and distribution, although hailed as one of the most important achievements of the twentieth century and considered by many countries a national necessity, has not kept pace with other technological developments, nor with updated energy and environmental policies. To bring the electrical infrastructure up to date, smart grids using communications, new operating structures and business practices are being implemented world-wide.

Smart grids address environmental concerns, increase system and equipment reliability and reduce infrastructure costs by accommodating significant local distributed renewable generation (such as wind and solar). The existing grid for electric power was designed for traditional large centralised generation typically located long distances from the loads. Smart grids include the traditional grid with extensions for electric vehicles, local generation and energy storage possibly provided by in-home fuel cells, stationary batteries, or even automobile batteries.

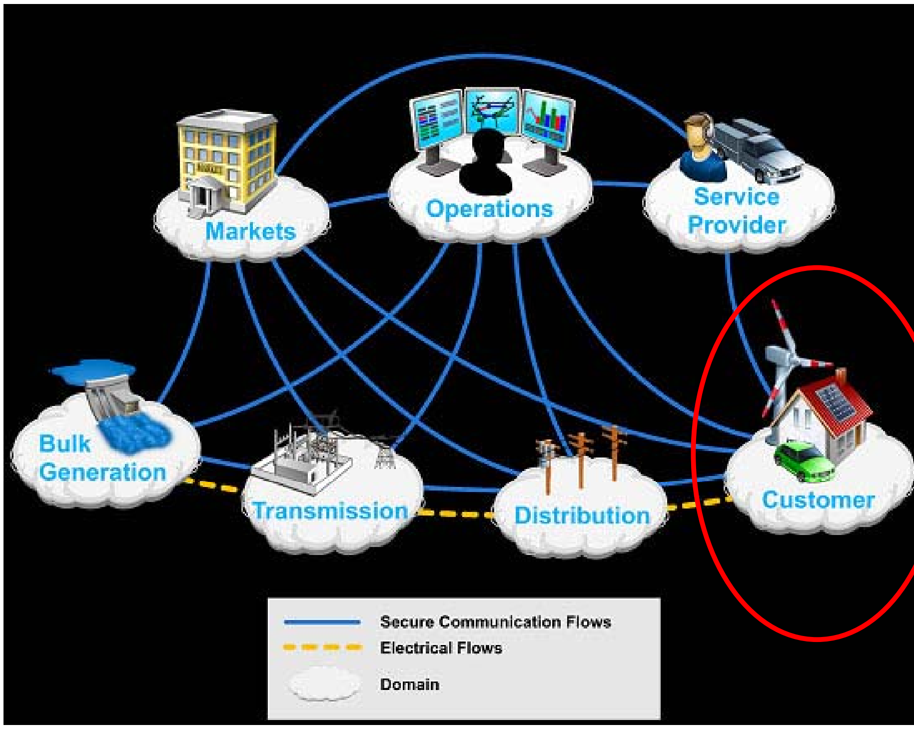


Figure 1 – The Domains of an Electric Utility Smart Grid

As shown in Figure 1, smart grids address many domains, one of which is the Customer. WG 1 is addressing this domain by focusing on the home aspect of smart grids. WG 1 is writing application standards for controlling energy consuming equipment and smart appliances in support of new technologies for energy efficiency, energy management conservation, and the widespread introduction of electric vehicles. WG 1 is introducing (in ISO/IEC 15067-3) an energy management agent that can help maximise residential efficiency through an automated analysis of energy costs, budgets, energy requirements and customer preferences such as timing, and through the integration of local generation sources.

A fundamental objective of utility operators is to balance supply and demand dynamically. An important tool to achieve this balance is distributed load control using demand response signals and pricing mechanisms such as time-varying or event-driven electric rates. Distributed load control encourages customers (with their permission) to reduce their demands at certain times. Figure 2 illustrates the smart grid aspects that are the focus on WG 1. Please note the variety of devices in the home that can be interconnected for effective energy management locally and linked to an external network for enhanced smart grid energy management.

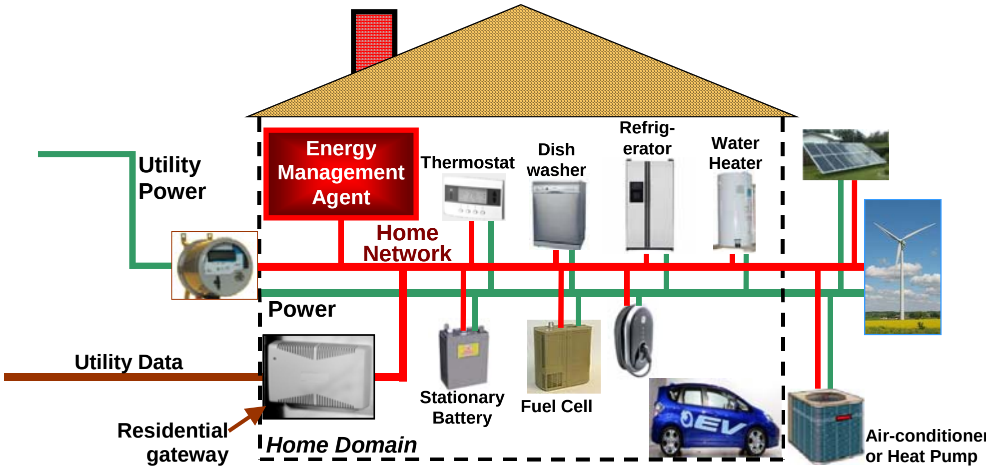


Figure 2 – WG 1 Focus – Customer Domain of Smart Grid

WG 1 standards for smart grids

Listed below are the WG 1 standards, technical reports and projects related to energy and smart grids issued or under development. Informal descriptions for some standards are contained in brackets following the standard title.

The complete list of WG 1 projects may be found on the ISO web site for SC 25 at:

http://www.iso.org/iso/iso_catalogue/catalogue_tc/catalogue_tc_browse.htm?commid=45270&development=on

WG 1 welcomes additional smart grid standards proposals especially for:

- Further integration of energy management components in the home, local power generation and storage with smart grids, load aggregators and public energy suppliers.
- Further integration between energy management devices and user interfaces such as entertainment and portable communications devices.
- Extensions of smart grid energy-management concepts to gas, water and district heating.
- Metrics and measurements to evaluate the performance of energy management systems.
- Schema for energy management product interoperability based on the ISO/IEC 18012 series.
- Privacy protection for energy management data communicated via the residential gateway architecture specified in the ISO/IEC 15045 series.

Published WG 1 standards related to smart grids

1. ISO/IEC 14543-2-1 *Information technology – Home electronic system (HES) Architecture – Architecture for home network supporting Classes 1, 2, and 3 communications – Part 2-1: Introduction and device modularity* [Overall architecture for HES communications standards.]

2. ISO/IEC 14543-3-1 *Information technology – Home electronic system (HES) Architecture – Part 3-1: Communication layers* [Part 3-1 to 3-7 specify a communications protocol for home networks]

3. ISO/IEC 14543-3-2 *Information technology – Home electronic system (HES) Architecture – Part 3-2: Communication layers*

4. ISO/IEC 14543-3-3 *Information technology – Home electronic system (HES) Architecture – Part 3-3: User process for network based control of Home electronic system (HES) Class 1*

5. ISO/IEC 14543-3-4 *Information technology – Home electronic system (HES) Architecture – Part 3-4: System management*

6. ISO/IEC 14543-3-5 *Information technology – Home electronic system (HES) Architecture – Part 3-5: Media and media dependent layers – Power line for network based control of HES Class 1*

7. ISO/IEC 14543-3-6 *Information technology – Home electronic system (HES) Architecture – Part 3-6: Media and media dependent layers*

8. ISO/IEC 14543-3-7 *Information technology – Home electronic system (HES) Architecture – Part 3-7: Media and media dependent layers – Radio frequency for network based control of HES Class 1*

9. ISO/IEC 14543-4 *Information technology – Home Electronic System (HES) architecture -- Part 4: Home and building automation in a mixed-use building* [Interface between home networks and building automation system networks that could carry energy management applications.]

10. ISO/IEC 14543-4-1 *Information technology – Home electronic system (HES) Architecture – Part 4-1: Communications layers – Application layer for the network enhanced control devices of HES Class 1* [Part 4-1 and 4-2 specify a communications protocol for command and control.]

11. ISO/IEC 14543-4-2 *Information technology – Home electronic system (HES) Architecture – Part 4-2: Communications layers – Transport, network and general parts of data link layer for network enhanced control devices of HES Class 1*

12. ISO/IEC 14543-5-1 *Information technology – Home electronic system (HES) Architecture – Part 5-1: Intelligent grouping and resource sharing for Class 2*

and Class 3 – Core protocol [Parts 5-x specify a discovery and association protocol for configuring devices on a home network.]

13. ISO/IEC 14543-5-22 *Information technology – Home electronic system (HES) Architecture – Part 5-22: Intelligent grouping and resource sharing for HES Class 2 and Class 3 – Application profile – File profile*

14. ISO/IEC 14543-5-4 *Information technology – Home electronic system (HES) Architecture – Part 5-4: Intelligent grouping and resource sharing for HES Class 2 and Class 3 – Device validation*

15. ISO/IEC 15018, *Information technology -- Generic cabling for homes* [Specifies structured cabling to carry home services among home devices and external devices via a gateway.]

16. ISO/IEC 15045-1 *Information technology – Home electronic system (HES) Residential Gateway, Part1: Introduction* [This document and ISO/IEC 15045-2, under development, specify the architecture of a residential gateway.]

17. ISO/IEC TR 15067-2 *Information technology – Home electronic systems (HES) application model – Part 2: Lighting model for HES* [Parts 2, 3 and 4 of ISO/IEC 15067 describe home system applications. Part 3 is being upgrade to a standard for energy management.]

18. ISO/IEC TR 15067-3 *Information technology – Home electronic system (HES) application model – Part3: Model of an energy management for HES*

19. ISO/IEC TR 15067-4 *Information technology – Home electronic system (HES) application model – Part 4: Security system for HES*

20. ISO/IEC 18012-1 *Information technology – Home electronic system (HES) – Guidelines for product interoperability – Part 1: Introduction* [This document and ISO/IEC 18012-2, under development, specify how products designed for different home networking protocols can be made to interoperate.]

WG 1 standards under development related to smart grids:

21. ISO/IEC 14543-3-10 *Information technology – Home electronic system (HES) architecture – Part 3-10: Wireless Short-Packet (WSP) protocol optimised for energy harvesting – architecture and lower layer protocols* [This communications protocol supports short data packets typically produced by energy harvesting devices that operate without a battery.]

22. ISO/IEC 14543-5-21 *Information technology – Home electronic system (HES) architecture – Part 5-21: Intelligent grouping and resource sharing for HES Class 2 and Class 3 – Application profile – AV profile*

23. ISO/IEC 14543-5-3 *Information technology – Home electronic system (HES) architecture – Part 5-3: Intelligent grouping and resource sharing for HES Class 2 and Class 3 – Basic application*

24. ISO/IEC 14543-5-5 *Information technology – Home electronic system (HES) architecture – Part 5-5: Intelligent grouping and resource sharing for HES Class 2 and Class 3 – Device type*

25. ISO/IEC 14543-5-6 *Information technology – Home electronic system (HES) architecture – Part 5-6: Intelligent grouping and resource sharing for HES Class 2 and Class 3 – Service type*

26. ISO/IEC 15045-2 *Information technology – Home electronic system (HES) gateway – Part 2: Modularity and protocol*

27. ISO/IEC 15067-3 *Information technology – Home electronic system (HES) – Model of demand response energy management for HES*

28. ISO/IEC 18012-2 *Information technology – Home electronic system (HES) – Guidelines for product interoperability – Part 2: Taxonomy and application interoperability model*

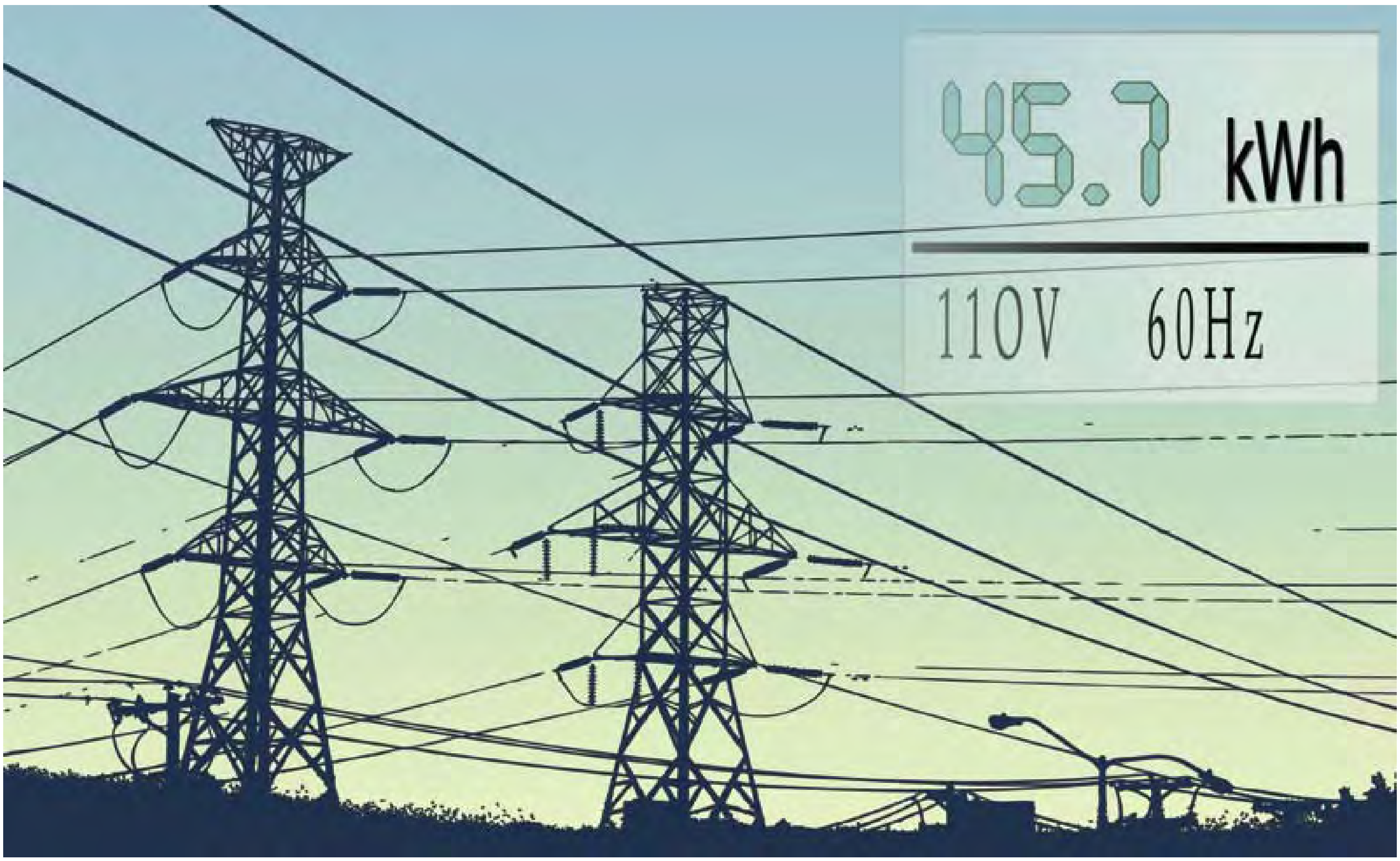
29. ISO/IEC 29145-1 *Information technology – Home electronic system (HES) – WiBEEM Standard for Wireless Home Network Services – Part 1: Physical Layer Specifications* [This series specifies is a version of a low powered radio that uses energy for a mesh network efficiently.]

30. ISO/IEC 29145-2 *Information technology – Home electronic system (HES) – WiBEEM Standard for Wireless Home Network Services – Part 2: MAC Layer Specifications*

31. ISO/IEC 29145-3 *Information technology – Home electronic system (HES) – WiBEEM Standard for Wireless Home Network Services – Part 3: Network Layer Specifications*

Privacy by Design:

Achieving the Gold Standard in Data Protection for the Smart Grid



June 2010

www.privacybydesign.ca

Information & Privacy Commissioner of Ontario

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Foreword

There are two schools of thought among electrical utilities regarding the Smart Grid. The first is that the Smart Grid is simply an extension of current functions and that taking a business-as-usual approach is sufficient. The second is that the Smart Grid presents new opportunities for growth and change, as well as new challenges for collecting more granular data than ever before on customers' energy consumption. Utilities that ascribe to the second group recognize that the Smart Grid will be transformative in nature and can take steps to address any new issues that may arise. I call this taking a "positive-sum" approach wherein the interests of both electrical reform *and* privacy may be achieved.

As Information and Privacy Commissioner of Ontario, I am joined by Ontario's largest electricity companies — Hydro One Inc. ("Hydro One") and Toronto Hydro — to showcase the strong privacy protections embedded in the province of Ontario's emerging Smart Grid system. Hydro One and Toronto Hydro provide electricity to over two million households in a province with comprehensive privacy laws, and are therefore uniquely positioned to understand how to implement large scale systems while respecting privacy. I would like to thank Laura Formusa, Hydro One Networks Inc., and Anthony Haines, Toronto Hydro Electric System, for their leadership.

With virtually every home and business in Canada's most populous province now having a smart meter, we can say that Ontario is a strong leader in laying the Smart Grid infrastructure that is essential to the future of electricity provision and the conservation of electricity. We are also a leader in the area of privacy and Smart Grid policy. The Office of the Information and Privacy Commissioner of Ontario is foremost in promoting the concepts of *Privacy by Design* and Positive-Sum applications of privacy around the world.

We hope this best practice document will assist utilities, including those in the United States and around the world, to understand how Fair Information Practices (FIPs) and *Privacy by Design* can be incorporated into the design and architecture of Smart Grid systems. Utilities will benefit enormously from striving to achieve the Gold Standard in Data Protection for the Smart Grid — *Privacy by Design*.

Ann Cavoukian, Ph.D.

Information and Privacy Commissioner
Ontario, Canada

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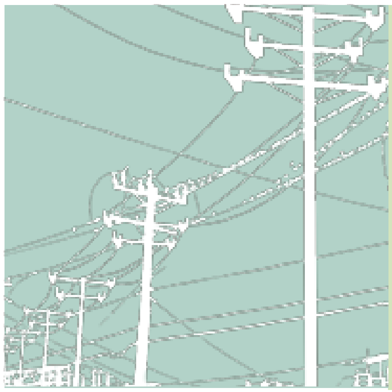


Executive Summary

Privacy by Design (the Gold Standard for data protection), is *the* standard to be adopted for Smart Grid implementation for data protection. Embracing a positive-sum model whereby privacy and energy conservation may be achieved in unison is key to ensuring consumer confidence in electricity providers, as Smart Grid projects are initiated. Customer adoption and trust of Smart Grid energy savings programs is an integral factor in the success of energy conservation.

The Smart Grid in Ontario

The Smart Grid in Ontario is developing through the widespread installation of smart meters, time-of-use, demand management initiatives, and the creation of a Smart Metering Entity resulting from legislative action by the Government of Ontario in the *Green Energy Act, 2009* and the *Electricity Act, 1998*. The province's goal is to meet electricity demand over the next 20 years, while also achieving energy conservation and use of renewable energy resources (for example, to discontinue the use of coal plants by 2014). Functional specifications were issued by the Government that all electricity providers must meet in achieving smart meter policy goals to support the Smart Grid, and the Smart Metering Entity is responsible for the consolidation, management and storage of consumer electricity consumption information.

Hydro One and Toronto Hydro are involved with several Smart Grid activities. Hydro One's focus is on integrating renewable energy generation, customer demand management, and system automation. As well, Hydro One will conduct pilots to investigate, understand and prepare for new innovative technologies to enable the Smart Grid. For example, a Smart Grid zone ("Smart Zone") will be created in a geographic subset of its system. Toronto Hydro's Smart Grid roadmap includes several initiatives focused on climate protection, energy security and customer satisfaction. Toronto Hydro's activities will be in the area of conservation and demand management, distribution grid automation and home energy management systems.

Personal information and the Smart Grid

What constitutes "personal information" on the Smart Grid is the subject of much discussion. Personal information is defined by the *Freedom of Information and Protection of Privacy Act* (*FIPPA*) and the *Municipal Freedom of Information and Protection of Privacy Act* (*MFIPPA*), as "recorded information about an identifiable individual." Once it becomes apparent that a Smart Grid technology, system or project will involve the collection of personal information, privacy considerations begin to apply, such as limiting the amount of personal information collected, used or disclosed, and the safeguarding of that information. The digitization of smart meter information has an impact on privacy experienced in other areas where traditional paper records are being transferred into digital form. Digital smart meter data, like all digital data, is vulnerable to accessing, copying, matching, merging and massive dissemination.

The changing nature and vast increase of information gathered on the Smart Grid is also resulting in changes in the nature of utilities as power providers. Lack of integration between various systems in the area of communications, operations and information systems, is a significant gap within which challenges may arise for utilities. Utilities should be aware of the gaps and opportunities to work *Privacy by Design* into these systems, such as the introduction of smart transformers and power line monitors, and the centralization and integration of data and processes.

Best practices for Smart Grid Privacy by Design

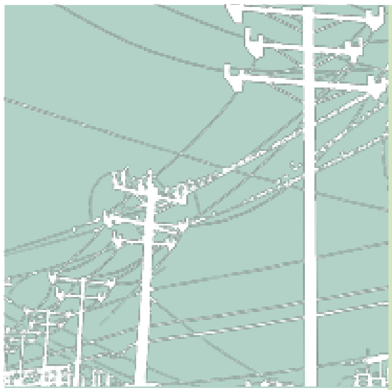
Privacy by Design extends to a "Trilogy" of encompassing applications: 1) IT systems; 2) accountable business practices; and 3) physical design and networked infrastructure. *Privacy by Design* may be accomplished by practicing the originating 7 Foundational Principles,[1] which have been specifically adapted to the Smart Grid context, to create Best Practices for Smart Grid *Privacy by Design*:

1. Smart Grid systems should feature privacy principles in their overall project governance framework and proactively embed privacy requirements into their designs, in order to prevent privacy-invasive events from occurring;
2. Smart Grid systems must ensure that privacy is the default — the "no action required" mode of protecting one's privacy — its presence is ensured;
3. Smart Grid systems must make privacy a core functionality in the design and architecture of Smart Grid systems and practices — an essential design feature;
4. Smart Grid systems must avoid any unnecessary trade-offs between privacy and legitimate objectives of Smart Grid projects;
5. Smart Grid systems must build in privacy end-to-end, throughout the entire life cycle of any personal information collected;
6. Smart Grid systems must be visible and transparent to consumers — engaging in accountable business practices — to ensure that new Smart Grid systems operate according to stated objectives;
7. Smart Grid systems must be designed with respect for consumer privacy, as a core foundational requirement.

Smart Grid Privacy by Design Use Case Scenarios

Each Best Practice can be applied by utilities in the planning of their Smart Grid activities. This is illustrated through two use case scenarios describing the implementation of *Privacy by Design* into Smart Grid projects in the areas of 1) customer information access and 2) customer enablement. The customer information access use case scenario shows how all customers must be authenticated, and how multiple consecutive access failure attempts will disable the account. In the first scenario, protecting access to customer information will foster trusting relationships — allowing the customer to trust the utility, and therefore increasing the likelihood of his/her participation to realize the benefits of the Smart Grid. The customer enablement use case scenario examines how privacy concepts may be built into the core design, directly involving customers in the dynamic management of the electrical grid.

1 *The 7 Foundational Principles of Privacy by Design* may be found in Appendix A.



Introduction

At the end of the day, it's all about standards. If we get that right at the onset, we create an ecosystem for the development of technologies that will thrive in the present and future.

Chuck Adams, President of IEEE[2]

While the Smart Grid has the potential to deliver substantial value, it represents a significant endeavour that will require privacy risk mitigation measures to be taken. Many technologies and standards are still in their early stages of development, and not all will move into commercialization or reach a suitable practice point for mass deployment. The costs and time required, as well as the benefits attained, will depend on the scope and pace of implementation, technology trends, and consumer acceptance and adoption. Utilities have an interest in ensuring that consumer adoption of Smart Grid energy saving programs is not impeded by fears relating to privacy. Electricity providers must embrace a new positive-sum business model — one that is protective of privacy — or risk losing consumer confidence and the public's trust.[3]

In November 2009 the Information and Privacy Commissioner of Ontario (IPC) released a white paper with the Future of Privacy Forum entitled, *SmartPrivacy for the Smart Grid: Embedding Privacy into the Design of Electricity Conservation,* to call attention to the privacy concerns related to the Smart Grid, and argue that energy conservation can be achieved without sacrificing the privacy of energy consumers. We call this a "positive-sum" doubly-enabling model, not the dated win-lose model involved in traditional zero-sum paradigms.[4] The paper explored how the nature of utilities as power providers will shift due to the large amounts of personal information they will be collecting from consumers as a result of advancements in the Smart Grid, such as the installation of smart meters and the use of smart appliances by households. The concepts discussed in that paper, featuring *Privacy by Design*, are gaining widespread momentum. Ontario's use of *Privacy by Design* has been adopted in various arenas including submissions to the U.S. National Institute of Standards and Technology and the U.S. Federal Communications Commission.[5] *Privacy by Design*

2 Chuck Adams, "Smart grid standards: Why are they needed and how will they work?" *Connected Planet*, 7 April 2010

3 A survey conducted in 22 countries revealed that 32 per cent of consumers do not trust energy companies, and 46 per cent trust energy companies, however only if they have direction from government. *Accenture New Energy World Survey*, 9 March 2010: http://newsroom.accenture.com

4 See A. Cavoukian, *Transformative Technologies Deliver Both Security and Privacy: Think Positive-Sum not Zero-Sum*, online at: www.ipc.on.ca

5 E.g. Comments Of The Center For Democracy & Technology Before the Department of Commerce, National Institute of Standards and Technology on Draft NIST Interagency Report (NISTIR) 7628, Smart Grid Cyber Security Strategy And Requirements, December 1, 2009, available online: http://www.cdt.org/files/pdfs/CDT%20Comment%20NISTIR%207628%20Draft%2012-02-09%20FINAL%20-%20updated.pdf; Comments Of The Center For Democracy & Technology Before the Federal Communications Commission In the Matter of Smart Grid Technology, October 2, 2009, available online: http://www.cdt.org/privacy/20091002_fcc_smart_grid.pdf .

encompasses and compliments parallel concepts in the area of safety,[6] with which utility personnel may be more familiar.

Privacy standards are needed against which utility stakeholders can map their Smart Grid developments and implementation.[7] For example, observers have commented that "making sense of all the data is a big challenge for utilities" in the United States.[8] Even in jurisdictions, such as the United States, that do not have overarching privacy laws as in Ontario, the need to protect the privacy of energy consumption data is being increasingly recognized, especially as it relates to the Smart Grid.[9]

The purpose of this paper is to put forward *Privacy by Design* (the Gold Standard for data protection) as *the* standard to be adopted for Smart Grid implementation, in order to protect data privacy. We will also showcase how Smart Grid programs in Ontario are being built with *Privacy by Design* as a central guiding design feature.[10] To discover how Ontario achieves the Gold Standard for the Smart Grid, *please read on…*

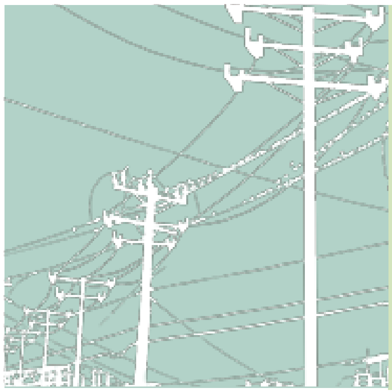
6 E.g. "Safety by Design" which requires considering health and safety issues at early design stages.

7 The U.S. GridWise Alliance, of which the Commissioner is a member, also recognizes this important need. "The Alliance believes that standards will be of critical importance as smart grid technologies are deployed at scale." Reported in: "GridWise Alliance Members Elected to US Smart Grid Panel" *SustainableBusiness.com News*, 23 November 2009, available online: http://www.sustainablebusiness.com/index.cfm/go/news.printerfriendly/id/19288.

8 M. LaMonica, "Peering beyond the meter in the smart grid," *CNET*, 11 February 2010, available online: http://news.cnet.com/8301-11128_3-10451082-54.html.

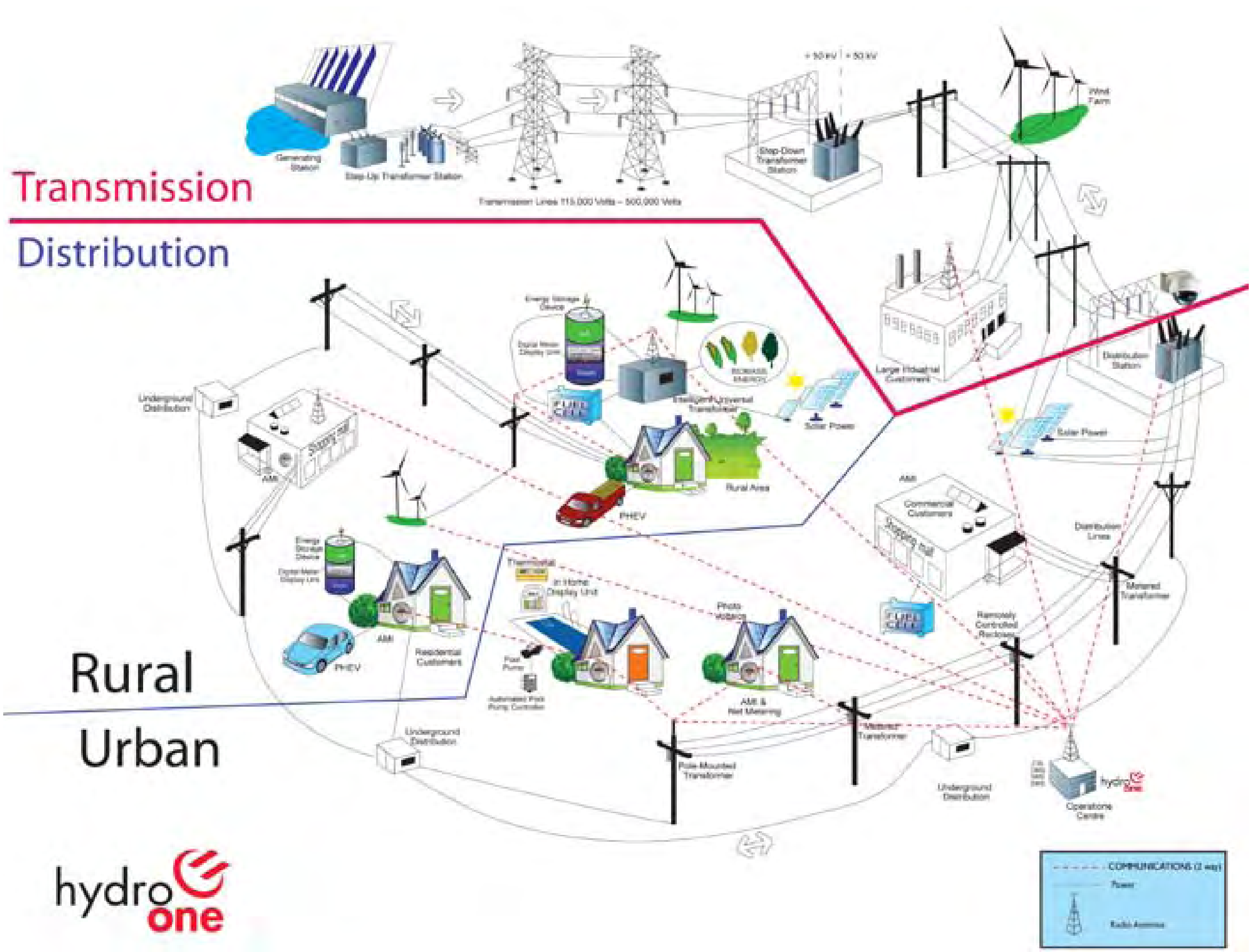
9 California SB 837.

10 For example, electricity distributors in Ontario are permitted to recover the cost of smart meter functionality from consumers so long as it does not exceed the *minimum* functionality required, unless those costs are approved by the Ontario Energy Board (OEB). However, we note that in making their decision, the OEB must take into account the benefits of additional functionality to the distributor's consumers (e.g. increased privacy). See *Ontario Energy Board Act, 1998*, Ontario Regulation 426/06 Smart Meters: Cost Recovery, s. 1 (2)-(3).



The Smart Grid in Ontario

Smart metering provides the anchor tenant for improved communications across the distribution system; communications provides for the convergence of information technologies with the delivery of power. It is the many opportunities this convergence provides that is labelled the "Smart Grid":

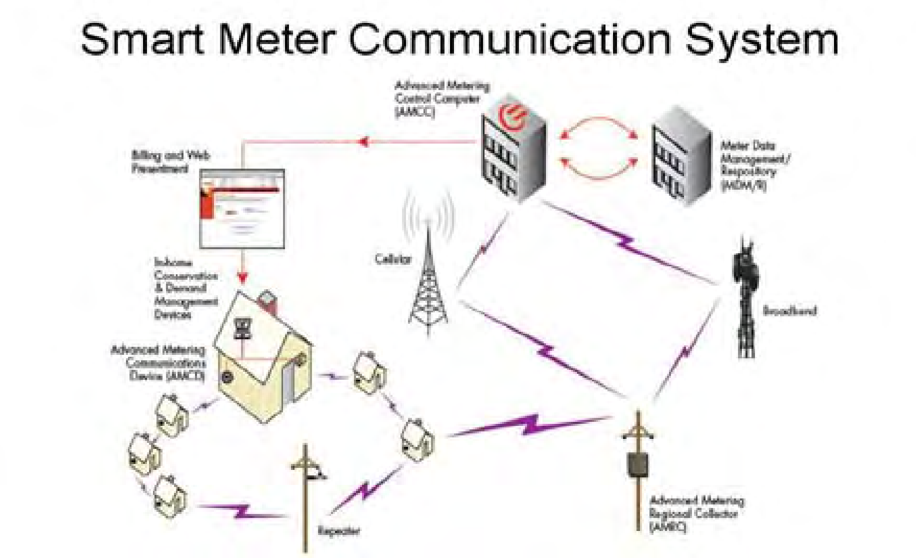


Source: Hydro One Networks Inc.

Ontario law defines the Smart Grid as:[11]

> …the advanced information exchange systems and equipment that when utilized together improve the flexibility, security, reliability, efficiency and safety of the integrated power system and distribution systems, particularly for the purposes of,
>
> (a) enabling the increased use of renewable energy sources and technology, including generation facilities connected to the distribution system;
>
> (b) expanding opportunities to provide demand response, price information and load control to electricity customers;
>
> (c) accommodating the use of emerging, innovative and energy-saving technologies and system control applications; or
>
> (d) supporting other objectives that may be prescribed by regulation.

While exactly what will comprise the Smart Grid in the future is unknown, major components of the future grid in Ontario will include advanced metering infrastructure, time-of-use pricing, demand management, and the creation of a Smart Metering Entity. Ontario's time-of-use pricing goal is to have 1 million customers on time-of-use by the summer of 2010, and by June 2011, to have 3.6 million customers on time-of-use. In order to implement time-of-use prices, electricity distribution companies must achieve four things: install smart meters, enrol those smart meters with the Meter Data Management Repository ("repository") maintained by the Independent Electricity System Operator (IESO), incorporate time-of-use prices within their services, and file their program with the Ontario Energy Board (OEB). At the end of 2009, the number of meters enrolled was 26 per cent of the government's 2010 target.[12] The Ontario government has established a plan that draws on customer demand management and renewable generation to help meet projected electricity demand over the next 20 years. This is projected to enable the shut down of coal plants in Ontario by 2014.[13]



Example of an Advanced Metering Infrastructure (AMI)
Source: Hydro One's Smart Meter (AMI) Solution: Over 1 Million Meters Deployed

11 *Electricity Act, 1998*, S.O. 1998, c. 15, Sched. A, s. 1.3

12 OEB Monitoring Report: Smart Meter Deployment and TOU Pricing – 2009 Fourth Quarter, February 25, 2010, available online: http://www.oeb.gov.on.ca/OEB/_Documents/SMdeployment/SM_Monitoring_Report_20100225.pdf.

13 C Puxley, "Ontario Promises to Close Coal Plants By 2014, Reduce Greenhouse Gas Emissions," redOrbit, 18 June 2007, available online: http://www.redorbit.com/news/business/972199/ontario_promises_to_close_coal_plants_by_2014_reduce_greenhouse/index.html.

Electricity distributors in Ontario are required to adhere to functional specification criteria when installing smart meters, metering equipment, systems and technology.[14] The specifications require a minimum functionality of hourly meter reads, and the ability to transmit this information without field visits. Smart meters contain an advanced metering communication device, and each has a visible display that includes its identification number and meter serial number. Transmission of meter reads may be as frequent as necessary to meet requirements, and must be done using an approved protocol and file structure. Distributors with advanced metering control computers may store up to 60 days worth of meter reads, and must not aggregate meter reads into rate periods or calculate consumption data prior to sending the information to the IESO's repository. The smart meter system must also report on confirming data linkages between the advanced meter communication device, the meter serial number and the customer's account. The smart meter system, including some parts the repository must also log successful transfer of meter reads as well as log unsuccessful attempts, including the cause and status of such attempts. In addition, the system must confirm the accuracy of meter readings and report suspected cases of meter theft, tampering or interference.

An Advanced Metering Infrastructure (AMI) is required to have "security features to prevent unauthorized access to the AMI and meter data and to ensure authentication to all AMI elements."[15] The IESO uses a unique ID for each electricity point of delivery (physical or virtual), including individual residences or multiple meters. The repository maintains internal links that relate each point to metered quantities. The master directory links all points, meters, and utilities. Meter reads are stored in the repository including interval consumption data and billing quantity data. It can support meter reads from 5 to 60 minute intervals. Meter data is aggregated for reporting and analysis. The repository can flag data as outdated and schedule it for re-aggregation when it is required. The repository supports overrides to allow for the utility to update inaccurate information.

The province's specifications also require that an AMI meet all applicable federal, provincial and municipal laws, codes, rules, directions, guidelines, regulations and statutes, including requirements of regulatory authorities and agencies such as the Canadian Standards Association and Measurement Canada.

The Smart Metering Entity was created by legislation to accomplish the government's smart metering initiative.[16] The entity has responsibility for the collection, management and storage of information related to the metering of consumers' consumption or use of electricity in Ontario, including data collected from distributors. In order to do this, the entity can operate one or more databases to facilitate collecting, managing, storing and retrieving smart metering data. The entity is required to provide and promote non-discriminatory access, on appropriate terms and subject to any conditions in its licence relating to the protection of privacy, by distributors, retailers, the Ontario Power Authority (OPA) and other persons. The Smart Metering Entity may also manage and aggregate the data related to consumers' electricity consumption or use. Distributors, retailers and other persons must provide the entity with the information it requires in fulfilling its objects or conducting its business activities. The IESO is designated as the Smart Metering Entity under Ontario Regulation 393/07 of the *Electricity Act, 1998*.

For an overview of electricity in Ontario, see Appendix B.

14 Functional specifications released on July 5, 2007 for advanced metering infrastructure in Ontario. See also *Electricity Act, 1998* s. 53.16. These functional specifications for advanced metering infrastructure in Ontario are the prescribed criteria for residential and small general service consumers and apply to meters, metering equipment, systems and technology, and any associated equipment, systems and technologies. They are prescribed in Ontario Regulation 425/06 under the *Electricity Act, 1998*.

15 *Ibid.*

16 Part IV.2 of the *Electricity Act, 1998*.

Hydro One key Smart Grid activities

Hydro One followed a three step process to develop its Smart Grid plan. The first step was to focus on integrating renewable energy generation, customer demand management, and system automation by leveraging the new communication infrastructure put into place for smart meters. Secondly, the Company formulated plans to utilize pilots and targeted development work to investigate, understand and prepare for new innovative technologies to enable the Smart Grid. In accordance with OEB guidelines and direction from Provincial Governments, Hydro One plans to fund targeted studies in the area of green energy technologies such as automated home energy networks and energy storage. The final step is the implementation of pilot projects to confirm viability of new technologies and products before widespread deployment. Hydro One takes an active role in forums to develop concepts and standards relating to the Smart Grid and regularly commissions universities and other consultants to examine, test and report on specific aspects of Smart Grid initiatives and technologies.

In order to undergo pilot testing, Hydro One is creating a geographic subset of its system as a Smart Grid demonstration area. Located in the Owen Sound area, the pilot will incubate Smart Grid applications, flesh out requirements for solution sets, while assessing opportunities for system-wide rollout, and establish design parameters and standards prior to full roll-out. Actual devices will be installed, various solutions built or upgraded as required, and business processes developed and tested. In addition, education and training may be required for local field resources needed to support the demonstration projects.

Hydro One's role in consumer demand management is to provide consumers with information and tools that allow them greater understanding and control over their electricity consumption, and help them reduce and shape that consumption. To this end, Hydro One has undertaken a number of initiatives to enable customers to respond in the manner they choose, including directly managing their own behaviour, offering incentive programs to dispose of energy inefficient appliances, purchase energy efficient equipment/technology, and to allow direct utility intervention and automation of their demand response.[17]

Time of Use Rate Examples - Commodity Cost Per Year

	Estimated Annual Commodity Cost		
	Off-peak (5.3¢/kWh)	Mid peak (8.0¢/kWh)	On-peak (9.9¢/kWh)
Clother dryer (1 load)	$24.96	$37.44	$45.76
Clothes washer (1 load/ hot wash) *	$63.96	$98.28	$120.12
Clother washer (1 load/cold wash)	$9.36	$14.04	$17.16
Vacuum cleaner (1/2 hour)	$11.44	$16.64	$20.80
Dishwasher (1 load) *	$49.40	$72.80	$93.60
AC Central 25 degrees (weekday)	$105.60		
AC Central 25 degrees (weekend)	$76.20		
AC Central 20 degrees (weekday)	$47.52		
AC Central 20 degrees (weekend)	$34.08		

* Cost of electric water heating included.

Source: Hydro One Networks Inc.[18]

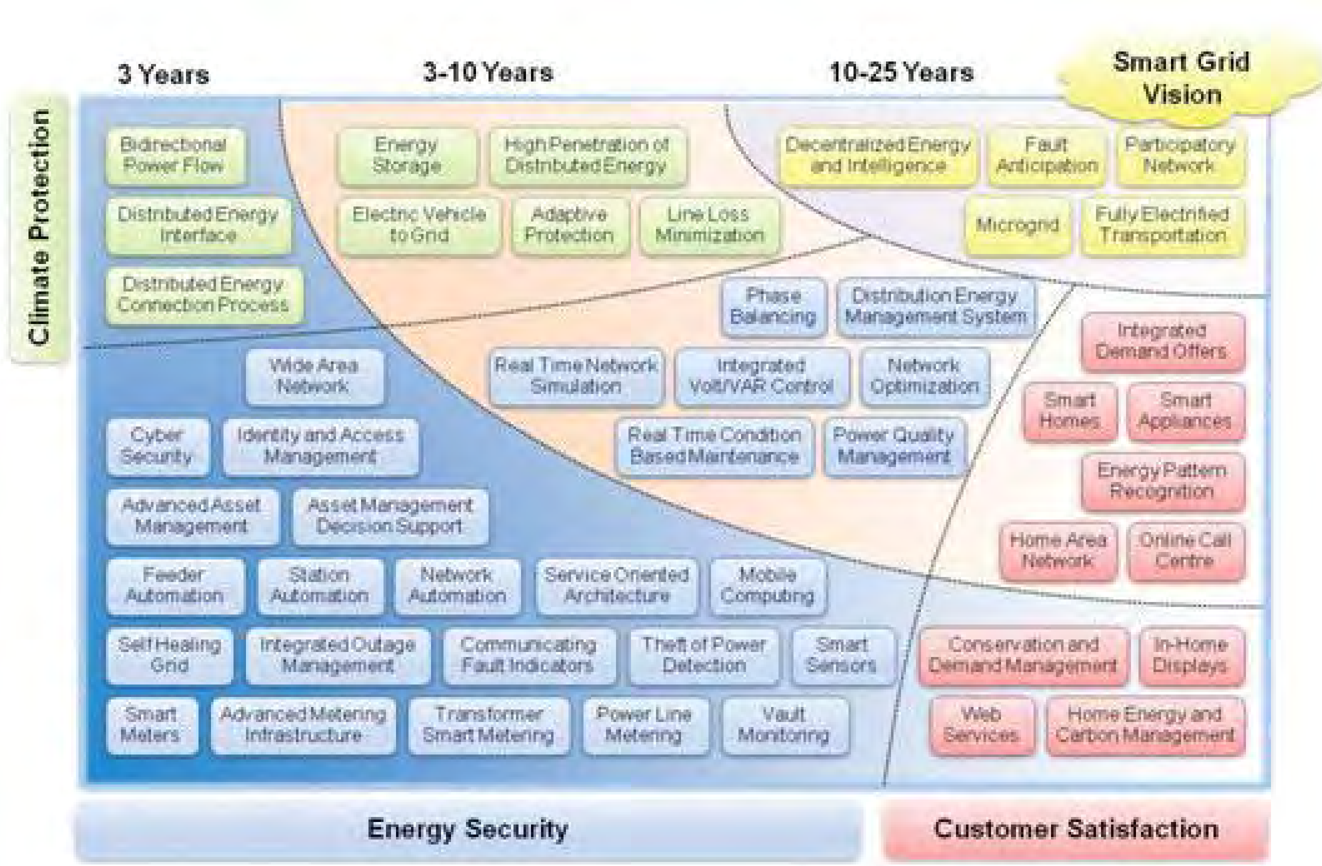
17 Hydro One currently offers four core OPA customer demand management programs to its customers, with contracts in place to continue doing so through 2010. These include: Great Refrigerator Roundup, Electricity Retrofit Incentive Program, PeakSaver®, and Power Saving Blitz. In addition, Hydro One is delivering one rate-funded program, PowerSaver® Plus online audit for its customers. Hydro One has also recently concluded a very successful demand response custom program approved by the OPA, Double Return and has undertaken a number of pilot programs, such as a zero interest loan and rebate pilot program for renewable energy technologies for the Ministry of Energy and Infrastructure.

18 Note, prices reflect commodity portion and not the utility's delivery charge which is the same at all times.

Hydro One will identify elements to be included in Hydro One's implementation of the Smart Grid through: acquisition of "smart devices" to showcase proposed technologies; acquisition of system integration technologies (both real-time and enterprise applications) that monitor, control and remediate faults, outage management/restoration systems, Geographic Information System ("GIS") technology, Energy Storage devices such as battery/compressed air energy storage ("CAES") as well as stationary power systems such as hydrogen fuel cells that can be used to power station services; deployment for proving both technology and inter-operability, as well as business benefits which will drive further adoption in other areas of Hydro One's networks.

Toronto Hydro key Smart Grid activities

Toronto Hydro has been proactively defining and planning for the Smart Grid since 2006 (see Smart Grid Roadmap below).



Source: Toronto Hydro Smart Grid Roadmap[19]

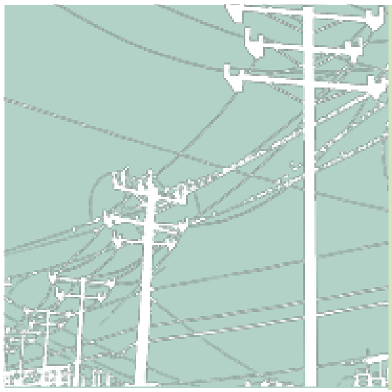
Toronto Hydro participates in the Ontario Smart Grid Forum, and the Advanced Feed-in Tariff which is a comprehensive program expected to substantially increase the deployment of renewable energies in Ontario. As well, it participates in the City of Toronto's "Change is in the Air: Clean Air, Climate Change, and Sustainable Energy Action Plan" — a municipal government policy that

19 See Toronto Hydro 2010 Electricity Distribution Rate Application: Exhibit G1 — Smart Grid, available online: http://www.torontohydro.com/sites/electricsystem/Pages/2010-rate-application.aspx.

includes becoming the renewable energy capital of Canada. The Smart Grid in Ontario will be built on elements that have been, are in the process of being, or will be, established.[20] These building blocks have enabled a wide array of functionalities to provide for the safe, reliable and efficient delivery of power. However, to achieve a Smart Grid, so as to enable advanced conservation schemes, accommodate a large penetration of distributed generation, and further improve on grid safety, reliability, and efficiency, new measures must be in place to expand the functionalities of these building blocks, construct integration paths, and develop new building blocks. Even while leveraging these foundational building blocks, much work will be required to achieve the Smart Grid. Toronto Hydro's Smart Grid Roadmap shows the timeline for implementation of climate protection, energy security and customer satisfaction goals.

Toronto Hydro Smart Grid projects touch on the following areas: customer display integration, web energy portal, OMS integration — customer portal, smart meter connect / disconnect, smart meter — outage identification, network meters integration, network monitoring integration, integration architecture and design, access network, internal network readiness, and smart grid network security.

20 Examples include: Advanced Metering Infrastructure ("AMI"), Distribution Automation, Distributed Generation, Asset Management, Enterprise Applications, Business Intelligence/Service Oriented Architecture, Communications, Conservation and Demand Management, Customer Enablement.



Personal Information on the Smart Grid

In Ontario, "personal information" is defined in the *Freedom of Information and Protection of Privacy Act* (*FIPPA*) and the *Municipal Freedom of Information and Protection of Privacy Act* (*MFIPPA*) as "recorded information about an identifiable individual."[21] *FIPPA* and *MFIPPA* provide a range of non-exhaustive examples of what personal information can include. For example, "personal information" includes the address and telephone number of an identifiable individual and the individual's name where it appears with other personal information relating to the individual or where the disclosure of the name would reveal other personal information about the individual.[22] Also, personal information can include any identifying number, symbol or other particular assigned to the individual.[23]

For information to be identifiable, there must be a "reasonable expectation" that an individual can be identified from the information.[24] In determining whether such reasonable expectation is met, the circumstances of a case and the issues arising in it on a balance of probabilities must be examined.[25] The ability to link data with personal information is also a key consideration in determining the scope of personal information and has been the subject of past IPC decisions.[26] In the context of the Smart Grid, the linkage of any personally identifiable information with energy use would render the linked data as personal information. While the precise scope of personal information on the future Smart Grid is not known, utilities should be cautious in employing a definition of personal information that is overly narrow in data linkage scenarios involving information indicating personal behaviour, as well as unique smart meter or appliance data (e.g. serial numbers).

The collection, use and disclosure of aggregated or de-identified personal information raise little, if any, privacy issues. It is outside the scope of this paper to provide guidance on de-identification practices for Smart Grid energy consumption data, however there is sufficient basis in, for example, the health sector's experience to suggest that utilities should be cautious when anonymizing personal information and in concluding that that information is in fact anonymized.[27] For example, it is possible in some cases that removing identifiers such as name and address do not guarantee that personal information is de-identified.[28]

21 *FIPPA* & *MFIPPA* s. 2(1)

22 *FIPPA* & *MFIPPA* s. 2(1)(d)&(h)

23 *FIPPA* & *MFIPPA* s. 2(1)(c). In the past, the IPC has found that personal information can also include personal behaviour even if it is not linked with the individual's name (MO-2188). See also billing for power consumption as personal information (PO-1723).

24 *Ontario (Attorney General) v. Pascoe*, [2002] O.J. No. 4300 at 2.

25 *Supra*, at 6.

26 See for example linkage of personal information discussed in P-488, P-1076, MO-2134, and PO-2265.

27 See for example A. Cavoukian and K. E. Emam, *A Positive-Sum Paradigm in Action in the Health Sector*, available online: http://www.ipc.on.ca/images/Resources/positive-sum-khalid.pdf. See also L. Sweeney, "k-Anonymity: A Model for Protecting Privacy", *International Journal on Uncertainty, Fuzziness and Knowledge-Based Systems* Vol. 10(5), 2002, pp. 557-570.

28 See for example IPC Orders P-722 and MO-2291.

Efforts to expand the definition of personal information beyond information linked to an identifiable individual are presently underway in California. A law, technology and public policy clinic at the University of California at Berkeley has developed the concept of "household energy data."[29]

While there is much discussion regarding what would constitute personal information on the Smart Grid, a determination that a particular set of data is personal information does not prevent the collection, use and disclosure of information that is necessary for the administration of Smart Grid programs. Rather, it serves to indicate that certain considerations in relation to that data must be taken into account. For example, considering the purpose for which the information was collected (called "primary purpose") is essential in determining appropriate disclosures of personal information. For example, the IESO's repository limits use and disclosure in the following manner:[30]

- Customers may only view data relating to their own consumption;
- Utilities may only see data relating to their own customers;
- Retailers may only see data relating to their own customers;
- Billing Agents may only have access to view billing quantities;
- Utilities may have the ability to edit Meter Reads for only their customers;
- Some users may not have the ability to view data;
- Only appropriately authorized users may have the ability to modify data.

The OEB's *Affiliate Relationships Code for Electricity Distributors and Transmitters* prohibits the release of consumer information (which could include personal information) to a utility's affiliate without the written consent of the consumer. An affiliate can be, for example, a subsidiary corporation under the utility or the utility's parent corporation. If there is more than one subsidiary corporation, than those corporations are also each other's affiliates.[31] The Code states that consent for disclosure must be obtained from the consumer, except to the extent that the disclosure is permitted by the utility's licence. Also, the code states consent is not required where the personal information is required to be disclosed for, e.g., billing purposes, law enforcement purposes, to comply with a legislative or regulatory requirement, or to process past due accounts that have been passed to a debt collection agency. Consumer information (which could include personal information) that has been sufficiently aggregated so that information relating to any individual consumer cannot reasonably be identified may also be disclosed to an affiliate.[32] The distribution licences for utilities contain similar provisions regarding disclosure of consumer information to any other party which would include a utility's affiliate or any other person or entity.

Disclosures of consumer information which comes within the definition of "personal information" as noted above must also meet the requirements of *FIPPA*, *MFIPPA* (where applicable) and any other applicable privacy legislation.

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29 This concept could include "data collected about an individual household in the Smart Grid that is revealing of home life by itself or when analysed or combined with other information." Examples provided are: "near real-time energy usage data, records of plug-in hybrid electric vehicle (PHEV) use, and specific metering data (e.g. thermostat temperature)." Comments Of The Center For Democracy & Technology Before the Department of Commerce, National Institute of Standards and Technology on Draft NIST Interagency Report (NISTIR) 7628, Smart Grid Cyber Security Strategy And Requirements, December 1, 2009, available online: http://www.cdt.org/files/pdfs/CDT%20Comment%20NISTIR%207628%20Draft%2012-02-09%20FINAL%20-%20updated.pdf.

The concept of household data also appeared in California bill SB 837 and stated: "The term "personal information" means any information that is maintained by an agency that identifies or describes an individual, family, household, or residence including, but not limited to, his or her name, social security number, physical description, home address, home telephone number, education, financial matters, utility usage, and medical or employment history." [emphasis added]

30 IESO, Meter Data Management and Repository (MDM/R) Functional Specification, Issue 2.0, pp. 27, available online: http://www.smi-ieso.ca/MDMR_Specification/MDMR_Functional_Specification_v2.0.pdf.

31 *Affiliate Relationships Code for Electricity Distributors and Transmitters* at 1.2, definition of affiliate. See also *Business Corporations Act*, R.S.O. 1990, c. B.16, s. 1(4).

32 Note, the Code refers to consumer information which could be information about an identifiable individual *or entity* whereas *FIPPA* and *MFIPPA* refer to personal information about an identifiable individual only. The Information and Privacy Commissioner's Office has also considered the issue of disclosure of personal information in the context of an affiliate-type relationship. See MC-040015-1.

Digitization of smart meter information

The modern concept of privacy emerged in reaction to information and communications technologies in the late 1800s that suddenly made it possible to effectively capture, store and disseminate information on a mass scale never before contemplated, such as the photograph, telegraph and mass printing methods.[33] The appearance of mainframe computers, centralized electronic databases and computerized records in the 1960s and 1970s triggered the next wave of privacy protections. In response to the misuse of large-scale computerized databases by private organizations in the financial, credit and medical sectors, fundamental "privacy" principles came into widespread currency.[34]

The Smart Grid's impact is being compared to the advent of the Internet, which was built without privacy in mind, and which now faces an extreme impediment and very high levels of scrutiny regarding privacy. In fact, the scope of issues in relation to Internet privacy is so huge that they threaten its future viability. Almost all online activities require identity information to be given from one party to another. If one counts cookies and IP addresses as personal information, then Internet users leave behind a trail of personally identifiable information everywhere they've been — and they have little idea how that data may be used or how well it is protected.[35] However, unlike the Internet, consumers cannot opt out of the Smart Grid.

Information systems used by utilities in their 100 year history range predominantly from those that are paper driven to those that are highly automated and interactive. Increasingly, utilities are using information to plan, design, and implement integrated information sharing systems. These systems enhance the ability to collect, access, and use information, including personal information, and introduce the potential for information to be entered once but used multiple times across and between many different systems. When information is digitized (i.e. taken from a paper-based medium to electronic), the implementation of electronic information collection and sharing capabilities increases and results in concerns over the use, or potential misuse, of personal information contained in these systems. Digitized information, unlike paper-based information, can be massively disseminated, matched and merged, and used with ease for purposes far beyond those for which the information was originally collected in the first place.[36] While it is true that someone can sit outside a home and determine when the occupants are home, or read a meter posted outside the home, this only involves one meter and one individual collecting the information. Digital smart meter data, like all digital data, is vulnerable to copying and sending, and therefore lends itself to the possibility for a much larger dissemination of "comings and goings." Much like the creation of electronic health records, several privacy considerations arise as a result of digitization.[37] Privacy considerations in relation to the Smart Grid are canvassed in the IPC's paper *SmartPrivacy for the Smart Grid: Embedding Privacy into the Design of Electricity Conservation* co-authored with the Future of Privacy Forum (available online www.ipc.on.ca).

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33 See A. Cavoukian, Privacy by Design Book, Ch. 16, available online: http://www.privacybydesign.ca/pbdbook/PrivacybyDesignBook-ch16.pdf; S. Warren and L. Brandeis, "The Right to Privacy," *Harvard Law Review* Vol. 4(5), 1890, pp. 193, available online: http://groups.csail.mit.edu/mac/classes/6.805/articles/privacy/Privacy_brand_warr2.html.

34 *Ibid.,* Privacy by Design Book.

35 See A. Cavoukian, *7 Laws Of Identity: The Case For Privacy-Embedded Laws Of Identity In The Digital Age*, available online: http://www.ipc.on.ca/images/Resources/up-7laws_whitepaper.pdf. E.g. Unlike the advent of the Internet, today's large-scale plans such as the U.S. broadband plan discusses embedding privacy at the outset. See National Broadband Plan: Connecting America, Ch. 4, available online: http://www.broadband.gov/plan/4-broadband-competition-and-innovation-policy.

36 IPC Order MO-1366: "A number of previous orders have identified that the format of information can affect the determination of whether disclosure would constitute an unjustified invasion of privacy … Order M-981 … Order P-1635 … M-849 … In the circumstances of the present appeal, I am satisfied that the disclosure of the personal information in electronic form, where it can be massively disseminated, matched and merged, and used for purposes far beyond those for which the information was collected in the first place, is a relevant factor to consider, and weighs significantly in favour of non-disclosure of the personal information in that format."

37 For an example of the many considerations involved with electronic health records, see A. Cavoukian and P. G. Rossos, *Personal Health Information: A Practical Tool for Physicians Transitioning from Paper-Based Records to Electronic Health Records*, available online: http://www.ipc.on.ca/images/Resources/phipa-toolforphysicians.pdf.

Changes experienced by utilities in implementing the Smart Grid

Leading the charge to the changing energy landscape is the shifting nature of information demands for utilities as power providers. The change is in part due to the large amount of information that utilities will be collecting from devices as a result of advancements towards the Smart Grid, such as the installation of smart meters and Intelligent Electronic Devices (IEDs). It is predicted that "[a] Smart Grid is expected to generate up to eight orders of magnitude more data than today's traditional power network."[38] Identified impacts of the Smart Grid on utility functions as it relates to consumers include the primary operation areas of home energy management, metering, and demand-side management.[39] Concern exists that utilities in other jurisdictions may be rushing ahead with Smart Grid implementation without fully considering the impacts on business processes.[40]

One key challenge in achieving the Smart Grid as envisioned relates to the fact that there are many communications, operational and information systems, and as a result there can be challenges with the level of integration between systems to achieve suitable utilization of the available information. The amount of data available from smart metering and Smart Grid devices will grow substantially and may require a significantly more robust means of validating, storing and filtering this data for optimal use. Additionally, two-way, high-data volume and frequency, and low-latency communications, may be required to support many of the Smart Grid operations, protections and control functions.

New technologies may be introduced arising from changes experienced by utilities in implementing the Smart Grid. In some instances this may involve using specific smart devices to monitor and/or adjust voltage levels and similar power conditions across lines and connection points. Smart energy regulators, capacitors, switches and power line monitors are technologies that can be used to support energy conservation by reducing energy losses, distributed generation penetration, plug-in vehicles, and improved reliability and management of utility assets. For Smart field devices challenges may lie in integrating diverse existing systems as well as applying information into new systems and services.[41]

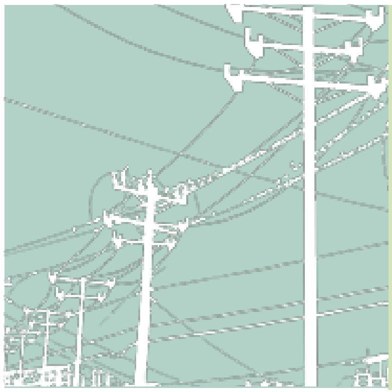
In addressing challenges arising from changes experienced by utilities in implementing the Smart Grid, utilities may find opportunities to adopt *Privacy by Design* when introducing new technologies, integrating communications, operational and information systems, as well as when updating business processes.

38 See http://newsroom.accenture.com/article_display.cfm?article_id=4971.

39 V Pothamsetty and S Malik, *Smart Grid: Leveraging Intelligent Communications to Transform the Power Infrastructure*, February 2009, pp. 9.

40 J Feblowitz and L. Goransson, *From Customer Service to Customer Engagement: Are Utilities Prepared for the Smart Grid Experience?*, February 2010, pp. 1. "Utilities are preoccupied with the implementation of physical infrastructure and have not thought through the implications of new technology and products on customer relationships or the business process."

41 Although technology solutions may be approaching commercialization, it is important to note that the right and best products should always be selected based on specific sets of criteria as part of a utility's Smart Grid strategy which embeds privacy (including security) considerations into the requirements of the program at the outset.



Privacy by Design: The Gold Standard for the Smart Grid

> *There is no technical reason to attempt to standardize all aspects of the Smart Grid today, if engineered and designed correctly.*[42]

Privacy by Design and the 7 Foundational Principles (The Gold Standard) is the next wave of privacy. They incorporate universal principles of fair information practices, but go well beyond them, to seek the highest global standard possible, representing a significant raising of the bar.[43] We believe that *Privacy by Design* should be adopted as the Gold Standard for the Smart Grid.

Privacy by Design is a concept developed by Commissioner Cavoukian back in the 90's, to address the ever-growing and systemic effects of information and communication technologies, and of large-scale networked data systems. *Privacy by Design* advances the view that the future of privacy cannot be assured solely by compliance with regulatory frameworks; rather, privacy assurance must ideally become an organization's default mode of operation. Initially, deploying Privacy-Enhancing Technologies (PETs) was seen as the solution. Today, we realize that a more substantial approach is required — extending the use of PETs to PETs *Plus* — taking a positive-sum (full functionality) approach, not the dated zero-sum. That's the "Plus" in PETs Plus: the win/win of positive-sum, not the either/or of zero-sum.

Privacy by Design extends to a "Trilogy" of encompassing applications: 1) IT systems; 2) accountable business practices; and 3) physical design and networked infrastructure. Principles of *Privacy by Design* may be applied to all types of personal information, but should be applied with special vigour to sensitive data. The strength of the privacy measures taken tends to be commensurate with the sensitivity of the data. The objectives of *Privacy by Design* – ensuring freedom of choice and personal control over one's information and, for organizations, gaining a sustainable competitive advantage — may be accomplished by practicing the following 7 Foundational Principles.

We have developed the following best practices for new Smart Grid projects by adapting the language and concepts contained in the IPC's paper *Privacy by Design: The 7 Foundational Principles* (available online at www.ipc.on.ca). While the vast majority of Smart Grid projects will not involve personal information, or will involve legacy systems that are not easily updated with *Privacy by Design* features, whenever there is an opportunity to incorporate *Privacy by Design* into existing systems that involve personal information, these best practices should be used.

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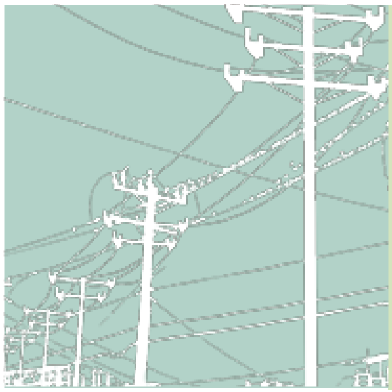
42 Although technology solutions may be approaching commercialization, it is important to note that the right and best products should always be selected based on specific sets of criteria as part of a utility's Smart Grid strategy which embeds privacy (including security) considerations into the requirements of the program at the outset.

43 Smart Grid Standards Adoption: Utility Industry Perspective, Prepared for Smart Grid Utility Executive Working Group and OpenSG Subcommittee, available online: http://osgug.ucaiug.org/Shared%20Documents/Accelerating%20Smart%20Grid%20Standards%20Adoption%20final%20v5%20090302.doc.



Best Practices: Privacy on the Smart Grid

1. Smart Grid systems should feature privacy principles in their overall project governance framework and proactively embed privacy requirements into their designs, in order to prevent privacy-invasive events from occurring

Smart Grid projects involving consumer information require privacy considerations to be integrated into their development, right from the project inception phase. Identifying and incorporating privacy considerations into such requirements provides a solid foundation for *Privacy by Design* principles. Project development methodologies are commonly used for the successful development of any large scale networked data system solution (e.g. ISO12207, Unified Process, etc).

Include the 7 Foundational Principles of *Privacy by Design* in the requirements development and design processes, and subsequently to the building and testing systems for alignment with those requirements. The utility should conduct Smart Grid project privacy impact assessments (PIA) or similar type of assessments as part of the requirements and design stages, to allow incorporation into requirements and plans — right from the outset. For in-flight projects, the PIA or similar type of assessments can be conducted at a later time in the program if necessary, with any corrective actions incorporated at that time.

2. Smart Grid systems must ensure that privacy is the default — the "no action required" mode of protecting one's privacy — its presence is ensured

Consumer information, specifically personally identifiable information on the Smart Grid, must be strongly protected, whether at rest or in transit. Personally identifiable information that is communicated wirelessly or over wired networks should be encrypted by default — any exceptions should be assessed (risk-based) on the impact to customers of third party access. It is much harder to protect personal information when it is stored in multiple locations — keep personal information in a minimal number of systems from which it may be securely shared. Similarly, allowing need-only access to this information will provide an extra layer of protection. It is important to consider the manner in which third parties will be allowed to gain access, for various legitimate support purposes — there must be appropriate language built into the contractual agreements to safeguard consumers. There should be as little persistency of personal information as possible. At the end of the cycle, personal information must be securely destroyed, in accordance with any legal requirements.

3. Smart Grid systems must make privacy a core functionality in the design and architecture of Smart Grid systems and practices — an essential design feature

Privacy must be a core functionality in the design and architecture of new Smart Grid systems and practices. However, these often involve refreshing the existing asset base, which previously had no real need to carry or transmit consumer information. It is understood that many utilities will be building onto existing legacy systems and that few will be able to work with a clean slate, but instead will need to introduce *Privacy by Design* principles into legacy systems as opportunities arise, to ensure the overall architecture is secure. It is important to understand how personal information is being handled within the enterprise and determine whether any adjustments need to be made due to challenges raised by new Smart Grid initiatives.

4. Smart Grid systems must avoid any unnecessary trade-offs between privacy and legitimate objectives of Smart Grid projects

Beyond making privacy the default by embedding it directly into systems, achieving *Privacy by Design* entails the ability to embed privacy without any loss of functionality of Smart Grid related goals.

5. Smart Grid systems must build in privacy end-to-end, throughout the entire life cycle of any personal information collected

Ensure that the people, processes and technology involved in Smart Grid projects consider privacy at every stage, including at the final point of the secure destruction of personal information.

6. Smart Grid systems must be visible and transparent to consumers — engaging in accountable business practices — to ensure that new Smart Grid systems operate according to stated objectives

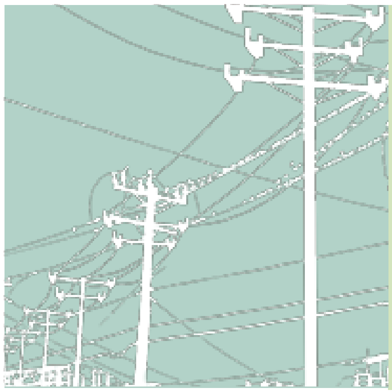
Records must be able to show that the methods used to both incorporate privacy as well as the Smart Grid objectives will meet the privacy requirements of the project. Ensuring such "requirements traceability" between the foundational privacy principles and each stage of Smart Grid project delivery will ensure that one is ready for a third party audit at any time.

Any non-compliant privacy deliverables will require an immediate remediation plan to correct the deficiency and provide an acceptable means of redress.

Informing consumers of the use to which personal information collected from them will be put is a key objective in achieving visibility and transparency.

7. Smart Grid systems must be designed with respect for consumer privacy, as a core foundational requirement

From a consumer perspective, it is essential to provide the necessary information, options, and controls so that consumers may manage their energy, costs, carbon footprints, and privacy.



Smart Grid Privacy by Design Use Case Scenarios

Two use case scenarios are provided here to illustrate methods of incorporating *Privacy by Design* following a background description of privacy considerations for the Wireless Mesh Network. The two use cases are: 1) Customer Information Access and 2) Customer Enablement.

Background: The Wireless Mesh Network

Consider the scenario where a utility has a fully functional smart meter deployment across the majority of its client base. These smart meters communicate information back into the utility through a meshed wireless configuration, where designated meters and repeaters act as secure gateways, and data collectors aggregate information for transmission back into the utility's data centre. During this initial phase, utilities will make this information available to their customers to assist them in managing their power consumption. As part of the next phase in grid modernization, the utility would work with its smart meter supplier to pilot derivative meters that can monitor transformer performance. Information from these transformer meters can be used by the utility to back-check the accuracy of smart meters, drawing early warnings of transformer overload or power theft.

Providing customers access to their meter reading information has many challenges, such as the following: registration, authentication and data protection. The information needs to be presented in a simple and easy-to-understand manner that is useful in helping customers manage their energy needs efficiently.

A utility following Smart Grid *Privacy by Design* will consider how to best design information flows to mitigate potential future customer privacy concerns. Since the smart meter information is broadcast wirelessly over the air, the obvious first level of security would be to encrypt the information. The second is to ensure that the smart meter network does not broadcast any sensitive customer information over the airwaves. Designing systems to only pass on the minimum information required protects privacy — in the case of this scenario, a unique numeric ID and consumption data is all that needs to be transmitted. The smart meter-to-customer correlation is only performed securely back in the utility's data centre.

The utility can take the assessment to an even higher level by considering whether transformer meters should communicate over a different wireless network than the smart meters. The rationale for this is that if the smart meter network were ever to be compromised, malicious third parties could not perform the same transformer-to-smart meter correlation, as could the utility. By segregating the information over dual networks, the correlation could only be done by being in possession of both sets of information, which would only be available in the utility's own data centre. While the final solution may well be a single network, it is these added measures of due diligence that will result in a solution truly inspired by *Privacy by Design*.

Use Case Scenario 1) Customer Information Access

When a utility wishes to provide access to information, it must consider how to positively identify the customer during registration and upon each subsequent visit. This step is extremely important because unauthorized access to customers' information will erode trust and result in a loss of consumer confidence.

Such customer access may be required, for example, in order to provide additional information to assist them in making choices around energy, cost, carbon footprint, and privacy.

Ensuring that the registrant to the customer information access service is indeed the owner of the utility account, and that unauthorized access attempts are kept to a minimum, are depicted in the requirements illustrated in Figure 1 below.

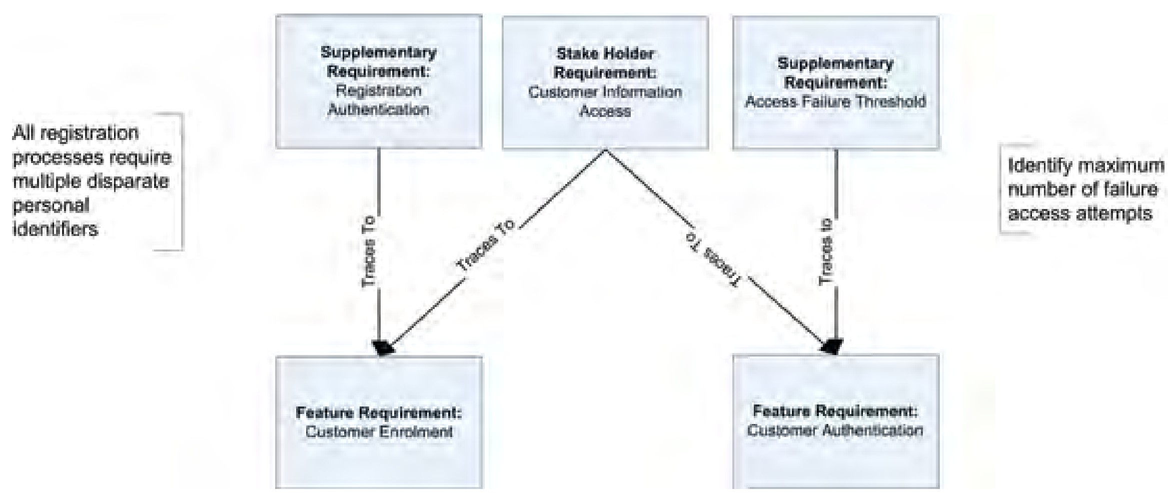


Figure 1 - Customer Information Access Requirements

The two features illustrated above, Customer Enrolment and Customer Authentication, are requirements defined by the utility. These two requirements will have supplemental requirements that may be traced to the features which apply privacy constraints upon them.

Figure 2 illustrates how a supplementary requirement such as an "Access Failure Threshold" can be incorporated and traced within the design of a Customer Information Access program, which would then be reviewed by the Smart Grid project team to ensure that it also meets their business needs:

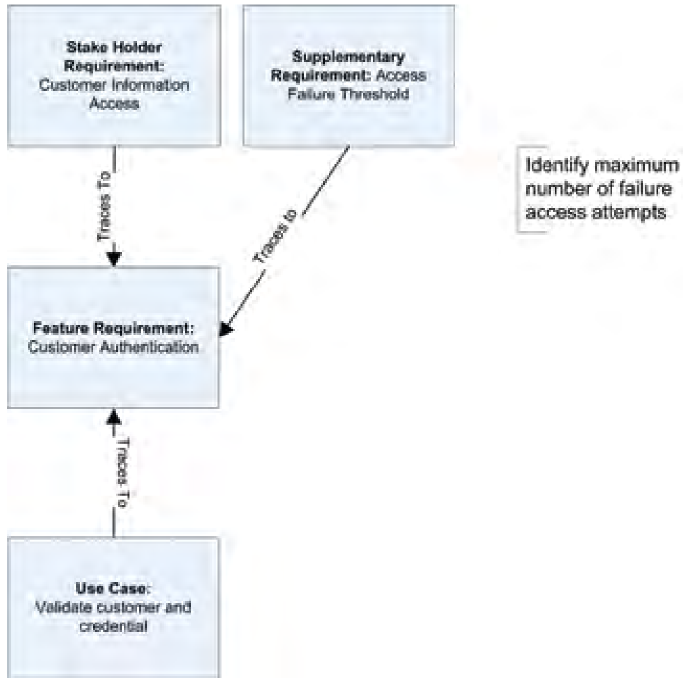


Figure 2 - Use Case Tracing for Customer Information Access

The requirement definition stage of any adopted Smart Grid project methodology involves the creation of one or more use cases to satisfy core foundational privacy requirements, such as "Access Failure Threshold," showing interactions between various actors (people and systems), as well as the functionality that will be delivered by the systems involved. For example, the diagram below illustrates four usage/operations case scenarios incorporating the same supplemental requirement of "Access Failure Threshold." They are: Authenticate Customer, Authentication Failure, Authentication Success and Welcome Page.

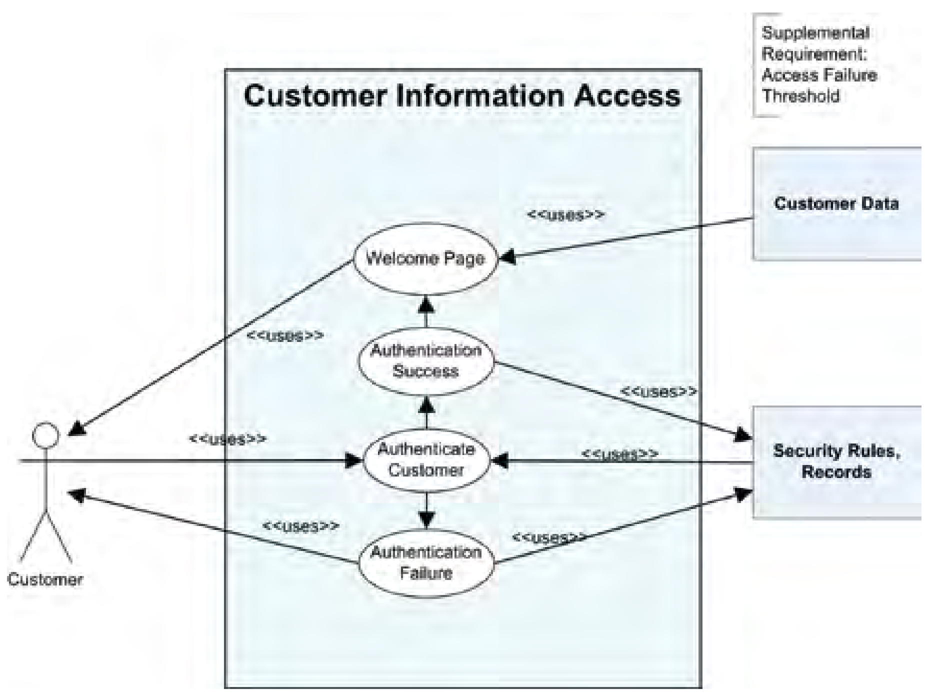


Figure 3 – System and Actor Diagram for Customer Information Access

The utility must then document all flows of information that would occur during customer authentication. The sequence presented is the successful access request. The steps are presented in Figure 4 below.

I. The customer provides his/her unique identifier and their challenge information.

II. The customer information access will require that the identifier and challenge information be verified. If correct and the account has NOT been disabled due to multiple access attempt failures, then the customer is considered to be authenticated.

III. The successful access is recorded.

IV. The basic information regarding the authenticated customer is then retrieved.

V. The customer is now presented with welcome information.

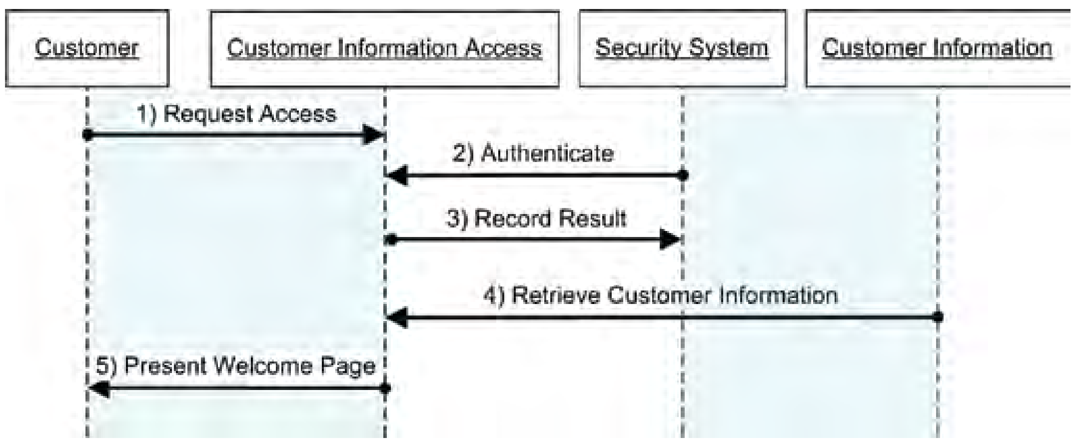


Figure 4 – Sequence Diagram for Customer Information Access

In this example, the requirement that all customers must be authenticated was illustrated. All access attempts are recorded, with multiple consecutive access failure attempts disabling the account. This requirement was developed to prevent unauthorized users from accessing an account by attempting to randomly create passwords.

Protecting access to customer information builds trust in the system, and thus increases the likelihood of customer participation to realize the benefits of the Smart Grid.

Use Case Scenario 2) Customer Enablement

A utility is in the process of rolling out smart meters and billing system changes to support time-of-use billing, and expects that future Smart Grid programs will include further customer enablement. Examples of future customer enablement include demand-response programs, conservation programs, voluntary curtailment, advanced device management, in-home displays, and many others. For the purpose of this use case scenario, consider the case of customers choosing to participate in demand-response programs, such as when there is a peak in power-demand and some customers have opted to make their thermostats available for a 2 degree Celsius reduction.

Within customer enablement, the concept of involving the customers in the dynamic management of the electrical grid provides opportunities for all stakeholders, and ultimately benefits the environment.

However, it also introduces new challenges, particularly in the realm of privacy and security. The success of a customer engagement program hinges on the utility's ability to empower willing customers to become active participants in their energy use and generation. This is broadly defined as "customer enablement" and covers the end-to-end scope of a customer's interaction with the utility's technology systems and processes. These interactions may be characterized as three basic activities:

I. *Enrolment* — The ability for an eligible customer to enrol and define their participation in programs offered by the utility.

II. *Usage* — The active operation and management of participating customers. This refers to the daily functioning of systems and processes for the utility to deliver the service. This area is often referred to as "Operation."

III. *Termination* — The ability for a customer to terminate their active participation.

In establishing customer enablement for this demand response program, the associated initiatives, from a simplified point of view, must consider several stages of deployment including establishing the objectives of the program, program definitions, and determining how customers can engage with the utility. In addition, establishing customer enablement in this project requires setting out how the program itself will run, including customer engagement and enrolment, registration programs, operations such as events requiring demand-response, and program life-cycle management and wrap-up. Below is an example of these requirements and their traceability:

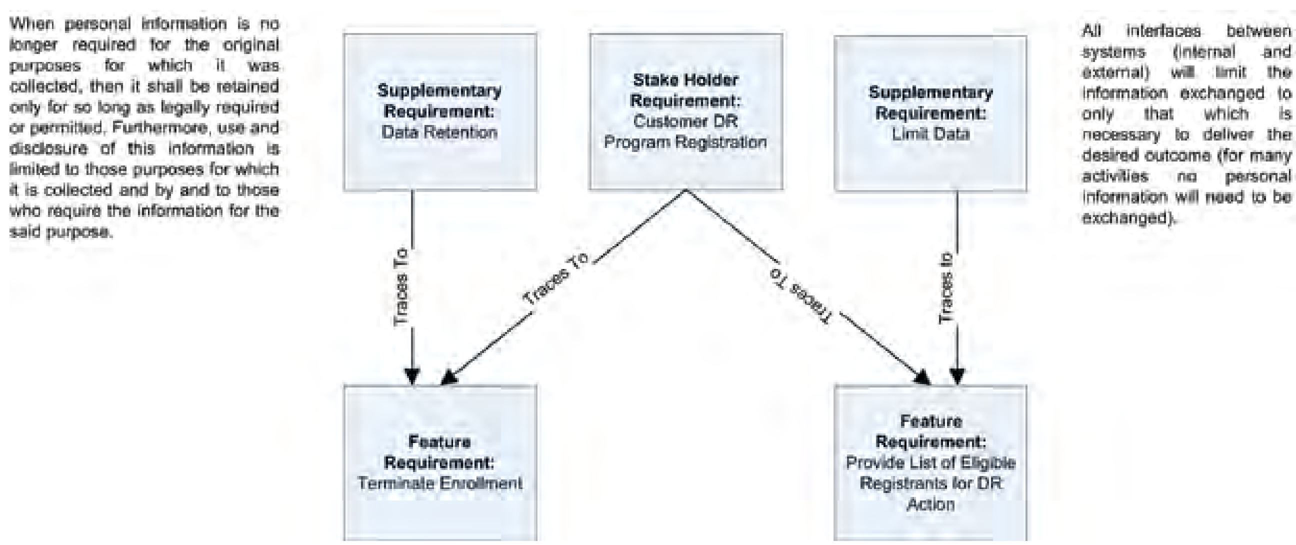


Figure 5 – Customer Demand Response Requirement Example

Note that the features being delivered are based on the business requirements to permit demand response registrants to terminate their enrolment and to provide eligible device information to a demand response program. Both of these have supplementary requirements placed on them to which the design and development teams must adhere. These supplementary requirements establish requirements for data retention, and requirements for what personal information is to be shared, or in this case, the opposite — limited, with downstream systems (i.e. limiting information only to that required for the particular purpose involved, "Limit Data").

The figure below illustrates how a supplementary requirement such as "Limit Data" can be incorporated and traced within the design of a demand management program, which would then be reviewed by the Smart Grid project team to ensure that it also meets their business needs:

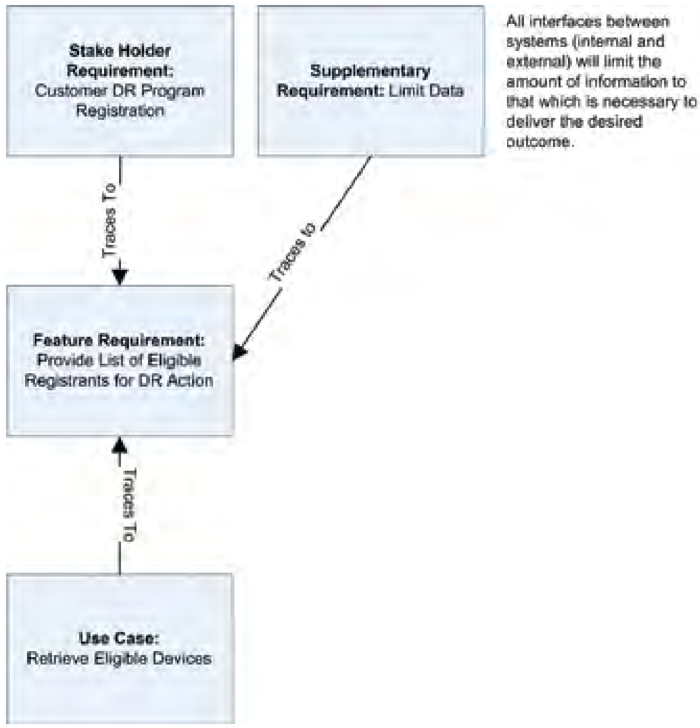


Figure 6 – Requirement Types for Demand Response Registrants

The requirement definition stage of any adopted Smart Grid project methodology involves the creation of one or more use cases to satisfy core foundational privacy requirements, such as "limit data," showing interactions between actors (people and systems), as well as the functionality that will be delivered by the systems involved. For example, the diagram below illustrates four usage/operations case scenarios incorporating the supplemental requirement of "limit data": Configure Program, Determine Program Action, Execute, and Retrieve Eligible Devices.

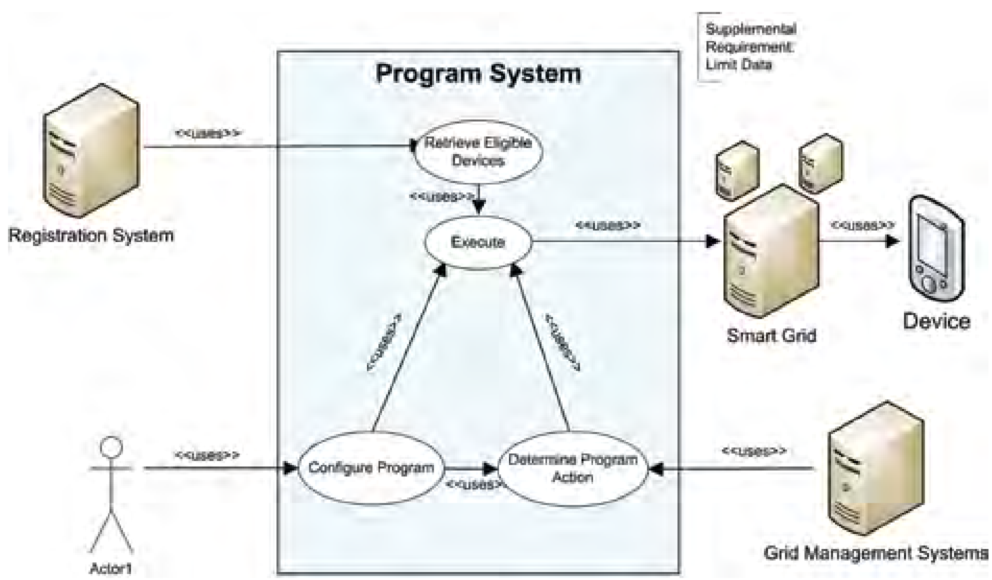


Figure 7 – System and Actor Diagram for Usage (part of Customer Enablement in the Smart Grid)

The utility must then document all flows of information that would occur in a demand response program (Figure 8 below), as follows:

I. ***Configure* —** Operators need to configure a program. This allows Hydro One to configure the behaviour of the demand response program when an event is received from the Smart Grid Management system.

II. ***Alert* —** The Smart Grid continually monitors the stability of the network and events are generated whenever problems occur (i.e. if demand exceeds supply).

III. ***Retrieve Devices* —** Based on configured rules in the demand response program, the system will determine how many consumer thermostats are needed to be adjusted to meet the DR need. At this point, the system is completely agnostic to specific customer data. It will retrieve device information from the registration system and will be limited to the device identifier and user constraints (e.g. minimum/maximum temperatures). Note: This is the essential step for the supplemental requirement to "Limit Data."

IV. ***Notify Device* —**The demand response system will request all the devices where the tolerances are allowable to change their temperature settings.

V. ***Deliver to Device* —** The Smart Grid ensures that the device is authenticated and the message is delivered securely to the device.

VI. ***Respond* —** Depending on the technology, a response will be provided to the request.

VII. ***Deliver Response* —** The Smart Grid ensures that the response is delivered to the demand response program system. The information is limited to an acknowledgement and state of action requested.

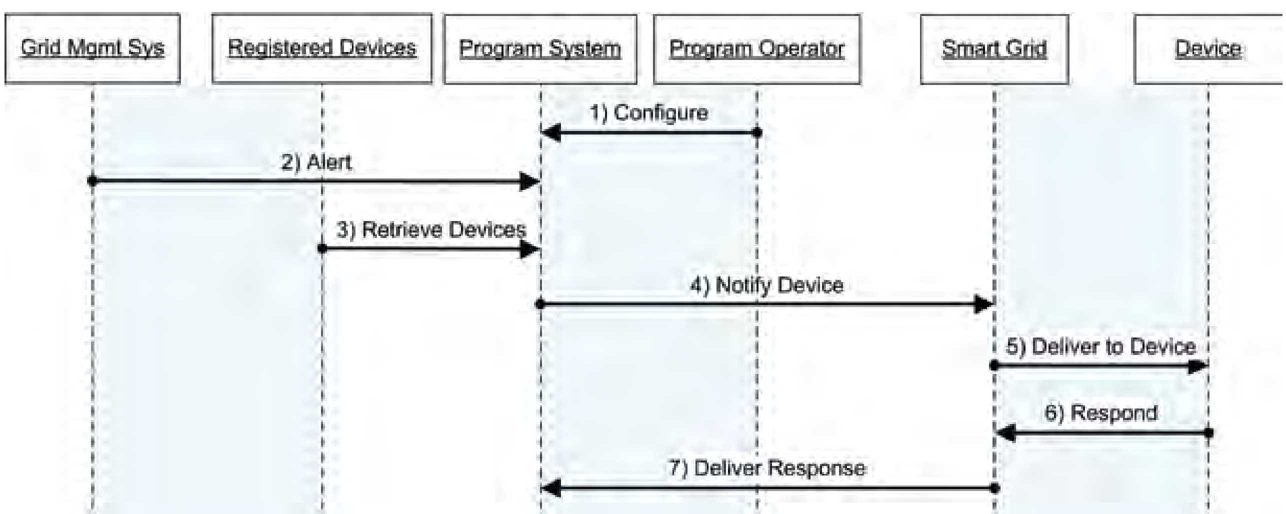
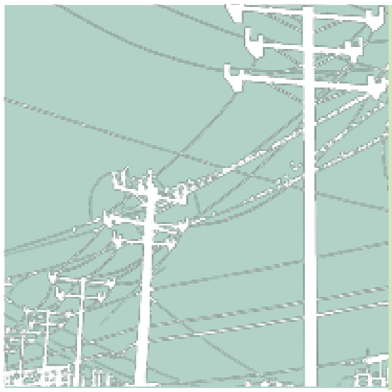


Figure 8 – Sequence Diagram for Usage (part of Customer Enablement in the Smart Grid)

In this example, the fundamental concept that underlies the entire flow is that the operating system executing demand response operations is completely blind to any of the specific, identifiable details of a given individual. Personally identifiable information is a function of program enrolment, but this association operates separately from device management. In other words, the system running the Smart Grid only knows the rules for the management of devices based on the program it is associated with, and is completely agnostic to the particular details of a given customer.

This distinction demonstrates several tenets of the Smart Grid *Privacy by Design*. The segregation of data is proactively embedded directly into the system design — it is not a reactionary after-thought or mechanism that is tacked on to the initial solution. Similarly, privacy is the default — not something that must be asked for by the customer or initiated separately by the utility. Not only is this an elegant solution, but the most efficient option from an operations perspective; it also achieves the utility's goal of demonstrating a strong respect for user privacy.

Finally, all use case designs and implementation artefacts must be reviewed to ensure compliance with this requirement and any supplementary requirements. When the system is delivered, test cases specifically aligned with the use cases will be developed and exercised. If the implementation deviates from the design artefacts, then it will be identified as a defect, requiring remediation. Thus, privacy is not only embedded into the design of the system, it is verified after it is built (trust but verify), and then tested along with other requirements.

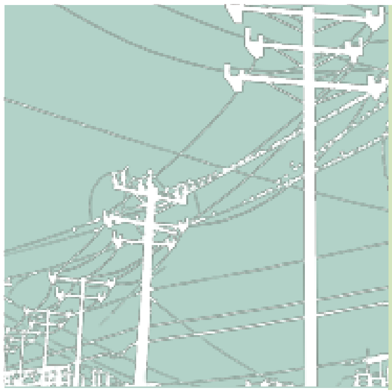


Conclusion

Utilities will face many challenges in their transformative role of revamping our current electricity system into a truly “Smart” Grid. We acknowledge that while a significant portion of the Smart Grid implementation will not involve consumer information, the amount of personal information being collected and the digital nature of that information will precipitate internal changes within utilities that go well beyond individual IT departments. The Best Practices for Smart Grid *Privacy by Design* were developed by the Information and Privacy Commission of Ontario (IPC) in collaboration with Ontario’s largest electricity providers, Hydro One and Toronto Hydro, to be used by utilities in Ontario and elsewhere, that will be facing these challenges. We hope that our Best Practices will help utilities view the challenges posed by the Smart Grid as opportunities to enhance consumer trust by building *Privacy by Design* directly into their Smart Grid systems.

In Ontario, we have been working on the question of privacy and the Smart Grid for several years. Hydro One Networks and Toronto Hydro — both subject to the privacy laws that the IPC oversees compliance with — began their Smart Grid projects knowing at the outset that privacy became an essential component any time that personal information was involved. The Information and Privacy Commissioner’s office embarked on work when first approached by the government several years ago on Bill 21, *Energy Conservation Responsibility Act, 2006*, which added amendments to the *Electricity Act, 1998* relating to smart meters, and the Smart Metering Entity.

Jurisdictions outside of Ontario may only be starting to enter into Smart Grid initiatives, such as the wide deployment of an advanced metering infrastructure. These utilities, now embarking upon Smart Grid initiatives involving the collection of personal information, may also benefit from these practices. In the U.S., for example, billions of dollars are being invested into new initiatives, fuelling the pace of Smart Grid implementation beyond the point where standards and practices around personal information are being fully developed. A point which bears repeating is that we must take great care not to sacrifice consumer privacy amidst a sea of enthusiasm for electricity reform. In this regard, other jurisdictions may benefit from our experience with building *Privacy by Design* into the foundational elements of all Smart Grid developments in Ontario.



Overview of Organizations

Information and Privacy Commissioner, Ontario, Canada

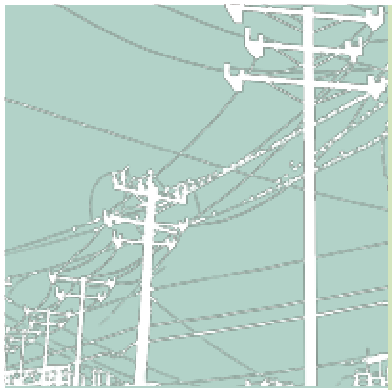
The role of the Information and Privacy Commissioner of Ontario, Canada is set out in three statutes: the *Freedom of Information and Protection of Privacy Act*, the *Municipal Freedom of Information and Protection of Privacy Act* and the *Personal Health Information Protection Act*. The IPC acts independently of government to uphold and promote open government and the protection of personal privacy. Under the three *Acts*, the Information and Privacy Commissioner: resolves access to information appeals and complaints when government or health care practitioners and organizations refuse to grant requests for access or correction; investigates complaints with respect to personal information held by government or health care practitioners and organizations; conducts research into access and privacy issues; comments on proposed government legislation and programs; and educates the public about Ontario's access and privacy laws.

Hydro One Inc.

Hydro One is the largest electricity transmission and distribution company in Ontario. Substantially all of Ontario's electricity transmission system is owned and operated by Hydro One. Its transmission system is one of the largest in North America based on assets, with almost 30,000 km of high-voltage transmission lines. Its distribution system is the largest in Ontario based on assets and spans roughly 75 per cent of the province, with over 123,000 km of wires serving approximately 1.3 million rural and urban customers, local distribution companies connected to the distribution system, and large industrial customers. Hydro One also operates, through its subsidiary, Hydro One Remote Communities Inc., small, regulated generation and distribution systems in a number of remote communities across Northern Ontario that are not connected to Ontario's electricity grid.

Toronto Hydro Electric System

Toronto Hydro Corporation is a holding company, which wholly-owns two principal subsidiaries: Toronto Hydro-Electric System Limited, distributes electricity and engages in Conservation and Demand Management ("CDM") activities. Toronto Hydro Energy Services Inc. provides street lighting services. The principal business of the Corporation and its subsidiaries is the distribution of electricity by Toronto Hydro-Electric System Limited. Toronto Hydro-Electric System owns and operates an electricity distribution system, which delivers electricity to approximately 690,000 customers located in the City of Toronto. It is the largest municipal electricity distribution company in Canada and distributes approximately 18% of the electricity consumed in Ontario.



Appendix A

The 7 Foundational Principles of Privacy by Design

1. ***Proactive*** not Reactive; ***Preventative*** not Remedial

The *Privacy by Design* (PbD) approach is characterized by proactive rather than reactive measures. It anticipates and prevents privacy invasive events before they happen. PbD does not wait for privacy risks to materialize, nor does it offer remedies for resolving privacy infractions once they have occurred — it aims to prevent them from occurring. In short, *Privacy by Design* comes before-the-fact, not after.

2. Privacy as the ***Default***

We can all be certain of one thing — the default rules! *Privacy by Design* seeks to deliver the maximum degree of privacy by ensuring that personal data are automatically protected in any given IT system or business practice. If an individual does nothing, their privacy still remains intact. No action is required on the part of the individual to protect their privacy — it is built into the system, by default.

3. Privacy ***Embedded*** into Design

Privacy by Design is embedded into the design and architecture of IT systems and business practices. It is not bolted on as an add-on, after the fact. The result is that privacy becomes an essential component of the core functionality being delivered. Privacy is integral to the system, without diminishing functionality.

4. Full Functionality — Positive-Sum, not Zero-Sum

Privacy by Design seeks to accommodate all legitimate interests and objectives in a positive-sum "win-win" manner, not through a dated, zero-sum approach, where unnecessary trade-offs are made. *Privacy by Design* avoids the pretense of false dichotomies, such as privacy vs. security, demonstrating that it is possible to have both.

5. End-to-End Lifecycle Protection

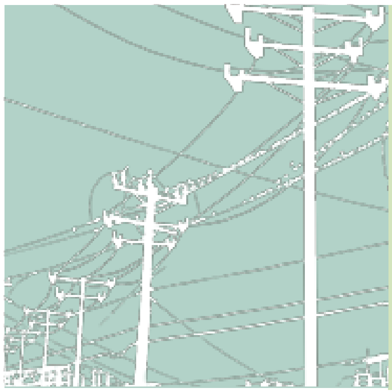
Privacy by Design, having been embedded into the system prior to the first element of information being collected, extends securely throughout the entire lifecycle of the data involved, from start to finish. This ensures that at the end of the process, all data are securely destroyed, in a timely fashion. Thus, *Privacy by Design* ensures cradle to grave, lifecycle management of information, end-to-end.

6. Visibility and Transparency

Privacy by Design seeks to assure all stakeholders that whatever the business practice or technology involved, it is in fact, operating according to the stated promises and objectives, subject to independent verification. Its component parts and operations remain visible and transparent, to users and providers alike. Remember, trust but verify.

7. Respect for User Privacy

Above all, *Privacy by Design* requires architects and operators to keep the interests of the individual uppermost by offering such measures as strong privacy defaults, appropriate notice, and empowering user-friendly options. Keep it user-centric.



Appendix B

Electricity in Ontario

Electricity in Ontario is shaped by a framework that involves a mix of law, regulation, standards and mandatory codes. The *Green Energy Act, 2009* and legislation including the *Electricity Act, 1998* established a smart metering entity, smart meter procurement requirements and functional specifications. Objectives of the province of Ontario in implementing the Smart Grid include increasing the availability of renewable energy in Ontario and increasing the use of renewable energy sources in Ontario. In addition, it is the province's goal to stimulate the search for and development of sources of energy, to stimulate energy conservation through the establishment of programs and policies, and to encourage prudence in the use of energy in Ontario.[44] Through the *Green Energy Act, 2009*, the government of Ontario updated a suite of laws to achieve these objectives.[45]

The wires that make up the Ontario electrical grid are interconnected with the U.S. electrical grid, including full circuits. As a result, U.S. standards in the area of the Smart Grid are also applicable. The U.S.-based North American Electric Reliability Corporation (NERC) develops standards that Ontario utilities must comply with, as specified under international agreements. NERC is a "standards authority" within the meaning of Ontario's *Electricity Act, 1998* and Ontario is a member of NERC coordinating councils.[46] The U.S. National Institute of Standards and Technology (NIST) are also developing standards in the area of cyber security and interoperability for the Smart Grid which will impact Ontario utilities.[47]

Previously, the energy sector in Ontario was dominated by one government-owned company, Ontario Hydro. This sector was restructured in the 90s to allow for greater competition and supply of electricity. Today, there are several energy sector players in Ontario in the area of transmission, distribution, management of electricity, policy setting, and enforcement.[48]

Transmission of electricity is primarily the responsibility of Hydro One, which operates most of the transmission lines in Ontario. Hydro One distributes electricity to large industrial and local distribution companies, such as Toronto Hydro, that distribute power to homes, schools and small

44 See Appendix C for an overview of fair information practices. See also *The 7 Foundational Principles: Implementation and Mapping of Fair Information Practices* available online: http://www.ipc.on.ca/images/Resources/pbd-implementation-7found-prin.pdf.

45 *Ministry of Energy Act* , s. 8 (1)

46 *The Green Energy Act, 2009* also allows for the creation of regulations that would require public agencies and certain consumers to establish energy conservation and demand management plans. When government makes a capital investment or acquires goods and services, it will have to consider energy conservation and efficiency. The *Act* provides guiding principles for government facilities along these lines, and restricts sale or lease of appliances and products that do not meet efficiency standards, or labelling requirements. The *Act* also facilitates participation of aboriginal people and community groups in developing renewable energy generation facilities, and transmission and distribution systems.

47 Memorandum Of Understanding Between The Ontario Energy Board And The North American Electric Reliability Corporation: http://www.nerc.com/files/OEB-NERC-MOU-Final.pdf.

48 NIST 800-53/82, NISTIR 7628. In addition, utilities must comply with ISO standards such as 17799/27001.

businesses. Hydro One also distributes electricity directly to certain areas of the province, including rural areas.

The Independent Electricity System Operator (IESO) forecasts the short term demand for electricity; electricity generators in turn bid to sell energy at the specified price. This process is done every five minutes and thus operates as a real-time spot market. To ensure reliability of the electricity supply, the IESO also ensures that extra energy is available, should it be needed, by paying certain power generators to be on stand-by. The IESO is one of eight Independent System Operators in North America. One of the IESO's legislative mandates is to plan, manage, and implement the smart metering initiative in Ontario.[49] The Ontario Power Authority (OPA) is responsible for longer term planning of the supply of electricity in Ontario.

The Ontario Energy Board (OEB) is a regulatory body which, among other responsibilities, issues electricity licenses to participants in the electricity industry. The Board protects the interests of individual consumers regarding the price of electricity, as well as the reliability and quality of electricity. The OEB also conducted a Smart Price Pilot in June 2006 which was the first pilot in North America to both examine changes in energy consumption behaviour in response to three different types of time-of-use pricing (off-, mid- and on-peak; critical peak pricing; critical peak rebates).[50] The OEB's objectives include facilitating the implementation of a Smart Grid in Ontario; promoting electricity conservation and demand management, including having regard to the consumer's economic circumstances; and to promote the use and generation of electricity from renewable energy sources.[51] The Government of Ontario can issue directives to the OEB requiring that it take steps relating to the establishment, implementation or promotion of the Smart Grid in Ontario.[52]

Toronto Hydro and Hydro One are part of the Ontario Smart Grid Forum, spearheaded by the IESO and involving others in the field, including representatives from the Ontario government and the OEB. The Forum released its report *Enabling Tomorrow's Electricity System* in February 2009, calling for a co-ordinated effort to increase reliability, develop economic opportunities, and promote environmental sustainability through Smart Grid technologies. One of the report's key recommendations stated that consumers should have access to timely information on their consumption and price information from a smart meter with two-way communication capability or via the Internet.[53]

Policy for the delivery of electricity is set out by the Ontario Ministry of Energy and Infrastructure, including the introduction of smart meters and the *Green Energy Act, 2009*. Similar to other players in the sector, the Ministry's goal is to ensure that electricity is increasingly reliable in the future. The Ministry is also involved with bringing innovation to the electrical grid, and focusing on cleaner and renewable forms of energy.

When it comes to privacy, data protection and transparency, the Ministry, OEB, IESO, OPA, Hydro One and Toronto Hydro all come within the oversight jurisdiction of the Information and Privacy Commissioner of Ontario.

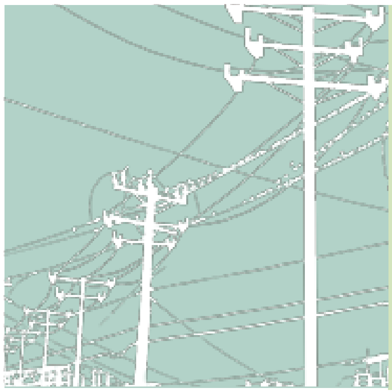
49 As Ontario Power Generation (OPG) does not handle personal information, they are not discussed in this section. OPG is the largest power generator in Ontario and produces 70 to 80 per cent of Ontario's energy. Its sources of electricity generation are hydroelectric, nuclear and fossil fuel.

50 *Electricity Act, 1998*, Ontario Regulation 452/06 Additional Objects of the IESO.

51 Consumption of electricity lowered by 5.7, 25.4 and 17.5 respectively. See Backgrounder: Ontario Energy Board Smart Price Pilot, July 26, 2007, available online: http://www.oeb.gov.on.ca/documents/communications/pressreleases/2007/press_release_smartpricepilot_backgrounder_20070726.pdf.

52 *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, s. 1(1)

53 *Ibid.*, s. 28.5 (1)



Appendix C

Fair Information Practices

By the late 1970s, information and communication technologies were facilitating a growing global trade in, and processing of, personal data. As various countries passed laws restricting the unlawful storage of personal data, the storage of inaccurate personal data, or the abuse or unauthorized disclosure of such data, worries arose that global trade would be constrained by the growing patchwork of national laws. In a far-sighted initiative, members of the Organisation for Economic Co-operation and Development (OECD) came together and agreed to codify a set of principles that might serve as a framework for countries to use when drafting and implementing their own laws. The result was the 1980 OECD Guidelines on the Protection of Privacy and Transborder Flows of Personal Data. Since 1980, these voluntary "fair information practices" (FIPs) have been widely adopted around the world in statutes, standards, codes of practice, information technologies, and in norms and common practices. In Canada, for example, businesses, consumers and the government agreed to adopt a comprehensive set of privacy practices, known as the Model Code for the Protection of Personal Information (CAN/CSA-Q830-96) or CSA Privacy Code (see below), which was subsequently incorporated in its entirety into Canada's private sector privacy law.[54] The Ontario *Freedom of Information and Protection of Personal Information Act* and municipal counterpart base their privacy protection rules on fair information practices, which are the basis for privacy legislation in most jurisdictions around the world.[55]

The National Institute of Standards and Technology (NIST) in the United States has primary responsibility to coordinate development of a framework for the Smart Grid that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems. Since advancing the Smart Grid is a priority for the Obama administration, NIST has expedited its standards development process. In its Second Draft Smart Grid Cyber Security Strategy and Requirements (NIST IR 7628) document, NIST uses fair information practice principles in discussing privacy considerations for the Smart Grid.[56]

In Ontario, utilities have been adhering to privacy law and fair information practices for years.

- Hydro One's Privacy Code reflecting these practices is available publically at: http://www.hydroone.com/OurCompany/Documents/privacy_code.pdf.

54 *Enabling Tomorrow's Electricity System: Report of the Ontario Smart Grid Forum*, available online: http://www.ieso.ca/smartgridreport.

55 See Schedule 1, *Personal Information Protection and Electronic Documents Act*, (2000, c. 5). See also A. Cavoukian, Privacy by Design, Ch. 16, available online: http://www.privacybydesign.ca/pbdbook/PrivacybyDesignBook-ch16.pdf. While there is a range of privacy principles (or 'fair information practices principles'), with OECD privacy principles at the beginning of the privacy spectrum, Privacy by Design the next wave of privacy protection principles. See next section.

56 See http://www.nist.gov/smartgrid/.

- Toronto Hydro's Privacy Policy Statement reflecting these practices is available publically at: http://www.torontohydro.com/sites/electricsystem/pages/privacypolicy.aspx

See below for the CSA Privacy Code principles:[57]

1. Accountability

An organization is responsible for personal information under its control and shall designate an individual or individuals who are accountable for the organization's compliance with the following principles.

2. Identifying Purposes

The purposes for which personal information is collected shall be identified by the organization at or before the time the information is collected.

3. Consent

The knowledge and consent of the individual are required for the collection, use, or disclosure of personal information, except where inappropriate.

4. Limiting Collection

The collection of personal information shall be limited to that which is necessary for the purposes identified by the organization. Information shall be collected by fair and lawful means.

5. Limiting Use, Disclosure, and Retention

Personal information shall not be used or disclosed for purposes other than those for which it was collected, except with the consent of the individual or as required by law. Personal information shall be retained only as long as necessary for the fulfillment of those purposes.

6. Accuracy

Personal information shall be as accurate, complete, and up-to-date as is necessary for the purposes for which it is to be used.

7. Safeguards

Personal information shall be protected by security safeguards appropriate to the sensitivity of the information.

8. Openness

An organization shall make readily available to individuals specific information about its policies and practices relating to the management of personal information.

9. Individual Access

Upon request, an individual shall be informed of the existence, use, and disclosure of his or her personal information and shall be given access to that information. An individual shall be able to challenge the accuracy and completeness of the information and have it amended as appropriate.

10. Challenging

An individual shall be able to address a challenge concerning compliance with the above principles to the designated individual or individuals accountable for the organization's compliance.

57 Privacy principles are found in the principles from the OECD Privacy Principles, the Generally Accepted Privacy Principles (GAPP), principles from ISO/IEC 27001, and concepts from ISTPA. The Global Privacy Standard modernizes the FIPs in the digital world, see: http:// http://www.ipc.on.ca/images/Resources/gps.pdf.

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Information & Privacy
Commissioner of Ontario

Health Sciences Practice and
Electrical Engineering & Computer
Science Practice

Exponent®

Summary Report on the Status of Research Related to Radiofrequency Field Exposure and Health

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Acronyms and Abbreviations

AGNIR	Advisory Group on Non-Ionizing Radiation
CCST	California Council on Science and Technology
CI	Confidence interval
EMF	Electric and magnetic fields
FCC	Federal Communications Commission
HCN	Health Council of the Netherlands
IARC	International Agency for Research on Cancer
ICNIRP	International Commission on Non-Ionizing Radiation Protection
HPA	Health Protection Agency of Great Britain
Hz	Hertz
OR	Odds ratio
RF	Radiofrequency
RR	Relative risk
SCENIHR	Scientific Committee on Emerging and Newly Identified Health Risks
SSM	Swedish Radiation Safety Authority
UK	United Kingdom

Limitations

At the request of BC Hydro, Exponent prepared this summary report on the status of research related to radiofrequency field exposure and health. The findings presented herein are made to a reasonable degree of scientific certainty. Exponent reserves the right to supplement this report and to expand or modify opinions based on review of additional material as it becomes available, through any additional work, or review of additional work performed by others.

The scope of services performed during this investigation may not adequately address the needs of other users of this report, and any re-use of this report or its findings, conclusions, or recommendations presented herein are at the sole risk of the user. The opinions and comments formulated during this assessment are based on observations and information available at the time of the investigation. No guarantee or warranty as to future life or performance of any reviewed condition is expressed or implied.

Introduction

In the summer of 2011, BC Hydro implemented their Smart Metering Program as the first step in modernizing the electricity system in British Columbia by replacing old analog meters with digital meters. Since that time, 1.8 million smart meters have been installed in homes and businesses throughout the province. Since many smart meters utilize wireless technology to transmit information, they emit electromagnetic energy in the form of radiofrequency (RF) fields (also called radio waves), much like many other electronic devices that are common in everyday life (e.g., cellular and cordless telephones, WiFi routers, baby monitors, garage door openers, and Bluetooth technology).

This report was prepared at the request of BC Hydro to provide a status report on current research that relates to RF fields and health. Smart meters are a relatively new technology with deployment in the United States and Canada growing steadily over the past six years or so. As with many new technologies, questions have arisen about health effects—in this case, the possible health effects that may occur from exposure to the RF fields created when signals are emitted from smart meters installed on homes and commercial buildings. Generally, concerns center on chronic health conditions and symptoms related to well-being. The effects of long-term exposures at low levels and the adequacy of the relevant existing standards have also been questioned.

The electromagnetic spectrum includes all forms of electromagnetic energy, which are characterized by their wavelength and frequency. Wavelength is the distance covered by one full electromagnetic wave cycle and frequency is the number of electromagnetic waves that pass a fixed point in one second, measured in units of Hertz (Hz). Energy along the electromagnetic spectrum is linked to frequency levels; it ranges from the low energy associated with low frequency and long wavelength (e.g., radio waves, power-frequency electric and magnetic fields [EMF], microwaves, and infrared light) to the high energy associated with high frequency and short wavelength (e.g., visible light, ultraviolet light, X-rays, and gamma-rays).[1] Radio waves (i.e., RF energy), are at the lower end of the electromagnetic spectrum. RF energy is typically defined as between 3,000 Hz ($3x10^3$) and 300 billion Hz (3×10^{11}).

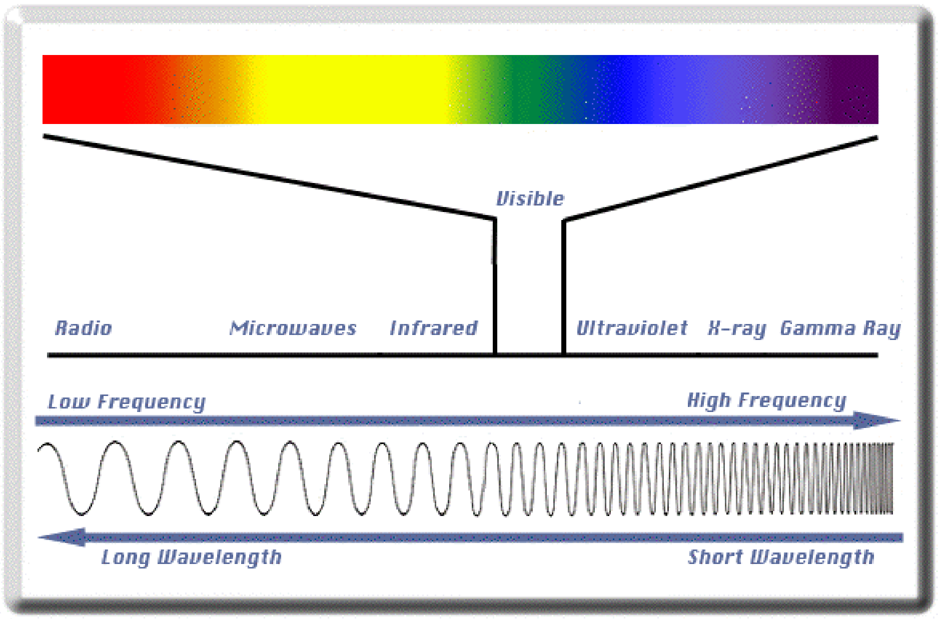

Figure 1. The electromagnetic spectrum

Over a century ago, RF energy began to be used across many disciplines—in science and medicine, in the communications and transportation industries, and by the military. One of the earliest uses was the wireless telegraph in the 1890s, followed by radio broadcasting in the early 20th century, radar during World War II, television broadcasting starting in the 1940s, and more recently, for microwave ovens. All of these technologies operate using strong RF signals.[2] Recent technological advancements have made it possible to utilize very weak RF signals for consumer products that are now common in our homes and businesses. As mentioned above,

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1 While RF and EMF are sometimes used synonymously by the public, in this report EMF will refer to the fields associated with the generation of electricity from power lines and electric devices at 50 or 60 Hz. All electromagnetic energy in the spectrum, including light, radiates outward from the source and is termed 'radiation.' The energy from very high frequency fields such as X-rays and gamma rays are known as ionizing radiation. RF and EMF are categorized as non-ionizing radiation and do not cause the biological changes that can occur from ionizing radiation.

2 The strength of the field (i.e., its intensity) is different than frequency, just as any sound, high or low depending on frequency can be loud or soft (high or low intensity).

these include cellular and cordless phones, baby monitors, garage door openers, Bluetooth devices, and WiFi routers, just to name a few.

Exposure to RF fields from these sources is considered either far-field or near-field based on physical distance from the source. Far-field exposure is defined, typically, as the location where the power density begins to decrease inversely with the square of the distance (i.e., very rapidly). Typical far-field sources include radio and TV transmitters, base stations, wireless local area network access points, and smart meters. Near-field exposure also is defined by the distance from a source, typically the region very close to antennas in which the power density does not necessarily decrease inversely with the square of the distance. As implied, near-field exposures occur when sources are close to the body, such as mobile phones and other handsets. An additional component to determine whether a source constitutes far-field or near-field exposure is the distance to the source in relation to the wavelength and the antenna geometry. The distance to a near-field source is often defined as closer than one-sixth of the wavelength and far field is typically equal to or greater than the size of the wavelength (EPRI, 2011).

Scientific research on RF energy from sources that utilize strong signals has been conducted since the 1940s; this research has consistently supported the development of health-based exposure limits and standards. The recent proliferation of technology that uses very weak RF signals has led to scientific research on exposure to RF fields from these devices and various health outcomes. This research has focused primarily on mobile phones, partly because of the close proximity of mobile phones to the human body when in use. In addition, the number of mobile phones in use (about 5 billion throughout the world in 2010) is a substantial factor in the attention given to research results related to mobile phones.

The widespread introduction of other devices that emit weak RF signals, such as smart meters, also has generated questions about exposure and health in two general areas: cancer risk from long-term exposure and symptoms related to well-being from short-term exposure. This report provides an overview of the current research on these two subjects.

The purpose of this report is to provide a summary of the significant research regarding RF exposure and health conducted by national and international health agencies and to assess the impact of recent research on the conclusions reached by these agencies. To provide a framework for our discussion of the research, the first section describes the health risk assessment and review process that scientists use to compile and evaluate research about the impact of any exposure to a chemical or physical agent on human health. The next section provides additional contextual information on the methods for evaluating the specific types of scientific studies discussed in this report. Section 3 discusses the regulatory standards and exposure guidelines in general and the standards that have been established for RF fields in particular, as well as the relevant exposure standard in Canada.

The conclusions of recent comprehensive reviews conducted by scientific and health organizations relevant to RF fields and health are discussed in Section 4. Finally, the last section summarizes recent RF research and the potential impact of this new research on the conclusions of recent comprehensive reviews, based on methods of health risk assessment described in Section 1.

1. Health Risk Assessments

Heath risk assessment approach

The standard process for evaluating a body of scientific research to understand the potential implications of an exposure is referred to as a risk assessment. Generally, risk assessments fall into two broad categories: an ecological risk assessment or a human health risk assessment.[3] A human health risk assessment is a four-step process that starts with a *hazard identification* to determine any possible risks associated with an exposure, which is performed by conducting a *weight-of-evidence review*, i.e., a systematic evaluation of the relevant scientific research. The next step is a *dose-response assessment* to determine the level of exposure at which a health risk might occur. Complementary to the dose-response assessment, an exposure assessment is performed to measure or estimate the magnitude, frequency, and duration of exposure to characterize the circumstances under analysis. Finally, a *risk characterization* is developed that provides a summary evaluation of a health risk based on the results of the hazard identification/weight-of-evidence review, dose-response assessment, and exposure assessment.[4]

Hazard identification/weight-of-evidence review

The review of scientific research is more than a collection of facts; rather, it is a method of obtaining and evaluating data to assure its accuracy and to determine whether the data correctly describes physical and biological phenomena. Since the proximity or co-occurrence of events or conditions does not guarantee a causal relationship, scientists use systematic methods to evaluate observations and assess the potential impact of a specific agent on human health.

Hazard identification involves analyzing *all* the evidence on a particular issue in a systematic and thorough manner. This analysis, a weight-of-evidence review, is conducted for three, broad research areas: epidemiology (observational studies of humans), *in vivo* research (laboratory

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[3] For the risk assessment process specific to electromagnetic field exposure utilized by scientific review panels, see General Approach to Protection Against Non-Ionizing Radiation (ICNIRP, 2002, pp. 541-544); Possible Effects of Electromagnetic Fields (EMF) on Human Health (SCENIHR, 2007, pp. 12-13); Recent Research on EMF and Health Risks (SSM, 2009, pp. 5-7); and Electromagnetic Fields: Annual Update 2008 (HCN, 2009, pp. 81-91).

[4] http://epa.gov/riskassessment/basicinformation.htm#arisk

studies of animals), and *in vitro* research (laboratory studies of cells and tissues). A weight-of-evidence review is designed to ensure that scientific studies with a given result are not selected out from the available evidence to advocate or suppress a hypothesis about an adverse effect. Three basic steps define a weight-of-evidence review: a systematic review of the published literature to identify relevant studies, an evaluation of each study to determine its strengths and weaknesses, and an overall evaluation of the data, giving more weight to higher-quality studies (i.e., well-designed and properly conducted).

Dose-response assessment

The concept of dose-response is a familiar part of daily life. A common household substance, bleach (sodium hypochlorite) provides a relevant example. Household bleach contains a highly-concentrated, 6 percent solution of sodium hypochlorite and carries a warning label that it is a hazardous and corrosive substance. A similar, but highly-diluted solution of sodium hypochlorite is used to disinfect many municipal drinking water supplies; in this case, the concentration of sodium hypochlorite is extremely low, and the dose is far too low to produce a toxic effect.

Almost anything in our environment can produce adverse effects if the exposure is high enough or occurs over a long period of time, so the goal for scientists is to determine the level and period of exposure below which adverse effects do not occur. A simple principle of the dose-response relationship for chemicals or physical agents that could affect biological functions is 'more is worse.' For this reason, laboratory experiments strive to expose animals at the highest level tolerated, to ensure that potential adverse effects are not missed. Should adverse effects result, subsequent experiments are performed that utilize lower levels of exposure to identify a level that does not produce adverse effects. Studies that demonstrate increased risks with higher dose are indications of a dose-response pattern, which, if consistent across valid studies, support inferences of a causal relationship.

Exposure assessment

The third step is to determine the way in which people could be exposed in a specific situation, including the amount and duration of exposure. This is important because an individual's exposure is one of the major factors for determining the potential for an impact on health. In the case of this report, the exposure assessment involves calculations of RF levels associated with the smart meter network and a comparison of those levels to relevant scientific guidelines and standards.

Risk characterization

The fourth step, risk characterization, is the final overall health risk conclusions that result from an evaluation of the hazard identification/weight-of-evidence review, the dose-response assessment, and the exposure assessment. The risk characterization will provide a summary evaluation of the weight of evidence in support of or against a health risk for the exposure of interest.

Weight-of-evidence review process

As mentioned above, a weight-of-evidence review evaluates data from three types of studies (Figure 1), which complement one another because of the inherent limitations of each type (discussed in the following section). Similar to puzzle pieces, the results of epidemiology and experimental studies are placed together to provide a picture of the possible relationship between exposure to a particular agent and disease.

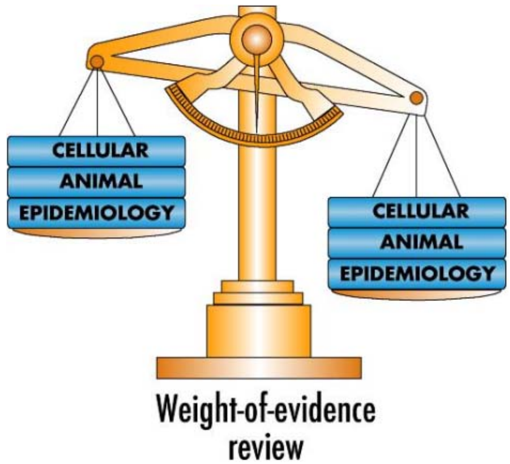

Figure 2. Weight-of-evidence reviews consider three types of research

A weight-of-evidence review is essential for arriving at a valid conclusion about a causal relationship because no individual study is capable of assessing causation with any reliability. Rather, evaluating that relationship is an inferential process that is based on a comprehensive assessment of all the relevant scientific research. The final conclusion of a weight-of-evidence review is a conservative evaluation of the strength in support of or against a causal relationship for each area of research, with primary focus on epidemiology studies and long-term *in vivo* studies. *In vitro* studies are also evaluated to determine whether they provide evidence of a mechanism for adverse effects that have been determined in the hazard identification, but provide less relevant data to the overall evaluation because the effects that occur in isolated cells and tissues may not be relevant when extrapolated to animals or humans.

2. Methods for Evaluating Scientific Research

Evaluating epidemiology studies

Epidemiology is the scientific discipline that studies the patterns and occurrence of disease in human populations and the factors that influence those patterns. Epidemiology studies examine and analyze people in their everyday setting, so by design, epidemiologists have little control over a study once it begins. Generally, epidemiologists enroll participants into studies, gather data on medical and life histories, and evaluate this data in relation to the health effect being studied. The two main types of epidemiology studies are *case-control studies* and *cohort studies* (Figure 2), and the main goal of an epidemiology study is to quantify and evaluate an *association*, i.e., the statistical measure of how exposures and health outcomes vary together in a study population.

A case-control study compares the characteristics of people with a disease (i.e., cases) to a similar group of people who do not have the disease (i.e., controls). The prevalence and extent of past exposure to a particular agent is estimated in both groups to assess whether the cases have a higher exposure level than the controls, or vice versa. A cohort study is the reverse of a case-control study in that researchers study a population without a disease and follow them over time to see if persons with a certain exposure develop disease at a higher rate than unexposed persons. Typically, a case-control study reports an association as an odds ratio (OR) and a cohort study reports an association as a relative risk (RR). An OR or RR $\leq$ 1.0 is generally interpreted to indicate there is no statistical association between the exposure and disease; conversely, a result > 1.0 may indicate that exposure will increase the risk of disease (Figure 3). A result of > 1.0, however, does not necessarily indicate there is a causal relationship. The interpretation of epidemiology studies requires a rigorous analysis of the influences of many other variables—such as chance, bias, or confounding—that may affect study results.

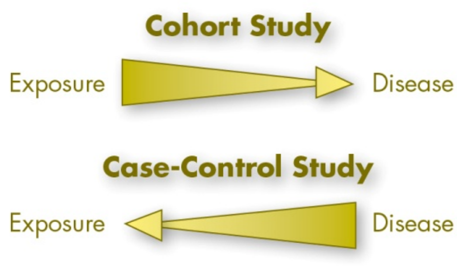

Figure 3. Basic design of cohort and case-control studies

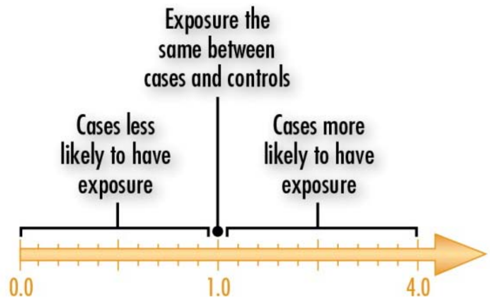

Figure 4. Interpretation of an odds ratio in a case-control study

Chance in epidemiology studies

Chance refers to a random event. In epidemiology studies, a statistical tool that is used to evaluate whether an association is due to chance is the confidence interval (CI). This can best be understood as a margin of error. Epidemiology studies typically use a 95% CI, which will indicate that if the study were conducted a large number of times, 95% of the measured estimates would be within the upper and lower limits. A resulting CI that does not include the value 1.0 is unlikely to be due to chance alone; these results are referred to as statistically significant. If an association if statistically significant, it is then necessary to determine whether other factors, such as bias or confounding, are affecting the results.

Bias in epidemiology studies

The systematic error in the design, conduct, or analysis of an epidemiology study is called bias. If bias is affecting a study's result, the estimate of an exposure's effect on the risk of disease may be distorted. The effect of bias on case-control studies is more prevalent because of their retrospective nature and the greater possibility of error in the selection process for the control group. Generally, persons selected for a control group are less likely to participate because they are healthy; if the remaining participants in the control group differ meaningfully from the case group, exposure comparisons may no longer be valid. Exposure misclassification bias, which is an erroneous classification of participants' exposure levels, is particularly relevant to studies of RF field exposure because of the difficulty in determining a valid exposure method or metric.

Confounding in epidemiology studies

Confounding is a situation in which an association is distorted because, in addition to the exposure under investigation, other risk factors may independently affect the development of disease. A hypothetical example is an association between coffee drinking in expectant mothers and low birth weight babies. Some women who drink coffee, however, also smoke cigarettes. When the smoking habits of expectant mothers are taken into account, coffee drinking may not be associated with low birth weight babies when the confounding effect of smoking has been removed.

As part of the weight-of-evidence review process, each epidemiology study is weighted and classified as providing sufficient, limited, or inadequate evidence in support of the adverse health effect being examined or suggesting the lack of an adverse health effect. In the case of sufficient evidence, the role of chance, bias, and confounding on the observed association must have been ruled out with reasonable confidence. If chance, bias, and confounding cannot be ruled out with reasonable confidence, then the data are classified as limited evidence. Inadequate evidence describes a data set that lacks quality, consistency, or power for conclusions regarding causality to be drawn.

Evaluating experimental studies

The results of experimental studies complement the findings of epidemiology studies. These two approaches are needed because humans have large variations in their genetic makeup, daily exposure levels, dietary intake, and health-related behaviors that cannot be controlled for in epidemiology studies. In laboratories, these variables can be more rigorously controlled to provide more precise information regarding the effects of an exposure.

A wide variety of approaches is available for assessing the possible adverse effects associated with exposures in experimental studies. The two general types of experimental studies are *in vivo* studies of whole animals and *in vitro* studies of isolated cells and tissues.

In vivo animal studies

Studies in which laboratory animals receive high exposures in a controlled environment provide an important basis for evaluating the safety of environmental, occupational, and drug exposures. These approaches are widely used by health agencies to assess risks to humans from medicines, chemicals, and physical agents (WHO, 1994; IARC, 2002; USEPA, 2002; USEPA, 2005). From a public health perspective, long-term (chronic) studies in which animals undergo exposure over most of their lifetime, or during their entire pregnancy, are of high importance in assessing potential risks of cancer and other adverse effects. In these long-term studies, researchers examine a large number of anatomical sites to assess changes and adverse effects in body organs, cells, and tissues.

These data are used in the hazard identification step of the risk assessment process to determine whether an environmental exposure is likely to produce cancer or damage organs and tissues. Health Canada mandates that lifetime *in vivo* studies or *in vivo* studies of exposures during critical sensitive periods are conducted to assess potential toxicity to humans (Health Canada, 1994). Furthermore, the Environmental Protection Agency's position is that, "…the absence of tumors in well-conducted, long-term animal studies in at least two species provides reasonable assurance that an agent may not be a carcinogenic concern for humans" (USEPA, 2005, pp. 2-22).

In vitro studies

In vitro studies are used to investigate the way that exposure acts on cells and tissues outside the body (mechanism of action) for effects that are observed in living organisms. The relative value of data from *in vitro* tests to a human health risk assessment is treated by the International Agency for Research on Cancer (IARC) and other agencies as supplemental to data obtained from *in vivo* and epidemiology studies. Responses of cells and tissues outside the body may not reflect the response of those same cells if maintained in a living system, so their relevance cannot be assumed (IARC, 1992). It may be difficult to extrapolate from simple cellular systems to complex, higher organisms to predict risks to health because the mechanism underlying effects observed *in vitro* may not correspond to the mechanism underlying complex processes like *carcinogenesis*. In addition, the results of *in vitro* studies cannot be interpreted in terms of potential human health risks unless they are performed in a well-studied and validated test system.

Convincing evidence for a mechanism that explains an effect observed in experimental or epidemiology studies can add weight to the assessment of cause-and-effect, and in some cases may clarify reasons for different results among species, or between animals and humans. *In vitro* studies are not used, however, by any health agency to assess risks to human health directly.

Replication of scientific research findings is the key to determining the reliability of any scientific claim. Confirmation of claims by multiple investigators from different research groups and the use of different methods help to strengthen confidence in the claim. In addition, experimental studies that are conducted in a 'blinded' fashion are given greater weight because they minimize potential bias and of investigators in the collection and analysis of data.[5]

Experimental research methods - cancer

Cancer research in the laboratory includes studies of various stages of cancer development. Research has established that cells may take several steps to change from ordinary cells to the uncontrolled growth typical of cancer. Cancer usually begins with a mutation, that is, an irreversible change in the genetic material of the cell. This is known as *initiation*. Other steps, or stages, must occur for a cancerous cell to develop into a tumor, one of which is *promotion*. Some exposures affect both of these stages and are known as complete carcinogens. Other types of exposures affect only initiation or only promotion.

In vitro bioassays are laboratory tests that isolate specific cells or microorganisms in a test tube or culture dish to assess the likelihood that exposure to an agent can cause mutations, a step necessary in the initiation of cancer. *In vivo* initiation tests also have been developed for animals, in which scientists expose the animals for less than lifetime periods to determine

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[5] Similarly, epidemiology studies that are conducted in a 'blinded' fashion minimize the potential bias of the reports of human subjects.

whether an exposure causes changes typical for the early stages of cancers in specific tissues such as liver, breast, or skin.

Other tests are designed to ascertain whether a specific exposure can stimulate tumor growth (i.e., promotion) in an animal in which cellular changes typical of initiation have already occurred. Studies of promotion include two steps: first, the animals are exposed to a chemical known to initiate cancer, and second, the animals are exposed to the agent to be tested as a promoter. The occurrence of cancer in animals exposed to an initiator and promoter is compared to the occurrence of cancer that develops in animals exposed only to the initiator.

Experimental research methods - reproductive and developmental toxicity

Studies in animals are used to assess whether an exposure can pose a risk to humans *in utero*. Experimental studies in pregnant animals provide a means for isolating the exposure in question from the myriad of other factors that can affect prenatal development. The results of these well-controlled animal studies are used by regulatory agencies to assess prenatal risk and help set human exposure limits (USEPA, 1991; USEPA, 1998; NTP, 2011).

To test the potential for an exposure to affect fetal development, pregnant mammals such as mice, rats, or rabbits are exposed from the time the embryo is implanted in the uterus to the day before delivery. Variations in study design include preconception exposure of the female in addition to exposure during gestation, and even further exposure after the animal is born. Protocols generally specify that the dose is set below the levels known to cause maternal toxicity, that unexposed controls are maintained at the same time period, and that the animals' health is monitored throughout the study. Endpoints measured include maternal body weight and weight change, the number and percent of live offspring, fetal body weight, the sex ratio, and external, soft tissue, or skeletal variations and malformations. The uterus can also be examined to assess the number of implantations and fetuses that have been lost, as an indication of miscarriage (USEPA, 1998).

Evaluating the cumulative body of experimental evidence

Key factors in evaluating individual *in vivo* studies include:

- The details of the protocol. Standard protocols usually specify at least 50 animals of each sex per dose level, in each of three different dose groups.
- The study design, including methods to minimize bias, and the analysis of the results.
- The adequacy of the dose levels selected.
- The way the study was actually conducted, including adherence to good laboratory practices in animal housing and monitoring.
- The evaluation of the effects on toxicity, tumors, or malformations, considering both biological and statistical issues (USEPA, 2005).

3. Exposure Estimation for Radiofrequency Fields

One of the most crucial aspects in the review of any epidemiology study is an evaluation of how exposure was measured. A good exposure metric should measure each individual participant's exposure to the agent under study from all sources at the appropriate time in the disease process. Measuring exposure to RF fields is difficult, however, for several reasons. In case-control studies, exposure must be estimated retrospectively, introducing the possibility of recall bias. In addition, while the use of personal exposure meters (exposimeters) can collect real-time measurements for far-field sources, the devices can be inconvenient or laborious for the participants, and it is not clear how near-field sources (such as mobile or cordless phones) affect the measurements. Also, the appropriate exposure metric and timing of exposure is unknown because of the absence of substantive knowledge about a specific mechanism by which RF energy could affect normal cells. Therefore, the focus on long-term exposure is based upon the standard assumption that exposure affecting the development of chronic disease such as cancer requires repeated exposure at elevated levels, similar to exposure to other known cancer causing agents such as tobacco smoke, alcohol, sunlight, and certain chemicals.

Different sources contribute differently to individual RF exposure, and although exposimeters have been recommended to measure RF exposure from far-field sources, their use is limited in large epidemiology studies because of their high costs and the effort required of participants to use them. Devices to measure total personal exposure have not been available or efficient to use, therefore exposure to RF has been estimated in epidemiology studies using a variety of surrogates to estimate RF exposure. Surrogates are useful in epidemiology studies when interest focuses on exposure from a specific source, but since there are many sources that can contribute to a person's RF exposure, surrogates may not provide a valid estimate of exposure for studies of RF and health. A group of investigators (Frei et al., 2010) recently evaluated the accuracy of surrogates for RF exposure by comparing them to personal measurements taken with an exposimeter (with and without the factor of mobile and cordless phone use), by correlating the results for a group of participants. The exposure surrogates they investigated included:

- Spot measurements at specific locations in the bedroom of a home, using a RF meter;[6]
- Distance from the nearest fixed transmitting source such as a television broadcasting transmitter or mobile phone base station measured by geocoding;
- A geospatial propagation model of RF levels calculated from a fixed source, using specific information on characteristics of the source transmitter;
- A full-exposure prediction model, considering multiple sources, individual information on communication devices, and behavioral characteristics such as time at home and in vehicles; and
- Self-assessment of exposure using a questionnaire.

The authors concluded that surrogates relying on distance only had limited accuracy for an exposure assessment given the variation in transmitting characteristics among sources and potential shielding and reflections of RF fields by buildings. Therefore, distance was reported to be an inappropriate surrogate for personal RF exposure. Calculations based on specifics of the technology provide more reliable estimates, but they only capture exposure from one type of source. The full exposure prediction model had the highest correlation to personal measurements, followed by spot measurements, and the geospatial propagation model. Since spot measurements record data in one location in a home, they are often used in studies of effects of short-term exposures, such as effects on sleep.

Exposure estimates of RF fields in epidemiology studies, even calculated levels, are not the same as actual RF levels encountered briefly at a single, fixed location, such as at the fence line of a radar station or next to a smart meter. The exposure estimate in epidemiology studies is intended to reflect the average person's exposure to RF fields over a specified period of time (i.e., time-averaged). It is evident then that brief instantaneous encounters with RF fields (for

6 RF meters measure RF intensity at a specific point in a specific location, which can be used to estimate an individual's exposure at that location. Exposimeters collect cumulative RF measurements on an individual over time, which are used to estimate exposure during a time span.

example, driving by a television broadcast transmission antenna or walking by a household's smart meter) would not significantly alter a person's long-term, time-averaged RF exposure.

Research also has been conducted on occupational exposure to RF fields given that a higher range of exposure typically occurs in the occupational environment compared to the general public. These studies generally use a person's occupational title or work history by job or task (job exposure matrix) to estimate exposure. Many early studies relied on occupational title taken from a death certificate. Later studies used a job exposure matrix to estimate the overall magnitude of a person's occupational RF exposure. Both methods have limitations. Death certificate data is often inaccurate, and a job exposure matrix may not take into account variation in exposure due to different job tasks within occupational titles, the frequency and intensity of contact to relevant exposure sources, or variation by calendar time.

Basis for regulatory standards and exposure limit guidelines

Government agencies and technical organizations are likely to promulgate regulatory standards or guidelines for limiting human exposure to a substance or physical agent if a health risk assessment indicates a potential health hazard from high exposures. Standards-setting agencies that develop regulatory standards and guidelines rely on weight-of-evidence reviews such as those described in the following section, in which national and international scientific agencies typically convene a panel of scientists that have expertise in the relevant disciplines (FCC, 1997; Health Canada, 2009; ICNIRP, 2009). The approach scientists use to develop health-based standards whether for contaminants in drinking water or a myriad of other regulated substances, or to ensure air quality or food safety, is to set exposure levels many times below the level at which research suggests any potentially adverse effect could occur. This conservative approach lowers the exposure limit well below the lowest known effect level; this reduction below the minimal effect level is commonly called a "safety factor."

The safety factor compensates for any unrecognized limitations in the research and exposure assessment, and it affords additional protection to the general public, as well as protection for sensitive populations, such as the elderly, children, and those with certain chronic diseases. Although there have been a few recent epidemiology studies of children and exposure to RF fields, most epidemiology studies of environmental exposures do not include sensitive populations, so additional measures often are taken to ensure the safety factor is relevant.

One method used by scientists is to incorporate information about the mechanism of action, i.e., how the agent affects the human body. This information helps to identify intensity levels that may or may not produce the effect, and may help to determine whether certain populations might be more sensitive or have different reactions due to their specific biological characteristics. Another method is to conduct experimental studies of animals at varying stages in their lifetimes to determine if the young or old are potentially more sensitive to exposure. These methods incorporate the basic scientific principle of dose-response, i.e., the probability that an effect occurs, or that the severity of an effect increases with the amount of exposure.

Basis for radiofrequency exposure standards

As discussed above, RF exposure standards (exposure limits) are developed based on a review of the relevant biological and health research using established scientific methods. Exposure standards address issues of both human health and safety, so exposure limits are based on research that identifies an exposure level that has not been linked to adverse effects after short-term (acute) or long-term exposure and then incorporates an adequate margin of safety. In the case of RF energy, exposure limits are set to identify the time-averaged intensity levels of RF fields at a specific frequency range that should not be exceeded.[7]

Based on the evaluation of the scientific research, the health effect known to be caused by high exposures to RF energy in the frequency range from 100 kHz to 300 GHz is a rise in body temperature through warming of tissues. This is the basis of the applicable public exposure limit set by Health Canada's Safety Code 6 and the exposure limits set by other organizations. The goal of the standard is to set limits at levels far below that which could cause this effect, since even a modest raise in body temperature can be distracting; it should particularly be limited in a work environment where such distractions can affect productivity. In addition,

7 Standards are also used for specifications for manufacturing products to ensure safe construction, or conformity or compatibility among different companies that make the same item, but in this report we are referring to safety and health standards.

higher exposure levels can lead to more serious adverse effects, including local cell damage and hyperthermia. In order to avoid these more serious effects, exposure limits in the RF standards are set below the level at which even minor effects from tissue heating might occur (FCC, 1997; FCC, 1999; Health Canada, 2009; ICNIRP, 2009).

Relevant standard in Canada

Industry Canada is responsible for regulating Canadian industries that produce RF energy in their operations, such as radiocommunications facilities and radio and television broadcasting installations. Health Canada, as part of its mandate to protect the health of Canadians, conducts research and investigations to recommend health protection limits to a myriad of common exposures such as RF energy. The limits developed by Health Canada in its document "*Limits of Human Exposure to Radiofrequency Electromagnetic Energy in the Frequency Range from 3kHz to 300 GHZ,*" have been adopted by Industry Canada for the purpose of protecting the general public and workers in occupations with high RF exposure levels (Health Canada, 2009). These guidelines, also referred to as Safety Code 6, were first developed in 1979. They are the result of continuous evaluations of published scientific studies, reviews, as well as research conducted by Health Canada. The most current update of Safety Code 6 is based on research and reviews of the scientific literature on RF energy that were published between 1999 (the date of the last update) through August 2009. Specifically, Safety Code 6 states that the exposure limits specified were established,

> … based upon a thorough evaluation of the scientific literature related to the thermal and possible non-thermal effects of RF energy on biological systems. Health Canada scientists consider all peer-reviewed scientific studies, on an ongoing basis, and employ a weight-of-evidence approach when evaluating the possible health risks of RF energy. This approach takes into account both the quantity of studies on a particular endpoint (whether adverse or no effect), but more importantly, the quality of those studies. Poorly conducted studies (e.g. incomplete dosimetry or inadequate control samples) receive relatively little weight, while properly conducted studies (e.g. all controls included, appropriate statistics, complete dosimetry) receive more weight. The exposure limits in Safety Code 6 are based upon the lowest exposure level at which scientifically-established human health hazards occur. Safety factors have been incorporated into these limits to add an additional level of protection for

the general public and personnel working near RF sources. The scientific approach used to establish the exposure limits in Safety Code 6 is comparable to that employed by other science-based international standards bodies. As such, the basic restrictions in Safety Code 6 are similar to those adopted by most other nations, since all recognized standard setting bodies use the same scientific data. It must be stressed that Safety Code 6 is based upon scientifically-established health hazards and should be distinguished from some municipal and/or national guidelines that are based on socio-political considerations (Health Canada, 2009, p. 7).

4. Scientific Reviews of Radiofrequency Fields and Health

Scientific research on RF exposure and health is reviewed regularly by independent scientific and governmental organizations worldwide. These organizations assemble expert panels, whose members have the knowledge and mandate to review relevant research and provide scientifically-grounded public health recommendations. In the past five years, several of these organizations have conducted weight-of-evidence reviews of the most current epidemiology, in vivo, and in vitro studies on this subject. Health Canada, the Health Council of the Netherlands (HCN), the International Commission on Non-Ionising Radiation Protection (ICNIRP), the Scientific Committee on Emerging and Newly Identified Health Risks (SCENIHR), the Swedish Radiation Safety Authority (SSM), and the Health Protection Agency of Great Britain (HPA) all have reviewed the research and independently supported establishing exposure limits on the basis of tissue heating or they have developed exposure limits for RF energy in various frequency ranges (HCN, 2009; ICNIRP, 2009; SCENIHR, 2009; SSM, 2009, 2010; HPA, 2012). A recent review conducted by the California Council on Science and Technology (CCST), which released its final report in April, 2011, focused exclusively on smart meters. The independent Advisory Group on Non-Ionizing Radiation (AGNIR) noted that organizations conducting smart meter exposure assessments have concluded that even under maximum exposure scenarios, exposure would be well within ICNIRP's exposure limits (HPA, 2012).

Based on their review of the research, all these agencies have concluded that RF exposure below the exposure limits developed by ICNIRP does not cause cancer or chronic diseases. In addition, their conclusions determined that adverse physiologic changes or adverse symptoms that affect well-being are not caused by exposure to RF energy within the limits for the general public determined by ICNIRP.

While some studies have reported non-thermal effects, i.e., effects that occur at RF exposure levels below that which raises body tissue temperature, the data in these studies have not been accepted as reliable because the observed biological effects were not consistent or reproducible.

In addition, the data are not supported by any plausible biological explanation as to how the effects could occur, and the biological effects reported in some of these studies are not known to be linked to adverse health effects (NRPB, 2003; NRPB, 2004; HCN, 2009; ICNIRP, 2009; SCENIHR, 2009; SSM, 2010; HPA, 2012).

Health Protection Agency

Health Effects from Radiofrequency Electromagnetic Fields

The report of the HPA was prepared by the independent Advisory Group on Non-ionizing Radiation, which reviewed research about RF and health through 2010 and part of 2011 to update its previous reports on electromagnetic fields since the agency was formed in 1999 (HPA, 2012). The review and assessment includes research on mechanisms of interaction with the human body and a variety of potential health impacts studied in cells, animals, and humans, including cancer, reproduction, immune response, symptoms and other effects on the nervous system. The report supports existing guidelines on limiting exposure such as ICNIRP's restrictions and Federal Communication Commission (FCC) limits, and commented regarding smart meters that "…given the low output power of typical devices, it is not expected that people's exposure will exceed the ICNIRP restrictions" (p. 55). The report concluded specifically as follows (pp. 318-320):

- Cellular studies have not provided robust evidence for an effect. "At present there is no known pattern of exposure conditions that has been shown consistently to cause a biological effect from exposures below guideline levels."

- Animal studies published have used a wide range of biological models, exposure levels, and signal modulations. There is no clear evidence of harmful effects from low level exposures, and large scale studies of initiation and development of cancer have been negative.

- "Studies of cognitive function and human performance measures do not suggest acute effects of RF field exposure from mobile phones and base stations."

- "The overall results of epidemiological studies to date do not demonstrate that the use of mobile phones causes brain tumours or any other type of malignancy, nor do they suggest causation is likely."

California Council on Science and Technology

Health Impacts of Radiofrequency Exposure from Smart Meters

The CCST has conducted the only review by a scientific panel that specifically addresses the health impacts of RF fields from smart meters.[8] To evaluate health questions, the CCST project team reviewed documents such as research papers and reviews, consulted with experts, and solicited written comments from experts in biology and medical sciences, physical sciences, and engineering (CCST, 2011). The report addresses topics such as RF emission levels, thermal and non-thermal effects, and the appropriateness of the relevant RF standard. The main conclusions of the CCST are:

- Smart meters emit lower levels of RF energy than many common household devices such as mobile phones and microwave ovens.
- The scientific studies conducted through 2010 "have not identified or confirmed negative health effects from potential non-thermal impacts of RF emissions such as those produced by existing common household devices and smart meters."
- The FCC guidelines[9] are acceptable and include a wide margin of safety, i.e., the recommended exposure limits are set well below levels where research indicates that effects could occur.

[8] The CCST was established in 1988 by the California state legislature and charged to "… offer independent expert advice to the state government and to recommend solutions to science and technology-related policy issues."

[9] The FCC standard is the relevant standard in the United States for RF-emitting devices such as smart meters and mobile phones. It is based on thermal effects, includes safety factors, and is comparable to Canada's Safety Code 6.

- The smart meters proposed for use by California utility companies emit RF energy that is a very small fraction of the exposure level established as safe by FCC guidelines.

- Based on current knowledge of potential non-thermal impacts, no other standards are needed to protect health.

The International Agency for Research on Cancer

IARC Monographs on the Evaluation of Carcinogenic Risks to Humans, Volume 102: Non-Ionizing Radiation, Part II: Radiofrequency Electromagnetic Fields (Not yet published)

In May 2011, the IARC convened a scientific panel to review the evidence on RF exposure and cancer and prepare a monograph, which is yet to be published.[10] Scientists with expertise in the various areas related to RF energy reviewed approximately 900 published studies on RF fields and cancer that considered the following sources of exposure:

- Environmental – broadcast antennas, base stations, medical devices, smart meters, and WiFi.

- Occupational – hi-frequency dielectric and induction heaters and radar installations.

- Personal Devices – cordless telephones, mobile telephone, Bluetooth devices.

These data covered several related areas, including: exposure parameters, cancer epidemiology, cancer in laboratory animals, and mechanistic data. The IARC's full report is not yet available, but a summary of the main conclusions of their review was published in July 2011 (Baan et al., 2011). The Working Group rated both epidemiologic and *in vivo* data as providing "limited evidence" for cancer. The epidemiologic data reported positive associations between use of mobile phones and a type of brain cancer. They also rated *in vivo* studies for carcinogenicity of RF exposure as providing "limited evidence" for cancer.

In the IARC's classification system, data is rated as providing "limited evidence" for cancer if a positive association between an exposure and cancer is found, although factors such as chance,

[10] The IARC is an agency of the World Health Organization. The agency's mission is to "coordinate and conduct research on the causes of human cancer, the mechanisms of carcinogenesis, and to develop scientific strategies for cancer prevention and control" (http://www.iarc.fr/).

bias, and confounding cannot be ruled out with reasonable confidence. The conclusion of "limited evidence" caused the IARC to include RF exposure in Group 2B "possibly carcinogenic to humans."

The IARC's categories err on the side of caution. Since 1971, when the IARC began to categorize agents by their current system, 946 agents have been reviewed.[11] Only one (caprolactam) has been classified as "probably not carcinogenic to humans" (Group 4). The vast majority of substances are classified as "possibly carcinogenic to humans" (Group 2B) or "not classifiable" (Group 3), leaving 107 substances classified as "carcinogenic to humans" (Group 1) and 61 "probably carcinogenic to humans" (Group 2A). Group 2B denotes exposures for which there is limited evidence of carcinogenicity in epidemiology studies and less than sufficient evidence of carcinogenicity in experimental studies of animals. Occupational exposures in textile manufacturing and firefighting, for example, are classified as 2B, as are substances such as pickled vegetables and coffee.

The IARC's classification of RF fields in Group 2B is based on the review of studies involving RF exposure from mobile phones. Although the Baan et al. (2011) summary is based on the IARC review panel's findings, they do not comment on the level of exposure. It should be noted that near-field exposure from mobile phones is far greater than the time-weighted average far-field exposure from smart meters. In addition, the degree to which exposures from mobile phones can be extrapolated to much lower exposures from devices such as smart meters is unknown. If a risk were to be confirmed for mobile phones, the risk for exposures to sources at much lower intensities, such as such as smart meters, would be expected to be lower as well based on the dose-response principle discussed previously.

[11] http://monographs.iarc.fr/ENG/Classification/index.php

The Swedish Radiation Safety Authority

Recent Research on EMF and Health Risk–7th Annual Report from SSM's Independent Expert Group on Electromagnetic Fields

The SSM published their most recent annual review on electromagnetic fields in December 2010. The agency's Independent Expert Group evaluated studies published in 2009 and 2010, including several that were available ahead of print in 2010 and published in 2011.

In particular, the SSM panel reviewed the INTERPHONE Study Group's (2010) pooled analysis of glioma and meningioma, two types of brain cancer, and identified both recall bias and participation bias as possible sources of systematic error in the study (discussed in detail in Section 5); this same conclusion was reached by the study authors as well (The INTERPHONE Study Group, 2010). The SSM also pointed out that although the Interphone Study could not provide a final resolution on the issue of mobile phones and brain cancer, they were able to exclude "with a high degree of certainty" risk from short-term mobile phone use, while "uncertainty still remains regarding very intensive and long-term use" (SSM, 2010, p. 37). The SSM's overall conclusion regarding the Interphone Study is that "the advent of these new data does not change the overall picture being that for up to about ten years of mobile phone use associations with brain tumour risk are unlikely" (SSM, 2010, p. 4).

The SSM also reviewed current scientific studies on RF exposure from mobile phone base stations and television and radio transmitters and various health outcomes. They concluded that "available data do not indicate any risks related to exposure to RF from base stations or radio or TV antennas. Taking into account also the low levels of exposure that these sources give rise to, health effects from transmitters are unlikely" (SSM, 2010, p. 4).

The Health Council of the Netherlands

Electromagnetic Fields: Annual Update 2008 and
Influence of Radiofrequency Telecommunications Signals on Children's Brains 2011

The HCN has issued two relevant reviews on the subject of radiofrequency fields and health since 2009. The Electromagnetic Fields Committee of the HCN issues annual updates on electromagnetic field research that focus each year on a topic or topics that have been at the forefront of reporting in both scientific journals and the general media during the previous year. The committee's fifth annual update for 2008, published in March 2009, focused entirely on the effects of electromagnetic fields on the nervous system. They reviewed studies of brain electrical activity, hearing and balance, regional cerebral blood flow, and cognitive functioning (e.g., memory, attention, and concentration). Their review concluded:

> Exposure to radiofrequency electromagnetic fields produced by mobile phones may lead to subtle changes in brain activity. However, the observed effects are temporary and small and, as far as is known, have no effect on health. The picture that emerges from studies of effects on cognitive functioning is unclear: some studies found minor and reversible effects while others found no effect (HCN, 2009, p. 97).

In October 2011, the HCN's Electromagnetic Fields Committee issued an advisory report on the effects of RF fields on the developing brains of children due to the continued interest in this topic and the increase in the number of studies available for review since the committee last addressed this topic in 2005.[12] They examined short-term effects only because there is very little data available on long-term effects in children. The committee concluded the following regarding brain development and function and effects on behavior and cognition:

> **Brain Development and Function**
>
> The Committee feels that consistent effects of exposure to radiofrequency electromagnetic fields on brain function in children have not been demonstrated. Insofar as effects were observed, they are temporary and minor and there are no signs that they can influence health. Animal studies also fail to demonstrate effects on brain function (HCN, 2011, p. 25).
>
> **Effects of Behavior and Cognition**
>
> Exposure to radiofrequency electromagnetic fields appears not to have a clear effect on behaviour and cognition in children. Animal studies only

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[12] The HCN reviewed research on radiofrequency fields and effects in children in an advisory report in 2002 and an advisory letter in 2005. These reviews, however, were limited by the scant amount of research that was available at the time. As the HCN points out, the call by HCN, the World Health Organization, and other scientific agencies for research to address this subject was answered. The new research justified their re-analysis of the available data, which resulted in their 2011 advisory report.

> used rats, and are therefore less relevant in the eyes of the Committee. A general problem in both studies with children and animal studies is the limited number of studies and, with one exception the small number of human subjects or animals per study (HCN, 2011, p. 26).

The International Commission on Non-Ionizing Radiation Protection

Exposure to High Frequency Electromagnetic Fields, Biological Effects and Health Consequences (100 kHz-300GHz)

In 2009, ICNIRP issued the results of their comprehensive review of the substantial body of research on RF fields and health effects (ICNIRP, 2009). Their review covered a period from 1998 through 2008 and was conducted specifically to provide a detailed analysis of the research since the publication of their 1998 exposure limits (ICNIRP, 1998). The review was conducted for three distinct research areas: dosimetry of high frequency RF fields, experimental studies of biological effects, and epidemiology studies, each of which covers a wide variety of topics and outcomes.

Based on their evaluation of the scientific evidence for biological effects at levels below those attributable to heating (i.e., non-thermal), the ICNIRP panel concluded:

> It is the opinion of ICNIRP that the scientific literature published since the 1998 guidelines has provided no evidence of any adverse effects below the basic restrictions and does not necessitate an immediate revision of its guidance on limiting exposure to high frequency electromagnetic fields. … With regard to non-thermal interactions, it is in principle impossible to disprove their possible existence but the plausibility of the various non-thermal mechanisms that have been proposed is very low. In addition, the recent in vitro and animal genotoxicity and carcinogenicity studies are rather consistent overall and indicate that such effects are unlikely at low levels of exposure. Therefore, ICNIRP reconfirms the 1998 basic restrictions in the frequency range 100 kHz–300 GHz until further notice (ICNIRP, 2009, p. 257).

More specifically, in their evaluation of studies on symptoms of well-being, they concluded:

> The evidence from double-blind provocation studies suggests that subjective symptoms, such as headaches, that have been identified by some individuals as associated with RF exposure, whilst real enough to the individuals concerned, are not causally related to EMF exposure (ICNIRP, 2009, p. 274).

5. Current Research on Radiofrequency Fields

The reviews conducted by scientific and governmental agencies are the benchmark for an overall assessment of health risk, but since there is often a time lapse between the publication dates of comprehensive reviews, other scientific data also must be evaluated to determine if any new evidence is available that may alter the conclusions of the most recent reviews.

This section evaluates studies of exposure to low levels of RF energy (both far-field and near-field exposure) and adverse effects such as cancer and non-specific symptoms that, for the most part, have been published in the past few years, and thus may not have been considered in the reviews discussed in the previous section.[13] More focus is placed on higher quality epidemiology and *in vivo* studies, regardless of the authors' conclusions. A number of weaker studies are noted as well, e.g., studies that utilize inadequate controls, proxy measurements, or a small sample size, but they provide little useful information overall to a risk assessment.

Studies of cancer

Studies of RF energy and cancer outcomes have been conducted since the 1970s. The number of studies had increased markedly in the last fifteen years, the time period in which the use of mobile phones became increasingly common. Epidemiology studies and long-term *in vivo* studies provide the most direct information about the effect of RF exposure on cancer development. Epidemiologists have examined mobile phone use and time trends in tumors with specific attention on brain cancer since the location on the body with the greatest potential exposure is the head. Laboratory studies of long-term exposure to animals, including exposures to the head, have been conducted as well. Exposure to RF fields from television and radio broadcast antennas and mobile phone base stations have been studied both by epidemiologists and in the laboratory. Since smart meters are a relatively new technology, there are few reviews or studies on exposure from this specific device; however, since frequencies used in mobile phones are similar to those used by smart meters, the emphasis in this report is on studies of

[13] There are no recent studies on RF from radar and cancer and only one recent study on RF from mobile phone base stations and cancer, so earlier studies are included in our discussion.

mobile phone use and health outcomes. It should be noted, though, that the intensity (strength) of RF fields from smart meters, under foreseeable use, is lower than that of mobile phones, and it is generally a far-field rather than a near-field exposure.

Epidemiology studies

The epidemiology studies reviewed in this section are grouped by exposure source (mobile phone base stations; AM/FM radio or TV broadcast transmitters; radar installations; and mobile phones). Currently the greatest source of individual exposure to RF fields for most people is from the use of mobile phones, for which a large set of epidemiology studies and pooled analyses were recently completed.[14] A person's overall RF exposure from mobile phone base stations and AM/FM radio or TV antennas is typically the lowest because, like all types of electromagnetic fields, RF field strength diminishes rapidly with distance from the source, and for most people, the time spent near such sources is minimal. RF exposure from sources such as base stations, transmitters, and antennas pose difficulties for individual exposure assessments in epidemiology studies. Since individuals usually spend their time in various locations during a day, or from week to week, a valid exposure metric of average exposure from environmental sources is difficult to determine. Exposure to RF fields from radar installations may be higher than exposure from mobile phones, but typically this type of exposure only occurs in occupational settings.

Exposure from mobile phone base stations

As mentioned, it is difficult to assess human exposure from a single environmental source such as a mobile phone base station because such exposure is compounded by other sources such as nearby AM/FM radio and TV broadcast transmitters and wireless appliances and devices in the home or workplace. In addition, local populations residing in the small radius around a mobile phone base station are typically too small to support an epidemiology study. Finally, these types

[14] Other household sources such as cordless phones and WiFi also contribute to an individual's household exposure, but are much weaker contributors. Only a weak signal needed to operate a WiFi network within a residence or building. In addition, since cordless phones have a base unit connected to telephone wiring in a house, they typically operate at far lower power levels than mobile phones and so produce lower RF exposures.

of studies do not take into account cancer latency—the latency period for most cancers to develop is decades rather than a few years.

There are only a few epidemiology studies that have examined RF exposure from mobile phone base stations and cancer. Eger et al. (2004) and Wolf and Wolf (2004) both assessed the rate of cancer of adults who resided near a mobile phone base station using distance as a proxy for exposure; however, epidemiology studies that estimate RF exposure for a small population group using only distance from a single base station are unreliable. These studies have additional limitations. Both used data that combined various cancer types that occurred in persons in the locality under study. Combining cancer types, however, is not a valid method to find causality because there are over 100 diseases that have been defined as cancer. These diseases affect different cells in the body, occur at various rates, and have different etiology (ACS, 2009). No valid conclusion can be drawn from these two studies because of flaws in their methodology and the small number of participants.

Better methods of estimating exposure are needed. Elliot et al. (2010) is one of the few epidemiology studies of childhood cancer and RF exposure that used methods to estimate exposure from *all* mobile phone base stations in the vicinity of the mother's residence during pregnancy (i.e., birth address). Cases were selected from the United Kingdom's (UK) National Cancer Registry 1999-2001 (n = 1,397) and four controls per case were matched by date of birth and sex from the UK's National Birth Register (n = 5,558) for children aged 0-4. The researchers assessed the mothers' exposure by using three different metrics: distance of birth address from the nearest base station; total RF output from all base stations within 700 metres; and modeled power density at the birth address. The authors found no association between a mother's exposure to RF fields from mobile phone base stations during pregnancy and risk of cancer in children.

Exposure from AM/FM radio and television broadcast transmitters

In the past few decades, peer-reviewed scientific research on exposure to RF fields from AM/FM radio or television broadcast transmitters has focused on the risk of cancer in children and adults. Until 2003, however, much of this research utilized an ecological design method with geographic correlations around a transmitter (e.g., Hocking et al., 1996; Dolk et al., 1997a; Dolk et al., 1997b; McKenzie et al., 1998; Cooper et al., 2001). Geographic correlations rely on group data (in this case, cancer rates) in specific geographic areas rather than individual data, which is a substantial limitation. In addition, studies using geographic correlation methods suffer from poor exposure assessment because distance is used as a proxy for RF exposure. Finally, the results of ecological studies are inherently limited because they do not consider the confounding effects of other RF sources, and the use of geographic area assumes that all persons within a certain radius have the same exposure levels from the source under investigation.

After 2003, a number of case-control studies were conducted that provide more reliable epidemiologic information than studies that use ecological methods. Ha et al. (2007; 2008)[15] is a large study of RF exposure from AM radio transmitters and childhood leukemia and brain cancer (cases: n = 1,928 - leukemia, n = 956 brain cancer; controls: n = 3,082) conducted in South Korea. Merzenich et al. (2008) conducted a similarly large study (cases: n = 1,959; controls: n = 5,848) of RF exposure from AM and FM radio and TV broadcast transmitters and childhood leukemia in Germany. Both studies used calculations based on the physical characteristics of the transmitters and residential address to assess RF exposure individually for each case and control. These calculations were designed to predict each child's total RF exposure at home from all existing transmitters the year before the cancer was diagnosed.

While both Ha et al. (2007) and Merzenich et al. (2008) provide some validation of the exposure assessment model using calculations, the evidence provided by Merzenich et al. is more complete (Schmiedel et al., 2009). The German study also was stronger in several other areas. First, the study calculations used for the exposure assessment in Merzenich et al. (2008) were validated *and* published (Schmiedel et al., 2009). In addition, while Ha et al. (2007) used clinic-based controls, Merzenich et al. (2008) randomly selected population-based and three controls per case were used, which lessens the possibility of bias. Finally, RF exposure levels of participants tended to be higher. Neither study reported an elevated OR or a statistically significant association with leukemia or leukemia subtypes (lymphocytic or myelocytic

[15] Ha et al. (2008) provides a correction to the data on total RF exposure published in Ha et al., 2007.

leukemia), even in those children who had highest levels of total RF exposure (99th percentile in Merzenich et al. = 1.7-7.7 V/m). Ha et al. (2007) did not report results that suggest a link with brain cancer.

Exposure from radar

One of the most common occupational exposures to RF fields occurs at military bases where workers may be exposed from radar installations; these RF fields may be at levels greater than the safety limits set in RF exposure standards. Other settings where RF exposure is common include facilities that manufacture mobile phones and the various occupations that utilize radio communications. As discussed by Berg et al. (2006), between 1988 and 2006 seven cohort studies and two case-control studies of occupational exposure to RF fields and cancer were published. Most of these studies estimated exposure by using the proxy of occupational histories, job titles, or job descriptions rather than direct measurements.[16] One of these studies (Szmigielski, 1996) reported some statistical associations between job description and leukemia, as did an earlier study by Milham (1985), but sources of bias in the study designs and confounding from other concomitant exposures lessen the weight of these results.

Groves et al. (2002) conducted a mortality follow-up of cancers in 40,581 veterans of the Korean War who served in the United States Navy; their follow-up was a 40-year extension the original cohort study that followed these veterans through 1974 (Robinette et al., 1980). The follow-up reported no association with brain cancer or testicular cancer, but reported an association with leukemia in one of the three naval occupations (electronics technician in aviation squadrons) that were deemed *a priori* to be in the high radar exposure category.

Morgan et al. (2000) followed an occupational cohort of workers at plants that designed, manufactured, and tested wireless communications devices (e.g., two-way radios, communications devices for the military and NASA, pagers, mobile phones, and wireless communications infrastructure) for the period 1976 – 1996. The cohort included 195,775 workers (2.7 million person-years) who were classified into four exposure groups for RF: high,

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[16] One of the cohort studies was non-occupational; it examined the RF exposure of amateur radio operators (Milham, 1988).

moderate, low, and background. The investigation found no association for any group with RF exposure and brain cancer or lymphoma/leukemia risk.

These earlier studies of environmental and occupational exposures including radar and broadcast transmitters (AM and FM radio and TV stations) have been among those evaluated in scientific reviews by national and international organizations, which found no consistent or convincing evidence that RF exposure is a cause of leukemia or any other cancer (ICNIRP, 1998, 2004; NRPB, 2004; IEEE, 2005).

Mobile phone exposure

One of the few studies of mobile phone use and leukemia was conducted by a group of researchers in 2010 (Cooke et al., 2010). Their case-control study conducted in South East England investigated leukemia risk in 806 adults. The researchers found no association between regular mobile phone use and leukemia when the case group was compared to the control population (OR = 1.06; 95% CI = 0.76-1.46). In addition, Cooke et al. (2010) found no risk or positive trend in relation to increased use time in years, cumulative calls, or cumulative hours.

Studies of mobile phone use and brain cancer have been conducted more frequently than studies of other health outcomes. Recently, Aydin et al. (2011) studied mobile phone use in children and adolescents and brain cancer in a multi-center, case-control study conducted in four European countries (Denmark, Norway, Sweden, and Switzerland). Their study included 352 cases in the age range 7 to 19 years who were diagnosed between 2004 and 2008. The 646 controls were selected randomly from various population registries and matched for age, sex, and geographical region. The study's results found no association between the regular use of mobile phones and increased risk of brain tumor (OR = 1.36; 95% CI = 0.92-2.02). Risk did not increase with either duration of use or for proximity, i.e., in the area of the head closest to where a mobile phone is held.

The INTERPHONE study is the most comprehensive set of epidemiology research conducted to date on mobile phone use by adults and cancer in the head and neck region (brain and salivary gland tumors). The IARC developed and coordinated this large multi-site, multi-national project that was conducted from 16 study centers in 13 countries (Australia, Canada, Denmark, Finland, France, Germany, Israel, Italy, Japan, New Zealand, Norway, Sweden, and the United Kingdom). The INTERPHONE researchers studied malignant brain tumors (glioma), benign brain tumors (meningioma and acoustic neuroma),[17] and salivary tumors of the parotid gland, and the study designs and methods used by the researchers were similar so that the results could be combined in a pooled analysis with reasonable confidence.[18]

At all of the study centers, the researchers first determined whether or not a participant was a regular user of a mobile phone (Cardis, 2007; The INTERPHONE Study Group, 2010). Regular use was defined as at least one call per week on average for a period of at least 6 months. For regular mobile phone users, duration of use, cumulative call time, and cumulative number of calls also was determined (Cardis et al., 2007). The analysis showed that the only positive association was in the highest category of cumulative call time, in which an association with this estimate of exposure was modestly increased. There was no evidence of a dose-response trend in any of the 10 categories of cumulative call time; results showed a weaker association in the category of cumulative call time just below the highest category, which is not what would be expected if mobile phone use caused brain cancer (The INTERPHONE Study Group, 2010).

A majority of the published epidemiologic studies to date from the INTERPHONE study centers have not reported an increased risk of brain tumors or meningioma and mobile phone use; however positive associations have been reported for parotid tumors in studies in subgroups defined by longer latency period or ipsilateral use (the side of head where the mobile phone is predominantly used), compared with the location of the tumor (Lonn et al., 2006; Sadetzki et al, 2008).

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[17] Acoustic neuromas are nerve sheath tumors that arise in the eighth cranial nerve (the acoustic nerve). The location of this nerve in relation to telephone use (near ear) is of particular interest for investigating associations with tumor development and mobile phone use.

[18] A pooled analysis combines the raw, individual-level data from a group of original studies and analyzes the data from the studies together. These methods are valuable because they increase the number of individuals in the analysis, which allows for a more robust and stable estimate of association. Meta- and pooled analyses are also important tools for qualitatively synthesizing the results of a large group of studies. Information on the design, methods, and study population at all the participating study centers is detailed in an article published in the European Journal of Epidemiology (Cardis et al., 2007).

Among the studies from individual countries, or pooled over several of the countries (Christensen et al., 2005; Lonn et al., 2005; Schoemaker et al., 2005; Hepworth et al., 2006; Schüz et al., 2006a), the statistical association between mobile phone use and brain cancer consistently tended to be less than 1.0, indicating that those diagnosed with brain cancer were less likely to have been mobile phone users. If interpreted at face value, this implies a reduced risk of brain cancer with regular phone use, compared to those who never used a mobile phone.

In 2010, The INTERPHONE Study Group published the results of brain tumor risk and mobile phone use combined from all the study center results. The overall risk estimate for glioma was below 1.0 (OR = 0.81; 95% CI: 0.70-0.94) as was the overall risk estimate for meningioma (OR = 0.79; 95% CI: 0.68 – 0.91), indicating no positive association, and that cases were less likely than controls to be non-users. The data did not indicate any increase in risk for longer duration of phone use, even in the category of over 10 years.

In a large study conducted by The INTERPHONE Study Group (2011) on mobile phone use and acoustic neuromas, the investigators compared cases with newly-diagnosed acoustic neuroma (n = 1,105) matched to two controls for each case (n = 2,145). The study authors concluded that the evidence did not support a role for mobile phone use in the development of acoustic neuroma with regular use (defined as an average of at least one call per week for 6 months), higher cumulative call time, or a higher cumulative number of calls because chance and reporting bias could not be excluded.

The pooled results of the INTERPHONE study (2010) is the largest to date on mobile phone exposure and brain cancer, and reported limited evidence of an association only for the group with the highest cumulative use of mobile phones although no evidence of dose-response pattern, which would add support for causality (The INTERPHONE Study Group, 2010). The authors concluded that recognized biases and errors in the execution of the study limit the strength of the conclusions we can draw from these analyses.

Most epidemiology studies published before the first publication of The INTERPHONE Study Group in 2004 did not report that use of mobile phone was associated with a risk of brain cancer (e.g., Muscat et al., 2000; Inskip et al., 2001; Muscat et al., 2002). One exception to this consistency of results is a group of studies published by Hardell et al. on the risk for malignant and benign brain tumors and mobile and cordless phone use. These researchers reported positive associations in pooled results of case-control studies (Hardell et al., 2006a, 2006b, 2011) with mobile phone use in subgroups of longer term users and ipsilateral use. The positive association also tended to be stronger with increased hours of use, suggesting a dose-response pattern. If these results were consistent across valid studies, they could be interpreted as supporting an inference of causality; however, several limitations in the analyses in these studies have been raised. The first limitation in all three studies is the unclear definition of user, in which a user includes any amount of use, with no minimum duration specified. In addition, data collection methods in several of these studies are a likely cause of bias. The definition of case groups varies across the pooled study data. Finally, the exposure definitions are unclear (type of mobile phone, whether data includes or excludes cordless phone use). These limitations have been noted by reviewers (e.g., Ahlbom et al., 2009; Swerdlow et al., 2011; HPA, 2012), who raise concerns about the validity of these results.

The majority of the studies conducted on cell phone use and cancer risk have been case-control studies, which are prone to bias, particularly when individuals are contacted to obtain data (participation bias) and when past exposure is assessed by self-reporting (recall bias). Cohort studies are generally less prone to these biases because information on participants may be available from an existing source, such as an occupational database. There has been only one cohort study, to date, that has reported results of cancer risks among mobile phone users (Johansen et al., 2001), as well as several follow-ups of this cohort (Schüz et al., 2006b; Frei et al., 2011). This retrospective cohort study used subscriber lists from the two mobile phone companies in Denmark as the surrogate for person-years of mobile phone exposure. The most recent update of this cohort extended the follow-up period for 5 years, from 2002 to 2007, and modified the cohort in order to obtain additional information on various socioeconomic data, such as education and income, which are potential confounding factors (Schüz et al., 2006b; Frei et al., 2011). In the latest update, the authors compared records of 358,403 mobile phone subscribers age 30+ with the Danish Cancer Registry. In addition, subscribers on the list were linked with another cohort study (Oksbjerg et al., 2010) that included socioeconomic data, so that the analysis could be adjusted for the effect of these factors on risk. Overall, no increased risk of brain tumors, acoustic neuromas, salivary gland tumors, eye tumors, leukemias, or overall cancer was observed in the large cohort studied. There is no evidence of increased risk even in those cases with long-term mobile phone subscriptions over 13 years (Frei et al., 2011).

By using subscriptions to mobile phone service as the surrogate for person-years of mobile phone exposure, the Frei et al. eliminated participation bias and recall bias that is of concern in many case-control studies that are based on self-reported exposure. Exposure could be misclassified, however, if there is substantial error in estimating phone use across the group labeled as subscribers. For example, users of mobile phones that were not listed as subscribers would be misclassified as unexposed in this cohort design, and corporate subscriptions were excluded. The data permitted assessment of long-term users, but heavy use in hours could not be identified.

Brain cancer rates over time

While the highest-use category in The INTERPHONE Study Group suggested a possible increased risk, as did the Hardell study data (Hardell, 2006a, 2006b; Hardell et al., 2011), there has not been an increase in incidence rates of brain cancer, which would be expected if this data were correct, particularly in the time period of 10 years after mobile phone use became widespread. This > 10 year period would allow for latency, i.e., the induction time for development of tumors. If causal, the association would lead to an increased rate of brain cancer since a longer period of exposure from mobile phone use had occurred in an increasingly larger population group.

The regular use of mobile phones in Nordic countries has increased markedly over a 28 year period, from 2% in 1980 to 79% in 2002, which Deltour et al. (2012) extrapolated to nearly 100% in 2008. In their study of time trends for incidence rates, Deltour et al. (2012) added 5 years of follow up to their previous study (Deltour et al., 2009) conducted among adults in four Nordic countries (Denmark, Finland, Norway, and Sweden) with a total adult population of 17 million people. Their follow-up study examined two questions: 1) what changes in *incidence* rates (occurrence of new cases) for glioma have been observed over time in the high-quality national cancer registries in these countries, and 2) what is the probability of detecting an increase in rates for different assumed risks, as estimated by modeling or simulation, from 10% to a doubling, for various assumptions of induction time.

The authors found that incidence rates over time showed no clear upward trend over the period studied (1973-2008). The simulations identified the level of induction period and risk that is compatible with these data and what can be excluded. They used cancer registry incidence data to simulate the probability of detecting various levels of increases in glioma. Simulated data sets tested the probability of detecting various increased risks after first use of a mobile phone over time, in all users and in heavy users, such as a 20 % increase, or a doubling of risk. Results showed that changes in these incidence rates over time were not compatible with even the modestly increased risks that were reported in a few of the epidemiology studies. The authors note that possible interpretations consistent with these observations are either that longer induction times than the highest one studied (15 years) are needed, risks of longer term use are lower than has been detected in even the minority of the studies, or that mobile phone use does not increase the risk of glioma.

Several other studies have examined time trends and brain cancer rates. Röösli et al. (2007) examined trends in Switzerland from 1969 to 2002. Two more recent studies have extended the data another 4 to 5 years. DeVocht et al. (2011) examined time trends in England from 1998 to 2007 and Inskip et al. (2010) completed an analysis of time trend in the United States from 1992 to 2006. None of these studies has indicated that the occurrence of brain cancer increased over time since the widespread use of mobile phones began in the late 1980s and has increased exponentially since then. The lack of increase in incidence rates over time provides some evidence against a causal link between mobile phone use and brain cancer.

Laboratory studies in animals

The research conducted in laboratory animals that examined RF fields and cancer was reviewed by ICNIRP (2009), the IARC (Baan, 2011), and most recently by the HPA (HPA, 2012). The IARC group reviewed over 40 *in vivo* studies, most of which were in the frequency range utilized by advanced meters. In addition, many of these studies were of high quality: they exposed the animals to continuous, substantial levels of RF energy, often at the level of the lowest thermal effect; exposure occurred over their entire lifespan; tissues in all organs were examined; good measures of dose were recorded; *in utero* or neonatal exposures were conducted; experiments were conducted with different species (mice as well as rats); and exposure was both whole body and localized.

The IARC monograph is not yet available, but the summary report (Bann et al., 2011) noted that none of the seven chronic 2-year bioassays showed an increased incidence of any tumor in tissues or organs of animals exposed to RF radiation for 2 years. Increased cancer incidence was reported in 2 of 12 studies of tumor-prone animals and in 1 of 18 studies using initiation promotion protocols. The IARC concluded that there is “limited evidence” from experimental *in vivo* studies animals for the carcinogenicity of RF energy.

The report of HPA’s independent advisory group became available April 2012. Like IARC, the review considered a wide range of research approaches to assess the effect of RF exposure on cancer. Studies in whole animals are a major component of assessing human cancer risk, which includes studies of laboratory rodents exposed up to their typical lifespan, similar long term studies in strains of the animals prone to develop cancer, initiation-promotion protocols, and co-carcinogenesis studies after exposure to RF in combination with a known carcinogen. They reported that “… large scale studies investigating the initiation and development of cancer have all been robustly negative…” (HPA, 2012, p. 318).

An additional relevant long-term animal study of cancer published in 2011 was not available for the HPA’s report (Lee et al., 2011). Lee et al (2011) examined the effect of chronic exposure to two types of RF signals in a mouse strain prone to developing lymphoma (AKR/J) within a year. The animals were exposed for 42 weeks to a level nearly 10 times above the ICNIRP exposure limit, and analysis showed no difference from non-exposed controls in survival time or in the development or spread of cancer.

A shorter-term study investigated the effects of RF exposure on tumor promotion. Paulraj and Behari (2011) studied the promotion of skin tumors initiated by dimethylbenz(a)anthracene (DMBA) and followed by 112 MHz, 2.45 GHz, or croton oil (a known promoter of mouse skin tumors). The RF exposure for 2 hours/day x 3 days/week for 16 weeks or continuous exposure for 2 hours/day for 14 days did not affect any indices of tumor promotion. In another experiment reported by these investigators, the growth of tumors in mice transplanted with ascites carcinoma cells and exposed to 2.45 GHz RF did not differ significantly from the control group.

Considerable interest has been focused on possible DNA-damaging effects of RF exposure because genetic changes in normal cells are one of the earliest changes in the progression to cancer. The HPA (2012) report noted some earlier studies that required replication. Since that report, two additional studies of DNA damage in animals exposed to RF have been reported. Jiang et al. (2012) compared groups of mice exposed to 900 MHz RF for 4 hours/day for 1, 3, 5, or 7 days or no exposure, which was then followed by exposure to gamma rays (a known cause of damage to DNA). Mice that were exposed to RF for one day, then gamma rays, showed the same extent of DNA damage as control mice exposed to gamma rays, but additional days of RF exposure led to a progressive reduction in DNA damage below that observed in control mice. The second study reported an increase in an indirect measure of DNA damage (levels of an oxidized DNA base in urine) in rats following 2 hours of exposure to a 1800 MHz field, but only three rats were tested in each group (Khalil et al., 2012).

The above studies published after the HPA (2012) review do not provide a basis to alter its conclusion that "there is no compelling evidence that RF fields are genotoxic or cause robust carcinogenic effects with exposures below guideline values" (HPA, 2012, p. 172).

The Federal Drug Administration in the United States has requested the National Toxicology Program[19] to conduct a laboratory study of long-term RF exposure of rats and mice. The study has begun, and will expose a large group of laboratory mice and rats to RF energy for several

[19] The National Toxicology Program is part of the United States Department of Health and Human Services.

hours a day for up to 2 years, from birth to old age. This will add to the existing research, which includes similar studies of cancer and long-term exposure to RF energy.

Summary of research on cancer

The IARC Working Group recently ranked RF energy in Group 2B, "possibly carcinogenic to humans" based on epidemiology studies of mobile phone use that provided 'limited evidence of carcinogenicity,' [20] and the 'limited evidence of carcinogenicity' in laboratory animals. Other scientific and health agencies have evaluated this same data, including IARC's animal bioassays and many, but not all, of the INTERPHONE studies, but they have not concluded that RF energy is likely to cause cancer (ICNIRP, 2009; SSM, 2010; HPA, 2012). Studies of time trends in several countries, most recently from the Denmark, Finland, Norway, and Sweden, are not consistent with an increased rate of brain cancer following the widespread use of mobile phones (Deltour et al., 2012). The first study of children and adolescents (Aydin et al., 2011), published after the IARC conducted their review, does not conclude that the scientific evidence supports an association between mobile phone use and cancer.

Studies of animals have not provided persuasive evidence that RF exposure damages DNA or otherwise affects the development of cancer.

The exposure limits developed by ICNIRP (2009) and the IEEE (2005) continue to be the reference point for exposure limits cited by The World Health Organization. Their recent fact sheet, *Electromagnetic fields and public health: mobile phones*, states:

> Currently, two international bodies (ICNIRP and IEEE) have developed exposure guidelines for workers and for the general public, except patients undergoing medical diagnosis or treatment. These guidelines are based on a detailed assessment of the available scientific evidence (WHO, 2011).

[20] This category is used when studies report an association, but when chance, bias, or confounding cannot be ruled out with confidence.

Studies of symptoms related to well-being

The scientific literature on exposure to low levels of RF energy and well-being includes studies of both near field (i.e., mobile phones) and far-field (i.e., mobile phone base stations, wireless networks, etc.) exposure. Most of these studies are concerned with short-term health effects, i.e., non-specific symptoms such as headache, sleep disturbances, and fatigue; both epidemiology studies and human experimental studies are suitable for evaluating these effects.

The literature on this subject includes a large number of relevant studies, however, many have significant limitations such as a small number of participants or, as discussed by Frei et al. (2010) their exposure assessments utilize either self-reporting methods or use distance from a single source as a surrogate. The recent studies selected for inclusion in this review incorporated factors that increased their quality: a large number of participants, improved exposure assessment methods, and field interventions.[21] They include a systematic review of studies on mobile phone base station exposure (Röösli et al., 2010), several epidemiology studies (Eger and Jahn, 2010; Heinrich et al., 2010; Mohler et al., 2010; Baliatsas et al., 2011; Heinrich et al., 2011; Frei et al., 2012), and one human laboratory study (Danker-Hopfe et al., 2010).

Röösli et al. (2010) conducted a systematic review of the literature published from August 2007 through March 2009 on the health effects of exposure to RF fields from mobile phone base stations. Their inclusion criteria required that the selected studies use objective measures of exposure and show a clear description of an acceptable method for selecting participants. In this manner, from the 134 potential results of their literature search, the study authors identified 17 that they deemed adequate based on exposure assessment and selection procedures—12 epidemiology studies and 5 human laboratory trials. The laboratory trials were randomized, double-blind studies on the perception of RF fields; these five studies were meta-analyzed by

[21] Field intervention studies are those in the ordinary environment (not a laboratory) in which the exposure sources are controlled by the research group. It shares characteristics with experimental studies because of the researchers' control of exposure and because participants do not know (i.e., are blinded to) the actual exposure.

Röösli et al (2010). [22] The 12 epidemiology studies, 10 of which were cross-sectional studies, included several outcomes of non-specific symptoms such as headache, tension, and sleep disturbances, as well as other outcomes such as cognitive function. As mentioned, Röösli et al. (2010) conducted a meta-analysis of four of the five human laboratory studies that tested the ability to detect the presence or absence of a RF field. (Although the authors had planned a meta-analysis of all the relevant studies, most of the studies did not sufficiently use similar methods or investigate similar endpoints to combine the data.)[23] When results of these studies were combined, the association did not indicate that individuals could detect whether or not the RF field was present. The same was true for individuals who reported they were sensitive to electromagnetic fields.

The results of these 17 studies, when considered together, did not provide evidence for an increase in health effects related to exposure; in addition, no one symptom or symptom pattern was consistently related to exposure. In addition, the authors noted that the cross-sectional studies "showed a noteworthy pattern: studies with crude exposure assessments based on distance showed health effects, whereas studies based on more sophisticated exposure measurements rarely indicated any association (Röösli et al., 2010, p. 890)."

Other recent human studies of far-field exposure published after the Röösli et al. (2010) systematic review described above primarily have been cross-sectional epidemiology studies. A recent cross-sectional study conducted by Eger and Jahn (2010) investigated 19 outcome categories (e.g., skin problems, toothache, weight loss, weight gain, and dizziness) for RF exposure in people who lived within 200 metres of mobile phone base stations. This study is limited by several flaws. Participants were volunteers rather than randomly selected, and the related important limitation is the low response rate to questionnaires, (23%), which can result in selection bias. The distance from two mobile phone base stations served as a surrogate for

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[22] The more reliable studies of humans are double-blind, which means that neither the participants nor the researcher is aware of the exposure status. In single-blind studies, only the participants are not aware of the exposure status. This blinding process helps to control for human error or bias to due to preconceptions about the experiment's results.

[23] Meta-analysis is an analytic technique used by epidemiologists that combines the published results from a group of studies into one summary result.

exposure, but although calculated in volts per meter, it was incomplete because it included no assessment of any other RF exposure sources, such as cordless phones, radio or television stations, or mobile phone use.

Another recent cross-sectional epidemiology study of non-specific physical symptoms was designed to assess the characteristics of individuals that may affect their response to questions of electromagnetic hypersensitivity (Baliatsas et al., 2011). The researchers conducted the study in the Netherlands in 2006, in which 3,611 participants responded to a questionnaire. The questionnaire included demographic characteristics (e.g., age, gender, and ethnicity) and social characteristics (e.g., education, occupation, home ownership). The participants also were required to answer questions that self-assessed environmental sensitivity to such factors as light, odors, and temperature and questions to evaluate the individual's ability to deal with stress. Finally, participants were asked to report on what they perceived to be their proximity to electromagnetic sources such as mobile phone base stations.[24] The study found that there was no relationship between actual distance to mobile phone base stations and report of symptoms, however, an increased report of symptoms was associated with the perception of proximity to base stations. The perception of being environmentally-sensitive, a lower rating on questions related to control, and certain demographic categories also were associated with an increased report of symptoms. The study's limitations include a low response rate (37%) and use of distance as an exposure surrogate.

As noted, one challenge of epidemiology studies of short-term effects such as headache, sleep disturbances, and fatigue when RF exposure levels are low is a valid estimate of exposure. As seen in the study by Baliatsas et al. (2011), perception of the existence of RF energy sources such as a mobile base station can be a source of reporting bias, particularly if a person holds the view that non-specific symptoms are related to that exposure. Several recent epidemiology studies have used improved exposure metrics. Heinrich et al. (2010, 2011) used personal dosimeters, which are an improved method to determine exposure; Mohler et al. (2010) used

[24] The questionnaire also asked about perceived proximity to power lines.

validated predictive mathematical models; and Danker-Hopfe et al. (2010) exposed participants to RF fields in a double-blind study.

In the study conducted by Heinrich et al (2010), the investigators studied the impact of RF exposure on the well-being of a large group of children (age 8 to 10, n=1,484) and adolescents (age 13 to 15, n=1,508) for seven different symptoms—headache, irritation, nervousness, dizziness, fear, sleep disorders, and fatigue. Their RF exposure was measured using personal dosimeters placed on the upper arm, except during night-time when it was fixed to a water bottle placed next to the bed. Since the investigators determined the dosimeter did not record valid measurements in a fixed position, only the measurements taken during the time the participants were awake were used. The dosimeters recorded RF exposure from mobile phones, cordless phones, and mobile phone base stations. The symptoms noted above were rated by the participants two times in the 24-hour period—at noon (for exposure during morning hours) and in the evening prior to bed (for exposure during afternoon hours). Although a few of the 24 associations calculated were slightly elevated, one for children (concentration) and two for adolescents (headache and irritation), they were not consistent for the two time periods. In addition, these results could not be confirmed in the top 10 percent of participants with the highest exposure. The authors concluded, therefore, that the few elevated associations reported were either chance or random events.

In addition to the 24-hour exposure data described above, the researchers considered self-reported personal data on chronic symptoms (6-month retrospective period) and demographic data that could act as potential confounders, such as age, educational level, study town and personal environmental concerns that had been collected through interview forms (Heinrich et al., 2011). The results of adjusting for these additional factors still did not support an association between the symptoms and RF exposure. The study authors noted that the measured exposure was less than 0.2 % of the ICNIRP exposure limit on average and less than 1% of the limit at the maximum measured exposure.

Mohler et al. (2010) conducted a cross-sectional study of sleep quality, including disturbances to sleep and daytime sleepiness in a randomly selected population of 1,375 adult residents of

Basel, Switzerland. The study authors used a validated predictive model to estimate exposure to far-field RF energy; in their analysis, the researcher also considered estimates of exposure from mobile and cordless phones that were both self-reported by the participants and derived from 6 months of data from a mobile phone operator. The participants provided data on a questionnaire that addressed sleep quality, overall health status, possible exposures such as mobile or cordless phone use and estimated duration, and various demographic factors. The results of this study indicated no association of decreased sleep quality with exposure to RF fields, even in the top 10 percent of participants with the highest exposure.

Danker Hopfe et al. (2010) conducted a field intervention study of 397 participants in 10 locations in Germany to assess subjective and objective measures of sleep quality and RF fields. In order to control background exposure, geographic areas were selected that received no mobile phone service, i.e., there were no mobile phone base stations close by. The residents selected were randomly exposed either to sham (no RF source) or RF exposure conditions. The exposure conditions were created using a portable mobile base station; both the investigators and the participants were blinded to exposure status. Questionnaires were completed prior to the study to assess sleep quality; data gathered included self-reported sleep disorders, sleep quality, and other subjective sleep parameters, as well as opinions on mobile communicating. Objective sleep data was measured using hours asleep, time to fall asleep, and wake time, as well as EEG and EOG readings. The experiment was conducted over two different 5-day time periods, one with sham exposure and the other with RF exposure from the portable base station. The study authors concluded that neither objective measures nor subjective measures were affected by RF exposure.

Although most recent epidemiology studies of RF exposure have been cross-sectional studies, one cohort study was conducted by a group of investigators in Switzerland (Frei et al., 2012). Using the cohort design to reduce bias and confounding, the study authors evaluated exposure to ordinary sources of RF in the environment. To assess both far-field and near-field exposure, they used a combination of calculated exposures (the geospatial propagation model, total personal exposure, and network operator data on mobile phone use), as well as self-reported mobile phone use, to investigate the effects of RF fields on non-specific symptoms related to quality of life and tinnitus. Information was collected from 1,122 individuals in a cohort at baseline and a follow up 1 year later. In the baseline questionnaire, 22% of participants identified themselves as sensitive to electromagnetic fields, and over 77% believed it is possible to develop symptoms in response to every day electromagnetic field exposure. Health status was evaluated by responses to a written questionnaire about somatic and headache complaints using standardized tests (von Zerssen and HIT-6, respectively) to score health complaints. The study's findings did not provide evidence that objective measures of near- or far-field exposures to RF fields in everyday life was associated with the development of non-specific symptoms or tinnitus, even in people who reported themselves as hypersensitive to electromagnetic fields.

Summary of studies on symptoms of well-being

None of these recent studies exposure to RF fields and non-specific symptoms (e.g., headache, sleep disturbances, and fatigue) has concluded that this exposure leads to acute symptoms or adverse effects. As a group, they do not alter the conclusions of review groups discussed in Section 4. It is important to note that the exposure levels in these studies all were below Canada's Safety Code 6 exposure limits.

Conclusion

The smart meters utilized by BC Hydro will operate in compliance with the regulations of Health Canada. Exposure to RF energy will be far below the exposure limits recommended by Health Canada, and those of ICNIRP and other scientific and regulatory agencies. In this report, recent scientific research regarding cancer and short term effects such as non-specific symptoms has been summarized to determine whether it might suggest adverse effects at levels below exposure limits recommended by these organizations. The reviews and the recently published research that includes improved exposure information in epidemiology studies and longer observation periods do not provide a reliable scientific basis to conclude that the operation of the Smart meters will cause or contribute to adverse health effects or physical symptoms in the population.

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Appendix A

RF Exposure from BC Hydro Smart Meters

BC Hydro is deploying Itron's Openway Centron Meters as part of its smart meter network. These smart meters utilize a 900 MHz RF signal to establish a meter-based network. While meters have an additional integrated ZigBee radio at a 2.45 GHz frequency, it is turned off by default. The data collected from this network is then received by special devices (i.e., collectors) to send electricity usage information back to BC Hydro.

As indicated above, BC Hydro's smart meters are equipped with the ZigBee radio transmitter that allows customers to choose to collect data from compatible home area network (HAN) devices.[1] When shipped, the ZigBee transmitter is turned off and does not result in any RF signal exposure to the customer. If the customer decides to activate the ZigBee transmitter, this transmitter will add an additional RF exposure that is 0.095% of the Safety Code 6 limit at a distance of 20 centimetres.[2] At typical, greater distances from the meter, the exposure will be much lower.

RF emitting devices (including smart meters) in Canada are required to comply with Health Canada's Safety Code 6 exposure limits.[3] These limits, established to protect the health of the general public, are based on the lowest level at which a health effect can occur. Moreover, for further protection, an additional safety factor is added, resulting in exposure limits for the general public that are well below the limit at which the harmful effects could occur.[4] These exposure limits change as a function of frequency to address the frequency-dependent consequences of RF signal exposure. At frequencies greater than 100 kHz, the exposure limit set by Safety Code 6 is based on thermal effects. Non-thermal effects, while present at higher frequencies, will only occur at signal levels that are above the threshold of thermal injury.

1 These devices, of which there are very few on the market, come with a special matching ZigBee transmitter. Devices without such a transmitter cannot communicate the information to the smart meter.

2 Based on "Analysis of Radio Frequency Exposure Associated with Itron OpenWay® Communications Equipment," Itron, 2011. The 0.037% value in this document was multiplied by a factor of 2.56 recommended by FCC OET 65 Bulletin to allow for an increase of exposure by environmental reflections.

3 http://www.ic.gc.ca/eic/site/smt-gst.nsf/eng/sf05990.html

4 Ibid.; Health Canada. Limits of Human Exposure to Radiofrequency Electromagnetic Energy in the Frequency Range from 3 kHz to 300 GHz – Safety Code 6. Ottawa: Health Canada, 2009.

As a consequence, in the frequency range that BC Hydro's smart meters operate, the exposure limit is based on the thermal effects. Specifically, at 900 MHz, this exposure limit[1] is 6 W/m^2.

RF exposure from BC Hydro's smart meters is very low, only a tiny fraction of Safety Code 6 limits. This is a consequence of two factors. First, the distance from residential areas to the smart meter is great. As the distance from the smart meter increases, the signal spreads out and less and less of signal power is available at any specific location. The signal power density drop-off with increasing distance is very rapid; for every doubling of the distance, the power density drops off by a factor of four. Second, the signal transmission by the meters is short and infrequent. BC Hydro's smart meters are configured such that they communicate for only a few seconds a day, spread out across the whole day. When averaged over 6 minutes, as prescribed by Safety Code 6, the exposure is greatly reduced compared to the peak power density from the smart meters.[2]

The combination of infrequent signal transmission and the energy spread due to distance results in a very low level of additional RF exposure produced by the smart meter. The additional exposure over background exposure, which is measured to be between 0.05% and 0.36% (depending on location) of the Safety Code 6 limit without smart meters transmitting, is 0.03% to 0.7 % of the Safety Code 6 limit,[3] even as close as 20 centimeters from the front of the meter. At the back of the meter, the exposure is at least a factor of 10 lower than in the front due to the shielding by the meter housing and panel. There will also be an additional reduction of exposure due to the shielding of the wall materials.[4] This additional exposure will drop of rapidly as a function of distance. Even when multiple smart meters are installed in a bank of meters, the RF exposure will be a tiny fraction of the Safety Code 6 limits. A smart meter signal

[1] Exposure is defined as the time-averaged power density of the RF signal that is present in the area accessible to humans. Power density is defined as the power measured in Watts (W) per unit area measured in square meters (m^2). Time average is prescribed to be over a 6-minute consecutive interval at frequencies greater than 100 kHz.

[2] Note that even the peak power density is below Safety Code 6 limits due to the effect of the distance.

[3] Average values. Upper range is for multiple meter banks, lower range is for single meters. Peak values may be higher, but no values above 1.7% of the Safety Code 6 limit have been observed (and these values include background exposure and may have been increased by non-smart meter transmitters).

[4] See e.g., EPRI. An Investigation of Radiofrequency Fields Associated with the Itron Smart Meter. Palo Alto: EPRI, 2010.

is one of the weakest sources of RF exposure in the residential environment. The table below compares some common sources of RF signals to that of the smart meter.

Table A-1. Comparison of RF signal exposure of smart meters to other common sources

	Source				
	Background (measured)[5]	Smart meter (20 cm in front)[6]	Smart meter bank (20 cm in front)[7]	Typical cell phone (next to head)	Typical cordless phone (next to head)
Exposure as percent of Safety Code 6	0.36	0.02	0.07-0.09	0.45-0.95	0.025-0.60

Two recent report that evaluated exposures to RF signals from Wi-Fi devices and smart meters are summarized below.

Wi-Fi devices

To address the recent public concerns related to the proliferation of Wi-Fi technology, Industry Canada (the Department of the Government of Canada with responsibility for regional economic development, investment, and innovation/research and development) performed measurements of RF fields in an Industry Canada boardroom located in Aurora, Ontario. The boardroom contained two Wi-Fi access points and 24 Wi-Fi-enabled devices (laptops). The aim of this study was to obtain measurements of the levels of aggregated RF exposure from multiple Wi-Fi access points and Wi-Fi-enabled devices in an indoor environment. It was found that the aggregated RF exposure levels at this indoor location are well below the maximum exposure limits for RF fields in Health Canada's Safety Code 6. In addition, the Wi-Fi access points selected for this study were operating at higher power compared with most of the Wi-Fi devices currently available on the Canadian market. Therefore, the measured values in this study are likely higher than would typically be observed in equivalent setups in public and private environments.[8]

5 Planetworks, "BC Hydro – Single Smart Meter Safety Code 6 Report," 2011
6 Ibid.
7 Planetworks, "BC Hydro – Bank of 10 Smart Meters," Safety Code 6 Report," 2011
8 Executive summary and download of the full 38-page test report at: http://www.ic.gc.ca/eic/site/smt-gst.nsf/eng/sf10383.html

Evaluation of radio frequency signals from smart meters in New Zealand

This study of RF signals from smart meters was commissioned by Arc Innovations Limited, a New Zealand company involved in the development, deployment, and management of advanced meter infrastructure (AMI) technology and services. The research was carried out by the Electric Power Engineering Centre, College of Engineering, University of Canterbury, Christchurch. The body of work was mainly related to the RF signals from the communications transmitters in the meters themselves and, where applicable, in other equipment forming part of the relevant network. Researchers assessed the RF signals from smart meters operating at 900 MHz, 1.8 GHz, and 2.4 GHz and reported that the wireless signals from smart meters fall well within the New Zealand safety standard (based on ICNIRP guidelines) for general public exposure levels and far below the levels often encountered from cell phone use.[9]

[9] http://www.research.canterbury.ac.nz/rss/news/index.php?feed=news&articleId=390. Download of a brief study summary and the full report at: http://www.epecentre.ac.nz/media/smartmeter.shtml

> Itron white paper

Wireless Transmissions:

An Examination of OpenWay Smart Meter Transmissions in a 24-Hour Duty Cycle

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Overview

This document is a supplement to the paper titled "Analysis of Radio Frequency Exposure Associated with Itron OpenWay® Wireless Communication Equipment." A key consideration for evaluating RF exposure from Itron smart meters is the duration of exposure—or how often the radios are transmitting. This report summarizes data collected from a representative large-scale OpenWay deployment over a typical 24-hour operational period, providing empirical data that quantifies the percentage of time a meter's radios are active (also known as the meter's "duty cycle").

Introduction

Itron OpenWay CENTRON® meters utilize wireless communications to transmit and receive data between meters and a collection device (such as a Cell Relay). To better characterize the level of RF emissions emitted during this data collection process, a study was conducted by Itron to determine the amount of time, within a 24-hour window, a meter's radio is actively transmitting.

The data collected by Itron represented approximately 7,000 meters in the sample network (see *Note #1*), over a 24-hour period, in order to determine the percentage of time that the meter was transmitting (again, the duty cycle). A read of the meter's transmit counters (bytes transmitted) was captured at noon on Wednesday, December 1, and again at noon on Thursday, December 2. To determine the total amount of data transmitted in that 24-hour period, the numbers from December 1 were subtracted from the numbers on December 2.

For example, if Meter X's transmit counter was at 10234342 when the reading was taken on December 1, but by December 2 the counter was up to 10432514, we can deduce that in 24 hours Meter X transmitted 198,172 bytes. While that figure is useful, it does not tell us what portion of the day that the meter was actually transmitting. To determine that figure, we must first convert the number of bytes to bits by multiplying by eight (198,172 x 8 = 1,585,376).

Next, because we know that these meters transmit data at a rate of 19,200 bits per second (see *Note #2*), we divide our total by 19,200 (1,585,376 / 19,200 = 82.57 seconds) to determine that the number of seconds the meter was actually transmitting was 82.57 seconds in 24 hours. Finally, to calculate the duty cycle, we must divide the number of active seconds by the number of seconds in a day (82.57/86,400 = 0.09557%). Therefore the daily duty cycle of meter X is ~0.1%.

Itron

Results

The following graphs and table summarize the results of the data gathered.

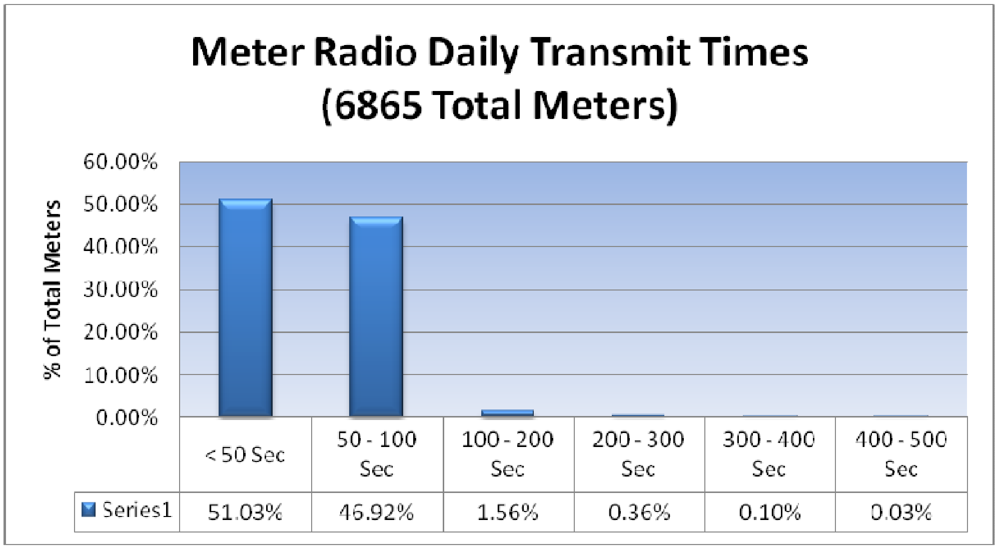

Fig. 1 Daily Transmit Times

Figure 1 shows that out of the 6,865 meters sampled, 97.95% of the meters transmitted for less than 100 seconds in the 24 hour period (duty cycle of less than 0.12% per day).

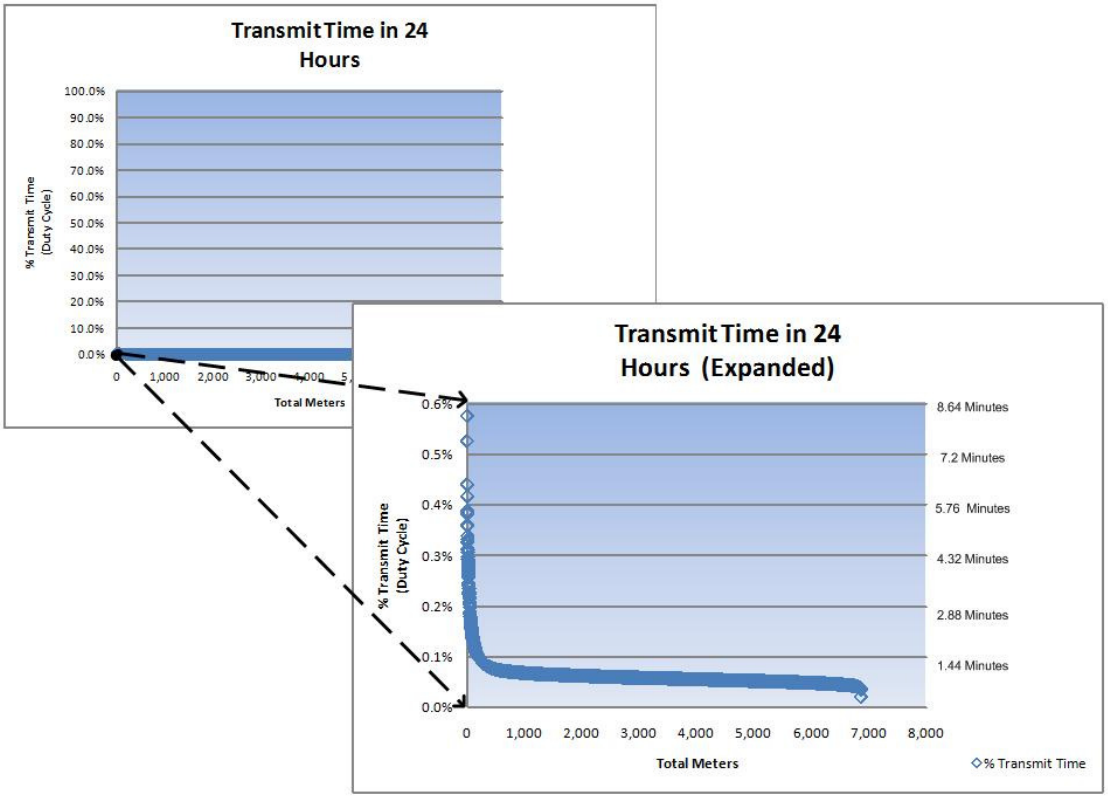

Fig. 2 Percentage of Transmit Time

Figure 2 represents a scatter plot of all meters' transmit times. Because the meters transmit for such a small percentage of the time, the first view appears as a solid blue line resting on the x-axis (below 1%). In the expanded view it is possible to see the maximum daily duty cycle is less than 0.6% (transmit time less than 8.64 minutes/day). This view also shows that 98% of the meters have a daily duty cycle of less than 0.1% (transmit time less than 1.44 minutes/day).

	Duty Cycle	Time
Mean	0.06%	53.14 seconds per day
Maximum	0.58%	497.8 seconds per day
Minimum	0.02%	18.31 seconds per day
Median	0.06%	49.81 seconds per day

Fig. 3 Transmit Time Statistics

The table above (*Figure 3*) shows that meter emission times vary, but even the maximum transmission represents less than 1% of the 24-hour period. Median and Mean (or average) times are relatively close together, which indicates the absence of many meters on the extreme ends of the range.

The sample period that was selected represents a day of higher-than-normal activity for the sample network. During this time, in addition to the two normally scheduled daily meter data reads, there were two crucial updates being transmitted to every endpoint on the network—one for an adjustment for Daylight Savings Time and the other was a crucial firmware update. In a typical day with no updates taking place, the numbers would more than likely be even lower.

Conclusion

OpenWay smart meters are advanced, highly-efficient devices. They are able to communicate a large amount of metering and event data in short bursts throughout a 24-hour period (each transmit burst is less than 150mSec). The worst case meter in the sample population was essentially silent (not transmitting) for over 99.40% of the day while the average meter was silent 99.94% of the day. In terms of FCC regulations for Maximum Permissible Exposure (MPE) limits, the worst case meter was less than 0.09% of the limit mandated by the FCC (0.00051 mW/cm^2 vs 0.61 mW/cm^2) with the average meter less than 0.009% of the FCC limit (0.000053 mW/cm^2 vs 0.61 mW/cm^2). [With the duty cycle is accounted for, See *Note #3*]

This empirical field data further refines our estimations for maximum duty cycle of Itron OpenWay meters. When accounting for the variations in cell size and data requests, our expectations for maximum duty cycle are 1% (14.4 min/day). The previous estimate prior to this field data was 5% duty cycle.

Itron takes all concerns about RF exposure very seriously and continuously strives to ensure its products meet or exceed FCC guidelines and regulations. In the case of OpenWay smart meters, Itron dramatically exceeds these mandates with a product that generates only a very small fraction of the FCC limits for RF exposure.

Note #1:

The sample meter data was taken from one of Itron's large-scale, operational network customers. It is representative of the OpenWay smart grid solution. There were 6,865 meters in the population sample, spread across 10 cells (average cell size of ~687 meters). The data for the Cell Masters is included in this analysis.

Note #2:

The 19,200 Kbps transmit rate represents the 1G RFLAN currently deployed at this site. Itron has released the 2G RFLAN (with SR3.0) which increases the transmit rate to 153 Kbps and added sub-timeslot efficiencies. For networks deployed with or moving to 2G RFLAN, the transmit efficiency will be greatly increased, so that with the same amount of data passing through the network, the amount of radio transmit time will significantly less.

Note #3:

The FCC has defined the Maximum Permissible Exposure (MPE) as the strength of electromagnetic fields or the equivalent power density associated with this field to which a person may be exposed without harmful effect. For the general population (individuals who might potentially be exposed to RF energy without their knowledge), the limits are set using the following equation:

General Population MPE: Exposure *[mW/cm²]* = Frequency *[MHz]* / 1,500

The MPE limits for continuous exposure by an Itron OpenWay smart meter is 0.61 mW/cm^2. These limits are based on the thermal effect of continuous RF radiation. To calculate the power density the following equation is used:

$$\text{Power\_Density } [mW/cm^2] = \frac{\text{Transmitter\_Power } [mW] \text{ x Antenna\_Gain } [times] \text{ x Duty Cycle}}{(\text{ 4 x pi x Distance } [cm] \text{ x Distance } [cm]\text{ })}$$

In the population sample discussed, the worst case meter had a duty cycle of 0.58% (0.0058). With power density of 0.088 mW/cm^2 during transmission, the resulting power density with duty cycle is 0.00051 mW/cm^2. When compared to the MPE limit set by the FCC (0.61mW/cm^2) this meter was at 0.084% of the allowable amount. The average meter had a duty cycle of 0.06% (0.0006). With power density of 0.088 mW/cm^{2}during transmission, the resulting power density with duty cycle is 0.000053 mW/cm^2. When compared to the MPE limit set by the FCC (0.61mW/cm^2) this meter was at 0.009% of the allowable amount.

About Itron

At Itron, we're dedicated to delivering end-to-end smart grid and smart distribution solutions to electric, gas and water utilities around the globe. Our company is the world's leading provider of smart metering, data collection and utility software systems, with nearly 8,000 utilities worldwide relying on our technology to optimize the delivery and use of energy and water. Our offerings include electricity, gas, water and heat meters; network communication technology; collection systems and related software applications; and professional services.

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> Itron white paper

Analysis of Radio Frequency Exposure Associated with Itron OpenWay® Communications Equipment

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Itron

Overview

This document provides information regarding radio frequency (RF) energy exposure from Itron's OpenWay wireless communications equipment, which is used by utilities for smart metering communications and other utility applications. The OpenWay equipment has been certified by the Federal Communications Commission (FCC) and Industry Canada (IC).

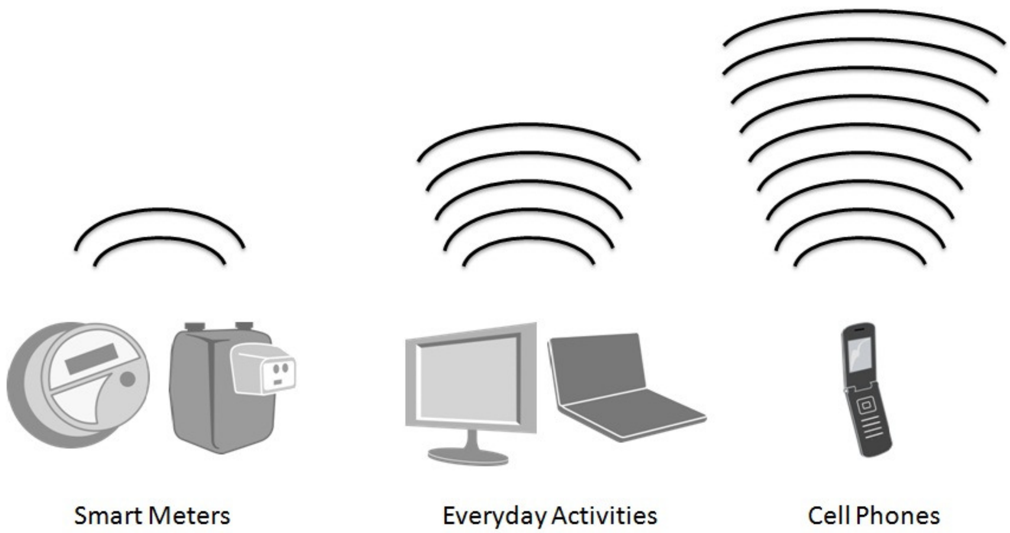
Introduction

We live in a world where RF energy is all around us. It plays a critical role in the communications systems that we depend on every day, such as police and fire radio systems and pagers, radio and television broadcasts, and cellular telephones. Many of the conveniences we've grown accustom to in our homes, such as cordless phones, wireless LAN (WiFi), and microwave ovens also utilize and emit RF energy.

This same technology is used by utilities and energy service providers to team with consumers to make our energy grid more efficient and reliable, and to optimize our use of limited energy resources. By providing a two-way communications network between the meters and the utility, the RF technology establishes the critical foundation for the realization of the Smart Grid.

It is important to recognize the relative amounts of RF energy the smart meters contribute to the existing RF environment. The chart below provides an approximate comparison of the various sources found in and around typical households.

RF Energy Comparison



Itron recognizes that there are concerns related to the health effects of exposure to RF energy and monitors the various organizations researching this topic. Additionally, Itron ensures that our products are compliant with the established regulatory requirements related to RF emissions.

Regulatory Compliance

The FCC recently revised a document detailing how to measure or calculate levels of RF radiation. The document titled "*OET Bulletin 65 Edition 97-01, Evaluating Compliance with FCC guidelines for Human Exposure to Radiofrequency Electromagnetic Fields"* may be found at www.fcc.gov/oet/rfsafety. Additionally, in June 2001, the FCC released "*OET Bulletin 65 supplement C Edition 01-01"* (known as OET-65C), which provides further guidance on determining compliance for portable and mobile devices.

The FCC has completed a rulemaking titled "*Guidelines for Evaluating the Environmental Effects of Radio Frequency Radiation"* (FCC Report and Order, ET Docket 93-62). This document combines standards developed by ANSI and the National Council on Radiation Protection and Measurement (NCRP). The new rules have been incorporated into Title 47 of the Code of Federal Regulations (Parts 1, 2, 15, 24, and 97). These rules dictate the level of compliance necessary to meet the standards.

The Industry Canada has also published an RSS-102 standard that addresses RF exposure issues on the territory of Canada. This standard references to the Safety Code 6 from Health Canada: "*Limits of Human Exposure to Radiofrequency Electromagnetic fields in the Frequency Range from 3 kHz to 300 GHz.*"

Types of RF Exposure and Maximum Permissible Exposure Limits

The revised ANSI standards, the NCRP Report and the FCC Rules and Guidelines define two types of exposure to RF energy:

Occupational / Controlled Exposure when persons are exposed as a consequence of their employment and they have been made fully aware of the potential for exposure and can exercise control over their exposure.

General Population / Uncontrolled Exposure when persons who are exposed to RF fields may not be made fully aware of the potential for exposure or cannot control their exposure.

The standards specify the Maximum Permissible Exposure (MPE) levels as the strength of electromagnetic field or the equivalent power density associated with this field to which a person may be exposed without harmful effect.

The FCC defines the Maximum Permissible Exposure (MPE) levels according to the following equations:

Occupational MPE: Exposure *[mW/cm^2]* = Frequency *[MHz]* / 300

General Population MPE: Exposure *[mW/cm^2]* = Frequency *[MHz]* / 1,500

The MPE limits are dependent on the frequency of the transmitting device and allow for higher levels of exposure for occupational/controlled environments.

The Itron OpenWay communications equipment is assessed against the more stringent General Population Exposure limits.

An important feature of the regulatory guidelines is that exposure, in terms of power density, may be averaged over certain periods of time with the average not to exceed the limit for continuous exposure. The averaging time is defined as six minutes for occupational/controlled exposure and 30 minutes for general population/uncontrolled exposure.

Itron OpenWay Wireless Communication Equipment under Consideration

The Itron OpenWay wireless communication equipment operates in the Industrial, Scientific and Medical (ISM) bands at frequencies from 902 MHz to 928 MHz and from 2,400 MHz to 2,483 MHz. Also, a small number of devices incorporate wireless modems operating at frequencies 824-849 MHz and 1,850-1,910 MHz designated for the cellular operators (Cell Relays constitute about 1% of all the OpenWay wireless devices and can be mounted on poles or as part of a meter). This analysis will focus on the OpenWay CENTRON® smart meter.

The following table reflects the data contained within the Certification Exhibits for FCC Rule Part: 15.247 for Itron OpenWay Smart Meters:

FCC ID	SK9AMI-xx
FCC Rule Part	15.247
Classification	Digital Transmission System Transmitter Frequency Hopping Spread Spectrum Transmitter
Device Category	Mobile
Environment	General Population / Uncontrolled Exposure
Exposure Conditions:	Greater than 20 centimeters (8 inches)
Frequency bands	RF LAN 902 – 928 MHz ZigBee 2,400 – 2,483.5 MHz
Transmitter Power*	RF LAN 24.83dBm (304.09 mW) at 902.25 MHz ZigBee 18.94 dBm (78.34 mW) at 2,475 MHz
Antenna Gain*	RF LAN 2.2 dB (1.660 times) at 902.25 MHz ZigBee 3.8 dB (2.399 times) at 2,475 MHz

*Values have been updated to reflect the latest meter hardware release (FCC ID: SK9AMI6)

The duty cycle (or amount of time a device is active in any given time period) will have a significant impact on the long term exposure levels for a device. The Itron OpenWay smart meters are actively transmitting a very small portion of the time. The maximum duty cycle for each transmitter is listed below:

Max Duty Cycle (over period of 30 minutes)	RF LAN ZigBee	5% 1%

For the Itron OpenWay smart meters wireless communication equipment, the MPE limits for continuous exposure are as follows:

Frequency	**MPE level**	
	Occupational	***General population***
RFLAN (902 MHz)	3.0 mW/cm^2	0.6 mW/cm^2
Zigbee (2,400 MHz)	8.0 mW/cm^2	1.0 mW/cm^2

Calculation of RF emissions

The FCC MPE levels represent the guaranteed safety limits based on the thermal effect of continuous RF radiation.

The FCC guidelines define the following equation to calculate the power density of RF radiation under far-field conditions:

$$\text{Power\_Density } [mW/cm^2] = \frac{\text{Transmitter\_Power } [mW] \times \text{Antenna\_Gain } [times]}{(4 \times \pi \times \text{Distance } [cm] \times \text{Distance } [cm])}$$

The 1992 ANSI/IEEE standard specifies that 20 cm (~ 8 inches) should be the minimum separation distance where reliable field measurements to determine adherence to MPEs can be made.

It is important to note that the Itron's equipment operates in short bursts randomly distributed over prolonged period of silence (5% and 1% duty cycles). According to the rules, the MPE levels for interrupted transmission should be calculated by averaging the active time over interval of 30 minutes in the case of General Population exposure or six minutes in the case of occupational exposure.

A comparison of the MPE from the Itron OpenWay smart meter's transmitters to the General Population MPE limits with the duty cycles accounted for is shown in the table below:

Transmitter	MPE Limit	MPE	Margin
RF LAN (902MHz)	0.6 mW/cm^2	0.0050 mW/cm^2	**0.833%** of the limit
ZigBee (2,405MHz)	1.0 mW/cm^2	0.00037 mW/cm^2	**0.037%** of the limit

The data indicates that the Itron OpenWay smart meters present an extremely low level of RF exposure when compared to the regulatory limits established for safe operation.

Summary

The RF power densities for OpenWay communications calculated according to the recommended method are only a small fraction of the Maximum Permissible Exposure limits.

Itron will continue to monitor the regulatory standards and research related to RF Exposure to verify that its products are in compliance with all applicable legal requirements.

Additional Information

Additional information from the World Health Organization

- *World Health Organization (WHO) Fact Sheet*
- *Electromagnetic Fields*
- *International EMF Project*

Information from the Federal and Drug Administration (FDA)

- *Radiation-Emitting Products*
- *Interference with Pacemakers and Other Medical Devices*

Information from the Federal Communications Commission (FCC)

- *Radio Frequency Safety*

Information from the California Council on Science and Technology (CCST)

- *Health Impacts of Radio Frequency from Smart Meters*

Information from Itron

- Itron Radio Frequency Resource Center

About Itron

At Itron, we're dedicated to delivering end-to-end smart grid and smart distribution solutions to electric, gas and water utilities around the globe. Our company is the world's leading provider of smart metering, data collection and utility software systems, with nearly 8,000 utilities worldwide relying on our technology to optimize the delivery and use of energy and water. Our offerings include electricity, gas, water and heat meters; network communication technology; collection systems and related software applications; and professional services.

To realize your smarter energy and water future, start here: www.itron.com.

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1.0 Reference: FBC Response to BCUC IR No. 2.1

Fortis BC claims there are “benefits associated with the implementation of AMI at this time that have driven ForitsBC’s decision to proceed with its application”, and “The response to BCUC IR1 Q53.11 indicates a $5.7 million loss of benefits if the project is delayed by two years”:

1.1 Please confirm that the implementation of smart meters alone would not result in the benefits being realized.

Response:

Confirmed. The realization of benefits requires the installation of all project components listed in Exhibit B-1, Section 1.1, not just the AMI meters.

1.2 Please discuss the need for a “smart grid” and associated systems and costs that would be necessary to take full advantage of a smart meters capabilities.

Response:

FortisBC considers that there are three fundamental drivers underlying the implementation of many smart grid technologies:

1. Cost savings / improved operating efficiency;
2. Reliability improvements; and
3. Customer uptake of new technologies.

In addition to providing many customer and utility benefits, the AMI component of the FortisBC Smart Grid focuses primarily on the first driver which is reducing costs by improving meter reading efficiency and reducing power theft.

Subsequent smart grid components will be proposed only if a cost/benefit analysis supports the deployment of that component. For example, if service reliability in some area of the system was considered degraded – and if a smart grid component such as distribution automation was deemed a cost-effective solution – then FortisBC would propose implementation of that capital project. At the same time, wide-scale distribution automation is highly dependent on the communications network that is proposed to be installed as part of the AMI Project. Thus, both the timing and cost of this smart grid component (and other similar components) is dependent on the prior implementation of AMI. Further, some components (such as electric vehicles or distributed generation) are entirely driven by customer uptake rates and thus inherently have a great deal of uncertainty around timing and costs.

1.3 Please discuss the timing for the implementation of a smart grid in FortisBC's service territory.

Response:

As discussed both in the Application and in the response to BCRUCA IR No. 1 Q1.2, FortisBC will propose future smart grid components only if a cost/benefit analysis supports the deployment of that component. Further, some components (such as electric vehicles or distributed generation) are entirely driven by customer uptake rates and thus inherently have a great deal of uncertainty around timing. Beyond the dates previously provided in the response to BCUC IR No. 1 Q12.3, FortisBC has no further information to provide on the timing for the implementation of a Smart Grid in FortisBC's territory.

1.4 Please compare and contrast the cost-benefits of implementing AMI with and without a smart-grid.

Response:

It is important to note that the term "smart grid", as discussed in section 3.2.3 of the Application, is characterized by the Company as "the application of digital technology to improve the efficiency, safety, reliability and cost-effectiveness of the electric power system." FortisBC views the implementation of AMI as but one component of a "smart grid". As well, completed projects such as the Distribution Substation Automation Program also align with the above definition of a smart grid.

Based on the Company's definition of the term "smart grid", it is not possible to provide a comparison of the costs-benefits of implementing AMI with and without a smart-grid as the implementation of AMI is, by definition, necessarily a part (one component) of the "smart grid".

Please also refer to the response to BCRUCA IR No. 1 Q1.1.

1.5 Please provide any evidence of actual smart meter and grid deployment in other service areas that have proven savings similar to what FortisBC is claiming.

Response:

FortisBC has been unable to locate any reports that report on the achievement of proven savings. Regardless, the combination of benefits and costs that FortisBC has forecast in this Application are necessarily unique to its service territory and customer base. For example, the Company is unaware of any utilities in North America (other than BC Hydro) that have quantified theft detection benefits.

FortisBC submits that the information in its AMI application is sufficient to justify and quantify the savings attributable to its proposed AMI system. As well, FortisBC proposes to report on benefits realization as described in its response to BCUC IR No. 1 Q56.3.

2.0 Reference: Application

2.1 Please list the number of customer calls related to smart meters that FortisBC has had in the last 6 months.

Response:

FortisBC has not been tracking this as a separate type of call since the numbers have been very small relative to total call volume. A rough estimate of the number of calls related to advanced meters in the last 6 months is less than 200. Approximately 100 more calls are estimated to have occurred due to customers thinking they had received an advanced meter when in fact a regular digital meter was installed as part of the normal meter exchange and compliance procedures.

2.2 Please indicate the number of customers that have, in some way, indicated that they do not want a smart meter installed.

Response:

As of October 30, 2012 FortisBC has received correspondence from 368 customers that have a negative opinion of the project and/or have stated they do not want a smart meter.

3.0 Reference: FBC Response to BCUC IR No. 2.1

Exhibit B-1, Section 4.1.2,

FortisBC indicates that that AMI transmissions are infrequent and very short in duration.:

3.1 Please indicate the frequency and duration of exposure to the 902-928 MHz band and other wireless bands FortisBC may use due to AMI as compared to other residential household technologies commonly in use.

Response:

The RF fields from AMI meters will be low compared to other residential technologies commonly in use. Please refer to the Application (Exhibit B-1) at Appendix C-5, Appendix A and the "OpenWay Radio Frequency and Safety Compliance" paper as provided below for details.

Itron

Table 1: Relative Power Density in microwatts per square centimeter (μW/cm^2)

FM radio or TV broadcast station signal	0.005
Itron Openway SmartMeter™ device at 10 feet*	0.005
Cyber cafe (Wi-Fi)	10 - 20
Laptop computer	10 - 20
Cell phone held up to head	30 - 10,000
Walkie-Talkie at head	500 - 42,000

Source: Richard Tell Associates, Inc
**Itron Openway SmartMeter for BC Hydro.*

- *Limited proximity to humans*: Radio frequency diminishes rapidly with distance from the meter. Itron's OpenWay meter is installed outside customer homes, where the power density is less than 0.5% of the limit set by Federal Communication Commission (FCC) and Industry Canada.

  In high-density residential complexes that use interior meter banks, the meters communicate with each other using a mesh network technology. A recent Electric Power Research Institute report, "An Investigation of Radiofrequency Fields Associated with the Itron Smart Meter," says that – regardless of how many meters are co-located in a meter bank - the additive effect *peaks* at just two times the power density of a single meter. And, the cumulative communication time of meters in a meter bank - *over a* year - would be equivalent to 4 minutes spent in a wireless internet café.

According to several reputable organizations, including the World Health Organization and Utilities Telecom Council, there is no demonstrated cause and effect relationship between low levels of radio frequency exposure and adverse human health effects. Itron recognizes that concerns about radio frequency emissions exist. As such, we continue to monitor the regulations and perform extensive testing to actively minimize radio frequency emission levels by all means possible.

Source: Prepared by Itron, Inc. on behalf of BC Hydro

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4.0 Reference: Project Costs and Benefits

Exhibit B-1, Section 5.0

FortisBC anticipates that the NPV of theft reduction is in excess of $38 million:

4.1 Please confirm that meter readers are currently visiting physical locations at least 6 times per year to read residential meters.

Response:

Confirmed – meter readers are scheduled to visit physical meter locations at least 6 times per year to read residential meters.

4.2 Please comment on the viability of meter readers providing information about homes on their route that could be bypassing meters and stealing electricity.

Response:

Please refer to the responses to BCUC IR No. 1 Q88.1, Q88.1.1 and Q88.3.1

4.3 What current legal options does FortisBC have to investigate suspected electricity theft that would change with the implementation of AMI?

Response:

The Company's legal options for investigating suspected electricity theft are not expected to change with the implementation of AMI.

4.4 Is it FortisBC's assertion that electricity theft will be reduced even with the reduction of physical meter readings that could confirm illegal meter bypasses?

Response:

Physical meter readings are not effective in identifying the type of meter bypasses typically found in the FortisBC service area. AMI deployment will improve tamper detection and data quality as well as enable energy balancing. The combination of these improvements will reduce electricity theft below current levels. Please refer to the responses to BCRUCA IR No. 1 Q4.2, BCUC IR No. 1 Q88.1 and Q88.1.1.

4.5 With fewer field staff (meter readers) how is it possible that FortisBC will better able to prevent and deter by-passing of meters?

Response:

Please refer to Exhibit B-1, Section 5.3.2 and the responses to BCUC IR No. 1 Q88.1, Q88.3.1 and BCRUCA IR No. 1 Q4.2 and Q4.4.

4.6 Please indicate the average number of residential meters that would be at the next level of the smart grid and how that would be a better indication of where meter by-passes are occurring including how this process would be better at reducing the electricity theft.

Response:

The next level of the smart grid consists of the feeder, transformer and portable meters required to support energy balancing. The application proposes the installation of 575 meters to support this function. For specific detail on how the meters will be deployed please refer to the responses to BCUC IR No. 1 Q54.1 and CEC IR No. 1 Q22.1 and Q77.2.

4.7 Is any percentage of the cost of meter reading staff shared with other organizations? If so how will those agreements change and will those organizations absorb the full cost of the meter readers?

Response:

No. FortisBC's electric meter reading staff are not shared with any other organization.

5.0 Reference: Project Costs and Benefits (Assumptions)

Exhibit B-1, Section 5.0 and response to BCUC IR No.1 #53.8.

FortisBC states in response to BCUC IR No. 1 #53.8 that a high-level assumption made is that : "Customer AMI meter refusals do not exceed 0.5% of customer base".

5.1 Based on reaction to BC Hydro's implementation of Smart Meters and FortisBC's proposed implementation of Smart Meters is this assumption still valid? Why or why not?

Response:

FortisBC believes the assumption regarding AMI meter refusals not exceeding 0.5 percent of the Company's customer base is still valid based on the customer refusal process identified in section 8.5 of the Application.

6.0 Reference: Future Benefits; Future Rate Structures

Exhibit B-1, Section 6.0

6.1 Please confirm that FortisBC is not applying for TOU rate structures and that such applications would need a separate, distinct approval process before the BCUC.

Response:

Confirmed.

7.0 Reference: APPLICATION

Exhibit B-1

7.1 Please discuss how FortisBC plans to deal with requests not to install smart meters with specific reference to those with electrohypersensivity or medical conditions who are medically advised to avoid exposure to wireless fields.

Response:

Please refer to the response to CSTS IR No. 1 Q34.4.

1.0 Reference: Application - Glossary of Terms - page vii

1.1 Would a device that does not emit RF fit within the definition of "advanced meter" as defined?

Response:

FortisBC confirms that the definition of "advanced meter" as provided in the Application encompasses both meters using PLC communications technology as well as meters using RF communications technology.

2.0 Reference: Application - Executive Summary - page 1 - line 6

2.1 Of the "immediate benefits" claimed in relation to the AMI Project, which of them can be achieved using non-RF communication technologies?

Response:

Although the benefits as summarized in the Executive Summary from the Application can largely be achieved using non-RF AMI communication technologies like PLC, such systems do not provide all of the functionality available with the proposed AMI system as discussed in section 7.5 of the Application.

In addition, it is important to note that the capital and operating costs for PLC are more than that required for the proposed AMI system, which would reduce the overall net benefit attributable to an AMI implementation if it were chosen.

2.2 What consideration has FortisBC given to the ability to achieve these "immediate benefits" using non-RF communication technologies?

Response:

Please refer to the response to BCUC IR No. 1 Q38.2 and Q38.3.

2.3 Disclose any and all contracts, correspondence, notes, memoranda and/or any other documents and particulars relating to consideration that FortisBC has given to the ability to achieve these "immediate benefits" using non-RF communication technologies.

Response:

In Exhibit C9-2, CSTS has made 14 demands, including this one, for "any and all" documents on a large variety of topics (IR 2.3, 3.3, 4.6, 4.9, 5.2, 6.3, 10.2, 12.3, 12.10, 13.3, 23.6, 27.3, 34.6, 54.16). Those topics range as far as any consideration that the utility has given, without any limitation of time period or context, to mandatory time-based rate structures (IR 5.2).

These document demands are not in the nature of proper information requests and are, rather, in the nature of document discovery in a litigation process.

Though FortisBC respectfully declines to respond to these 14 demands as posed, it has nonetheless endeavoured, subject to considerations of relevance, proportionality and privilege (each of which would limit the scope of response to the 14 demands even if made in the litigation context), to address in other IR responses the subject matter that CSTS has raised.

3.0 Reference: Application - Executive Summary - page 1 - lines 8 - 11

FortisBC refers to the AMI Project as being "consistent" with provincial government policy and "consistent" with the Regulations made pursuant to the Clean Energy Act.

3.1 Where do the Regulations require the use of RF communication technology?

Response:

FortisBC does not assert that the Regulations require the use of RF communication technology, however the Company notes that the Regulations do not prohibit the use of RF communication technology.

3.2 Has Fortis BC considered whether RF communication technology is necessary to achieve consistency with the CEA and regulation?

Response:

Please refer to the response to CSTS IR No. 1 Q3.1.

3.3 Disclose any and all contracts, correspondence, notes, memoranda and/or any other documents and particulars relating to consideration that FortisBC has given to whether RF communication technology is necessary to achieve consistency with the CEA and regulation?

Response:

Please refer to the response to CSTS IR No. 1 Q2.3.

4.0 Reference: Application - Executive Summary - page 1 - line 18

FortisBC estimates that the AMI Project will be at a capitol cost of $47.7 million.

4.1 Is FortisBC aware that the British Columbia Human Rights Tribunal has accepted a representative complaint against BC Hydro's smart meter program on behalf of a class consisting of those persons allegedly diagnosed as being electro-hypersensitive who have been advised to avoid wireless technology?

Response:

FortisBC is aware that on August 28, 2012, the B.C. Human Rights Tribunal (BCHRT) issued a decision addressing whether to accept a complaint filed by CSTS against BC Hydro alleging discrimination on the basis of physical disability in relation to BC Hydro's SMI implementation.

In its decision, the BCHRT agreed that CSTS had alleged a potential breach of the *Human Rights Code,* but took exception to the reference to "unspecified medical conditions" in alleging various disabilities. Further, the BCHRT found that while CSTS is an appropriate representative, the class, as defined for the purposes of the complaint, is overbroad. Specifically, the BCHRT notes that the defining characteristics must be specific enough to clearly delineate membership, and that a vague and medically-unsubstantiated reference by a physician to avoid wireless technology is insufficient to constitute a disability for the purposes of the complaint.

The decision provided CSTS the option of filing an amended complaint within 30 days of the date of the decision to restrict the class to those persons allegedly diagnosed with electro-hypersensitivity who have been advised to avoid wireless technology. FortisBC is aware that an amended complaint has been filed by CSTS in this regard. Finally, in its decision, the BCHRT noted the possibility (in the event an amended complaint was received) of holding a hearing on the discrete issue of whether or not electro-hypersensitivity is a disability for the purposes of the *Human Rights Code.*

4.2 What consideration has FortisBC given to the prospect of implementing, voluntarily or by order, a program allowing a customer to opt out of having an RF emitting meter at his/her home?

Response:

FortisBC has considered the matter. Please refer to the responses to CEC IR No. 1 Q50.1-50.6.

4.3 What would be the cost to FortisBC / opt-out customers of implementing, voluntarily or by order, a program allowing a customer to opt out of having an RF emitting meter at his/her home (“the Cost”) ?

Response:

Please refer to the response to CEC IR No. 1 Q50.6.

4.4 How would that Cost be reflected in rates over a ten year period following the implementation of the opt-out program?

Response:

The revenue received from radio-off fees would be forecast and recorded as “Other Income” similar to other tariff fees. These revenues would be offset by increased O&M costs. The net result would be a forecast zero rate impact.

Please also refer to the response to CEC IR No. 1 Q50.6.

4.5 How would that cost vary as per the number of customer participants?

Response:

Please refer to the response to CEC IR No. 1 Q50.6 and Q50.6.1.

Of the two cost components discussed, the one-time fee of $110 would not vary based upon the number of customers who elect to opt out.

4.6 Disclose any and all contracts, correspondence, notes, memoranda and/or any other documents and particulars relating to consideration that FortisBC has given to the prospect and cost of implementing, voluntarily or by order, a program allowing a customer to opt out of having an RF emitting meter at his/her home?

Response:

Please refer to the response to CSTS IR No. 1 Q2.3.

4.7 What other electrical utilities have a wireless smart meter program that includes a customer opt out option and what fees, if any, have been charged to the customer in those respects?

Response:

Please refer to the response to BCUC IR No. 1 Q117.1 and CEC IR No. 1 Q96.1.

4.8 In the view of FortisBC, how have these utilities, referenced in question 4.7 above, rendered their respective opt out options feasible?

Response:

FortisBC assumes that all of the utilities referenced in CSTS IR No. 1 Q4.7 proposed “feasible” opt out options for the specific circumstances of the utility in question.

4.9 Disclose any and all contracts, correspondence, notes, memoranda and/or any other documents and particulars relating to consideration that FortisBC has given to the approaches and feasibility measures taken by other utilities that have incorporated an opt out option into their respective RF emitting meter programs.

Response:

Please refer to the response to CSTS IR No. 1 Q2.3.

4.10 Provide full financial costs of data management, maintenance, storage and customer relations associated with the AMI project.

Response:

Please see Table 5.1.b (page 72) of the Application (Exhibit B-1). Financial costs estimated for data management, maintenance, and storage are embedded in the IT Hardware, Licencing, and Support costs shown in the table. Please also refer to the response to BCUC IR No. 1 Q42.2.

The Company presumes that by “customer relations” the question is referring to improvements in Customer Service accruing from the implementation of the proposed AMI Project. For details on improvements to customer service, please see Section 3.2.5 of the CPCN Application. Costs required to deliver the anticipated benefits are embedded in the overall cost of the proposed project, $47.7 million, details of which are found in Section 5.1 of the CPCN Application.

4.11 Provide particulars as to legal costs associated with the present application.

Response:

Legal costs incurred to date relate primarily to negotiation of the Itron contract, and amount to approximately $360,000. These costs are embedded in line 2 of Table 5.1.1.a, as updated in the response to BCUC IR No. 1 Q50.1 and Errata No. 1.

Legal costs forecast as part of the regulatory process are provided in the response to BCUC IR No. 1 Q50.1.2.

5.0 Reference: mandatory time-based rate structure

5.1 Has FortisBC considered implementing a mandatory time-based rate structure or a mandatory critical peak pricing structure?

Response:

The Company intends to evaluate voluntary time-based rates as a complement to existing rate structures. There are no current plans to make time-based rates mandatory.

5.2 Disclose any and all contracts, correspondence, notes, memoranda and/or any other documents and particulars relating to consideration that FortisBC has given to implementing a mandatory time-based rate structure or a mandatory critical peak pricing structure?

Response:

Please refer to the response to CSTS IR No. 1 Q2.3.

6.0 Reference: local government input

6.1 What input has FortisBC received from local governments with respect to the prospective AMI program?

Response:

The comments FortisBC has received from local governments with respect to the prospective AMI program have been related to the health and privacy concerns of their constituents discussed in Section 8.0 of the Application, as well as the feasibility of an opt-out provision.

FortisBC notes that a common concern expressed by municipalities served directly and indirectly by the Company is a desire for rate mitigation, which is a benefit the proposed Project provides.

6.2 Which local governments have asked to be spared from all or parts of the AMI program?

Response:

No local government has asked FortisBC "to be spared" from all or parts of the AMI program. Osoyoos and Kaslo have provided written responses to FortisBC suggesting that an opt out clause be considered. Other municipal governments have passed motions of a similar nature but have not contacted FortisBC directly.

6.3 Disclose any and all contracts, correspondence, notes, memoranda and/or any other documents and particulars relating to input that FortisBC has received from local governments with respect to the prospective AMI program.

Response:

Please refer to the response to CSTS IR No. 1 Q2.3.

7.0 Reference: Application - Customer Health Concerns - page 3 - line 15

7.1 Would Fortis BC expect the referenced customer health concerns to exist with respect to non-RF communication technology?

Response:

FortisBC does not consider that there are health concerns founded on accepted science regardless of whether the AMI system uses RF or non-RF technology.

8.0 Reference: Application - Project Description - page 3 - line 21

8.1 What are the various means by which meter data is forwarded from the WAN to the HES? Does this include transmission over wires?

Response:

As discussed in Section 4.1.3 of the Application, the preliminary network design identifies fibre optic cable, cellular modem, WiMAX and satellite as data backhaul options. Fibre optic cable could be considered "wired" transmission.

9.0 Reference: Application - Overview of the Project - page 6 - line 11

9.1 Can non-RF communication technology provide the "near real time two-way communication capability" referred to on page 6, line 11?

Response:

"Non-RF" technologies such as PLC are capable of providing the "near real time two-way communication capability". PLC has the cost and functionality limitations described in Section 7.3 of the Application (Exhibit B-1).

10.0 Reference: Application - Approach taken- page 12 - line 18

FortisBC says that it retained the services of an experienced consultant to facilitate the AMI system procurement process.

10.1 What considerations has FortisBC and/or its "experienced consultant" given to non-RF communication technologies in the context of the procurement process?

Response:

Please refer to the response to BCUC IR No. 1 Q38.3.

10.2 Disclose any and all contracts, correspondence, notes, memoranda and/or any other documents and particulars relating to consideration that FortisBC and/or its "experienced consultant" have given to non-RF communication technologies in the context of the procurement process.

Response:

Please refer to the response to CSTS IR No. 1 Q2.3.

11.0 Reference: Application - Approach taken- page 13 - lines 9 - 11

11.1 Has FortisBC monitored the progress and results from utilities that have implemented or are in the process of implementing advanced metering projects without the use of RF communication technology?

Response:

FortisBC believe that's very few PLC systems have been selected in North America since 2008. FortisBC has monitored the progress of FortisAlberta, which has implemented PLC AMI technology.

11.2 What has FortisBC found in that regard, with respect to the success of those programs?

Response:

Please refer to the responses to BCUC IR No. 1 Q113.1-113.1.3. FortisBC understands that the current generation of PLC technology has constraints on the total number of hourly customers that can be supported off each substation.

12.0 Reference: Application - Project Alternatives

12.1 What consideration has FortisBC given to the use of third party telephone lines as an alternative to the RF mesh LAN solution? What would the cost be in that regard and how would that cost be reflected in rate increases over a long term period?

Response:

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.

12.2 What barriers or show-stoppers would exist to prevent the deployment of non-RF emitting meters along with a third party telephone line LAN communications infrastructure?

Response:

Please refer to the response to CSTS IR No. 1 Q12.1.

12.3 Disclose any and all contracts, correspondence, notes, memoranda and/or any other documents and particulars relating to consideration that FortisBC has given to the use of third party telephone lines as an alternative to the RF mesh LAN solution?

Response:

Please refer to the response to CSTS IR No. 1 Q2.3.

12.4 What consideration has FortisBC given to the expansion of its fibre optic network as an alternative to the RF mesh LAN solution?

Response:

Please refer to the responses to Shadrack IR No.1 Q1, Q2, Q3, Q4 and Q7.

12.5 What would be the hard costs for connecting smart meters to fibre optics when a) fibre optic cabling is already in place; and b) when fibre optic cable is not in place? What would be the cost of using of a fibre optic network as an alternative to the RF mesh LAN solution and how would that cost be reflected in rate increases over a long term period? Provide cost analysis of connecting all Fortis BC AMI meters in the province to fibre optic versus the cost of continually replacing wireless components every 7 to 10 years.

Response:

FortisBC does not agree with the assertion that wireless components require replacing every 7-10 years. While it has been acknowledged in section 4.1.3 of the Application (Exhibit B-1) that some technologies, particularly those offered as services by third parties, may have shorter useful lives; the bulk of the wireless equipment to be installed during the proposed AMI project is expected to last 20+ years. All expected upgrades, battery replacements and device replacements have been accounted for in the original financial analysis of the project.

FortisBC assumes the reference to “hard costs” to include only capital costs and exclude ongoing operating costs. FortisBC does not consider the exclusion of operating costs as a valid method for analyzing the financial viability of a project, particularly in the case when leasing infrastructure that is already in place. This requires little capital but carries significant operating costs. For this reason, FortisBC has provided a cost analysis inclusive of both capital and ongoing operating costs.

The table appearing below provides the cost analysis for fibre optic alternatives asked for in the question, based on the following assumptions:

- Lease Existing Fibre option – This option assumes that fibre infrastructure is already in place to the nearest transformer, and a small length of fibre cable between the transformer and meter is needed. It should be noted that this infrastructure is not known to exist in the FortisBC service area but, assuming it does, a reasonable market rate for leasing a fibre pair is used.

- Build Fibre option – Assumes that a fibre build is required along the entire FortisBC distribution network to access the meters. The per kilometer build rate is contracted out at a reasonable rate based on prior fibre construction projects and market rates.
- Meters are available with a fibre interface and their costs are similar to the proposed RF meters.
- Estimates are AACE class 5, and are useful for relative comparison purposes.
- Capital costs include all the associated costs to build and deploy infrastructure.
- Project NPV captures the total cost to the ratepayer in 2012 dollars, including benefits from the AMI system for all options. Negative values denote a net benefit to the ratepayer.

Table CSTS IR1 12.5 AMI Fibre to Meter vs. Proposed AMI Solution

	Capital Cost ($000s)	Project NPV ($000s)
Lease Existing Fibre	$90,681	$39,910
Build New Fibre	$320,348	$191,676
Proposed AMI Solution	$47,689	-$17,629

It is apparent from this table that either of the fibre options would represent significant additional costs to the ratepayer when compared to the proposed AMI solution with no corresponding benefits. This is due to the large capital costs of both options, and in the case of the lease option, significant ongoing lease costs for the fibre infrastructure. On this basis, FortisBC continues to believe that the AMI Project as proposed is a cost-effective and prudent solution.

12.6 What communities are not supplied by fibre optics?

Response:

FortisBC does not have this information.

12.7 Has an agreement with Telus regarding shared used of fibre optics been considered?

Response:

Please refer to the response to Shadrack IR No. 1 Q4.

12.8 Would the use of a fibre optic network as an alternative to the RF mesh LAN solution eliminate health and environmental concerns with respect to the AMI Project?

Response:

FortisBC does not consider that there are health concerns founded on accepted science related to AMI systems, regardless of whether they use RF or non-RF technology.

12.9 What barriers or show-stoppers would exist to prevent the deployment of non-RF emitting meters along with a fibre-optic LAN communications infrastructure?

Response:

Please refer to the responses to Shadrack IR No. 1 Q1, Q2, Q3, Q4 and Q7.

12.10 Disclose any and all contracts, correspondence, notes, memoranda and/or any other documents and particulars relating to consideration that FortisBC has given to the expansion of its fibre optic network (and/or the use of a third party fibre optic network) as an alternative to the RF mesh LAN solution?

Response:

Please refer to the response to CSTS IR No. 1 Q2.3.

12.11 If satellite communication technology is utilized with AMI meters, does this eliminate the mesh network and synchronization management RF signals?

Response:

No, satellite technology is used where appropriate in the WAN to backhaul aggregated meter data. The RF mesh is still required for LAN communication to the meters.

13.0 Reference: Fire risk

13.1 Is FortisBC aware that there has been concern over the fire risk associated with smart meters?

Response:

Yes. Please refer to the response to Tatangelo IR No. 1 Q59.

13.2 What consideration has FortisBC given to fire risk associated with its prospective AMI Project?

Response:

FortisBC considered the risk of fire from energy theft, and the reduction of this risk resulting from AMI, in Section 5.3.2 of Exhibit B-1.

Please also refer to response to BCUC IR No. 1 Q47.3.

13.3 Disclose any and all contracts, correspondence, notes, memoranda and/or any other documents and particulars relating to consideration that FortisBC has given to fire risk associated with its prospective AMI Project.

Response:

Please refer to the response to CSTS IR No. 1 Q2.3.

14.0 Reference: Application - Decision deadline of 7/20/2013 - page 8, line 28

14.1 How does the prospect of reconsideration and appeal (to the British Columbia Court of Appeal) factor into FortisBC's need for a timely decision on this application and how might FortisBC's contract pricing be affected by the prospect of such an appeal?

Response:

The outcome of the Court of Appeal is not relevant to the Company's application for an Advanced Metering Infrastructure since it relates to legislation that does not apply to FortisBC. If the question instead relates to the prospect of a possible reconsideration or appeal of the Commission's decision regarding FortisBC's proposed project, the Company notes that the decision of the Commission would, once made, be binding unless or until set aside.

15.0 Reference - Application - Environment - page 126

15.1 What communications technology is the basis for Manitoba Hydro's business case for the deployment of electric smart meters?

Response:

As per the Manitoba Hydro website[1], it conducted a smart meter pilot from 2006 to 2009 that consisted of 4,500 RF meters and 200 meters operating on PLC. The website indicates that Manitoba Hydro is currently compiling pilot data and market information for its business case development.

15.2 What communications technologies have been employed by the meter programs in Quebec, Ontario and Saskatchewan?

Response:

Hydro Quebec has selected Landis & Gyr for its deployment which uses RF communications.

SaskPower is installing the Sensus Flexnet System which uses RF communications.

Within Ontario there are over 4.5 million meters deployed using the following technologies *(% breakdown by each technology is approximate)*

- Elster - RF *(33% of marketplace)*
- Sensus - RF *(32% of marketplace)*
- SilverSpring Network - RF *(1% of marketplace)*
- SmartSynch – RF *(0.5% of marketplace)*

[1] http://www.hydro.mb.ca/corporate/facilities/smart_meters.shtml

- Tantalus – RF *(1% of marketplace)*
- Trilliant – RF *(32.5% of marketplace)*

16.0 Reference - Application - Environment - page 134, lines 19 - 20

FortisBC states "as meters are intentionally installed outside the home, it is unlikely for customers to be in close proximity to a meter for prolonged periods of time."

16.1 On what basis has FortisBC assessed the likeliness that customers will be in close proximity to a meter for prolonged periods of time?

Response:

Please refer to the response to CSTS IR No. 1 Q16.2.

16.2 How does the installation of a meter outside the home factor into the likeliness that a customer may be in close proximity to a meter for prolonged periods of time?

Response:

FortisBC agrees that the statement could have been written more clearly. There is no relationship between the location of a customer's meter and the duration of their proximity to it.

The bulleted section of the Application from which the reference was taken is discussing the impact of distance on EMF exposure, not the duration or "duty cycle". Duty cycle is discussed separately in a subsequent bullet in the same section of the application.

The referenced statement should have been phrased as, "as meters are intentionally installed outside the home, a customer's distance from the meter is maximized".

16.3 Has FortisBC considered that a meter (or a bank of meters in the case of an apartment complex) may be located on the exterior wall of a bedroom? How does this consideration affect the likeliness that a customer may be in close proximity to a meter for prolonged periods of time?

Response:

Please refer to the response to CSTS IR No. 1 Q16.2. FortisBC notes that a bank of meters does not materially change the level of emissions as governed by Safety Code 6, and as such does not require a different consideration with respect to any perceived health effects resulting from the implementation of the project.

17.0 Reference - Application - Environment - page 134, line 24

17.1 In evaluating the EMF risks posted by the proposed meters, does FortisBC consider it important to consider the following specifics?

A. The frequency and extent of fluctuation of RF levels?

B. The duration of each instance of an RF emission?

C. The frequency with which an RF emission occurs?

Response:

The factors that FortisBC considers important in evaluating EMF exposure are described in the referenced section of the Application, Exhibit B-1, Section 8.4.2, p134-135

All items listed above are considered in determining compliance with Health Canada Safety Code 6.

17.2 What is the frequency and extent of fluctuation of RF levels with respect to the proposed meters? Is the on/off manner in which emissions occur analogous to the fluctuating emission levels of a strobe light? At what speed are the emissions flashing on and off? How often? What is the frequency with which an RF emission occurs? What is the duration of each transmission?

Response:

Please refer to the response to BCSEA IR No. 1 Q55.5.

17.3 What is the duration of each instance of an RF emission with respect to the proposed meters?

Response:

Please refer to the response to BCSEA IR No. 1 Q55.5.

18.0 Reference - Application - Appendix C-5

18.1 Disclose all the projects that Exponent has provided an opinion or report on, with respect to matters of health, safety and/or environment, and briefly summarize the conclusions on the opinion / report provided by Exponent in each instance.

Response:

FortisBC considers this request overly broad. Exponent's work for other clients may in any case also be subject to attorney-client privilege.

19.0 Reference - Application - Appendix C-5 - pages 7 and 8 (of 47)

Exponent says the exposure assessment evaluates the amount and nature of human exposure from the agent being studied.

19.1 In evaluating the nature of RF exposure, what consideration has FortisBC and/or Exponent given to the extent and amount of fluctuations in RF levels, the frequency with which instances of RF emissions occur and the speed at which the emissions are flashing on and off?

Response:

The exposure characteristics of the RF signals from the FortisBC AMI meters were considered from the perspective of Safety Code 6 compliance and more generally with respect to the relevant scientific literature.

19.2 Have there been studies or tests of exposure risk in relation to exposure to RF emissions that replicate the actual pattern of emissions that are expected to occur from the proposed meters, i.e. replicating the extent and amount of fluctuations in RF levels, the frequency with which instances of RF emissions occur and the speed at which the emissions are flashing on and off?

Response:

Exponent is aware of laboratory studies that have involved exposures to RF signals of similar frequencies, on/off 'speeds', and generally higher intensities and longer duration duty cycles.

20.0 Reference - Application - Appendix C-5 - page 7

Exponent says the final step in the analysis is to compare the specific exposure to the relevant standard.

20.1 On what basis has FortisBC and/or Exponent assumed that standard to be correct, i.e. the thermal standard.

Response:

Safety Code 6 is a legally binding standard in Canada. The basis and provisions of Safety Code 6 are similar to standards developed by many other national and international scientific, health, and governmental agencies.

20.2 What consideration has FortisBC given to the assessment of exposure risks according to alternative standards such as the non-thermal standard?

Response:

FortisBC is not aware of any science-based, generally accepted "non-thermal standard".

20.3 Whereas the Safety Code 6 standard measures the thermal condition of the body after six minutes of exposure to microwave radiation, how will FortisBC assess the cumulative effect(s) of the frequencies regularly transmitted by the smart meters over a long term period?

Response:

FortisBC has no plans to perform laboratory studies to measure thermal conditions of the body. There is no scientific basis to assume from a range of realistic exposure scenarios and the known operating characteristics of the FortisBC AMI meters that the thermal condition of the body will be affected by RF signals from FortisBC smart meters.

21.0 Reference - Application - Appendix C-5 - page 15

Exponent says:

"The effect that would occur first, given sufficient RF exposure, is that of raising the body temperature"

21.1 On what basis has the author assumed that raising the body temperature is the effect that would occur first?

Response:

National and international guidelines and standards for RF exposure have examined the research literature and concluded that the adverse effect with the lowest threshold is tissue heating.

21.2 Is there controversy as to whether raising the body temperature is the effect that would occur first?

Response:

Despite the fact that there is consensus among standard-setting organizations that tissue heating is the adverse effect with the lowest threshold, scientists have looked for effects occurring at lower levels of exposure. Some scientists have argued that adverse effects may occur at lower levels of exposure but the evidence is insufficient to support this argument. See for example, the conclusion of the International Commission on Non-Ionizing Radiation Protection (ICNIRP) (2009):

It is the opinion of ICNIRP that the scientific literature published since the 1998 guidelines has provided no evidence of any adverse effects below the basic restrictions and does not necessitate an immediate revision of its guidance on limiting exposure to high frequency electromagnetic fields. The biological basis of such guidance remains the avoidance of adverse effects such as "work stoppage" caused by mild wholebody heat stress and/or tissue damage caused by excessive localized heating (D'Andrea et al. 2007). With regard to non-thermal interactions, it is in principle impossible to disprove their possible existence but the plausibility of the various non-thermal mechanisms that have been proposed is very low. In addition, the recent in vitro and animal genotoxicity and carcinogenicity studies are rather consistent overall and indicate that such effects are unlikely at low levels of exposure. Therefore, ICNIRP *reconfirms the 1998 basic restrictions in the frequency range 100 kHz–300 GHz until further notice (p. 257)*[2].

21.3 Set out the range of opinion amongst scientists and medical professionals who have expressed an opinion on the matter of whether raising the body temperature is the effect that would occur first?

Response:

The range of opinions about the adverse effect of RF exposure with the lowest threshold is scattered across the scientific literature. As part of the work towards evaluating and updating the ICNIRP standard, this agency invited scientists from around the world to participate in an international seminar on the topic of non-thermal RF electromagnetic fields (ICNIRP, 1997)[3]

21.4 Particularize the position of those scientists and medical professionals who have expressed an opinion (contrary to that of Exponent) on the matter of whether raising the body temperature is the effect that would occur first?

Response:

The position of a limited number of scientists who have been most vociferous in advocating a contrary position is summarized in the 2007 Bioinitiative report (http://www.bioinitiative.org/).

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[2] International Commission on Non-Ionizing Radiation Protection (ICNIRP). Review of the scientific evidence on dosimetry, biological effects, epidemiological observations, and health consequences concerning exposure to high frequency electromagnetic fields (100 kHz to 300 GHz). Oberschleißheim, Germany: ICNIRP, 2009.

[3] Non-Thermal Effects of RF Electromagnetic Fields. Proceedings of the International Seminar on Biological Effects of Non-Thermal Pulsed and Amplitude Modulated RF Electromagnetic Fields and Related Health Risks, Munich, Germany, November 20-21, 1996. Munich: International Commission on Non-Ionizing Radiation Protection; 1997

22.0 Reference - Application - Appendix C-5 - page 15

22.1 On what basis has the author assumed that an adequate approach to protection is achieved by setting exposure limits according to the point of tissue warming?

Response:

Please refer to p. 17 of Appendix C-5 of the Application (Exhibit B-1).

22.2 Is there controversy as to whether an adequate approach to protection is achieved by setting exposure limits according to the point of tissue warming?

Response:

Please refer to the response to CSTS IR No. 1 Q21.2.

22.3 Set out the range of opinion amongst scientists and medical professionals who have expressed an opinion on the matter of whether an adequate approach to protection is achieved by setting exposure limits according to the point of tissue warming.

Response:

Please refer to the response to CSTS IR No. 1 Q22.1.

22.4 Particularize the position of those scientists and medical professionals who have expressed an opinion (contrary to that of Exponent) on the matter of whether an adequate approach to protection is achieved by setting exposure limits according to the point of tissue warming?

Response:

Please refer to the response to CSTS IR No. 1 Q22.1.

23.0 Reference - Application - Appendix C-5

23.1 Who is/are the author(s) of the Exponent report?

Response:

William Bailey, Ph.D. (30 years of training and experience including laboratory and epidemiologic research, health risk assessment, and comprehensive exposure analysis involving alternating current, direct current, and radiofrequency electromagnetic fields), **Linda Erdreich, Ph.D.** (epidemiologist with 32 years of experience in environmental epidemiology and health risk assessment including environmental and occupational chemicals, radiofrequency energy, electric and magnetic fields (EMF), and stray voltage), and **Yakov Shkolnikov, Ph.D.** (Testing of systems that produce or communicate via electromagnetic signals. Electromagnetic interference analysis and exposure assessments of devices and systems including smart meter networks, radar installations, cell phones, radio towers, MRI machines, transmission and distribution lines, consumer electronic devices, and medical device implants).

23.2 Set out the qualifications of the author(s) of the Exponent report.

Response:

Please refer to the response to CSTS IR No. 1 Q23.1.

23.3 Are these authors being held out as experts in a field? If so, what is the alleged scope of their expertise?

Response:

Please refer to the response to CSTS IR No. 1 Q23.1.

23.4 Provide a copy of the cv of each author of the Exponent report.

Response:

The CVs of Drs. Erdreich, Bailey, and Shkolnikov are provided as Appendix CSTS IR1 23.4.

23.5 On what other projects or reports have these authors participated on behalf of Exponent or otherwise.

Response:

Please also refer to the response to CSTS IR No. 1 Q23.4.

23.6 Disclose any and all contracts, correspondence, emails, notes, memoranda and/or any other documents (including previous drafts of the Exponent Report) exchanged as between FortisBC (or its subcontractors including Util-Assist Inc.) and Exponent.

Response:

Please refer to the response to CSTS IR No. 1 Q2.3.

24.0 Reference - Application - Appendix C-5 - non-thermal effects - p.17

24.1 Particularize the reference to "some studies" that have reported effects occurring with RF exposures below the level that raises the body temperature ("the Nonthermal Studies").

Response:

Please refer to the references on p. 21 of Appendix C-5 of the Application (Exhibit B-1), where studies were noted. Please also refer to the response to CSTS IR No. 1 Q21.3.

24.2 Provide a copy of each of the Nonthermal Studies.

Response:

No compilation of studies based upon just one group of potential mechanisms has been performed. Please also refer to the response to CSTS IR No. 1 Q24.1.

24.3 Provide a copy of each and every review of the Nonthermal Studies.

Response:

Please refer to the response to CSTS IR No. 1 Q24.2.

24.4 Has each and every review ever done of the Nonthermal Studies found the data in the Nonthermal Studies to be unreliable?

Response:

No survey of "each and every review" in the scientific literature on RF field has been performed to address this question.

24.5 Has any review done of the Nonthermal Studies denied the occurrence of biological effects at nonthermal levels of exposure?

Response:

No survey of "any review done" in the scientific literature on RF fields has been performed to address this question.

As noted in Appendix C-5 from the Application, known adverse health effects can be caused by high exposures to RF, with the effect that would occur first, given sufficient exposure, being an increase in the body temperature. This is the basis of the applicable public exposure limit.

25.0 Reference - Application - Appendix C-5

25.1 Produce a digital PDF copy of each and every report, review and/or study referenced and/or discussed in the Exponent report.

Response:

Copies of published scientific papers cannot be distributed because of copyright restrictions. Links to publically available studies and to abstracts of studies (in the Pub Med data base) subject to copyright are provided below:

American Cancer Society (ACS), Cancer Facts & Figures 2009. Atlanta: American Cancer Society, 2009. http://www.cancer.org/acs/groups/content/@nho/documents/document/500809webpdf.pdf

Ahlbom A, Green A, Kheifets L, Savitz D, Swerdlow A. ICNIRP Standing Committee on Epidemiology. Epidemiology of health effects of radiofrequency exposure. Environ Health Perspect 112:1741-1754, 2004. http://www.ncbi.nlm.nih.gov/pubmed/15579422

Ahlbom A, Feychting M, Green A, Kheifets L, Savitz DA, Swerdlow A, ICNIRP Standing Committee on Epidemiology. Epidemiologic evidence on mobile phones and tumor risk – a review. Epidemiology 20:1-14, 2009. http://www.ncbi.nlm.nih.gov/pubmed/19593153

Aydin D, Feychting M, Schuz J, Tynes T, Andersen TV, et al. Mobile phone use and brain tumors in children and adolescents: A multicenter case-control study. J Natl Cancer Inst 203:1264-1276, 2011. http://www.ncbi.nlm.nih.gov/pubmed/21795665

Baan R, Grosse Y, Lauby-Secretan B, El Ghissassi F, Bouvard V. Benbrahim-Talla L, Guha N, Islami F, Galichert L, Straif K, WHO International Agency for Research on Cancer Working Group. Carcinogenicity of radiofrequency electromagnetic fields. Lancet Oncol 12:624-626, 2011. http://www.ncbi.nlm.nih.gov/pubmed/21845765

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Cooper D, Hemmings K, Saunders P. Re: “Cancer incidence near radio and television transmitters in Great Britain. I. Sutton Coldfield transmitter; II. All high power transmitters.” Am J Epidemiol 153:202-204, 2001. http://www.ncbi.nlm.nih.gov/pubmed/11159167

Danker-Hopfe H, Dorn H, Bornkessel C, Sauter C. Do mobile phone base stations affect sleep of residents? Results from an experimental double-blind sham-controlled field study. Am J Hum Biol 22:613-618, 2010. http://www.ncbi.nlm.nih.gov/pubmed/20737608

de Vocht F, Burstyn I, Cherrie JW. Time trends (1998-2007) in brain cancer incidence rates in relation to mobile phone use in England. Bioelectromagnetics 32:334-339, 2011. http://www.ncbi.nlm.nih.gov/pubmed/21280060

Deltour I, Johnasen C, Auvinen A, Feychting M, Klaeboe L, Shuz J. Time trends in brain tumor incidence rates in Denmark, Finland, Norway, and Sweden 1974-2003. J Natl Cancer Inst 101:1721-1724, 2009. http://www.ncbi.nlm.nih.gov/pubmed/19959779

Dolk H, Shaddick G, Walls P, Grundy C, Thakrar B, Kleinschmidt I, Elliott P. Cancer incidence near radio and television transmitters in Great Britain, I. Sutton Coldfield transmitter. Am J Epidemiol 145:1-9, 1997a. http://www.ncbi.nlm.nih.gov/pubmed/8982016

Dolk H, Elliot P, Shaddick G, Walls P, Grundy C, Thakrar B. Cancer incidence near radio and television transmitters in Great Britain, II. All high power transmitters. Am J Epidemiol 145:10-17, 1997b. http://www.ncbi.nlm.nih.gov/pubmed/8982017

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26.0 Reference - Application - Appendix C-5 - page 22

26.1 How is “intensity (strength)” defined. Has there been consideration of the amount / extent of fluctuation of RF levels with respect to the proposed meters? Has there been consideration of the power of emissions during the signaling phase with respect to the proposed meters?

Response:

The “intensity (strength)” of a RF field is commonly expressed in units of power density defined as Watts per square meter (W/m2) or equivalent units.

The questions regarding RF levels and power during signalling are covered by Safety Code 6. Please also refer to the response to BCSEA IR No. 1 Q55.5.

27.0 Reference - Application - pollinating insects

27.1 Is FortisBC aware that there has been concern over the potential impact of the AMI Project on pollinating insects and/or birds?

Response:

FortisBC understands that concerns have been raised regarding advanced meters impacting bee colonies. Please refer to the response to WKCC IR No. 1 Q6.

27.2 Has there been any consideration as to the potential impact of the AMI Project on pollinating insects and/or birds?

Response:

Exponent is not aware of a body of scientific evidence that confirms any adverse effect of RF fields on insects and/or birds at the frequencies and intensities of RF fields produced by the FortisBC smart meters.

27.3 Disclose any and all contracts, correspondence, notes, memoranda and/or any other documents and particulars relating to consideration as to the potential impact of the AMI Project on pollinating insects and/or birds.

Response:

Please refer to the response to CSTS IR No. 1 Q2.3.

28.0 Reference - Application - page 47 - lines 2 & 3

28.1 What is the basis for FortisBC's statement that there is long-term certainty with respect to fibre-optic cable technology?

Response:

FortisBC would like to clarify that this statement is in reference to the physical fibre optic cable. It is viewed as physical infrastructure that once installed will have a long useful service life.

The termination equipment (lasers and diodes) that make use of the fibre optic cable are subject to the same pressures as typical communications equipment: to become faster, cheaper and more functional and therefore may become obsolete and unsupported faster than the cable.

29.0 Reference - Response to BCUC IR1 32.2

29.1 Who are the referenced third party cellular providers that will provide backhaul service for the AMI Project?

Response:

FortisBC has not committed to any third party provider for cellular service related to the proposed AMI project.

30.0 Reference - Response to BCUC IR1 38.2

30.1 What wired technologies are "perfectly capable" of meeting the requirement of hourly consumption reads?

Response:

FortisBC understands that newer PLC technologies (that would have been commercially available during the FortisBC RFP) are capable of hourly consumption reads.

31.0 Reference - Util-Assist Inc.

31.1 Do Util-Assist Inc. and Itron have any shareholders, officers and/or directors in common?

Response:

No, Util-Assist and Itron do not have any shareholders, officers or directors in common.

32.0 Reference - Response to BCUC IR1 119.4

32.1 Disclose a copy of FortisBC's letter in response to customer concerns over health issues, redacted to eliminate disclosure of personal information.

Response:

Please refer to Appendix CSTS IR1 32.1

33.0 Reference - Response to BCUC IR1 117.0

33.1 Does the electrical utility in the U.S. state of Maine allow opt-out for no fee?

Response:

FortisBC understands that Central Maine Power[4] charges an opt-out fee.

33.2 Does Nelson Hydro allow an opt-out for fee in relation to its RF emitting drive-by meters?

Response:

FortisBC is aware that Nelson Hydro allows customers to "opt-out" and that a fee is applicable.

33.3 Where does FortisBC consider that the Clean Energy Act and/or Regulation require the installment of a wireless RF emitting smart meter (as opposed to a meter based on a non-RF communication system)?

Response:

Please refer to the response to CSTS IR No. 1 Q3.1.

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[4] http://www.cmpco.com/smartmeter/smartmeteroptions.html

34.0 Reference - Response to BCUC IR1 117.4

34.1 Will FortisBC suspend service for those customers refusing installation of an AMI meter until such time that an AMI meter is installed?

Response:

As stated in the Application (Exhibit B-1) at page 142:

Regardless of FortisBC's efforts, some customers may continue to refuse the installation of an advanced meter. In these cases, FortisBC intends to follow the following process:

- *Continue productive dialogue with the customer where possible, making an effort to address concerns and ensuring the customer is aware that they have the option of relocating the meter on their property at their expense.*
- *Continue to provide billing using estimated readings for up to six months.*
- *After three months of refusal to provide access to exchange the meter, and in absence of extenuating circumstances, suspension of the customer's service until the advanced meter is installed.*

FortisBC does not take suspension of an individual customer's service lightly, but also cannot support ongoing manual meter reading or estimating once advanced metering has been deployed.

34.2 Particularize the reference to the provisions in the Terms and Conditions of the Electric Tariff on which FortisBC relies for its asserted right to suspend service for those customers refusing installation of an AMI meter until such time that an AMI meter is installed.

Response:

Section 8.2 of the Terms and Conditions of FortisBC's Electric Tariff is provided below:

8.2 Suspension of Service

The Company and the Customer may demand the Suspension of Service whenever necessary to safeguard life or property, or for the purpose of making repairs on or improvements to any of its apparatus, equipment or work. Such reasonable notice of the Suspension as the circumstances permit shall be given.

> The Company may suspend Service to the Customer for the failure by the Customer to take remedial action acceptable to the Company, within 15 days of receiving notice from the Company, to correct the breach of any provision of these Terms and Conditions to be observed or performed by the Customer. The Company shall be under no obligation to resume Service until the Customer gives assurances satisfactory to the Company that the breach which resulted in the Suspension shall not recur.
>
> The Company shall have the right to suspend Service to make repairs or improvements to its electrical system and will, whenever practicable, give reasonable notice to the Customer.
>
> The Company shall have the right to suspend or terminate Service at any time without notice whenever the Customer has breached any agreement with the Company, or failed to pay arrears within the specified time, fraudulently used the Service, tampered with the Company's equipment, committed similar actions, compromised the Company's Service to other Customers or if ordered by an authorized authority to suspend or terminate such Service. The cause of any Suspension must be corrected, and all applicable charges paid before Service will be resumed. Suspension of Service by the Company shall not operate as a cancellation of any contract with the Company, and shall not relieve any Customer of its obligations under these Terms and Conditions or the applicable rate schedule.

34.3 On what basis does FortisBC claim that RF emitting meters are "the standard metering technology? Where in the Clean Energy Act and Regulation are RF emitting meters required?

Response:

For clarity, the description of AMI meters as the proposed standard metering technology in the response to BCUC IR No. 1 Q117.4, and as discussed in section 3.1 of the Application, relates to the electric industry's transition away from metering technologies that require consumption data to be manually collected through a labour intensive process, to the use of AMI meters that remotely and cost effectively collect and transmit consumption data back to the utility. Please also refer to the response to CSTS IR No. 1 Q3.1.

34.4 Has FortisBC considered providing hard-wired communication technology solutions for those customers who refuse an RF emitting meter on the basis of health concerns or disability requiring accommodation?

Response:

In matters related to health, FortisBC relies on the expertise of the Provincial Health Officer, Health Canada, and World Health Organization, who have all confirmed that wireless meters pose no known health risk or reason for concern.

In situations requiring accommodation, FortisBC will assess extenuating circumstances for individual customers on a case-by-case basis.

34.5 Is FortisBC aware that there have been concerns about the potential impact of RF communication technology on pacemakers and other medical equipment?

Response:

Medical equipment such as pacemakers are designed to operate in 900 MHz and 2.4 GHz RF environments since these are common frequencies for baby monitors, cordless phones and WiFi routers for example. These are the same frequencies on which advanced meters transmit and receive, so FortisBC believes any concerns would be unfounded.

Please also refer to the response to WKCC IR No. 1 Q7.

34.6 Disclose any and all contracts, correspondence, notes, memoranda and/or any other documents and particulars relating to consideration regarding concerns about the potential impact of RF communication technology on pacemakers and other medical equipment?

Response:

Please refer to the response to CSTS IR No. 1 Q2.3.

34.7 Will FortisBC enter private property of a customer for the purpose of installing an RF emitting AMI meter where the customer has posted signage explicitly denying FortisBC access to the private property for the purpose of installing an RF emitting AMI meter?

Response:

The FortisBC process for customers refusing the installation of an advanced meter is described in Exhibit B-1 Section 8.5. It may not be possible for an installer to assess the intent of the customer without accessing private property.

34.8 Produce a copy of the California Utility Commission's decision with respect to PG&E's application regarding an opt-out program.

Response:

The California Utility Commission's decision can be found at the following link:

http://docs.cpuc.ca.gov/efile/PD/153864.pdf

35.0 Reference - Spectrum Analysis

35.1 What spectrum analysis field studies has FortisBC used to assess the AMI meter technology in relation to a) local radon levels; and b) proximate hydroelectric dams in the Kootenays?

Response:

FortisBC has no knowledge of the radon levels within its service area as this information is not considered relevant to the operation of an electric utility. Further, FortisBC is unaware of any plausible scientific relationship between spectrum analysis field studies and local radon levels. On that basis no assessment has been conducted.

FortisBC is unaware of any plausible scientific relationship between spectrum analysis field studies and the location of hydroelectric dams in the Kootenays. On that basis no assessment has been conducted.

35.2 What initiatives has FortisBC taken to work cooperatively with other service providers (who rely on microwave technology) to gather and compare data and take steps to ensure public safety from the potential crosstalk of their various frequencies? The other service providers referenced in this question would include hydroelectric dam operations, broadband over power lines, TV and radio stations, emergency services, gas providers, WiFi networks, radar and cell towers.

Response:

Please refer to the responses to CSTS IR No. 1 Q12.8 and Shadrack IR No. 1 Q26.

35.3 Given that most environments affected by the transmissions of the AMI meters are uncontrolled environments, what steps has FortisBC taken to:

a) measure the RF field intensities in the areas where the meters are to be installed;

b) make the local population aware of the intensity of that field; and

c) inform the public of i) the health risks they are exposed to; and ii) strategies that could be employed by individuals to mitigate risk.

Response:

FortisBC does not intend to measure RF intensities in the field as a matter of course. AMI meters will not impact the health risks of the public.

36.0 Reference - Executive Summary (CPCN Application) Page 2 Lines 3-6

Green house gas (GHG) emissions will be reduced as well. FortisBC meter reading vehicles drive approximately 500,000 kilometres per year and consume approximately 80,000 litres of gasoline. The associated 191 tonnes of resulting GHG emissions will be reduced with the reduction in meter reading vehicles.

36.1 Provide evidence that GHG smog is less hazardous than electromagnetic (RF) smog since both have been classified as 2b carcinogens by the World Health Organization.

Response:

FortisBC could not find “GHG smog”, “GHG” or “smog” on the list of 2b carcinogens. FortisBC has not made any assertions regarding the hazards of GHG emissions that would require it to provide evidence in any case.

If “electromagnetic (RF) smog” refers to RF emissions, please see Exhibit B-1, Appendix C-5.

36.2 Explain how the environment is better served by producing layers of RF smog rather than having the meter readers drive electric cars?

Response:

Please refer to the response to CSTS IR No. 1 Q36.1 and the response to Tatangelo IR No. 1 Q42.

37.0 E.S.2.0 EXECUTIVE SUMMARY

Page 2 Lines 24-29

NEW AMI METERS WILL IMPROVE BILLING ACCURACY AND FREQUENCY

Bill estimates will be virtually eliminated since meter readings will be available when they are required. As well, new Measurement Canada regulations have decreased the error tolerances for calibrating and testing meters, requiring greater accuracy from meters. The AMI Project will result in the accelerated replacement of the electro-mechanical meters with more accurate meters that meet the new Measurement Canada regulations.

37.1 What are the new Measurement Canada regulations (S-S-06) and what provisions of those regulations require wireless meters? In what way are the proposed AMI meters more accurate than FortisBC's present mechanical meters?

Response:

Section 5.3.4 of the Application (Exhibit B-1) discusses FortisBC's interpretation of S-S-06 and its implications on Fortis BC operations. FortisBC has not stated that S-S-06 regulations require existing meters to be replaced with wireless meters. A copy of the S-S-06 Regulations is provided as Appendix B-7 to the Application (Exhibit B-1).

The proposed AMI meters are manufactured to the ANSI C12.20 standard which specifies increased accuracy over the ANSI 12.1 standard that the existing electro-mechanical meters were required to meet. The new meters are required to be accurate to within 0.5% compared to 2% for the electro-mechanical fleet.

38.0 PROJECT NEED

3.1 Description of Existing System Page 17 Lines 12-15

Solid-state (or digital) meters (non-AMI) for the remaining meter population in the Company's service territory. This includes several hundred interval Timeof-Use meters, as well as wireless Encoder/Receiver/Transmitter (ERT)meters used for hard-to-access meter locations;

38.1 Explain what type of time-of-use metering is in use by FortisBC now.

Response:

FortisBC uses digital time-of-use meters that store usage in each time-of-use "bucket" in separate registers within the meter. Since the time-of-use buckets vary according to the time of day, day of the week and with holidays, the meter is pre-programmed to adjust for these changes (and for daylight savings adjustments).

38.2 Explain how the ITRON AMI will be an improvement over the time-of-use metering presently in use by FortisBC.

Response:

Please refer to Exhibit B-1, Section 3.2.5, pp 31-32 and the response to CSTS IR No. 1 Q38.1.

39.0 PROJECT NEED

3.2 Advanced Metering Infrastructure Page 18 Lines 21-32, Page 19 lines 1-8

FortisBC is committed to making improvements that positively impact the safety, efficiency and reliability of its electric service. FortisBC has determined that the implementation of AMI technology is a prudent decision when the number of available benefits is considered. The AMI Project will address two customer priorities: mitigating rate increases, and a desire for better information regarding energy use. Given customer concerns regarding rising electricity rates, the rate-mitigating effect of AMI underscores that the Project is in the public interest. Further, AMI will provide better information about electrical consumption, allowing the Company and its customers to more efficiently manage electricity usage and the associated costs. Benefits attributable to the AMI Project are summarized as follows:

1. Provides better and more energy consumption information allowing customers and the Company to efficiently manage electricity usage and the associated costs;

2. Consistency with British 1 Columbia's energy objectives;

3. Is a prerequisite step in the evolution of the Company's long-term smart grid vision;
4. Provides numerous non-financial benefits to the Company's customers; and
5. Results in approximately $19 million in savings (on a net present value basis) as evaluated over a 20 year period (associated rate reduction of approximately 1 percent). Each of these benefits is discussed in further detail below.

39.1 What measures would be taken by third party testing organizations to ensure safety as well as measures for early identification and reporting of potential problems in AMI Meters.

Response:

FortisBC currently utilizes the services of the Fortis Alberta (Acheson) meter shop to manage its meter population. Acheson is accredited by Measurement Canada to perform all aspects of meter service and repair as well as manage the meter retest and meter compliance programs for FortisBC.

FortisBC and Acheson operate under a joint Quality Management System to ensure conformance with "Criteria for the Accreditation of Organizations to Perform Inspections Pursuant to the Electricity and Gas Inspection Act and the Weights and measures Act (S-A-01:2010)".

Annual third-party audits are conducted at FortisBC to ensure the Quality Management System is maintained. The audits cover all aspects of meter storage, record keeping, meter handling, as well as ensuring any employee or contractor is trained and current on the Quality Management System. All non-conformances, meter repair orders, customer complaints and disputes are also reviewed. The audit and findings are reviewed annually by the intercompany Revenue Metering Management group and provided to Measurement Canada to support their annual audits.

39.2 What safety precautions will be implemented by FortisBC during the court of AMI meter installation? Will installation be done under full load?

Response:

As discussed in BCUC IR No. 1 Q47.1, FortisBC has established, safe meter exchange procedures. FortisBC confirms that exchanges are typically done on services that are under load and that this consideration forms part of the established, safe meter exchange procedures.

39.3 What installation measures, from a process and testing perspective, will FortisBC be undertaking to identify risks and to manage them effectively?

Response:

Please refer to the responses to BCUC IR No. 1 Q47.2 and Q47.3.

39.4 What training and/or qualifications will be required of personnel conducting AMI meter installations?

Response:

The training that will be required for personnel conducting AMI meter installations is described in the response to BCUC IR No. 1 Q47.1.

39.5 What active measures will FortisBC take to monitor and respond so as to minimize potential risks following installation?

Response:

The considerations described in BCUC IR No. 1 Q47.3 will help ensure a safe meter installation. After installation, FortisBC will actively monitor and respond to alarms built into the meter and will of course respond promptly to calls from any customers expressing concerns.

39.6 Would FortisBC commit to record and publicly report any and all post-installation incidents involving damage to AMI meters, home owner appliances, overheating and/or fire. What systems will FortisBC have in place for analyzing such postincident events for the purpose of identifying associations and/or trends.

Response:

FortisBC anticipates providing some form of periodic reporting to the Commission as a requirement of a positive decision on the Application. FortisBC does not object to including information for the types of events described in the question above in these reports.

FortisBC reports incidents to the appropriate regulatory agencies (e.g. BC Safety Authority, WorkSafeBC) as necessary and would continue to do so.

39.7 In the event of a post-installation customer complaint regarding power quality, how will such a complaint be dealt with in relation to the customer's meter installation history? Would such a complaint necessarily result in the immediate dispatch of a technician to the customer's address?

Response:

FortisBC will continue to respond to power quality issues as it does today. FortisBC will first establish through dialogue with the customer that the power quality concern is not in fact a more urgent matter that requires immediate dispatch of personnel.

If the matter is a power quality issue, the representative will create a "Power Quality" dispatch order that is forwarded to the Dispatch Attendant. The dispatch order will be issued to the appropriate field services group who will conduct an onsite investigation. While onsite, or as soon as practicable, the FortisBC employee will review the findings with the customer to ensure there is an understanding of whether the power quality issue is being caused by the utility or customer wiring. If the power quality issue is being caused by the utility a repair crew will be dispatched to make the necessary repairs and the dispatch order will be closed.

39.8 What material will be included in each of the proposed AMI meters?

Response:

The Itron AMI meter is a multi-component product with a variety of materials, including metal, plastics/polycarbonates and electronics/circuit board materials.

39.9 Do the proposed AMI meters have a mechanism to automatically shut-off power in the event of a problem?

Response:

No, the meter will not automatically shut-off power in the event of a detected problem. The meter will alert the Company to problems, and the Company would have the ability to remote disconnect power if required.

40.0 PROJECT NEED

3.2.2. Clean Energy Act Page 22&23 Lines 29-31 & 1-3

While IHDs, as described above, will be one future DSM measure available to customers (with appropriate DSM incentives provided), the simple provision of customer consumption information via the proposed online customer information portal is expected to have an immediate impact on customer decisions regarding the timing and amount of energy consumption.

40.1 What incentives will be provided to customers to encourage use of IHD?

Response:

Please refer to the response BCUC IR No. 1 Q28.1.

40.2 Will IHD use require activation of the Zigbee transmitter?

Response:

Yes, IHD use will require activation of the Zigbee radio.

40.3 What are the costs of these incentives and have they been included in the business case?

Response:

The IHD program costs were filed as part of the DSM Plan in the 2012 – 2013 Revenue Requirements and Review of 2012 Integrated System Plan Application, which was approved by the Commission in Order G-110-12 on August 15, 2012. These costs are not included in the AMI business case.

Please also refer to the response to CEC IR No. 1 Q88.1.

40.4 Explain and substantiate the expectation that the online portal will have an immediate impact on timing and amount of energy consumption.

Response:

FortisBC has not assumed that the full benefit of the online portal will result in immediate realization of the full savings. The savings are phased in over time as described in the response to BCUC IR No. 1 Q16.1.

Please also refer to the responses to BCUC IR No. 1 Q8.1, and CEC IR No. 1, Q15.4 and Q24.2.

40.5 Where has the experience of use of this portal resulted in significant changes in customer habits and use?

Response:

FortisBC considers that improved access to consumption information, whether from an online portal or an in-home display, will provide the type of stand-alone benefits discussed in the responses to BCUC IR No. 1 Q8.1 and CEC IR No. 1 Q15.4.

The studies referenced in that response contain a discussion of those impacts along with information on the jurisdictions in which they were implemented.

Whether the changes are significant is subjective however the Company notes that the expected peak and consumption reductions attributable to in-home displays are greater than those forecast for the inclining block rate that FortisBC already has in place.[5]

Once the data provided by the AMI system is available, it will be possible to implement an optional time-based rate that once supported by other technologies further improves the conservation potential.

Each component, increased information and rate structure, has an effect on customer behaviour. The greatest impact can be achieved by having both a conservation rate in place and supporting the rate with an information source such as IHD or the online portal. The AMI system is required in order to take advantage of this potential.

40.6 Explain if this incentive and expected results is dependent upon time of use billing.

Response:

[5] Table ES-1 of Appendix C-1

Please refer to the response to CSTS IR No. 1 Q40.5.

41.0 PROJECT NEED

3.2.3 Historical Perspective Page 25 Lines 25-29

Detailed monitoring and control has been possible for some time, particularly as enabled by FortisBC's recently completed Distribution Substation Automation Program (DSAP). FortisBC's CPCN Application for DSAP described its legacy electro-mechanical protection and metering equipment as antiquated and obsolete.

41.1 Provide particulars with respect to the information being gathered by the current monitoring system.

Response:

The Distribution Substation Automation Program included the installation of modern microprocessor-based relays, metering and SCADA equipment at FortisBC's legacy distribution substations. These devices had previously been successfully deployed at all substations constructed since the mid-1990s. The information gathered by this equipment includes:

- Power, energy, voltage, current and harmonics readings for each substation transformer;
- Power, energy, voltage, current and harmonics readings for each distribution feeder;
- Substation equipment alarms; and
- High-voltage circuit breaker and disconnect switch status.

41.2 Explain what was being controlled and the circumstances under which this control has been utilized with the current system.

Response:

The control being referred to is the remote operation of FortisBC equipment located within its 65 electric substations.

This would include the FortisBC System Control Centre operators remotely controlling:

- High-voltage circuit breakers to restore transmission lines or distribution feeders following an outage;

- Recloser tagging switches to permit live-line work on FortisBC lines and feeders; and
- Transformer tapchangers and regulators to adjust the voltage being sent out to the distribution system.

41.3 Explain on what basis the current electro-mechanical protection and metering equipment was determined to be antiquated and obsolete, with details about who made this determination.

Response:

In August 2007, FortisBC filed a CPCN application for the Distribution Substation Automation Program (DSAP) seeking approval to removing existing electromechanical relays and metering and install up-to-date protection, metering and communications equipment at the Company's legacy distribution substations. The protection, metering and communications technology installed with the DSAP is used by a large number of electric utilities in North America, and the Company has included substation automation technology as a standard and integral component of distribution substation design and construction since 1999.

As stated in its final argument, FortisBC submitted that the DSAP was consistent with the 2007 BC Energy Plan and would support:

- reduced operating and capital costs;
- reduced duration of customer outages;
- improvements in safety;
- the ability to provide a detailed load and reactive power profile for all substations and feeders;
- the ability for a focused reduction of system losses (in combination with a future AMI implementation);
- greenhouse gas reductions related to reduced crew travel for manual switching and recloser tagging.

In its decision associated with BCUC Order C-11-07 approving the DSAP, the Commission made the following determinations:

- "The Commission Panel therefore concludes that replacing the existing legacy technology with new electronic technology is appropriate." [p. 11];

- "The Commission Panel therefore concludes that replacing the existing technology with new electronic technology that is compatible with current FortisBC proven electronic technology, even though it limits the suppliers, is appropriate." [p. 12];
- "The Commission Panel also concludes that this new electronic technology should meet certain future functional CMMS capability requirements and future remote operation of devices and security requirements." [p. 12];

"The Commission Panel therefore accepts that new electronic technology is expected to meet the WorksafeBC requirements for safe operation. The Commission Panel also acknowledges that this Program is only the first step towards automation and that more benefits will be derived by providing a link into the CMMS and remote automation of devices external to the substations." [p .13]

42.0 PROJECT NEED

3.2.3 FORTISBC SMART GRID VISION Page 26

Figure 3.2.3.a - Timeline of Historical Technology Deployments at FortisBC Fibre-optic backbone network between the Kootenay and Okanagan communications system

42.1 Explain and provide basis for the decision not to use this fibre-optic backbone for the grid.

Response:

The fibre-optic backbone between the Okanagan and Kootenay regions is currently not in place. If this project is deployed in the future, it will be used for backhauling smart grid (and therefore AMI) information to the data centre. Please see Exhibit B-1, Section 4.1.3.

If installed, this fibre-optic backbone will be inter-substation. It should be noted that this fibre-optic infrastructure will not cover the distribution network and will not be suitable for connecting devices on the distribution grid such as residential meters.

43.0 PROJECT NEED

3.2.3 FORTISBC 1 SMART GRID VISION Page 28 Lines 1-5

The largest opportunity yet to be attributed to system improvements such as DSAP includes the measurement and confirmation of current system losses and identification of future system loss reductions. This opportunity requires the implementation of an advanced metering system in conjunction with the already implemented DSAP as an essential component of the smart grid.

43.1 Why are RF emitting AMI meters required to detect losses?

Response:

The selection of the communications technology is not specifically relevant to loss detection. Any communications medium which supports the ability to obtain periodic time-synchronized interval readings of all customer meters would enable loss detection.

43.2 Particularize the losses that are incurred with the current system?

Response:

Please refer to the responses to BCSEA IR No. 1 Q31.3, CEC IR No. 1 Q20.1, Q20.2, Q77.2 and BCUC IR No. 1 Q78.3.2.

44.0 PROJECT NEED

3.2.3(2) FORTISBC SMART GRID VISION

THE KEY ROLE OF AMI IN THE SMART GRID Page 29 Lines 18-23

An important step toward the deployment of the smart grid is the installation of technology capable of providing the communication required to ensure information is available from all devices on the distribution grid. The AMI Project will enable the Company to better understand power consumption trends, and reduce power theft through an improved ability to identify and locate unmetered consumption. The ability of an advanced metering system to provide comprehensive information regarding consumption at the customer endpoint.

44.1 Provide the names and providers of all the potential devices on the distribution grid.

Response:

FortisBC has not selected potential devices for the distribution grid, so cannot answer this question.

44.2 Explain in detail how the AMI project will improve ability to identify and locate unmetered consumption when the vast majority of stolen electricity occurs at places other than at the meter.

Response:

Please refer to the responses to BCUC IR No. 1 Q78.3.2, CEC IR No. 1 Q20.1, Q20.2, Q21.1 and Q77.2 for discussion of why losses occur and how the AMI Project would support their detection.

44.3 Provide the comprehensive information regarding customer consumption that will be gathered and transmitted wirelessly.

Response:

The comprehensive information regarding customer consumption refers to the collection of hourly interval data (energy usage for each hour) in addition to the customer's total monthly energy consumption.

45.0 PROJECT NEED

3.2.3(3) FORTISBC 1 SMART GRID VISION Page 29 lines 24-27

THE KEY ROLE OF AMI IN THE SMART GRID

The ability of an advanced metering system to provide comprehensive information regarding consumption at the customer endpoint, in conjunction with the information available from the advanced distribution metering already deployed at the substation level, would allow the Company to accurately measure actual losses on a near-instantaneous and annual basis.

45.1 What measures are being taken to ensure security of comprehensive data at the customer end point?

Response:

FortisBC notes the term "comprehensive" data in the question. To clarify, data transmitted from the meter to the utility is confined to aggregate consumption data at the premise and other operational data such as power interruptions. The data is encrypted for transmission and is matched with customer information after it arrives at the utility (behind the Company firewall) for billing purposes.

Please see Section 8.4.3 and Appendix F-1 of the Application for details on security of the proposed AMI system.

46.0 PROJECT NEED

3.2.4 FINANCIAL BENEFITS TO CUSTOMERS Page 30 lines 14-19

The main cost savings include:

1. Reductions in costs related to manual meter reading function;
2. Reduction of revenue loss associated with electricity theft;
3. Avoided cost of accelerated replacement of existing meters associated with the new Measurement Canada sampling plan (S-S-06);
4. Reductions in costs related to meter exchanges and meter compliance testing;

46.1 Substantiate the statement that the smart meter program will reduce the testing of meters for accuracy and meter exchanges.

Response:

Please refer to Exhibit B-1, Section 5.3.4 regarding the avoided cost of Measurement Canada compliance, and Exhibit B-1, Section 5.3.5 and the response to BCUC IR No. 1 Q5.1 regarding the meter exchange benefit.

47.0 PROJECT NEED

3.2.5(2) CONSERVATION RATE STRUCTURES

Page 32 lines 4-7

AMI will provide flexibility in administering any future time based rates, including changes to on peak/off peak rate periods or time buckets. As well, AMI will allow FortisBC customers to move from a consumption based rate (like RIB) to a time-based rate (like TOU) without requiring a change in the metering.

47.1 Would smart meters require re-programming for rate adjustments?

Response:

In the event that the Company proposes, and the BCUC approves, time-based rate structures such as those noted in the preamble to the question, the AMI meters would have the new rate structures pushed to them over the communications network if required. Rate structure changes may also be implemented entirely within the Meter Data Management System (MDMS) and CIS.

For informational purposes, existing electro-mechanical and digital meters are incapable of centralized changes, requiring field staff to remove and replace them as required by the attributes of any applicable new time-based rates. Further, existing electro-mechanical and digital meters, and existing manual meter reading limit the availability and efficacy of some time-based rates such as critical peak pricing or TOU.

47.2 If so, what would be the cost for this re-programming?

Response:

Please see Section 6.5 of the CPCN Application which provides approximate costs and advises that conservation rate structures are considered a future benefit, for which full program costs and benefits have yet to be fully investigated.

47.3 If so, have these costs been included in the business plan?

Response:

No, these costs have not been included in the financial analysis. Please also refer to the response to CSTS IR No. 1 Q47.2.

47.4 Would this be done remotely?

Response:

The implementation of time-based rates will not require any new metering hardware. If the implementation of time-based rates required new firmware in the meter, FortisBC expects this would be done remotely. Please also refer to the response to CSTS IR No. 1 Q47.1

47.5 Would customers be informed of, or give approval for this re-programming in advance?

Response:

Please refer to the response to CSTS IR No. 1 Q47.4. Any amendments to rates and/or rate structures require the prior approval of the British Columbia Utilities Commission, and if approved would be communicated to FortisBC's customers.

48.0 PROJECT NEED

3.2.5.(3) CONSERVATION RATE STRUCTURES Page 32, lines 17-22

Increased awareness and access to more information has proven an effective tool that allows customers to modify their usage habits in an effort to lower their bills and save energy as detailed in the Navigant report provided as Appendix C-1. As part of its 2012 Long Term Resource Plan, FortisBC has included estimated savings of 2.3 GWh beginning in 2015 and increasing to 8.9 GWh by 2025 related to the behavioural changes enabled by the FortisBC online web portal.

48.1 Since the projected dramatic reduction in energy consumption by 2025 is based on the new billing method, substantiate the statement that time-of-use and critical peak pricing reduce consumption.

Response:

The reduced consumption induced by conservation rates is based on the economic principle of price elasticity of demand. The demand for a product or service (including electricity) is assumed to decline when the price increases (with a few rare exceptions). Conservation rate structures such as TOU and CPP increase the price of electricity at certain times and therefore are assumed to reduce consumption at those times.

Evidence of this effect in various pilot studies and utility studies is provided in Exhibit B-1, Appendix C-1.

48.2 In what other countries, states or provinces has this result been realized? Provide substantiation.

Response:

Please refer to Exhibit B-1, Appendix C-1 and the response to CSTS IR No. 1 Q48.1.

49.0 PROJECT NEED

3.2.5(4) NON-FINANCIAL CUSTOMER SERVICE AND OPERATIONAL BENEFITS

ENHANCED BILLING INFORMATION Page 32 Lines 23-32

In 2011, 25 percent of all calls to the FortisBC Contact Centre were related to billing queries. The AMI system allows customers to access billing information through the online customer information portal or an IHD, providing them with more detailed information about their energy consumption, including both the timing and amount of energy consumed. If a customer does not choose to access this additional information themselves, they can continue to contact FortisBC by fax, telephone or email where agents will have access to the same detailed meter reading information and will be better able to assist customers with their billing enquiries. This improved service is expected to result in increased customer satisfaction.

49.1 Support the claim that enhanced billing will reduce the need for FortisBC to provide supports to its customers.

Response:

FortisBC does not believe that the referenced section of the Application claims that enhanced billing will reduce the need for FortisBC to provide support to its customers.

As noted in Exhibit B-1, Section 5.3.6:

… the availability of enhanced metering data from AMI will positively impact customer satisfaction and also provide operational cost savings resulting from a reduced call volume to the Company's Contact Centre. As the volume of any long term reduction in call volume is difficult to estimate prior to AMI implementation, the Company has identified this as a non-quantifiable benefit, and has not included any cost reductions related to this reduced call volume …

49.2 What information will be available that is not already available online?

Response:

The following information not currently available online will be made available once AMI is implemented:

- Hourly consumption data, available approximately 24 hours after the consumption occurs; and
- Temperature data that can be compared directly with consumption data.

49.3 What consumption data will be provided that cannot be provided by devices already on the market that are compatible with analog meters?

Response:

FortisBC is aware of devices on the market that wirelessly transmit consumption data from certain types of analog (electro-mechanical) meters to display devices within the home. Please also refer to the responses to BCSEA IR No. 1 Q19.1 and Q19.2.

50.0 PROJECT NEED

3.2.5(6) Non-Financial Customer Service and Operational Benefits

Immediate Notification of Power Outages and Restoration Page 38 Lines 23-27

The AMI system will provide FortisBC with visibility down to the point of delivery at the customer's meter. This capability will provide detailed power outage information, including the time duration of the outage and the number and location of customers affected by the outage.

50.1 Is it not true that the current system provides much of the information given above, e.g. the number of customers affected?

Response:

The current system (customers calling in to report power outages and system control operators using field reports, the GIS system and other data sources to estimate the scope of the outage) provides an estimate of the numbers of customers affected by, and the duration of, outages. This information is not as complete as the information provided by AMI.

50.2 What information will be provided by the new system that is not available today? Provide substantiation.

Response:

The AMI system will not provide new information regarding outages. It will provide more complete information.

50.3 What is the current average delay between the occurrence of the outage and the time FortisBC is aware of it?

Response:

Downstream of the distribution station feeder breaker, FortisBC relies solely on customer phone calls for outage information, and therefore FortisBC has no accurate information regarding the actual time of the outage event. The outage "starts" when FortisBC becomes aware of it through a customer call.

With AMI, data would be available regarding the actual time and location of the customer outages.

50.4 What will be the average delay between the occurrence of the outage and the time FortisBC is aware of it? Substantiate.

Response:

Please refer to the response to BCUC IR No. 1 Q102.1.

50.5 Provide documentation of performances in other jurisdictions, e.g. Ontario, California, Florida to substantiate your expectations.

Response:

From the MIT Technology Review http://www.technologyreview.com/view/506711/smart-meters-help-utility-speed-sandy-restoration/

As power utilities work to restore electricity service to millions of people in the wake of Hurricane Sandy, at least one utility has found its investment in smart meters is making a difference.

Pepco, which serves Washington D.C. and parts of Maryland, is using these two-way meters to automatically locate where power outages on its network occurred. Once *power is restored, the utility can also ping meters to verify service, rather than send out a crew or make a phone call, according to a Pepco representative. In the case of Pepco, its meters automatically send a "no power" report to its outage management system, which is quicker than having a person call in and overcomes any possible language barriers. Checking restored service from central officers via meters also saves time and personnel.*

The utility, which has about 425,000 activated smart meters, had more 100,00 [sic] people suffer from power outages and 40,000 at its worst. The company projected that 95 percent of its affected customers were back online as of this morning. Pepco, which found that the automated meters sped up restoration following Hurricane Irene last year, is gathering data on how much they improve its efficiency, a representative said.

From a report available at http://www.smartgridnews.com/artman/publish/news/Sandy-victim-Smart-grid-sure-worked-for-me-5240.html/?fpm in regard to the AMI-enabled outage system at PPL Electric Utilities serving customers in Pennsylvania:

A residential PPL customer posted a note to tell us that for him, real time tracking and online reporting via texts and the utility's website, all enabled by smart meters, made all the difference in Hurricane Sandy.

"I could not only check on repair status for my own home (with crew on site info and estimated time to repair), I could also remotely online check the status of our two rental houses without having to physically drive to each to check them out. This capability alone is a huge plus for consumers."

51.0 PROJECT NEED

27.0 (7) Reference: Project Need IR#1 Responses Page 42 & 43

Lines 9-28 & 1-2

Exhibit No. B-1, Tab 3.0, Section 3.2.5, pp. 38-39

Improved Power Quality Monitoring

BCUC IR1 27.1 Explain how AMI meters will report electric service and wiring errors?

Response:

AMI meters can detect a variety of conditions that are indicative of electric service or wiring errors. All AMI meters can detect inversion, removal and reverse power flow. Polyphase meters also have the ability to continuously monitor the electric service for metering installation or tampering problems through the system and installation diagnostic checks. The following programmable diagnostic checks can be enabled in the HES data collection engine: Diagnostic 1: Cross-Phase, Polarity and Energy Flow Check – This diagnostic verifies that all meter elements are sensing and receiving the correct voltage and current angles for each phase of a specific polyphase electric service. The current tolerance is +/- 90 degrees.

Diagnostic 2: Phase Voltage Deviation Check – This diagnostic verifies that each individual phase maintains an acceptable voltage level with respect to the other phases. Problems such as shorted potential transformer windings, incorrect phase voltage, and loss of phase potential among others may be indicated. The phase voltage deviation can be set to 1% -25%. Diagnostic 3: Inactive Phase Current Check – This diagnostic verifies that each individual current phase maintains an acceptable current level. It may indicate problems such as current diversion and open or shorted circuits, among others. The inactive phase current can be set for 2 0.05 amps to 200 amps. the meter and service. FortisBC expects this functionality to be enabled (at no additional cost) prior to meter deployment.

51.1 Explain and substantiate why a AMI meter that has a plastic cover and plastic components is no more susceptible to overheating and catching on fire than a meter with a glass cover and metal components.

Response:

FortisBC has been successfully deploying meters with these components at some customer premises for the past 15 years and exclusively since 2006, and based on that experience has no reason to believe that AMI meters will be susceptible to overheating or catching on fire.

51.2 Explain, in detail, and substantiate, how the plastic covers and plastic components of the AMI are an improvement over the glass covers and metal components of the current analogue meters.

Response:

FortisBC has not claimed any benefit from the type of meter cover used in AMI meters and believes that AMI meters will be compliant with the applicable legal framework.

Regardless, Elster and Itron, the current suppliers of non-AMI revenue meters for FortisBC, no longer offer glass meter covers.

51.3 If the plastic covers and plastic components of the AMI meter are not an improvement over the glass covers and metal components of the analogue meters, explain, in detail, and substantiate, in what way they are of comparable quality and why, if of comparable quality, they are in need of being replaced.

Response:

Please refer to the response to CSTS IR No. 1 Q51.2.

51.4 If the plastic covers and plastic components of the AMI are of a lesser quality than the glass covers and metal components of the analogue meters, explain, in detail, and justify, why you are using substandard materials in the AMI meters.

Response:

Please refer to the response to CSTS IR No. 1 Q51.2.

51.5 Will FortisBC accept responsibility for a meter fire that is attributable to the use of a plastic rather than a glass meter cover?

Response:

FortisBC believes that AMI meters will be compliant with the applicable legal framework. In the event a fire is alleged to be caused by an AMI meter FortisBC and any relevant authorities will assess the cause of the fire and assess where the responsibilities lie with respect to costs for remedial actions.

51.6 Explain and substantiate why wireless smart meters do not have surge protectors.

Response:

It is incorrect to state that AMI meters do not have surge protection. As described in the responses to BCUC IR No. 1 Q47.4 and Q47.4.1, the Itron meters that FortisBC is intending to use do have surge protection to ensure that the meter itself can safely withstand overvoltage events.

52.0 PROJECT DESCRIPTION

4.1 AMI Project Components Page 41 Lines 14-22

The network architecture of FortisBC's proposed AMI system provides an Internet Protocol (IP)-based platform that enables advanced security measures, interoperability with other systems, and streamlined operation, including capability to support potential future advanced metering applications. The AMI solution will be capable of collecting electrical consumption information from all customer meters, and will have the additional capacity required for future collection of information on distribution devices on the power system. The system will also allow customers to access their consumption information through a secure and private online customer information portal.

52.1 Give examples of the smart meter grid functioning with other IP systems and future applications.

Response:

Please refer to the response to CSTS IR No. 1 Q60.1.

52.2 Give examples of the type of information that might be gathered in the future by the AMI meter grid.

Response:

FortisBC does not anticipate collecting additional information in the future from customers. FortisBC expects any information gathered from future smart grid applications would be used to optimize the operation of the system.

52.3 Give specific examples of the specific type of information regarding electrical consumption from individual meters that will be gathered by the AMI meters.

Response:

The electrical consumption data that will be collected from the individual meters will include the electrical consumption for a particular household on an hourly basis. The electrical consumption data specifically shows the total KWh of electricity that has been used by a household during a specific period of time.

This information is currently collected on a bi-monthly basis by meter readers, however, with the introduction of the AMI system this information will be collected more frequently.

52.4 How is FortisBC ensuring the integrity and security of this and all data that is being gathered and transmitted wirelessly?

Response:

Please refer to Section 8.4.3 of the Application for a description of the security related to the AMI system.

53.0 PROJECT DESCRIPTION

4.1 (1) AMI Project Components Page 43 Lines 1-5

The AMI system proposed by FortisBC is scalable for customer growth, and therefore will support the same services and functions for a higher meter population in the future. Further, the AMI system proposed is capable of supporting gas and water meters within the Company's service area, which may create revenue opportunities for the utility and its customers in the future as explained in section 8.3.

53.1 Please explain what is meant by "scalable".

Response:

"Scalable" in this context means capable of supporting more customers.

53.2 Who is the customer who would benefit from this?

Response:

Please refer to the response to BCSEA IR No. 1 Q29.2.

53.3 Will this model of ITRON meter support water and gas measurements?

Response:

Yes, the AMI system will support water and gas measurements. The Itron meter by itself is not sufficient to support water and gas measurements.

53.4 What modification to the meter will be required for water and gas measurement and what costs will be associated with such modification?

Response:

No modification to the meter will be required for water and gas measurement as the meter by itself would not be part of any future support provided for gas and/or water meters.

53.5 What costs, if any, that are associated with this "scalable" feature are included in the business plan?

Response:

There are no incremental costs associated with the "scalable" feature.

54.0 PROJECT DESCRIPTION

4.1 AMI Project Components

4.1.1 (2) HOME-AREA NETWORK Page 43 Lines 14-16

The selected meters also support Zigbee Smart Energy v2.0, which is being developed by the ZigBee Alliance specifically to provide additional functionality related to the delivery and use of energy and water.

54.1 What is the additional functionality the Zigbee transmitter will bring to the delivery and use of energy and water?

Response:

Zigbee Smart Energy v2.0 includes additional functionality related to:

- Deployments in multi-dwelling units;
- Supporting multiple energy service interfaces in a single premise;

- Supporting any transport layer based on IETF IP compliant standards, including but not limited to ZigBee IP, other RF-based and Power Line Carrier (PLC)-based transports; and
- Supporting internationally recognized standards to ensure long-term interoperability with multiple technologies.

54.2 What is meant by "demand response"?

Response:

"Demand response" refers to mechanisms that allow customers to manage their consumption of electricity in response to electricity supply conditions.

54.3 Who has control of the Zigbee transmitter's functionality, e.g. who turns it off and on?

Response:

FortisBC would control the operation of the ZigBee radio. FortisBC intends to turn on the ZigBee radio only at the request of the customer.

54.4 What is FortisBC's view as to owns the data that is gathered?

Response:

The collection and use of customer information is subject to the *Personal Information and Privacy Act.*

With respect to the Home Area Network, please refer to the response to CSTS IR No. 1 Q54.11.

54.5 With whom or what (agency, company, network etc.) will the Zigbee application interface?

Response:

The Zigbee radio will communicate only with the FortisBC AMI system and devices that the customers choose to connect to the HAN.

54.6 How often will data gathered by Zigbee be transmitted to FortisBC?

Response:

Please refer to the response to CSTS IR No. 1 Q54.11.

54.7 Where will the data be sent, e.g. with what agencies, companies, networks, etc, will it be shared?

Response:

There is no data being sent to FortisBC in the initial deployment of AMI. The only data might be sent to FortisBC in the future would be message confirmation and load control confirmation as discussed in the response to CSTS IR No. 1 Q54.11.

Any information gathered is subject to the *Personal Information and Privacy Act*.

54.8 Can the Zigbee's remote functionality be used to reduce or to turn power off to a home or to an individual appliance?

Response:

Please refer to the response to BCSEA IR No. 1 Q15.6.8.

54.9 Has FortisBC considered requiring customers to have the Zigbee transmitter turned on? When might this requirement take effect?

Response:

FortisBC has no plans to require the Zigbee radio to be turned on.

54.10 What will be the ramifications to the customer if she/he refuses activation of the Zigbee transmitter?

Response:

FortisBC intends to turn on the Zigbee radio at the request of the customer.

54.11 How often will the data gathered by the Zigbee transmitter be transmitted to FortisBC?

Response:

FortisBC intends to operate the HAN in a manner that would result in Zigbee only transmitting data into the home. If HAN device control is implemented at some point in the future message confirmation or load control confirmation could be also transmitted. Please also see the response to BCSEA IR No. 1 Q15.6.8.

54.12 What is the minimum interval between Zigbee data relays?

Response:

There is no minimum other than for designs to account for network quality on the utility side. On the HAN side the Zigbee SEP 1.x spec says that a device may not query a meter more frequently then every 2 seconds for no longer then 15 minutes.

54.13 Is the Zigbee transmitter required for time-of-use billing?

Response:

No.

54.14 What RF frequency will be used to transmit Zigbee data?

Response:

The Zigbee radio operates in the 2.4 GHz band (similar to many WiFi routers and cordless phones).

54.15 What is the peak (not average) power density of Zigbee transmissions?

Response:

Zigbee transmissions calculated at a distance of 20 cm are approximately 0.031 mW/cm^2 during active transmission (not reduced to account for duty cycle).

Zigbee transmissions at 50 cm and 1 percent duty cycle are approximately 0.00013 mW/cm^2.

54.16 Disclose any and all contracts, correspondence, notes, memoranda and/or any other documents and particulars relating to FortisBC's consideration as to requiring customers to have the Zigbee transmitter turned on.

Response:

Please refer to the response to CSTS IR No. 1 Q2.3.

55.0 PROJECT DESCRIPTION

4.1.1 (3) Local Area Network. Page 44 Lines 5-9

When the customers purchase a compatible IHD, they will be required to contact FortisBC in order to securely enable the communications path between the AMI meter and their IHD. The communications path is secured by encryption keys specific to the AMI meter at the customer's premises and their IHD.

55.1 By what means is the data being transferred between the AMI meter and the IHD?

Response:

The data is transmitted between AMI meter and the IHD using secure Zigbee wireless communications.

55.2 If wirelessly, what frequency is used?

Response:

Please refer to the response to CSTS IR No. 1 Q54.14.

55.3 If wirelessly, how often will the signal be sent?

Response:

Please refer to the response to CSTS IR No. 1 Q54.12.

55.4 How is this data being made secure from hackers beyond use of encryption keys?

Response:

Data transmitted via the Zigbee radio is secured by the use of encryption keys.

56.0 PROJECT DESCRIPTION

4.1.1 (4) Local Area Network Page 44 Lines10-12

It is expected that when customers have accurate and timely energy use and cost information upon which to base decisions, they will choose to conserve electricity and change when they consume electricity.

56.1 If significant reduction in energy use is associated with IHDs, why aren't these being provided to every customer as part of the program?

Response:

FortisBC believes that more significant investments in energy efficiency (such as IHDs) should be accompanied by a customer investment to help ensure customer commitment.

In most PowerSense programs the customer chooses and buys the make/model (and installer where applicable) of the program measure, whether it is a LED light bulb or heat pump. PowerSense provides an incentive to encourage customers to buy the more efficient products, and which partially pays for the incented device.

56.2 How does having an IHD, without time of day usage billing, cause customers to "change when they consume electricity"?

Response:

In the past FortisBC customers have shown a willingness to conserve energy during peak periods at the request of the utility when market prices are high so as to lower power purchase costs for customers in general. The Company acknowledges that the greatest incentive to shift usage, on an individual customer basis, comes from having time-based rates in place that provides an immediate financial impact to the consumer.

56.3 Do IHDs alone (without TOU billing) contribute to conservation?

Response:

Please refer to Exhibit B-1, Appendix C-1 and the responses to CSTS IR No. 1 Q40.5, CEC IR No. 1 Q15.4 and Q24.2.

56.4 If so, is this conservation permanent or is it a transitory factor, the result of having a new "gadget".

Response:

As noted in the Navigant study (Appendix C-1, page 28), information on savings persistence is limited. Navigant suggested assuming a 10% decline in savings in the year following implementation. FortisBC accepts that the initial impact on consumption due to the installation of devices such as the IHD may wane in subsequent years. However, other studies and meta-studies have concluded that savings do persist, and can be maintained particularly where support and education are ongoing. One such meta-study concluded that*, "Evidence from the 27 studies that measured within-study persistence of feedback effects suggests that feedback-related energy savings are often persistent, although multiple studies also suggest that the persistence of energy savings may rely on the continued provision of feedback."*[6]

[6] Advanced Metering Initiatives and Feedback Programs: A Meta-Review for Household Electricity-Saving Opportunities, Ehrhart-Martinez, Donnelly and Laitner, 2010. Available at http://aceee.org/research-report/e105

FortisBC is of the opinion that the availability of accurate and timely consumption information, as provided by devices such as an IHD, along with continued education and support will provide savings persistence for its customers.

57.0 PROJECT DESCRIPTION

4.1.2 (5) LOCAL AREA NETWORK   Page 45   Lines 15 & 16

The AMI meters will communicate via a 900 MHz radio frequency RF mesh solution, and will transmit, on average, for less than a minute a day.

57.1 What other types of signals are there other than data signals?

Response:

FortisBC presumes that the question is intended to ask, "what are other types of signals ("non-data signals" for the purposes of the responses to the CSTS IR No. 1 57.x series of questions), other than regularly scheduled daily meter reads."

Other types of signals are:

- On-Demand reads;
- Tamper/Theft Alerts;
- Firmware Downloads: Firmware downloads over the RFLAN are typically done once a year (reflecting major system releases); and
- Command/Control Messages (synchronization, security, data integrity and dynamic network resiliency): The nature of the RF mesh network requires that meters maintain communications with their neighbor meters to ensure the security, stability, self-healing and integrity of the network.

57.2 Considering all signal types, not just data signals, on average how many signals per day will an AMI meter transmit?

Response:

The average number of 900 MHz RF transmissions in a 24 hour period is ~1,268 (less than one time per minute). This includes all types of signals.

57.3 Considering all signal types, not just data signals, what is the maximum number of signals an AMI meter will transmit per day?

Response:

Please refer to the response for CSTS IR No. 1 Q57.2.

Additionally, the average number of 2.4 GHz ZigBee transmissions in a 24 hour period will vary based on the HAN settings:

- For a meter set to "quiet mode" with no allowed devices, the ZigBee radio will not transmit;
- If the customer elects to have devices connected to the ZigBee radio, the average number of signals will be based upon the settings of the devices.

57.4 How many times per day on average will an AMI meter transmit billing data?

Response:

FortisBC will determine this during the Define/Design phase of the proposed AMI Project. However, typical deployments return consumption interval data 2 or 3 times per day.

57.5 How long will each data signal last?

Response:

The duration of any individual signal will be a function of the amount of data being transmitted. Signals may be as short as 18mSec or as long as 125mSec.

57.6 How long will each non-data signal last?

Response:

Please refer to the response to CSTS IR No. 1 Q57.5.

57.7 What is the peak power density of the data signals?

Response:

Peak power density is calculated at the FCC/IC specified distance of 20 cm during active transmission (does not account for duty cycle):

- 900 MHz RF Mesh Radio: 0.227 mW/cm^2
- 2.4 GHz ZigBee Radio: 0.031 mW/cm^2

57.8 What is the peak power density of the non-data signals?

Response:

There is no difference in the power density during transmission.

57.9 What will be the interval between each data signal?

Response:

Please refer to the response to CSTS IR No. 1 Q57.2.

57.10 What will be the interval between each non-data signal?

Response:

Please refer to the response to CSTS IR No. 1 Q57.2.

58.0 PROJECT DESCRIPTION

4.1.2 (6) LOCAL AREA NETWORK Page 45 Lines 23-27

• The RF spectrum used by the LAN does not require a license (similar to most home wireless devices such as wireless routers and cordless telephones). Therefore, there is no capital or recurring cost to use the spectrum. In addition, the solution is designed to function in the modern RF environment, ensuring minimal interference with other devices using the same band.

58.1 What is Fortis doing to prevent the wireless meters from interfering with other electrical appliances?

Response:

Please refer to the response to BCUC IR No. 1 Q31.2.4.

58.2 If interference is caused by the AMI meters, what will Fortis or ITRON do to resolve the problem?

Response:

Please refer to the responses to BCUC IR No. 1 Q31.2.3 and Q31.2.4 and Shadrack IR No. 1 Q24 and Q25.

58.3 What is the expected capital outlay when technological development calls for changes in equipment and spectrum and where will that capital come from?

Response:

FortisBC does not expect changes in equipment and spectrum during the 20 year life of the meter.

59.0 PROJECT DESCRIPTION

4.1.2 (7) LOCAL AREA NETWORK Page 45 Lines 28-29

All data is ultimately transmitted to a collector through the LAN. The collector in turn transmits the data back to the utility, via the WAN.

59.1 How is the data made secure for transmission from the AMI meter to the collector?

Response:

The proposed AMI Project integrates security as a fundamental building block of the LAN architecture. The CGR 12400 offers strong security capabilities that are based on Cisco's Connected Grid security principles and widely adopted cryptographic and security standards.

- Access Control;
    - Mutual authentication and authorization of all nodes connected to the network;
    - IEEE 802.1x-based identity, strong username and passwords;
- Data Integrity, Confidentiality and Privacy;
    - Link-layer encryption in the NAN mesh (AES-128);
    - Network-layer encryption in the WAN (IPsec);
    - Scalable key management – generation, exchange and revocation of encryption keys;
- Threat Detection and Mitigation;
    - Network segmentation of users, devices and applications in NAN and WAN;
    - Access-lists on field area router to filter traffic between users and devices;
    - High-performance firewall in the control-centre to protect critical assets;
- Device and Platform Integrity;
    - Tamper-resistant mechanical design, security alerts generated if compromised;
    - Hardware chip to store router's X.509 certificate, other security credentials; and
    - Tamper-proof secure storage of router configuration and data.

59.2 How is the data made secure for transmission from the collector to the utility?

Response:

Please refer to the response to CSTS IR No. 1 Q59.1.

59.3 How many RF transmitters does a collector have?

Response:

The collectors will typically include the 900 MHz RF radio along with a backhaul link for the WAN.

59.4 What are the frequencies and power of each transmitter?

Response:

The RF radio transmits in the 902 MHz to 928 MHz ISM. Please refer to Table 2 in the Connected Grid Router Data Sheet, provided as Appendix CSTS IR1 59.4, for specifics.

59.5 How far, on average, does a collector transmit?

Response:

Please refer to the response to WKCC IR No. 1 Q1.

59.6 What is the maximum distance a collector can transmit?

Response:

The maximum transmission distance is dependent on the RF environment and the propagation of the RF signal. Please also refer to the response to WKCC IR No. 1 Q1.

59.7 How many transmitters are in collector units?

Response:

Please refer to the response to CSTS IR No. 1 Q59.3.

59.8 Will there be any AMI relay transmitters?

Response:

There are RF Range Extenders in the preliminary design that will extend and fill gaps in the RF mesh. Range Extenders are similar to AMI meters and act as a link in the RF mesh in the same way as other AMI meters, however are installed on Company infrastructure.

59.9 If so, under what circumstances?

Response:

Please refer to the response to CSTS IR No. 1 Q59.8.

59.10 If so, how many transmitters will be in each relay transmitter and what will be their frequencies and power?

Response:

Each range extender contains a single 900 MHz RF radio identical to those in the AMI meters.

59.11 Will these collectors be placed on private and/or public property?

Response:

The AMI Project proposes to place collectors on pre-existing FortisBC infrastructure (ex: poles, substations).

59.12 What consideration has FortisBC made regarding obtaining permission to use such property?

Response:

Please refer to the response to CSTS IR No. 1 Q59.11.

60.0 PROJECT DESCRIPTION

4.1.2 (8) LOCAL AREA NETWORK Page 45 Lines 30-32

The network will use an IPv6 stack. This will enable additional Company applications to access the LAN network using the same RF mesh technology and equipment.

60.1 What are the additional applications that will access the LAN network?

Response:

Additional applications which would depend on the LAN network include:

- Distribution automation;
- Demand response control for customers that choose to participate;
- Integration of distributed generation; and
- Integration of electric and plug-in hybrid vehicles (EVs and PHEVs).

61.0 PROJECT DESCRIPTION

4.1.2 (9) LOCAL AREA NETWORK Page 46 Lines 15-20

Advanced meters will transmit consumption data back to FortisBC through the LAN andWAN. The meters will record consumption information hourly and transmit those readings approximately 4 to 6 times a day in order to provide customers who choose to access their consumption information through the secure customer information portal with near real-time data. High-priority operational data, such as outage information, will be transmitted immediately.

61.1 How will data which is available 4 to 6 times a day help control consumption which is needed on a minute to minute time frame?

Response:

FortisBC does not believe that consumption information is required on a minute-by-minute time frame to help control consumption. AMI will make hourly consumption information available via the customer portal within approximately 24 hours of the consumption occurring, which is considerably more frequent than the typical 60 day frequency with which it is reported to customers today.

If customers wish to receive near real-time consumption information, they can choose to purchase an IHD device.

62.0 PROJECT DESCRIPTION

4.1.3 (10) Pages 46-47 Lines 29-3 Direct Network Connected -- In locations where collectors are located on infrastructure where FortisBC already has installed long haul fibre optic cable and where spare capacity exists, connecting directly to this fibre is the best long term solution as it provides sufficient bandwidth for immediate and future needs, with medium capital outlays and no monthly service fees. In addition, there is a long term certainty with respect to the technology.

62.1 Is fibre optic technology more efficient than wireless, capable of carrying more data?

Response:

While fibre optic technology is capable of carrying more data than wireless technology, it is at higher cost and is not economically feasible for low data volume metering system. Please also refer to the response to CSTS IR No. 1 Q12.5.

62.2 Is fibre optic cable more secure than wireless?

Response:

Both fibre optic cable and wireless technologies can employ encryption technologies to make end to end communications very secure.

For fibre optic cable, the need to access the cable provides additional physical security when compared to wireless technology. For this reason, many fibre optic devices assume that access to the fibre is secure and therefore do not have built-in device authentication. This reliance on the inherent physical security of fibre optic networks could be exploited if access to the physical fibre medium or one of the end-point devices could be gained.

On the other hand, the inability to control access to the transmission medium (air) has forced the wireless industry to develop very secure authorization and authentication procedures for accessing networks, therefore unauthorized access to the network should not occur.

FortisBC's proposed AMI network contains advanced authentication, authorization and encryption mechanisms at multiple levels of the system to ensure that unauthorized devices cannot gain access to the network and that end-to-end data cannot be decrypted and read if intercepted.

63.0 PROJECT DESCRIPTION

4.1.3 (11) WIDE AREA NETWORK Page 47 Lines 4-13

• WiMAX – Using1.8 GHz WiMAX point to multipoint (PtMP) technology is a good option when a single base station located near existing FortisBC network infrastructure can be used to provide service to a large number of collectors, or when a radio system can be employed or already exists to service other FortisBC assets….The technology can be expected to be available for approximately 7-10 years but FortisBC can mitigate this risk by purchasing spares.

63.1 How far will an AMI meter transmit?

Response:

Please refer to the response to WKCC IR No. 1 Q1.

63.2 On average, how far will collectors be from the smart meters?

Response:

This will be finalized during the Define/Design phase of the proposed AMI Project.

63.3 What is the maximum distance collectors will be from smart meters?

Response:

This will be finalized during the Define/Design phase of the proposed AMI Project.

63.4 On what structure will collectors be placed?

Response:

Please refer to the response to CSTS IR No. 1 Q59.11.

63.5 How many transmitters are in collector units?

Response:

Please refer to the response to CSTS IR No. 1 Q59.3.

63.6 What are their specifications? Please provide all.

Response:

The collectors contain a 900 MHz radio operating in the same power range as the LAN radio in the meters, and a connection for the WAN. Please see Table 2 and Table 3 in the Connected Grid Router Data Sheet, provided as Appendix CSTS IR1 63.6, for specifics.

63.7 What is the shortest distance between collectors and residences?

Response:

This will be finalized during the Define/Design phase of the proposed AMI Project.

63.8 In areas where homes are distant from each other, how will data be sent to the collector?

Response:

This will be finalized during the Define/Design phase of the proposed AMI Project. Where needed, range extenders mounted on FortisBC infrastructure will be used to extend and fill gaps in the RF mesh.

63.9 How much money is being spent to mitigate the expected change in technology in 7-10 years?

Response:

Please see Table 5.1.b (page 72) of the CPCN Application, "IT Hardware, Licencing, and Support Costs" under Sustaining Capital which covers estimated costs over the entire 20 year project life.

63.10 Is this cost included in the business case?

Response:

Yes. Please refer to the response to CSTS IR No. 1 Q63.9.

63.12 How often is it expected that software will change and upgrades will be needed to AMI meters, collectors and other infrastructure components?

Response:

FortisBC cannot estimate how often software/firmware upgrades will be required during the life of the project.

63.13 If the wireless technology's future is so uncertain, why was it selected instead of fibre optics?

Response:

FortisBC does not consider the future of wireless technology to be uncertain. Please also refer to the response to Tatangelo IR No. 1 Q18.

63.14 Was a cost comparison done between wireless technology which requires ongoing upgrades and secure, certain fibre optics? If so, please provide. Was one done over 20 years to compare long term costs, given the acknowledged short lifespan of the wireless technology? If so, please provide. If not, why not?

Response:

All systems require ongoing upgrades and replacements. Analysis of the viable WAN options is discussed in Exhibit B-1, Section 4.1.3, p48 (including the use of fibre optic transmission for the

WAN). The cost of using of fibre optics throughout the LAN and WAN to communicate directly with every meter is prohibitive as described in the response to CSTS IR No. 1 Q12.5.

64.0 PROJECT DESCRIPTION

4.1.4(12) HEAD END SYSTEM Page 50 Lines 8-9

These systems are designed to seamlessly integrate with numerous upstream and downstream systems.***AND***

4.2.1 PROCUREMENT PROCESS Page 53 Lines 8-11

Requirements included in the RFPs ensured that the selected system would be able toprovide meter reading services for other utilities (electric, gas, water) within the Company's service area. The proposed AMI system is capable of integrating to existing and future FortisBC systems and is also scalable to accommodate future customer growth.

64.1 What other types of systems is the Grid designed to integrate with? Give examples please.

Response:

Please refer to the response to BCUC IR No. 1 Q12.3.

65.0 PROJECT DESCRIPTION

IR#1 (8) Responses Page 51 Lines 20-29

BCUC IR1 - 31.2.3 Would the use of PLC in these areas eliminate these issues on the 900 MHz band? If not, please explain why not.

Response: The use of PLC in the areas where rural WISPs or amateur radio operators are operating in the 900-928 MHz band would likely eliminate the specific issues alluded to in the previous questions. However, as discussed in section 7.5 of the Application, PLC would not provide all the functionality FortisBC has specified, in addition to being significantly more expensive.

Furthermore, though PLC may mitigate specific issues for the frequency band in question, it can potentially cause interference in other bands where the equipment is not capable of rejecting and minimizing it.

65.1 Explain and substantiate why electromagnetic radiation that is transmitted and received by a wireless smart meter is not responsible for creating harmonics on the electrical lines.

Response:

The undesired coupling of an additional signal onto the power system from an external RF source is not referred to by engineers as *harmonics*, but rather as *interference*. The IEEE 100 Standard ("The Authoritative Dictionary of IEEE Standards Terms") defines *harmonics* as "a sinusoidal component of a periodic wave or quantity having a frequency that is an integral multiple of the fundamental frequency". On that basis, only integer multiples of the 60 Hertz power system frequency would be considered harmonics.

Given that the power system is designed for 60 Hertz operation, the physical properties of the associated wiring and devices also means that they are an extremely poor receiving antenna/conductor of frequencies above several hundred hertz. In other words, any coupling of RF interference which does occur would be insignificant and several orders of magnitude below the level of the power system voltage and current and hence would be indistinguishable from normal expected noise.

65.2 Explain and substantiate why harmonics on electrical lines do not cause corrosion and interference with

a) Household electrical appliances and devices;

b) Personal wireless devices;

c) Other smart meters.

Response:

Please refer to the response to CSTS IR No. 1 Q65.1 for a clarification regarding the misuse of the term *harmonics*.

As discussed in that response, since the power system is designed for 60 Hertz operation, the physical properties of the associated wiring and devices also means that they are an extremely poor receiving antenna/conductor of frequencies above several hundred hertz. In other words, any coupling of RF interference which does occur would be insignificant and several orders of magnitude below the level of the power system voltage and current and hence would be indistinguishable from normal expected noise.

FortisBC notes that the electric power system and RF transmissions associated with AM/FM radio, television, satellite and more recently cell phones and WiFi equipment have successfully coexisted for over one hundred years. On that basis, the Company considers that there is no demonstrated or plausible link between the incremental low-level RF emissions from an AMI meter and damage to power system equipment (utility and/or customer).

65.3 Explain and substantiate how corrosion in meters and electrical lines do not result in fires in meters and on electrical lines.

Response:

FortisBC agrees that corrosion and poor connections in meter bases (irrespective of the type of meter) and electrical lines can occasionally result in fires. Please also refer to the response to Tatangelo IR No. 1 Q59.

66.0 PROJECT DESCRIPTION

4.2.2 PROCUREMENT RESULTS Page 55 Lines 9 & 10

No proposals were received for AMI systems using other forms of communication technology.

66.1 Why didn't Fortis ask for quotes for a non RF emitting system?

Response:

Please refer to the response to BCUC IR No. 1 Q38.2 and Q38.3.

67.0 PROJECT DESCRIPTION

4.2.2(14) PROCUREMENT RESULTS Page 56 Lines 8-10

METER DISPOSAL

Meter disposal is included in the Itron-managed deployment activities. FortisBC will conduct random audits of the recycling / disposal process to ensure compliance with all applicable environmental regulations.

67.1 Why are analogs being destroyed?

Response:

The Company understands the term "analogs" (or analogues) to refer to electro-mechanical meters.

Please see Section 5.3.4 of the CPCN Application, Measurement Canada compliance, which describes why electro-mechanical meters are being removed from service.

Please also refer to the responses to CEC IR No. 1 Q45.1 and Q45.4.

67.2 How many unused analogs are in your inventory? Will these be destroyed?

Response:

The Company has 88 meters for use in old A-Base sockets in the field that cannot be converted as they are built into the walls of the customer premises. These will be corrected as part of the proposed AMI Project.

The Company also has 279 meters kept for the purpose of retest/compliance change outs.

All remaining electro-mechanical meters will be scrapped as part of the proposed AMI Project.

67.3 What is the cost of the destruction of used and unused analogs?

Response:

Please refer to the responses to CEC IR No. 1 Q45.1 and Q45.4.

67.4 Why aren't some analogues being saved in the event that accommodation is required for disabled persons or an opt-out program is implemented?

Response:

FortisBC notes that even in the absence of approval for the proposed AMI Project, the Company would need to replace all electro-mechanical meters relative to Measurement Canada compliance guidelines as described in Section 5.3.4 of the CPCN Application.

67.5 What is the current availability of new analogue meters on the global market?

Response:

Please refer to the response to CEC IR No. 1 Q12.2.

68.0 PROJECT DESCRIPTION

4.3(15) Project Management Page 56 Lines 12-16

The project management approach will follow standard project management practices and methodologies including the use of applicable project templates and tools. Working together with Itron, FortisBC has been able to outline clear objectives and a project timeline and milestones. This allows the scope to be focused and controlled, and budgeted resources can be closely managed.

68.1 What model of ITRON meter is being considered?

Response:

OpenWay Centron (C2S0 and C2S0D)

68.2 What is the design of the Itron Meter chosen?

Response:

FortisBC does not understand this question. The various design elements of the Itron meter are discussed extensively throughout Exhibit B-1 and the information request responses in the regulatory proceeding.

68.3 Does the meter chosen have a plastic cover or plastic components?

Response:

Yes, the Itron AMI meter does have a plastic cover. Please refer to the response to CSTS IR No. 1 Q39.8.

68.4 Does the meter chosen have a glass cover and metal components?

Response:

Please refer to the responses to CSTS IR No. 1 Q39.8 and Q68.3.

68.5 Provide the Manufacturers documentation of the anticipated life expectancy of the wireless smart meter.

Response:

Please refer to the response to BCUC IR No. 1 Q1.2 and Attachment BCUC IR1 69.1.

69.0 PROJECT COSTS AND BENEFITS

Table 5.0 (1) - AMI Cost and Benefit Summary Page 69 Line 13

Theft Reduction (38,386)

69.1 Please substantiate the $38.4 million in theft?

Response:

Please see Section 5.3.2 of the CPCN Application.

70.0 PROJECT COSTS AND BENEFITS

Table 5.1.b(2) – Summary of All Incremental 1 Non-Project Costs and Benefits

Page 72 Lines 1

Measurement Canada Compliance (146) (909) (903) (1,478) (15,119) (18,555)

70.1 Please substantiate the $18.5 million in savings due to Measurement Canada.

Response:

Please see Section 5.3.4 of the CPCN Application.

71.0 PROJECT COSTS AND BENEFITS

Table 5.1.b(3) – Summary of All Incremental 1 Non-Project Costs and Benefits Page 72 Lines 1

Meter Reading - - (998) (2,544) (54,574) (58,116)

Disconnect/Reconnect - (133) (414) (544) (12,176) (13,267)

Contact Centre - 20 7 (20) (1,163) (1,157)

71.1 Explain increases in Meter Readers' costs $998,000 (2014) to $2.5 million (2015), and an average increase of $3.6 million over 15 years?

Response:

To clarify, Table 5.1.b (page 72) of the CPCN Application is the Summary of All Incremental Non-Project Costs and Benefits. It depicts Gross AMI minus Status Quo to arrive at Net AMI costs/benefits. Bracketed numbers indicate cost reductions flowing from the proposed AMI Project.

For the meter reading category, the numbers reflect the reductions in the cost of providing meter reading to be experienced as the proposed AMI Project is implemented (2014 and 2015) and thereafter when AMI operations replace manual meter reading.

Please see Section 5.3.1 of the CPCN Application.

71.2 Explain the increase of $13.3 million in connect/disconnect costs?

Response:

To clarify, Table 5.1.b (page 72) of the CPCN Application is the Summary of All Incremental Non-Project Costs and Benefits. It depicts Gross AMI minus Status Quo to arrive at Net AMI costs/benefits. Bracketed numbers indicate cost reductions flowing from the proposed AMI Project.

For the disconnect/reconnect category, the numbers reflect the reductions in the cost of manually disconnecting/reconnecting service to be experienced as the proposed AMI Project is implemented (2014 and 2015) and thereafter when AMI is fully operational.

Please see Section 5.3.3 of the CPCN Application.

71.3 What is the current cost for the contact centre?

Response:

In 2011, direct operating and maintenance expense, covering the entire Trail, BC Contact Centre operations was approximately $2.1 million.

To clarify, the numbers noted in Table 5.1.b (page 72) of the CPCN Application, are the difference between Status Quo and AMI operations, reflecting the benefits accruing at the contact centre related to AMI – a reduction in soft reads offset in 2014 and 2015 by higher call volume.

72.0 PROJECT COSTS AND BENEFITS

Table 5.1.b(4) – Summary of All Incremental 1 Non-Project Costs and Benefits Page 72 Lines 1

Table 5.1.b below provides a breakdown of the net sustaining capital and operating costs as well as benefits resulting from the implementation of AMI. The costs and benefits presented in this table are not included in the capital expenditure request of $47.7 million related to the AMI Project, but will be included in future revenue requirement and capital expenditure applications.

72.1 The initial costs of $47 million were for 115,000 meters pro-rated at $409/meter. What additional costs will be incurred that are not included in the cost projections above? Why is this cost so much higher than what is being paid in Ontario and Quebec?

Response:

FortisBC does not anticipate incurring additional costs beyond what has already been included in the financial analysis.

FortisBC does not have information on the cost per customer in Ontario and Quebec, so cannot verify if the cost is "so much higher" or whether it is in fact lower.

Please also refer to the response to BCPSO IR No. 1 Q36.1.

73.0 PROJECT COSTS AND BENEFITS 5.1.1(5) CPCN DEVELOPMENT/APPROVAL COSTS Page 73 Lines 5-21

In the event that the proposed Project is not approved, FortisBC intends to apply, as part of its next revenue requirement, for recovery of the Project development costs incurred. FortisBC submits that these costs have been prudently incurred, particularly in consideration of the following:

- Section 17 of the CEA, which includes the government's goal of having smart metres, other advanced meters and a smart gird in use with respect to customers other than those of the authority;
- The Commission's Reasons for Decision accompanying Order G-168-08, and in particular the Commission Panel's encouragement to FortisBC to continue its efforts to develop and, in due course, reapply for approval of a comprehensive and complete program for the installation and implementation of Advanced Metering Infrastructure and related technologies; and
- Recognition that a majority of Canadian utilities are transitioning to the use of advanced metering systems as the industry standard in metering. Based on FortisBC's submission regarding the prudence of the incurred Project development costs, the recovery of these costs has been included as part of the proposed AMI Project, as well as in all alternative scenarios as discussed in Section 7.0.

73.1 On what basis does FortisBC claim the entitlement to recover the Project development costs incurred if this CPCN was denied.

Response:

For clarity, FortisBC does not claim an "entitlement" to recover the Project development costs. In the event the CPCN was denied, FortisBC would still be required to seek Commission approval for recovery of costs incurred for the development of the AMI Project. It is the Company's position that given the considerations identified in Section 5.1.1 of the Application, the decision to proceed with an application for the implementation of AMI at this time should be considered reasonable, and the expenditures incurred related to that application as prudent. In particular, Order G-168-08 regarding the Company's 2007 AMI Application noted the following:

- A need for FortisBC to consider the regulations before proceeding with its AMI Project;
- A need to further develop the application to consider the opportunities for co-ordination to achieve optimal effectiveness;
- A need to consider whether any economies of scale could be made available through collaboration;

- A need to consider the coordination of the Company's AMI project with BC Hydro's SMI project, particularly with respect to timing and technology selection; and
- A need to further define the expected costs of the project to mitigate the risk of exposure to unknown future costs related to the project.

Given the encouragement provided by the Commission in Order G-168-08 to the Company to continue its efforts to develop, and in due course, reapply for approval of an AMI Project, FortisBC proceeded with the development of its current Application including consideration of the above items as discussed in Section 1.4.1 of the Application. Based on this, the Company believes the costs related to this Application, including those incurred to complete the necessary activities to address the above identified items, should be considered reasonable and prudent. However, FortisBC acknowledges that the ultimate determination on this matter would be the subject of a future application in the event this CPCN application is denied.

74.0 PROJECT COSTS AND BENEFITS

5.1.2(6) ONGOING SUSTAINING CAPITAL AND OPERATING COSTS

Page 74 Lines 17-28
Page 75 Lines 1 - 8

For staffing, FortisBC has anticipated adding an additional 9.5 FTEs to support the AMI system and new processes. The breakdown of these resources is as follows:

- Business Analyst – 2 additional resources to work the billing process, review reports, work queues and dashboards on a daily basis and respond to any alerts and alarms;
- Technical Analyst – 2 additional resources required for the day to day support of AMI-related network infrastructure including servers, security appliances, routers and firewalls. This role includes the planning and implementing of firmware and application upgrades and providing help desk support;
- System Analyst – 2 additional resources required for the day to day support of AMI software applications, including planning and implementing upgrades as well as developing and testing new enhancements for the new applications;
- Communications Technician – 1 additional field resource 1 required to troubleshoot, fix, replace and/or install AMI-related network devices;
- Communication Structures and Equipment – 8.05 percent depreciation rate based on the 2011 Depreciation Study.

COMPOSITE CCA RATE

- The Project composite CCA rate of 15.72 percent was calculated based on the followingCCA rate of each asset class as below:
- Computer Hardware and Software associated with AMI – 30 percent declining balance per CCA Class 46; and
- Meters – 8 percent declining balance per CCA Class 50.

74.1 Explain Composite Depreciation vs. CCA rate?

Response:

Depreciation is an accounting method of allocating the cost of an asset over its useful life. Different assets will have different useful lives and will therefore be depreciated over longer or shorter periods of time. The Company commissioned a 2011 Depreciation Study that recommended various depreciation rates for the Company's various asset classes. Rather than present the depreciation for each asset class as a separate line item, the Company calculated the composite weighted average depreciation rate for all of the assets included in the project and applied that rate to the total depreciable assets of the project.

CCA means Capital Cost Allowance and is the tax depreciation rate specified by the Canada Revenue Agency by asset class as an allowable deduction from income for tax purposes. Rather than present the CCA rate for each asset class as a separate line item, the Company calculated the composite weighted average CCA rate for all of the assets included in the project and applied that rate to the capital expenditures allowed for tax purposes.

75.0 PROJECT COSTS AND BENEFITS

5.3.1 (9) METER READING Page 79 Lines 4-7

Meter readers take manual readings using a handheld device, and at the end of each day the meter reader must return to the field office and upload the reads into the Customer Information System (CIS) for billing. The majority of customer meters, residential and small commercial, are read on a bimonthly cycle (approximately 60 days).

75.1 Currently the meter readers have to drive back to the office to upload readings. Why can this not be done from the readers' home or other designated network more conveniently (and more cheaply)?

Response:

FortisBC is conscious, as always, of the need to maximize the security of information. Therefore, given that meter readers would have to drive from the end of the daily meter reading route to some point (residence, field office, or other) in order to upload consumption data, the Company has decided to make that point the field offices in which security controls can more reasonably be maintained.

Further, specific to considering a location other than a Company-owned facility such as a meter reader's residence, this would entail the installation and maintenance of secure Company infrastructure at each applicable meter reader residence, creating an unnecessary cost considering the infrastructure exists in the Company's field offices.

76.0 PROJECT COSTS AND BENEFITS

5.3.1(10) METER READING Pg. 80 Table 5.3.1.a below provides a summary of meter reading costs for thepast four years.

76.1 Salaried meter readers will be made redundant and according to the figures presented, represent a savings to FortisBC of $2,421,063. These positions will be replaced with IT personnel to manage the AMI project which will offset these figures. What are these costs? What positions will be created for IT and what will be the net difference?What consideration has FortisBC given to the impact of the loss of these meter readers jobs and the lost revenues and taxes to the province? What will be cost to the taxpayer issuing employment insurance cheques to these unemployed people?

Response:

Please refer to the response to BCUC IR No. 1 Q58.1.3 for details on the new positions and the costs associated with them that have been proposed as part of the AMI Project.

Please see Section 4.4 of the CPCN Application and BCPSO IR No. 1 Q44.1 for information on the Company's talent transition plans for the existing meter reading workforce.

FortisBC considers the net benefits accruing from the implementation of the proposed AMI Project, inherent in the improved ability to manage the cost of electricity to have merit for all FortisBC customers.

76.2 Why does FortisBC require additional consumption data beyond bimonthly readings?

Response:

Please refer to Section 3.0 of the Application as well as the response to CSTS IR No. 1 Q61.1.

76.3 Has FortisBC considered a program whereby customers send meter readings in by way of transmission of digital photographs?

Response:

No, FortisBC has not considered this. Please also refer to the response to Shadrack IR No. 1 Q33.

77.0 PROJECT COSTS AND BENEFITS

5.3.2 (11) THEFT REDUCTION p.80-81 Lines 2-8

The calculation detailed in the table above is based upon the following inputs. A 2011 study prepared by Dr. Darryl Plecas, RCMP University Research Chair at the University of the Fraser Valley, estimates that 13,206 indoor marijuana grow premises existed province wide n 2010. As FortisBC serves approximately 6 percent of residential electric customers in BC, 792 sites were calculated to exist in the Company's service area. This figure is assumed to increase at 2 percent annually in the status quo model, resulting in an overall figure of 824 grow sites in FortisBC's service territory in 2012.

77.1 Particularize how FortisBC proposes to use the AMI Program data to eliminate theft once theft is discovered.

Response:

The AMI theft detection program is described in Section 5.3.2 of Exhibit B-1 and more information is provided in the responses to BCUC IR No. 1 Q54.1, Q54.2, Q88.1 as well as CEC IR No. 1 Q21.2 and Q77.2.

77.2 In the event that theft is discovered by use of the AMI Program, what is FortisBC going to do that is not doing now?

Response:

The Company response to electric theft once theft is discovered will not change from the current approach.

77.3 What percent of theft, that FortisBC is currently aware of, has been eliminated?

Response:

FortisBC estimates that 8 percent of the number of theft sites in the service area is identified each year. Please refer to the response to BCPSO IR No. 1 Q45.1

77.4 If 93 kWh per day per residence is the ceiling at which an investigation is warranted, why have these investigations not been carried out on a regular basis on every one of these residents to confirm theft or not?

Response:

The 93 kWh threshold established by the 2006 amendment to the *Safety Standards Act* is not an indication of electric theft but rather an indication that a commercial marijuana production site may be located in a residence. Municipalities may request a list of residential premises from electric utilities which exceed this ceiling and subsequently conduct an investigation to check the safety of the premise.

The 93 kWh daily threshold is for metered consumption and not a ceiling above which or below theft is indicated. Please refer to the response to BCUC IR No. 1 Q78.5.1.

77.5 If 13,740 BC addresses are suspected as per the 'Plecas Report", why have these not been investigated or shut down already?

Response:

The 13,740 sites are the estimated number of residences in BC in 2012 which contain indoor marijuana operations, and not specific addresses. FortisBC does investigate any premise where theft is suspected. Please refer to the responses to BCUC IR No. 1 Q85.3, Q853.2 and Q85.4.

77.6 Provide the source of the Plecas Report figures.

Response:

Dr. Plecas cites the sources used in estimating the number of BC indoor marijuana sites in the report. FortisBC has no visibility of the referenced sources. Please refer to Exhibit A2-1 filed by Commission staff on August 14, 2012.

77.7 Never on a utility bill has a customer been shown a breakout of savings from the reduction of energy theft. Will FortisBC be introducing this as a customer credit in their billing systems in the future if this is a relevant feature of the AMI?How will the stated 'reduction in safety hazards' of a grow-op affect the consumer?Explain what evidence exists that can be presented that will confirm that this is even a relevant issue to anyone other than an insurance company?

Response:

The response to BCUC IR No. 1 Q53.14.2 explains how AMI benefits will be realized in revenue requirements.

The presence of an electric bypass presents a fire hazard which exposes the customer, first responders and neighbors to personal safety hazards. The reduction in electric theft will mitigate these risks for all consumers affected. As detailed discussion of the potential hazards associated with indoor marijuana production is contained in “Marihuana Growing Operations in British Columbia Revisited” (2005) by Plecas, D., Malm, A., and Kinney, B. This report is attached as Appendix CSTS IR1 77.7. Please refer also to Exhibit A2-7 filed by Commission staff on September 14, 2012.

77.8 If approximately 6% or 792 sites been identified in the FortisBC region, why have these not been investigated or shut down?Explain making the assumption on an increase of 2% a year? If FortisBC and law enforcement were doing an adequate job of identifying these sites the numbers of grow-ops should be declining and thus producing a credit to the customers account?Will FortisBC allow an independent cyber security expert to demonstrate the ease of hacking the AMI?

Response:

Please refer to the responses to CSTS IR No. 1 Q77.5 and BCUC IR No. 1 Q79.1. For a detailed discussion on the security features of the AMI Project please refer to Section 8.4.3 and Appendix F-1 of the Application.

78.0 PROJECT COSTS AND BENEFITS5.3.4 (14) MEASUREMENT CANADA COMPLIANCE Pg. 93 lines 27-33, Pg. 94 lines 1-3

An AMI deployment would replace these meters, incurring only the incremental capital costs of approximately $68.86 per meter to replace the existing meters with AMI enabled meters. The proposed AMI Project would avoid the cost of replacing these meters in the future, and eliminate the meter exchange and compliance sampling costs required to manage the electro-mechanical meter population to its projected end of life under Measurement Canada's revised sampling plan (S-S-06). Subsequently, when compliance and meter exchange activities resume approximately six years after the conclusion of the project, FortisBC expects significant compliance test savings 1 due to the larger compliance groups that would be created. A much smaller percentage of the meter population would need to be exchanged and tested compared with the status quo.

78.1 Why are new AMR meters exempt of S-S-06 testing for accuracy for six years?

<u>Response:</u>

FortisBC assumes the question was referring to the proposed AMI meters, as opposed to AMR meters.

The meters to be used in the proposed AMI project are not exempt from S-S-06 testing for six years. As explained in the response to BCPSO IR No. 1 Q48.3 and Q48.4, the six years refers to the time during which FortisBC does not expect to require compliance testing of meters.

78.2 Nowhere is there any certification to be found that the AMI are structurally safe; neither the housing or the internal components. Explain why not?

<u>Response:</u>

FortisBC disagrees with the statement in the question above. Itron designs and tests their metering devices to be compliant with LMB-EG-07 (Measurement Canada's "Specifications for Approval of Type of Electricity Meters, Instrument Transformers and Auxiliary Devices") and ANSI/NEMA C12.1 ("American National Standard for Electric Meters – Code for Electricity Metering"). These same standards have been applied to all FortisBC metering equipment including the previously used electro-mechanical meters. The ANSI C12.1 standard specifically covers specifications for the design and construction of metering devices including sealing, enclosures, terminals/markings, and construction and workmanship. For example, meters designed for outdoor application must meet the physical performance specifications described in the NEMA 250 standard for Type 3R enclosures. The NEMA 3R standard requires:

> "Enclosures constructed for either indoor or outdoor use to provide a degree of protection to personnel against access to hazardous parts; to provide a degree of protection of the equipment inside the enclosure against ingress of solid foreign objects (falling dirt); to provide a degree of protection with respect to harmful effects on the equipment due to the ingress of water (rain, sleet, snow); and that will be undamaged by the external formation of ice on the enclosure."

On this basis, FortisBC considers that AMI meters are structurally safe.

78.3 Is there is any Canadian recognized certification that FortisBC has on file that verifies structural and component compliance safety?

Response:

Please refer to the response to CSTS IR No. 1 Q78.2.

78.4 Will FortisBC allow these units to be inspected by independent, qualified, independent third parties to ensure that their structural housing and component parts meet acceptable safety standards?

Response:

FortisBC considers that based on the response to CSTS IR No. 1 Q78.2, unnecessary additional third-party testing would only add costs to the Project with no corresponding benefit.

78.5 Explain why the AMI should be exempt from immediate inspection.

Response:

Please refer to the response to CSTS IR No. 1 Q78.4.

79.0 PROJECT COSTS AND BENEFITS

5.3.5 (15) METER EXCHANGES Pg. 94 lines 18-22 The AMI Project will result in the replacement of nearly all existing meters with new AMI enabled meters. This will avoid operating costs that would have been incurred sampling and retesting meters for six years after meter deployment. After year six, the cost of meter exchanges is expected to begin returning to the pre-AMI deployment levels.

79.1 What failure rate is assumed for each new AMI meter?Explain how the failure rate is determined if these new meters have not been tested?If these new metres have been properly tested for the failure rates, not just power consumption metering, will FortisBC provide the written report and the qualifications of the company doing the testing? Is the testing done by an independent body?

<u>Response:</u>

The Company is unclear as to what failure rate the question is asking about.

If the reference relates to failure rates associated with Measurement Canada compliance, please see Section 5.3.4 of the CPCN Application. For the expected AMI meter failure rate please refer to CEC IR No. 1 Q6.1. For life expectancy data, please refer to the response to BCUC IR No. 1 Q69.1.

79.2 What is the basis for the life expectancy used in the business case? Explain the position FortisBC takes with the 'hot' installation of these AMI meters.Will the contracted installers be journeyman electricians?Explain why FortisBC does not allow CSA or UL testing as an act of good faith. Would it not be in their best interest to placate public concerns as well as verify their own position?What will be the additional cost to implement an OMS enhancement system? Table 6.3.a shows ‘potential savings’ from an OMS. Will FortisBC provide the study showing the calculation of these figures?

<u>Response:</u>

For life expectancy of the AMI meters, please refer to the response to BCUC IR No. 1 Q69.1.

Regarding the meter exchange process, please refer to the responses to BCUC IR No. 1 Q47.1, CEC IR No. 1 Q52.1 and CEC IR No. 1 Q52.2.

FortisBC believes that the equipment proposed to be installed as part of the AMI Project will be compliant with the applicable legal framework. Additional testing is therefore not required.

Regarding OMS, please see Section 6.3 of the CPCN Application and the responses to BCUC IR No. 1 Q102.3 and CEC IR No. 1 Q86.1. As the OMS is considered a potential future benefit, a study has not been completed at this point.

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Senior Managing Scientist

Professional Profile

Dr. Linda S. Erdreich is a Senior Managing Scientist in Exponent's Health Sciences Center for Epidemiology, Biostatistics, and Computational Biology. Ms. Erdreich is an epidemiologist with 32 years of experience in environmental epidemiology and health risk assessment. She specializes in assessing epidemiological research and integrating this information with that from other disciplines for qualitative and quantitative risk assessments. She has prepared risk assessments for environmental and occupational chemicals, radiofrequency energy, electric and magnetic fields (EMF), and stray voltage. Dr. Erdreich has also prepared analyses of complex epidemiological evidence suitable for communication with interested parties of various backgrounds, including other scientists, executives, elected officials, and the general public. She has been particularly active in updating standards regarding non-ionizing radiation, both low frequencies (EMF) and radio frequencies. Dr. Erdreich has provided support to government agencies and private clients in health risk assessment and epidemiology.

Prior to joining Exponent, Dr. Erdreich was a Principal Scientist with Bailey Research Associates, where she specialized in epidemiologic research and analysis. Before that, Dr. Erdreich managed a research program in risk assessment at the U.S. Environmental Protection Agency and contributed to the development of risk assessment methods and guidelines. Dr. Erdreich has served on advisory committees to government, regulatory organizations, and industry regarding health risk assessments of chemicals and electromagnetic fields. Dr. Erdreich served as an adjunct associate professor at the Robert Wood Johnson Medical School in New Jersey.

Academic Credentials and Professional Honors

Ph.D., Epidemiology, University of Oklahoma, 1979
M.S., Biostatistics and Epidemiology, University of Oklahoma, 1977
M.Ed., Science Education, Temple University, 1968
B.A., Biological Sciences, Temple University, 1964

Fellow, American College of Epidemiology

U.S. Environmental Protection Agency: Special Achievement Award for Development of EPA's Proposed Risk Assessment Guidelines, 1984; Certificate of Achievement, Mentor: Research Apprenticeship Program, 1983; Special Achievement Award for Development of Methodologic Approaches to Risk Assessment Essential to the Agency, 1982

U.S. Public Health Service Traineeship, 1975–1979; Graduate Dean's Research Prize, University of Oklahoma, 1978

Publications

Erdreich LS, Alexander DD, Wagner ME, Reinemann D. Meta-analysis of stray voltage on dairy cattle. J Dairy Sci 2009; 92:5951–5963.

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Erdreich LS, Roberts W. Identifying flawed reasoning in biomedical science: A more cogent argument than "Junk Science." Toxic Torts and Environmental Law Committee Newsletter. American Bar Association, Summer 2006.

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Invited Presentations

Erdreich L. Basics of Epidemiology. American Industrial Hygiene Association Short Course, July, 2006–2011.

Erdreich L. Meta-analysis of stray voltage studies. 46th Annual Rural Energy Conference, in LaCrosse, WI, February 28–29, 2008.

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Erdreich, LS. Epidemiology of radio frequency energy exposure and health. Armed Forces Epidemiology Board, San Diego, CA, February 2002.

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Erdreich LS. The two newest studies: what questions should we ask? EMF Seminar: Focus on Research, Electric Power Research Institute, March 1994.

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Erdreich LS. State policy options for managing extremely low frequency electromagnetic fields. Conference on Health Effects of High Voltage Power Lines, Center for Environmental Health, University of Connecticut, West Hartford, CT, June 1990.

Erdreich LS. Current public health issues in EMF. University of Oklahoma College of Public Health Alumni Day, Oklahoma City, OK, October 1989.

Thorslund T, Erdreich LS, Hegner R. Testing hypotheses of mechanism using epidemiologic data. Presented at the International Symposium on Chemical Mixtures: Risk Assessment and Management, Cincinnati, OH, June 1988.

Erdreich LS, Sonich C. Hypersusceptible subgroups of the population: determining numbers at risk. Presented at Satellite Meeting of the Environmental Mutagen Society, March 1983.

Prior Experience

Bailey Research Associates, Principal Scientist, 1991–1999
Environmental Research Information (ERI), Senior Research Associate, 1989–1991
Clement Associates, Senior Associate, 1987–1989
U.S. Environmental Protection Agency, Office of Research and Development, Methods Evaluation and Development Staff, Group Leader, 1984–1987
U.S. Environmental Protection Agency, Office of Research and Development, Environmental Criteria and Assessment Office, Senior Epidemiologist, 1980–1984

Current Academic Appointments

- Adjunct Associate Professor, Department of Environmental and Community Medicine, Robert Wood Johnson Medical School, University of Medicine & Dentistry of New Jersey, 1993–present

Teaching Appointments

- Lecturer, Short Course on Electromagnetic Energy: University of Texas Health Science Center, Center for Environmental Radiation Toxicology, San Antonio, Texas (1998, 2000
- Adjunct Assistant Professor, Institute of Environmental Health, University of Cincinnati Medical Center, 1982–1987
- Teaching Assistant, Department of Biostatistics and Epidemiology, University of Oklahoma School of Public Health, 1975–1979
- Teacher of Biology and Chemistry, Ann Arbor, MI; Philadelphia, PA; Montgomery County, MD, 1964–1972

Advisory Positions

- Institute of Electrical and Electronics Engineers (IEEE), 1992–present
  - Chair, Epidemiology Workgroup of Subcommittee 4 Safety Level with Respect to Human Exposure to Radiofrequency Fields (3 kHz–33 GHz), for the Standards Coordinating Committee 28 Non-Ionizing Radiation, 1992–2000
  - Member, Standards Coordinating Committee 28 Non-Ionizing Radiation, and Subcommittee 3 Safety Levels with Respect to Human Exposure (0-3 kHz), Institute of Electrical and Electronics Engineers (IEEE)
- Member of the Committee on Man and Radiation (COMAR) of the Engineering in Medicine and Biology Society, 1995–2000; 2002–2007; 2009-2012

- Chair of the Expert Panel to advise the Massachusetts Department of Public Health, Bureau of Environmental Health Assessment regarding radio-frequency exposure from the Air Force Space Command's PAVE PAWS radar system on Cape Cod, 1998–1999
- Member of a panel convened by Health Canada to review a toxicity assessment of a priority substance under the Canadian Environmental Protection Act (1,3-butadiene), 1998
- Served on peer review panels for risk assessments for chromium, cadmium, acrylamide, and for methylmercury, convened by Toxicology Excellence for Risk Assessment, a non-profit, 501(c)(3) corporation, 1997–1998
- Contributor to NATO Standardization Agreement: Evaluation and Control of Personnel Exposure to Radio-Frequency Fields - 3 kHz to 300 GHz, 1995
- At EPA, managed and co-authored the agency's first draft Interim Methods for Development of Inhalation Reference Doses, 1987–1988
- Member of U.S. EPA's work group to develop Oral Reference Doses for non-carcinogens, available on Integrated Risk Information System (IRIS), 1986–1987
- Member of EPA's Risk Assessment Forum's Technical Panel: Developing a Scientific Policy for Thyroid Neoplasia, 1986–1987
- Panel member for an EPA workshop in weight of evidence/hazard identification for non-cancer health endpoints, 1986–1987
- Co-Chair of EPA's agency-wide committee to write Risk Assessment Guidelines for Chemical Mixtures, 1985–1986
- Program Committee to plan a national symposium Epidemiology and Health Risk Assessment, sponsored by private, governmental and academic institutions, 1984–1985
- Member, Environmental Advisory Council to the City of Cincinnati. Appointed to the Executive Committee, 1986, 1984–1987
- Planned and managed an international symposium on "Advances in Risk Assessment of Systematic Toxicants and Chemical Mixtures," held October 1984; co-edited the proceedings, 1983–1984
- Chairperson for two international symposia: "Risk Assessment for Multiple Chemical Exposures," sponsored by EPA, 1981–1983

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Principal Scientist

Professional Profile

Dr. William H. Bailey is a Principal Scientist in Exponent's Health Sciences practice. Dr. Bailey specializes in applying state-of-the-art assessment methods to environmental and occupational health issues. His 30 years of training and experience include laboratory and epidemiologic research, health risk assessment, and comprehensive exposure analysis. Dr. Bailey has investigated exposures to alternating current, direct current, and radiofrequency electromagnetic fields, 'stray voltage', and electrical shock, as well as to a variety of chemical agents and air pollutants. He is particularly well known for his research on potential health effects of electromagnetic fields and has served as an advisor to numerous state, federal, and international agencies. Currently, he is involved in research on exposures to marine life from submarine cables and respiratory exposures to ultrafine- and nanoparticles. Dr. Bailey is a visiting scientist at the Cornell University Medical College and has lectured at Rutgers University, the University of Texas (San Antonio), and the Harvard School of Public Health. He was formerly Head of the Laboratory of Neuropharmacology and Environmental Toxicology at the New York State Institute for Basic Research, Staten Island, New York, and an Assistant Professor and NIH postdoctoral fellow in Neurochemistry at The Rockefeller University in New York.

Academic Credentials and Professional Honors

Ph.D., Neuropsychology, City University of New York, 1975
M.B.A., University of Chicago, 1969
B.A., Dartmouth College, 1966

Sigma Xi; The Institute of Electrical and Electronics Engineers/International Committee on Electromagnetic Safety (Subcommitee 3, Safety Levels with Respect to Human Exposure to Fields (0 to –3 kHz) and Subcommittee 4, Safety Levels with Respect to Human Exposure to Radiofrequency Fields (3 kHz to 3 GHz); Elected member of the Committee on Man and Radiation (COMAR) of the IEEE Engineering in Medicine and Biology Society, 1998–2001

Publications

Bailey WH, Johnson GB, Bishop J, Hetrick T, Su S. Measurements of charged aerosols near ±500 kV DC transmission lines and in other environments. IEEE Transactions on Power Delivery 2012; 27:371–379.

Shkolnikov YP, Bailey WH. Electromagnetic interference and exposure from household wireless networks. 2011 IEEE Symposium on Product Compliance Engineering (PSES), October 1–5, 2011.

Kavet R, Bailey WH, Bracken TD, Patterson RM. Recent advances in research relevant to electric and magnetic field exposure guidelines. Bioelectromagnetics 2008; 29:499–526.

Bailey WH, Wagner M. IARC evaluation of ELF magnetic fields: Public understanding of the 0.4μT exposure metric. Journal of Exposure Science and Environmental Epidemiology 2008; 18:233–235.

Bailey WH, Erdreich L. Accounting for human variability and sensitivity in setting standards for electromagnetic fields. Health Physics 2007; 92:649–657.

Bailey WH, Nyenhuis JA. Thresholds for 60-Hz magnetic field stimulation of peripheral nerves in human subjects. Bioelectromagnetics 2005; 26:462–468.

Bracken TD, Senior RS, Bailey WH. DC electric fields from corona-generated space charge near AC transmission lines. IEEE Transactions on Power Delivery 2005; 20:1692–1702.

Bailey WH. Dealing with uncertainty in formulating occupational and public exposure limits. Health Physics 2002; 83:402–408.

Bailey WH. Health effects relevant to the setting of EMF exposure limits. Health Physics 2002; 83:376–386.

Kavet R, Stuchly MA, Bailey WH, Bracken TD. Evaluation of biological effects, dosimetric models, and exposure assessment related to ELF electric- and magnetic-field guidelines. Applied Occupational and Environmental Hygiene 2001; 16:1118–1138.

Bailey WH. ICNIRP recommendation for limiting public exposure to 4 Hz–1 kHz electric and magnetic fields. Health Physics1999; 77:97–98.

Bailey WH. Principles of risk assessment with application to current EMF risk communication issues. In: EMF Risk Perception and Communication. Repacholi MH, Muc AM (eds), World Health Organization, Geneva, 1999.

De Santo RS, Bailey WH. Environmental justice tools and assessment practices. Proceedings, American Public Transit Association, 1999.

Bailey WH, Su SH, Bracken TD. Probabilistic approach to ranking sources of uncertainty in ELF magnetic field exposure limits. Health Physics 1999; 77:282–290.

Bailey WH. Field parameters. Proceedings, EMF Engineering Review Symposium, Status and Summary of EMF Engineering Research. Bracken TD and Montgomery JH (eds), Oak Ridge National Laboratory, Oak Ridge, TN, April 28–29, 1998.

Bailey WH. Policy implications. Proceedings, EMF Engineering Review Symposium, Status and Summary of EMF Engineering Research. Bracken TD and Montgomery JH (eds), Oak Ridge National Laboratory, Oak Ridge, TN, April 28–29, 1998.

Bailey WH. Probabilistic approaches to deriving risk-based exposure guidelines: Application to extremely low frequency magnetic fields. In: Non-Ionising Radiation. Dennis JA and Stather JW (eds), Special Issue of Radiation Protection Dosimetry 1997; 72:327–336.

Bailey WH, Su SH, Bracken TD, Kavet R. Summary and evaluation of guidelines for occupational exposure to power frequency electric and magnetic fields. Health Physics 1997; 73:433–453.

Bracken TD, Senior RS, Rankin RF, Bailey WH, Kavet R. Magnetic field exposures in the electric utility industry relevant to occupational guideline levels. Applied Occupational and Environmental Hygiene 1997; 12:756–768.

Blondin J-P, Nguyen D-H, Sbeghen J, Goulet D, Cardinal C, Maruvada P-S, Plante M, and Bailey WH. Human perception of electric fields and ion currents associated with high voltage DC transmission lines. Bioelectromagnetics 1996; 17:230–241.

Bailey WH, Charry JM. Acute exposure of rats to air ions: Effects on the regional concentration and utilization of serotonin in brain. Bioelectromagnetics 1987; 8:173–181.

Bailey WH, Charry JM. Measurement of neurotransmitter release and utilization in selected brain regions of rats exposed to dc electric fields and atmospheric space charge. Proceedings, 23rd Hanford Life Sciences Symposium, Interaction of Biological Systems with Static and ELF Electric and Magnetic Fields, 1987.

Pavildes C, Aoki C, Chen J-S, Bailey WH, Winson J. Differential glucose utilization in the parafascicular region during slow-wave sleep, the still-alert state and locomotion. Brain Research 1987; 423:399–402.

Bailey WH, Charry JM. Behavioral monitoring of rats during exposure to air ions and DC electric fields. Bioelectromagnetics 1986; 7:329–339.

Charry JM, Shapiro MH, Bailey WH, Weiss JM. Ion-exposure chambers for small animals. Bioelectromagnetics 1986; 7:1–11.

Charry JM, Bailey WH. Regional turnover of norepinephrine and dopamine in rat brain following acute exposure to air ions. Bioelectromagnetics 1985; 6:415–425.

Bracken TD, Bailey WH, Charry JM. Evaluation of the DC electrical environment in proximity to VDTs. Journal of Environmental Science and Health Part A 1985; 20:745–780.

Gross SS, Levi R, Bailey WH, Chenouda AA. Histamine modulation of cardiac sympathetic responses: A physiological role. Federation Proceedings 1984; 43:458.

Gross SS, Guo ZG, Levi R, Bailey WH, Chenouda AA. 1984. Release of histamine by sympathetic nerve stimulation in the guinea pig heart and modulation of adrenergic responses. Circulation Research 1984; 54:516–526.

Dahl D, Bailey WH, Winson J. Effect of norepinephrine depletion of hippocampus on neuronal transmission from perforant pathway through dentate gyrus. Journal of Neurophysiology 1983; 49:123–135.

Guo ZG, Gross SS, Levi R, Bailey WH. Histamine: Modulation of norepinephrine release from sympathetic nerves in guinea pig heart. Federation Proceedings 1983; 42:907.

Bailey WH. Biological effects of air ions on serotonin metabolism: Fact and fancy. pp. 90–120. In: Conference on Environmental Ions and Related Biological Effects. Charry JM (ed), American Institute of Medical Climatology, Philadelphia, PA, 1982.

Weiss JM, Goodman PA, Losito BG, Corrigan S, Charry JM, Bailey WH. Behavioral depression produced by an uncontrollable stressor: Relationship to norepinephrine, dopamine, and serotonin levels in various regions of rat brain. Brain Research Reviews 1981; 3:167–205.

Bailey WH. Ion-exchange chromatography of creatine kinase isoenzymes: A method with improved specificity and sensitivity. Biochemical Medicine 1980; 24:300–313.

Bailey WH, Weiss JM. Evaluation of a ‘memory deficit’ in vasopressin-deficient rats. Brain Research 1979; 162:174–178.

Bailey WH, Weiss JM. Effect of ACTH 4-10 on passive avoidance of rats lacking vasopressin (Brattleboro strain). Hormones and Behavior 1978; 10:22–29.

Pohorecky LA, Newman B, Sun J, Bailey WH. Acute and chronic ethanol injection and serotonin metabolism in rat brain. Journal of Pharmacology and Experimental Therapeutics 1978; 204:424–432.

Koh SD, Vernon M, Bailey WH. Free-recall learning of word lists by prelingual deaf subjects. Journal of Verbal Learning and Verbal Behavior 1971; 10:542–574.

Book Chapters

Bailey WH. Principles of risk assessment and their limitations. In: Risk Perception, Risk Communication and its Application to EMF Exposure. Matthes R, Bernhardt JH, Repacholi MH (eds), International Commission on Non-Ionizing Radiation Protection, Oberschleißheim, Germany, 1998.

Bailey WH. Biological responses to air ions: Is there a role for serotonin? pp. 151–160. In: Air Ions: Physical and Biological Aspects. Charry JM and Kavet R (eds), CRC Press, Boca Raton, FL, 1987.

Weiss JM, Bailey WH, Goodman PA, Hoffman LJ, Ambrose MJ, Salman S, Charry JM. A model for neurochemical study of depression. pp. 195–223. In: Behavioral Models and the Analysis of Drug Action. Spiegelstein MY, Levy A (eds), Elsevier Scientific, Amsterdam, 1982.

Bailey WH. Mnemonic significance of neurohypophyseal peptides. pp. 787–804. In: Changing Concepts of the Nervous System. Morrison AR, Strick PL (eds), Academic Press, New York, NY, 1981.

Bailey WH, Weiss, JM. Avoidance conditioning and endocrine function in Brattleboro rats. Pp 371–395. In: Endogenous Peptides and Learning and Memory Process. Martinez JL, Jensen RA, Messing RB, Rigter H, McGaugh JL (eds), Academic Press, New York, NY, 1981.

Weiss JM, Glazer H, Pohorecky LA, Bailey WH, Schneider L. Coping behavior and stress-induced behavioral depression: Studies of the role of brain catecholamines. pp. 125–160. In: The Psychobiology of the Depressive Disorders: Implications for the Effects of Stress. Depue R (ed), Academic Press, New York, NY, 1979.

Technical Reports

Normandeau, Exponent, Tricas T, Gill A. Effects of EMFs from undersea power cables on elasmobranchs and other marine species. U.S. Dept. of the Interior, Bureau of Ocean Energy Management, Regulation, and Enforcement, Pacific OCS Region, Camarillo, CA. OCS Study BOEMRE 2011-09, May 2011.

Jardini JA, et al. Electric field and ion current environment of HVDC overhead transmission lines. Report of Joint Working Group B4/C3/B2.50, CIGRĖ, August 2011.

Johnson GB, Bracken TD, Bailey WH. Charging and transport of aerosols near AC transmission lines: A literature review. EPRI, Palo Alto, CA, 2003.

Bailey WH. Probabilistic approach to ranking sources of uncertainty in ELF magnetic-field exposure limits. In: Evaluation of Occupational Magnetic Exposure Guidelines, Interim Report, EPRI Report TR-111501, 1998.

Bracken TD, Bailey WH, Su SH, Senior RS, Rankin RF. Evaluation of occupational magnetic-field exposure guidelines; Interim Report. EPRI Report TR-108113, 1997.

Bailey WH, Weil DE, Stewart JR. HVDC Power Transmission Environmental Issues Review. Oak Ridge National Laboratory, Oak Ridge, TN, 1996.

Bailey WH. Melatonin responses to EMF. Proceedings, Health Implications of EMF Neural Effects Workshop, Report TR-104327s, EPRI, 1994.

Bailey WH. Recent neurobiological and behavioral research: Overview of the New York State powerlines project. In: Power-Frequency Electric and Magnetic Field Research, EPRI, 1989.

Bailey WH, Bissell M, Dorn CR, Hoppel WA, Sheppard AR, Stebbings, JH. Comments of the MEQB Science Advisors on Electrical Environment Outside the Right of Way of CU-TR-1, Report 5. Science Advisor Reports to the Minnesota Environmental Quality Board, 1986.

Bailey WH, Bissell M, Brambl RM, Dorn CR, Hoppel WA, Sheppard AR, Stebbings JH. A health and safety evaluation of the +/- 400 KV powerline. Science Advisor's Report to the Minnesota Environmental Quality Board, 1982.

Charry JM, Bailey WH, Weiss JM. Critical annotated bibliographical review of air ion effects on biology and behavior. Rockefeller University, New York, NY, 1982.

Bailey WH. Avoidance behavior in rats with hereditary hypothalamic diabetes insipidus. Dissertation, City University of New York, 1975.

Selected Invited Presentations

Bailey WH. Measurements of charged aerosols around DC transmission lines and other locations. International Committee on Electromagnetic Safety TC95/ Subcommittee 3: Safety Levels with Respect to Human Exposure to Electromagnetic Fields, 0 – 3 kHz. December 2011.

Bailey WH, Erdreich LS. Human sensitivity and variability in response to electromagnetic fields: Implications for standard setting. International Workshop on EMF Dosimetry and Biophysical Aspects Relevant to Setting Exposure Guidelines. International Commission on Non-Ionizing Radiation Protection, Berlin, March 2006.

Bailey WH. Research-based approach to setting electric and magnetic field exposure guidelines (0-3000 Hz). IEEE Committee on Electromagnetic Safety, December 2005.

Bailey WH. Conference Keynote Presentation. Research supporting 50/60 Hz electric and magnetic field exposure guidelines. Canadian Radiation Protection Association, Annual Conference, Winnipeg, June 2005.

Bailey WH. Scientific methodology for assessing public health issues: A case study of EMF. Canadian Radiation Protection Association, Annual Conference, Public Information for Teachers, Winnipeg, June 2005.

Bailey WH. Assessment of potential environmental effects of electromagnetic fields from submarine cables. Connecticut Academy of Science and Engineering, Long Island Sound Bottomlands Symposium: Study of Benthic Habitats, July 2004.

De Santo RS, Coe M, Bailey WH. Environmental justice assessment and the use of GIS tools and methods. National Association of Environmental Professionals, 27th Annual Conference, Dearborn, MI, June 2002.

Bailey WH. Applications to enhance safety: Research to understand and control potential risks. Human Factors and Safety Research, Volpe National Transportation Systems Center/Dutch Ministry of Transport, Cambridge, MA, November 2000.

Bailey WH. EMF health effects review. EMF Exposure Guideline Workshop, Brussels Belgium, June 2000.

Bailey WH. Dealing with uncertainty when formulating guidelines. EMF Exposure Guideline Workshop, Brussels Belgium, June 2000.

Bailey WH. Field parameters: Policy implications. EMF Engineering Review Symposium, Status and Summary of EMF Engineering Research, Charleston, SC, April 1998.

Bailey WH. Principles of risk assessment: Application to current issues. Symposium on EMF Risk Perception and Communication, World Health Organization, Ottawa, Canada, August 1998.

Bailey WH. Current guidelines for occupational exposure to power frequency magnetic fields. EPRI EMF Seminar, New Research Horizons, March 1997.

Bailey WH. Methods to assess potential health risks of cell telephone electromagnetic fields. IBC Conference—Cell Telephones: Is there a Health Risk? Washington, DC, June 1997.

Bailey WH. Principles of risk assessment and their limitations. Symposium on Risk Perception, Risk Communication and its Application to EMF Exposure, International Commission on Non-Ionizing Radiation Protection, Vienna, Austria, October 1997.

Bailey WH. Probabilistic approach for setting guidelines to limit induction effects. IEEE Standards Coordinating Committee 28: Non-Ionizing Radiation, Subcommittee 3 (0–3 kHz), June 1997.

Bailey WH. Power frequency field exposure guidelines. IEEE Standards Coordinating Committee 28: Non-Ionizing Radiation, Subcommittee 3 (0–3 kHz), June 1996.

Bailey WH. Epidemiology and experimental studies. American Industrial Hygiene Conference, Washington, DC, May 1996.

Bailey WH. Review of 60 Hz epidemiology studies. EMF Workshop, Canadian Radiation Protection Association, Ontario, Canada, June 1993.

Bailey WH. Biological and health research on electric and magnetic fields. American Industrial Hygiene Association, Fredrickton, New Brunswick, Canada, October 1992.

Bailey WH. Electromagnetic fields and health. Institute of Electrical and Electronics Engineers, Bethlehem, PA, January 1992.

Bailey WH, Weiss JM. Psychological factors in experimental heart pathology. Visiting Scholar Presentation, National Heart Lung and Blood Institute, March 1977.

Presentations

Perez V, Alexander DD, Bailey WH. Air ions and mood outcomes: A review and meta-analysis. Poster presentation at the American College of Epidemiology, Chicago, IL, September 8–11, 2012.

Shkolnikov Y, Bailey WH. Electromagnetic interference and exposure from household wireless networks. Product Safety Engineering Society Meeting, San Diego, CA October 2011.

Nestler E, Trichas T, Pembroke A, Bailey W. Will undersea power cables from offshore wind projects affect sharks? North American Offshore Wind Conference & Exhibition, Atlantic City, NJ, October 2010.

Nestler E, Pembroke A, Bailey W. Effects of EMFs from undersea power lines on marine species. Energy Ocean International, Ft. Lauderdale, FL, June 2010.

Pembroke A, Bailey W. Effects of EMFs from undersea power cables on elasmobranchs and other marine species. Windpower 2010 Conference and Exhibition, Dallas, TX, 2010.

Bailey WH. Clarifying the neurological basis for ELF guidelines. Workshop on Practical Implementation of ELF and RF Guidelines. The Bioelectromagnetics Society 29th Annual Meeting, Kanazawa, Japan, June 2007.

Sun B, Urban B, Bailey W. AERMOD simulation of near-field dispersion of natural gas plume from accidental pipeline rupture. Air and Waste Management Association: Health Environments: Rebirth and Renewal, New Orleans, LA, June 2006.

Bailey WH, Johnson G, Bracken TD. Method for measuring charge on aerosol particles near AC transmission lines. Joint Meeting of The Biolectromagnetics Society and The European BioElectromagnetics Association, Dublin Ireland, June 2005.

Bailey WH, Bracken TD, Senior RS. Long-term monitoring of static electric field and space charge near AC transmission Lines. The Bioelectromagnetics Society, 26th Annual Meeting, Washington, DC, June 2004.

Bailey WH, Erdreich L, Waller L, Mariano K. Childhood leukemia in relation to 25-Hz and 60-Hz magnetic fields along the Washington DC—Boston rail line. Society for Epidemiologic Research, 35th Annual Meeting, Palm Desert CA, June 2002. American Journal of Epidemiology 2002; 155:S38.

Erdreich L, Klauenberg BJ, Bailey WH, Murphy MR. Comparing radiofrequency standards around the world. Health Physics Society 43rd Annual Meeting, Minneapolis, MN, July 1998.

Bracken TD, Senior RS, Rankin RF, Bailey WH, Kavet R. Relevance of occupational guidelines to utility worker magnetic-field exposures. Second World Congress for Electricity and Magnetism in Biology and Medicine, Bologna, Italy, June 1997.

Weil DE, Erdreich LS, Bailey WH. Are 60-Hz magnetic fields cancer causing agents? Mechanisms and Prevention of Environmentally Caused Cancers, The Lovelace Institutes 1995 Annual Symposium, La Fonda, Santa Fe, NM, October 1995.

Bailey WH. Neurobiological research on extremely-low-frequency electric and magnetic fields: A review to guide future research. Sixteenth Annual Meeting of the Bioelectromagnetics Society, Copenhagen, Denmark, June 1994.

Blondin J-P, Nguyen D-H, Sbeghen J, Maruvada PS, Plante M, Bailey WH, Goulet D. The perception of DC electric fields and ion currents in human observers. Annual Meeting of the Canadian Psychological Association, Penticton, British Columbia, Canada, June 1994.

Erdreich LS, Bailey WH, Weil DE. Science, standards and public policy challenges for ELF fields. American Public Health Association 122nd Annual Meeting, Washington, DC, October 1994.

Bailey WH, Charry JM. Particle deposition on simulated VDT operators: Influence of DC electric fields. 10th Annual Meeting of the Bioelectromagnetics Society, June 1988.

Charry JM, Bailey WH. Contribution of charge on VDTs and simulated VDT operators to DC electric fields at facial surfaces. 10th Annual Meeting of the Bioelectromagnetics Society, June 1988.

Bailey WH, Charry, JM. Dosimetric response of rats to small air ions: Importance of relative humidity. EPRI/DOE Contractors Review, November 1986. Charry JM, Bailey WH, Bracken TD (eds). DC electric fields, air ions and respirable particulate levels in proximity to VDTs. International Conference on VDTs and Health, Stockholm, Sweden, June 12–15 1986.

Charry JM, Bailey WH. Air ion and DC field strengths at 10^4 ions/cm^3 in the Rockefeller University Small Animal Exposure Chambers. EPRI/DOE Contractors Review, November 1985.

Charry JM, Bailey WH. DC Electrical environment in proximity to VDTs. 7th Annual Meeting of the Bioelectromagnetics Society, June 1985.

Bailey WH, Collins RL, Lahita RG. Cerebral lateralization: Association with serum antibodies to DNA in selected bred mouse lines. Society for Neuroscience, 1985.

Kavet R, Bailey WH, Charry JM. Respiratory neuroendocrine cells: A plausible site for air ion effects. Seventh Annual Meeting of The Bioelectromagnetics Society, June 1985.

Bailey WH, Charry JM. Measurement of neurotransmitter release and utilization in selected brain regions of rats exposed to DC electric fields and atmospheric space charge. 23rd Hanford Life Sciences Symposium, Richland, WA, October 1984.

Bailey WH, Charry JM, Weiss JM, Cardle K, Shapiro M. Regional analysis of biogenic amine turnover in rat brain after exposure to electrically charged air molecules (air ions). Society for Neuroscience, 1983.

Bailey WH. Biological effects of air ions: Fact and fancy. American Institute of Medical Climatology Conference on Environmental Ions and Related Biological Effects, October 1982.

Goodman PA, Weiss JM, Hoffman LJ, Ambrose MJ, Bailey WH, Charry, JM. Reversal of behavioral depression by infusion of an A2 adrenergic agonist into the locus coeruleus. Society for Neuroscience, November 1982.

Charry JM, Bailey WH. Biochemical and behavioral effects of small air ions. Electric Power Research Institute Workshop, April 1981.

Bailey WH, Alsonso DR, Weiss JM, Chin S. Predictability: A psychologic/ behavioral variable affecting stress-induced myocardial pathology in the rat. Society for Neuroscience, November 1980.

Salman SL, Weiss JM, Bailey WH, Joh TH. Relationship between endogenous brain tyrosine hydroxylase and social behavior of rats. Society of Neuroscience, November 1980.

Bailey WH, Maclusky S. Appearance of creatine kinase isoenzymes in rat plasma following myocardial injury produced by isoproterenol. Fed Assoc Soc Exp Biol, April 1978.

Bailey WH, Maclusky S. Appearance of creatine kinase isoenzymes in rat plasma following myocardial injury by isoproterenol. Fed Proc 1978; 37:889.

Bailey WH, Weiss JM. Effect of ACTH 4-10 on passive avoidance of rats lacking vasopressin (Brattleboro strain). Eastern Psychological Association, April 1976.

Prior Experience

President, Bailey Research Associates, Inc., 1991–2000
Vice President, Environmental Research Information, Inc., 1987–1990
Head of Laboratory of Environmental Toxicology and Neuropharmacology, New York State Institute for Basic Research, 1983–1987
Assistant Professor, The Rockefeller University, 1976–1983

Academic Appointment

- Visiting Fellow, Department of Pharmacology, Cornell University Medical College, New York, NY, 1986–present

Prior Academic Appointments

- Visiting Scientist, The Jackson Laboratory, Bar Harbor, ME, 1984–1985
- Head, Laboratory of Neuropharmacology and Environmental Toxicology, NYS Institute for Basic Research in Developmental Disabilities, Staten Island, NY, 1983–1987
- Assistant Professor, The Rockefeller University, New York, NY, 1976–1983
- Postdoctoral Fellow, Neurochemistry, The Rockefeller University, New York, NY, 1974–1976
- Dissertation Research, The Rockefeller University, New York, NY, 1972–1974
- CUNY Research Fellow, Dept. of Psychology, Queens College, City University of New York, Flushing, NY, 1969–1971
- Clinical Research Assistant, Department of Psychiatry, University of Chicago; Psychiatric Psychosomatic Inst., Michael Reese Hospital, and Illinois State Psychiatric Inst, Chicago, IL, 1968–1969

Teaching Appointments

- Lecturer, University of Texas Health Science Center, Center for Environmental Radiation Toxicology, San Antonio, TX, 1998
- Lecturer, Harvard School of Public Health, Office of Continuing Education, Boston, MA, 1995, 1997
- Lecturer, Rutgers University, Office of Continuing Education, New Brunswick, NJ, 1991–1995
- Adjunct Assistant Professor, Queens College, CUNY, Flushing, NY, 1978
- Lecturer, Queens College, CUNY, Flushing, NY, 1969–1974

Editorship

- Associate Editor, Non-Ionizing Radiation, *Health Physics*, 1996–present

Advisory Positions

- ZonMw – Netherlands Organization for Health Research and Development, 2012; 2007-2008, reviewer for National Programme on EMF and Health
- US Bureau of Ocean Energy Management, Regulation and Enforcement, 2009–2010
- Canadian National Collaborating Centre for Environmental Health, reviewer of Centre reports, 2008
- Island Regulatory and Appeals Commission, province of Prince Edward Island, Canada, 2008
- National Institute of Environmental Health Sciences/ National Institutes of Health, Review Committee, Neurotoxicology, Superfund Hazardous Substances Basic Research and Training Program, 2004
- National Institute of Environmental Health Sciences, Review Committee Role of Air Pollutants in Cardiovascular Disease, 2004
- Working Group on Non-Ionizing Radiation, Static and Extremely Low-Frequency Electromagnetic Fields, International Agency for Research on Cancer, 2000–2002
- Working Group, EMF Risk Perception and Communication, World Health Organization, 1998–2005
- Member, International Committee on Electromagnetic Safety, Subcommittee 3 - Safety Levels with Respect to Human Exposure to Fields (0 to 3 kHz) and Subcommitee 4 - Safety Levels with Respect to Human Exposure (3kHz to 3GHz) Institute of Electrical and Electronics Engineers (IEEE), 1996–present
- Invited participant, National Institute of Environmental Health Sciences EMF Science Review Symposium: Clinical and In Vivo Laboratory Findings, 1998
- Working Group, EMF Risk Perception and Communication, International Commission on Non-Ionizing Radiation Protection, 1997
- U.S. Department of Energy, RAPID EMF Engineering Review, 1997
- Oak Ridge National Laboratory, 1996
- American Arbitration Association International Center for Dispute Resolution, 1995–1996
- U.S. Department of Energy, 1995
- National Institute for Occupational Safety and Health, 1994–1995
- Federal Rail Administration, 1993–1996
- U.S. Forest Service, 1993
- New York State Department of Environmental Conservation, 1993
- National Science Foundation
- National Institutes of Health, Special Study Section—Electromagnetics, 1991–1993
- Maryland Public Service Commission and Maryland Department of Natural Resources, Scientific Advisor on health issues pertaining to HVAC Transmission Lines, 1988–1989
- Scientific advisor on biological aspects of electromagnetic fields, Electric Power Research Institute, Palo Alto, CA, 1985–1989

- U.S. Public Health Service, NIMH: Psychopharmacology and Neuropsychology Review Committee, 1984
- Consultant on biochemical analysis, Colgan Institute of Nutritional Science, Carlsbad, CA, 1982–1983
- Behavioral Medicine Abstracts, Editor, animal behavior and physiology, 1981–1983
- Consultant on biological and behavioral effects of high-voltage DC transmission lines, Vermont Department of Public Service, Montpelier, VT, 1981–1982
- Scientific advisory committee on health and safety effects of a high-voltage DC transmission line, Minnesota Environmental Quality Board, St. Paul, MN, 1981–1982
- Consultant on biochemical diagnostics, Biokinetix Corp., Stamford, CT, 1978–1980

Professional Affiliations

- The Health Physics Society (Affiliate of the International Radiation Protection Society)
- Society for Risk Analysis
- International Society of Exposure Analysis
- New York Academy of Sciences
- American Association for the Advancement of Science
- Air and Waste Management Association
- Society for Neuroscience/International Brain Research Organization
- Bioelectromagnetics Society
- The Institute of Electrical and Electronics Engineers/Engineering in Medicine and Biology Society
- Conseil International des Grands Reseaux Electriques

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Yakov P. Shkolnikov, Ph.D., P.E.
Managing Engineer

Professional Profile

Dr. Shkolnikov specializes in the development and analysis of high performance electronic devices, software, and communication systems.

As the head of the software task force at Exponent, Dr. Shkolnikov assists clients in software and algorithm development, software reliability analysis, and intellectual property evaluations. Dr. Shkolnikov has extensive experience in algorithm design and has developed methods and software in such diverse areas as analysis and visualization of radiological imaging data, computer vision, machine learning, statistical data processing, testing of medical implants, instrumentation of diagnostic systems, internet-protocol (IP) based communication, and analysis of ground penetrating radar data.

He also performs reliability, verification, and validation analysis of software used in medical, automotive, desktop, and embedded applications. He has developed C / C++, LabVIEW, MATLAB, and several other script and controller languages, as well as employed tools such as auto-documenting software and static verifiers (PolySpace).

Dr. Shkolnikov also assists clients in technical analyses supporting complex litigation cases such as class action lawsuits and patent and trade secret litigation. He has experience in infringement, obviousness, and validity analysis of patents for consumer electronic devices and software. He also has assisted clients in locating prior-art and prior-use examples, and has overseen large document and software reviews inherent to such cases.

In addition, Dr. Shkolnikov evaluates and tests systems that produce or communicate via electromagnetic signals. He has experience in electromagnetic interference analysis and exposure assessments of devices and systems as varied as smart meter networks, radar installations, cell phones, radio towers, MRI machines, transmission and distribution lines, consumer electronic devices, and medical device implants.

Dr. Shkolnikov has published over 25 peer-reviewed papers on electrical engineering topics such as semiconductor physics, computer graphics, and electrical safety and has participated in numerous technical conferences on medical device analysis and semiconductors. He has a patent on the security of RFID cards, and has filed several provisional patents on cell phone power management and mechanical strain sensing. Dr. Shkolnikov holds a research faculty appointment at the School of Biomedical Engineering, Science and Health Systems at Drexel University, and is a guest lecturer at Princeton University in the Department of Mechanical & Aerospace Engineering. He is currently a referee for *Health Physics* and was also a referee for *Physical Review Letters* from 2006–2011.

Academic Credentials and Professional Honors

Ph.D., Electrical Engineering (minor in Mechanical Engineering), Princeton University, 2005
M.A., Electrical Engineering, Princeton University, 2004
B.S., Engineering Physics, Cornell University (*summa cum laude*), 1999

Graduated ranked 1st in the School of Engineering, *Summa Cum Laude*, Cornell University; Gordon Wu Fellow, Princeton University; Merrill Presidential Scholar, Cornell University; Tau Beta Pi

2010 IEEE Region 1 Award, Category 3B: Technological Innovation (Industry or Government), for the Development of Mathematical Methods for Computing Ground-Penetrating Radar to Detect Land Mines

The Institute of Electrical and Electronics Engineers/International Committee on Electromagnetic Safety, Subcommittee 4, Safety Levels with Respect to Human Exposure to Radiofrequency Fields (3 kHz to 300 GHz)

Licenses and Registrations

Licensed Professional Engineer, New Jersey, #GE47825

Patents

US Patent No. 7,936,274: Shield for Radio Frequency ID Tag or Contactless Smart Card, issued May 3, 2011 (Shkolnikov Y, Du Y, McGoran B).

Publications

Shkolnikov YP. Weighted principal component analysis for real-time background removal in GPR data. Paper in Proceedings, SPIE Defense, Security, and Sensing Symposium, Vol 8357, June 2012.

Shkolnikov YP, Bailey WH. Electromagnetic interference and exposure from household wireless networks. 2011 IEEE Symposium on Product Compliance Engineering (PSES), October 2011.

Shkolnikov YP, Bowden A, MacDonald D, Kurtz SM. Wear pattern observations from TDR retrievals using autoregistration of voxel data. J Biomed Mater Res B Appl Biomater 2010 August; 94(2):312–317.

Kurtz SM, Ochoa JA, Lau E, Shkolnikov Y, Pavri BB, Frisch D, Greenspon AJ. Implantation trends and patient profiles for pacemakers and implantable cardioverter defibrillators in the United States: 1993–2006. PACE 2009. doi: 10.1111/j.1540-8159.2009.02670.

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Guest Lectures

Shkolnikov YP. Electricity and the human body. Mechanical Engineering, Princeton University, Princeton, NJ, November 22, 2011, April 8, 2010, April 9, 2009, and 2007.

Shkolnikov YP. Got risk? Managing risk and reliability in modern technology. Cornell Club of Central New Jersey, Princeton, NJ, December 4, 2009.

Villarraga M, Shkolnikov YP. Medical device failure analysis during the design process. Department of Biomedical Engineering, Drexel University, Philadelphia, PA, May 6, 2009.

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Shkolnikov YP, Villarraga M. Introduction to electrophysiology. Mechanical Engineering, Princeton University, Princeton, NJ, 2007.

Shkolnikov YP, Villarraga M. Failure analysis during the design process of medical devices. Compliance Online, 2007.

Shkolnikov YP, Villarraga M. Medical device failure analysis during the design process. Department of Biomedical Engineering, Drexel University, Philadelphia, PA, 2007.

Academic Appointments

Visiting Research Professor, School of Biomedical Engineering, Drexel University, 2005–2011

Peer Review

- Referee for *Health Physics*
- Past Referee for *Physical Review Letters,* 2006–2011

Professional Affiliations

- Senior member, Institute of Electrical and Electronics Engineers—IEEE
- Member, International Society for Optics and Photonics—SPIE

Project Experience

Computer Architecture and Networks

- Analysis of computer networks including Internet, WAN, LAN, and smart meter networks
- Analysis of shared memory architecture for mobile computer devices
- Analysis of interrupt handling scheme in mobile processors.
- Software source code analysis (C, C++, Assembly) to identify vulnerabilities and errors in code
- Shielding and interference from RFID and related devices
- Intellectual property/patent investigations semiconductors, software, internet and telephony equipment
- Scalability analysis and improvement of IPTV systems
- Prior art and prior use searches for video game, consumer products, testing equipment and other electronic products
- Patent portfolio review and technical due diligence
- Memory technology analysis and reverse engineering
- Reconstruction of physical geometry and zone mapping of hard drives

Machine Learning, Signal Processing, and Computational Science

- Design of 2D/3D image processing and machine learning algorithms
- Statistical signal processing
- Detection algorithms
- GPGPU software development
- Computer graphics software use and algorithm development
- Analysis of GPU hardware reliability
- Analysis of patent infringement in computer graphics, image processing, and hardware design

Health, Safety, and Medical Products

- Compliance assessment per 47CFR1.1307, 47CFR1.1310, IEEE C95.1, IEEE C95.6, IEC 60601-1-2, IEC 60479-1, ICNIRP 1998, ICNIRP 2010, and other RF and electrical health and safety standards
- Electric shock and electrocution investigations
- Software and methodology development for analysis of FTIR, small punch, tensile testing, tissue property testing, radiological images, and field-testing data
- Assistance in technology transfer product development for biological weapons detection
- Design development, review, and analysis for medic diagnostic equipment companies
- Source code review and modeling to identify failure mode in medical device software
- Failure analysis in medical products including diagnostic equipment, surgical equipment, and implants
- EMI and EMC evaluation of medical products
- Electric and magnetic field exposure and heating from transmission and distribution lines
- Medical products intellectual property analysis
- Risk assessment and FMEA analysis
- Reverse engineering analysis of diagnostic equipment
- Technical analysis of implantable cardioverter defibrillators (ICD), infusion pumps, pacemakers, implantable pulse generators (IPGs), orthopedic implants, blood flow meters, electrosurgical and robotic equipment
- Electromagnetic finite element analysis (AC/DC and RF) of installations

Computer Forensics and Security

- Verification of integrity of the produced digital images: Metadata analysis, image content analysis, photogrammetric analysis
- Enhancement, recovery, and analysis of video surveillance data
- Recovery and analysis of EPROM memory data relating to construction accident
- Data snooping and interception
- Development of automated text and document analysis tools

- Development of technology to secure contents of smart cards
- Security analysis of payment card shipment method
- Security analysis of a data storage and review facility
- Security product performance evaluation
- Validation of hard-drive data sanitization procedure
- Restoring damaged data
- Analysis of wireless transmission systems including encryption, anti-jamming, and error correction

Reliability

- Hardware in the loop testing and probing of microprocessor to identify malfunction
- Electromagnetic finite element analysis (FEA) of components, products, machines, RF exposure, electric shock hazard, reliability, electrostatic discharge, and effects of defects in manufacture and materials
- Electromagnetic interference with the function of GPS systems
- Shielding and interference from RFID and related devices
- Analysis of software and hardware component reliability of automotive products
- Analysis of RF emissions for purposes of a recall decision
- Product misuse investigations

Acoustic Analysis

- Forensic analysis of acoustic data, speech enhancement and other audio data processing, audio acquisition system design and evaluation, waveform/spectral based hearing damage assessment

Semiconductors

- Solid-state sensor design
- Semiconductor packaging design, processing, and failure analysis
- Semiconductor physics
- Intellectual property analysis of fabrication processes, semiconductor materials and devices
- Fiber optic systems
- Low electrical noise systems and data acquisition

Cryogenics, Vacuum, and Magnetic Systems

- Operation and design of cryogenic systems
- Operation, control and design of electromagnetic and permanent magnet systems
- Operation and service of high and ultra high vacuum equipment, systems, and pumps

FORTIS BC™

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Dear :

Thank you for your correspondence regarding FortisBC's Advanced Metering Infrastructure (AMI) project proposed by FortisBC Inc. (FortisBC or We). Your input is important to us.

FortisBC believes that advanced meters will provide numerous benefits to our customers. Those include:

- Significant financial savings to customers over the life of the project
- More detailed electricity use information available to customers to help them manage their bills
- Immediate detection of power outages, thereby allowing FortisBC for more effective restoration of electricity to customers
- Enhanced ability for FortisBC to detect electricity theft, thereby reducing associated safety risks and resulting in cost savings to customers
- Reduction for FortisBC of the number of vehicles it requires for meter reading, resulting in lower operational expenses and eventually cost savings for customers and less greenhouse gas emissions

FortisBC intends to obtain a Certificate of Public Convenience and Necessity for the AMI project from the British Columbia Utilities Commission (the Commission or BCUC) and is currently in the process of finalizing its application to the Commission. Once this application is filed, we will go through a public regulatory process before the Commission that will end with the Commission providing a decision on whether or not we receive a CPCN for, and can proceed with, the AMI project. Customers interested in learning more about the Commission or the regulatory process can visit www.bcuc.com.

FortisBC understands that some of our customers may have certain concerns regarding advanced meters. With respect to health concerns related to electromagnetic fields (EMF), the emission levels from the advanced meters will be below regulated levels set by Health Canada (Safety Code 6). Furthermore, BC's Provincial Health Officer and the BC Cancer Agency have stated that current research does not show that advanced meters present any health hazard. A copy of this statement can be found at the Ministry of Health (http://www.health.gov.bc.ca/pho/issues.html). FortisBC relies upon the expertise of these authorities to assess the health impact of EMF from advanced meters.

Specific to the AMI project proposed by FortisBC, we have commissioned an independent consultant to provide a study on the safe operation of the advanced

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meters to be installed in FortisBC's service areas. His study, based on peer reviewed research, concludes:

> "The advanced meters utilized by FortisBC will operate in compliance with the regulations of Health Canada. Exposure to RF energy will be far below the exposure limits recommended by Health Canada, and those of ICNIRP and other scientific and regulatory agencies. In this report, recent scientific research regarding cancer and symptoms has been summarized to determine whether it might suggest adverse effects at levels below exposure limits recommended by these organizations. The reviews and the recently published research with improved exposure information do not provide a reliable scientific basis to conclude that the operation of the advanced meters will cause or contribute to adverse health effects or physical symptoms in the population."

If you would like to learn more about magnetic fields, please visit the World Health Organization web site at http://www.who.int/peh-emf/about/WhatisEMF/en/index.html.

FortisBC's goal throughout the AMI project is to communicate with customers and the public about the merits of advanced meters and to address customers' and the public's concerns to our best ability. To help the customers and the public better understand the AMI project, FortisBC has developed a webpage at www.fortisbc.com/ami where you can find Frequently Asked Questions (FAQ), and general updates regarding the AMI project as it progresses through the regulatory process before the BCUC and during the implementation phase.

Sincerely,

Ian Dyck
Manager, Electricity Advanced Metering Infrastructure

Data Sheet

Cisco 1000 Series Connected Grid Routers

The Cisco® 1000 Series Connected Grid Routers (CGR 1000 Series) are versatile communications platforms purpose-built to meet the communication infrastructure needs of electric, gas and water utilities. The multi-service capabilities of these platforms allow customers to converge multiple applications such as Advanced Metering Infrastructure (AMI), Distribution Automation (DA), Integration of Distributed Energy Resources (DER) and Remote Workforce Automation on to a single platform.

The CGR 1000 Series is the latest addition to Cisco's Connected Grid portfolio designed for utilities to provide a highly secure, reliable, and scalable communication infrastructure. These ruggedized products are certified to meet harsh environmental standards, including IEEE 1613 and IEC 61850. The CGR 1000 platforms supports wireless network interfaces such as IEEE 802.15.4 g/e wireless personal area network (WPAN), 2G/3G cellular and IEEE 802.16e WiMAX.

The Cisco CGR 1000 routers are powered by Connected Grid Operating System (CG-OS) that is built upon Cisco's world class networking technologies and adapted to the needs of energy utilities. This software delivers grid operators with the benefits of open standards-based, multi-service networking, strong network security, robust manageability, and high reliability. The distributed intelligence capabilities integrated into CG-OS software allows customers to run applications such as Supervisory Control and Data Acquisition (SCADA) protocol translation on the routers directly eliminating the need for additional device.

The Cisco CGR 1000 Series offers two platforms, shown in Figure 1. They include: The Cisco 1120 Connected Grid Router (CGR 1120), which is designed for indoor deployments; and the Cisco 1240 Connected Grid Router (CGR 1240), which is a weatherproof router in a NEMA Type 4 enclosure for outdoor deployments.

Figure 1. Cisco 1000 Series Connected Grid Routers

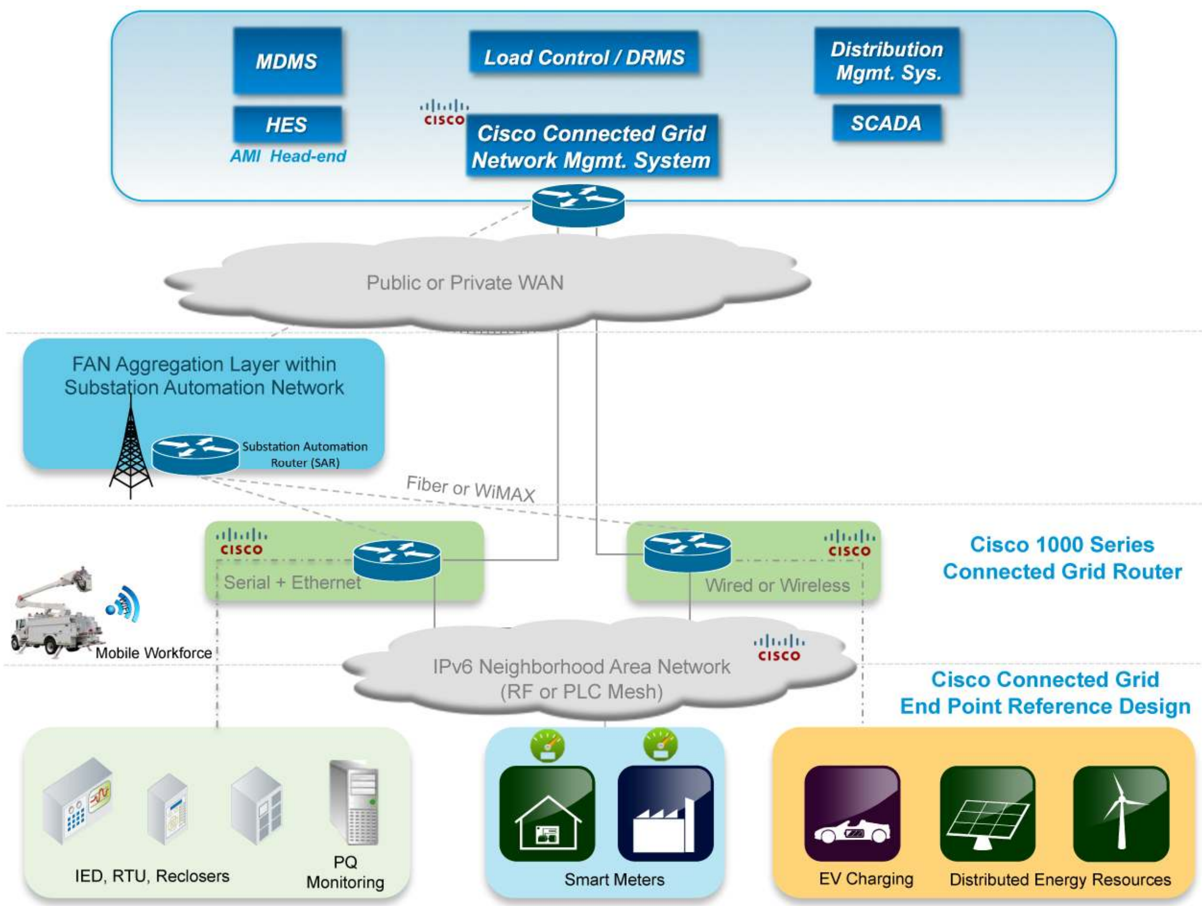
Connected Grid FAN Solution and CGR 1000 Series

Utilities all over the world are undergoing significant transition in their grids—from transmission to consumption. Regulatory mandates are advancing initiatives around smart metering, grid reliability, and integration of solar and wind farms into the distribution grid. This in turn, imposes a unique set of challenges for utilities to build a bi-directional communications field area network (FAN) that enables these diverse applications and also scales across millions of endpoints.

Cisco's Connected Grid FAN solution has been specifically developed to meet these challenges, using design principles from industry-leading Cisco GridBlocks architecture. Under the GridBlocks architecture, a typical communications network for the distribution grid is a two-tier architecture with Neighborhood Area Network (NAN) and Wide Area Network (WAN).

The NAN provides network connectivity to end points such as smart meters and DA devices. These endpoints form a mesh network based on radio frequency (RF) or power-line communications (PLC) technologies. The mesh network is aggregated at an intelligent device such as a field area router (FAR) mounted on pole-tops or in secondary substations. The WAN tier provides network connectivity from the FAR to the utility's control center over either a public 2G/3G network, or over a utility-owned (private) WiMAX or Ethernet fiber network. Figure 2 displays the solution's inclusion within the network.

Figure 2. Cisco Connected Grid Field Area Network Solution



The Connected Grid FAN solution comprises of the following products: Cisco 1000 Series Connected Grid Routers, Connected Grid Device Manager (CG-DM), Connected Grid Network Management System (CG-NMS) and Connected Grid End Point reference design (CG-EP), an open standards-based IPv6 networking stack that can be embedded in a variety of smart grid end points, such as smart meters.

Finally, CG-NMS is a software platform for managing multi-service communication networks and security infrastructure for smart grids. CG-NMS is a scalable, secure, modular open platform with pluggable architecture designed to help enable an ecosystem of multi-vendor capabilities for interoperability across not only communications networks, but also legacy and next-generation power grid equipment, over time.

Primary Business Benefits and Architectural Features

The CGR 1000 Series Routers leverage Cisco's core IP networking technologies with purpose-built hardware and software to create an open platform for utilities to build multi-service, secure and reliable Field Area Network that lowers their total cost of ownership.

Converged Multi-Service Network Architecture

The CGR 1000 Series is a flexible modular platform supporting various wired and wireless interfaces. The CGR 1000 Series router supports a 900 MHz IPv6 RF Mesh that can aggregate up to 5,000 end devices such as smart meters. The router has integrated ethernet and serial interfaces to connect to DA devices such as sensors, capacitor bank controllers, recloser controllers, and remote terminal units. SCADA protocol (serial to IP) translation features allow customers to easily integrate legacy (non-IP) devices on to an IP network. Integrated Wi-Fi port enables remote workforce automation and secure wireless console access while integrated GPS enables location mapping of the router. The modular design provides an easy upgrade path to future communication interfaces without platform replacement.

The CGR 1000 Series portfolio of routers offers platforms for both indoor and outdoor deployments. These platforms come with flexible mounting kits that allow utilities to deploy the routers on a broad array of existing assets such as distribution poles, walls, and inside pad-mounted enclosures. In addition, the CGR 1000 Series offers a wide range of external antenna choices to meet coverage, throughput, and range requirements.

Connected Grid OS provides a set of network and application layer services to help enable customers run multiple applications on a converged communication network. The network segmentation and quality of service (QoS) features allow customers to logically separate different application traffic and to apply specific constraints on each traffic flow. In addition, CG-OS is capable of integrating and hosting utility-specific third-party applications. This allows customers to eliminate cost, space, power, and complexity of deploying and managing single-purpose devices. Customers can also add more applications over time to meet future business needs.

Security

Cisco integrates security as a fundamental building block of the field area network (FAN) architecture. The CGR 1000 Series offers strong security capabilities that are based on Cisco's Connected Grid security principles and widely adopted cryptographic and security standards.

Security Principle	CGR 1000 Features and capabilities
Access Control	• Mutual authentication and authorization of all nodes connected to the network • IEEE 802.1x-based authentication, Role-Based Access Control • Certificate-based identity, strong username and passwords

Data Integrity, Confidentiality and Privacy	• Link-layer encryption in the NAN mesh (AES-128) • Network-layer encryption in the WAN (IPsec) • Scalable key management – generation, exchange & revocation of encryption keys
Threat Detection and Mitigation	• Network segmentation of users, devices and applications in NAN and WAN • Access-lists on field area router to filter traffic between users and devices • High-performance firewall in the control-center to protect critical assets
Device and Platform Integrity	• Tamper-resistant mechanical design, security alerts generated if compromised • Hardware chip to store router's X.509 certificate, other security credentials • Tamper-proof secure storage of router configuration and data

Network Reliability and High Availability

The CGR 1000 Series Routers have been designed with both device level and network level reliability to meet harsh physical environments. The CGR 1000 Series is built to meet stringent compliance standards such as IEEE 1613 and IEC 61850-3. The enhanced thermal design and conduction cooling with no moving parts allows support for extended temperature support. Additionally, the routers offer mechanisms for backup power to help ensure uptime for mission-critical applications in the event of power outages. Finally, the support for multiple WAN communication modules, and the network resiliency and routing features in CG-OS, allows utilities to deploy enterprise-class high availability in their communication networks for the distribution grid.

Network Management

A complete suite of network management tools is critical for lowering operating expenses (OpEx) while improving network availability. They do so by simplifying and automating many of the day-to-day tasks associated with managing such challenging network requirements. The embedded management features available in the CGR 1000 Series, Connected Grid Device Manager (CG-DM), and the Connected Grid Network Management System (CG-NMS) allow customers to effectively meet these requirements.

The Cisco FAN solution provides operators with extensive instrumentation and diagnostic information for geographic locations, wireless interfaces, battery management, and other grid-specific details. This information can be fed into the CG-NMS for day-to-day operations, operator dashboards, and real-time troubleshooting. Ease-of-use features such as secure zero touch deployment and a graphical field tool help enable non-IT field technicians to deploy and manage FAN communication equipment effectively. In addition to the utility-specific functionality, the Cisco solution provides customers with true enterprise-class fault, configuration, accounting, performance, and security (FCAPS) functionality such as a programmatic XML interface based on the Network Configuration Protocol (NETCONF) industry standard, Role-Based Access Control (RBAC), over-the-air software upgrades, and security management functionality.

Open Standards

Cisco's strategy is to encourage the creation and adoption of open communication standards for the smart grid. This in turn encourages the growth of an ecosystem of standards-based, interoperable devices and applications from different vendors while reducing the risk of adopting new technologies for utilities.

The Cisco Connected Grid solution is based on a series of open standards, many of them adopted from IP-based technologies such as IPv6. By use of these standards, customers are able to architect and design their network independent of the application layer or physical layer infrastructure. This protects any existing investment while lowering the total cost of ownership for the network over time.

Cisco Connected Grid Modules for CGR 1000 Series

There is not a single technology—wireless or wireline—that will be able to satisfy utilities' requirements for field area network applications. Different technologies may offer the best solution in terms of geography, performance, cost and other constraints, such as regulation, existing and planned infrastructure, coverage and SLA requirements. Customers also need the flexibility to upgrade to new communication technologies in the future while protecting their investment in the platforms deployed today. The CGR 1000 Series routers meet these requirements by use of module slots that accommodate Connected Grid Modules (CGM) offering a diverse range of connectivity options. Table 1 identifies Connected Grid Modules for the CGR 1000 Series.

Table 1. Connected Grid Modules for CGR 1000 Series

Connected Grid Module (CGM) Slots	• The CGR 1120 accommodates 2 modules • The CGR 1240 accommodates 4 modules
Connected Grid Modules (CGM) Families	• IEEE 802.15.4g/e WPAN (900 MHz RF Mesh) • Cellular: 2G/3G (Global System for Mobile Communications [GSM] and Code Division Multiple Access [CDMA]) • IEEE 802.16e WiMAX

Cisco's Connected Grid Wireless Personal Area Network (WPAN) Module

Cisco's Wireless Personal Area Network (WPAN) Connected Grid Module provides utilities with an IPv6 based, IEEE 802.15.4 g/e compliant wireless connectivity solution for FAN Applications. The CGR1000 series provides dynamic network discovery and self-healing networking. In addition, the multi-hop mesh networking provides a high endpoint to collector ratio. Table 2 outlines the RF characteristics of the Cisco Connected Grid Module—WPAN.

Table 2. Technical Specifications of Connected Grid WPAN Module

Channels	902-928 MHz unlicensed ISM
Frequency Hopping Spread Spectrum (FHSS)	64 channels, 400 KHz per channel
Transmitter Power	26 dBm
Link Budget	Over 134 dB
Receiver Sensitivity	-112 dBm
Standards Compliance	• IEEE 802.15.4 g/e • IETF 6LOWPAN • IPv6 • IETF RPL.
Robust Security	• AES 128-bit encryption • IEEE 802.1x

Cisco Connected Grid Third-Generation (3G) Cellular Module

Cisco's Connected Grid 3G Cellular Module for the Cisco 1000 Series Connected Grid Routers supports the latest 3G standards (High-Speed Packet Access [HSPA] and Evolve-Data Optimized [EVDO] Rev A) and is backward-compatible with Universal Mobile Telecommunications Service (UMTS), Enhanced Data Rates for Global Evolution (EDGE), General Packet Radio Service (GPRS), and EVDO Rev 0/1xRTT. The 3G modules have two variants:

- Global System for Mobile Communications (GSM) and UMTS version is based on 3G Partnership Project (3GPP), and supports HSPA (High-Speed Uplink Packet Access (HSUPA) and High-Speed Downlink Packet Access (HSDPA)), UMTS, EDGE, and GPRS

- Code Division Multiple Access (CDMA) version is based on 3GPP2, and supports EVDO Rev A/Rev 0 and 1xRTT

Table 3 lists the 2G/3/G cellular Connected Grid Modules for the CGR 1000 Series

Table 3. 2G/3G Cellular Connected Grid Modules for CGR 1000 Series

Cisco Connected Grid Module 3G GSM Module: **CGM-3G-HSPA**	• HSPA+: 850, 900, 1900, and 2100 MHz (forward link up to 7.2 Mbps; reverse link up to 2.0 Mbps) • Backward compatibility: ◦ HSDPA: 850, 1900, and 2100 MHz (forward link up to 7.2 Mbps; reverse link up to 384 kbps) ◦ UMTS: 850, 900, 1900, and 2100 MHz (forward link up to 2.0 Mbps; reverse link up to 384 kbps) ◦ EDGE: 850, 900, 1800, and 1900 MHz (forward link up to 236 kbps; reverse link up to 124 kbps) • GPRS: 850, 900, 1800, and 1900 MHz (forward link up to 80 kbps; reverse link up to 42 kbps)
Cisco Connected Grid Module 3G CDMA Module: **CGM-3G-EVDO**	• CDMA 1xEV-DO Rev A (forward link up to 3.1 Mbps; reverse link up to 1.8 Mbps) • Backward compatibility: ◦ CDMA 1xEV-DO Rel 0 (forward link up to 2.4 Mbps; reverse link up to 153.6 kbps) • CDMA 1xRTT (forward link up to 153.6 kbps; reverse link up to 153.6 kbps)

Cisco's Connected Grid WiMAX Modules

Cisco's IEEE 802.16e-compliant WiMAX Connected Grid Module for the CGR 1000 routers provides utilities with reliable, robust, and secure connectivity solutions. WiMAX has been deployed by utilities worldwide as an alternative to using a service provider-based 2G/3G cellular network. A WiMAX based solution provides the utility network managers with greater control over the communication network infrastructure, deployment, management, and performance. Table 4 displays the Technical specifications of the Cisco Connected Grid WiMAX Modules.

Table 4. Technical Specifications of Connected Grid WiMAX Modules

Access Scheme	IEEE802.16e-2009
Operation Mode	TDD
Frequency Spectrum	Choice of flexible spectrum offerings in the licensed, lightly licensed and unlicensed bands • CGM-WIMAX-1.8GHZ: 1.8 GHz Band: 1800-1830 MHz • CGM-WIMAX-2.3GHZ: 2.3 GHz Band: 2300–2400 MHz • CGM-WIMAX-2.5GHZ: 2.5 GHz Band: 2496–2690 MHz • CGM-WIMAX-3.4GHZ: 3.4 GHz Band: 3300–3600 MHz • CGM-WIMAX-3.6GHZ: 3.6 GHz Band: 3500–3800 MHz
Channel Bandwidth	3.5, 5.0, 10 MHz
Output Power (Average)	23 dBm for 64QAM 5\6
Transport Options	• IP CS • ETH CS
Standards Based WIMAX Security	• PMKv2 • AES-128 • EAP-TLS • Support for X.509 digital certificates
QoS	Five (5) QoS classes: UGS, RT, eRT, nRT, BE
Modem Diagnostics	Tx power, received signal strength indication (RSSI), carrier-to-interference-plus-noise-reduction (CINR), modem state, base station ID (if connected), frequency (if connected)
Base Station Scanning	Configurable list of base stations (up to 10 base stations)

Cisco 1000 Series Connected Grid Routers Specifications

Table 5 lists hardware specifications and Table 6 lists the software features for the CGR 1000 Series routers

Table 5. Cisco CGR 1000 Series Hardware Specifications

	CGR 1240 (Pole-mount)	CGR 1120 (Din-rail Mount)
Physical Specifications		
Dimensions (H x W x D)	28.7 cm x 24.6 cm x 21.6 cm 11.3 in. x 9.7 in. x 8.5 in. (without Antennas)	8.9 cm x 22.9 cm (W) x 20 cm 3.5 in. x 9.0 in. x 7.8 in.
Rack Height	N/A	2 RU
Pole Mount	Yes	No
Wall-mount	Yes	Yes
Din-rail Mount	No	Yes
Typical Weight Fully Configured	23 lbs (10.4 kg) Unit weight includes base chassis with four communication modules, AC power supply, and 8-Amp-hr battery backup unit	8 lbs (3.6 kg) Unit weight includes base chassis with four communication modules, AC power supply, and 8-Amp-hr battery backup unit
Operating Temperature[1]	-40℃ to +70℃ (-40℉ to 158℉) with type test to 85℃ (185℉) for 16 hours	-25℃ to +60℃ (-25℉ to 140℉) with type test up to 85℃ (185℉) for 16 hours
Communication Modules		
IEEE 802.15.4 WPAN[2]	Yes	Yes
3.5G AT&T HSPA+/UMTS/GSM/GPRS/EDGE	Yes	Yes
3.5G (Non-US) HSPA+/UMTS/GSM/GPRS/EDGE	Yes	Yes
CDMA EV-DO Rev A/0/1xRTT—Verizon	Yes	Yes
CDMA EV-DO Rev A/0/1xRTT—Sprint[2]	Yes	Yes
CDMA EV-DO Rev A/0/1xRTT—Generic[2]	Yes	Yes
WiMAX: IEEE 802.16e- 2.3 GHz	Yes	Yes
WiMAX: IEEE 802.16e- 3.6 GHz[2]	Yes	Yes
WiMAX: IEEE 802.16e- 1.8 GHz[2]	Yes	Yes
WiMAX: IEEE 802.16e- 3.4 GHz[2]	Yes	Yes
WiMAX: IEEE 802.16e- 2.5 GHz[2]	Yes	Yes
On-board Interfaces		
Gigabit Ethernet Combination Ports (10/100/1000 Copper, 100/1000 SFP)	2	2
10 /100 Fast Ethernet Copper Ports	4	6
Wi-Fi (IEEE 802.11 b/g/n)	Yes (Autonomous)	Yes (Autonomous)
Serial (RS-232/RS-485)[2]	2	2
GPS for Location	Yes	Yes
IRIG-B[3]	BNC connector	No
Digital Alarm Inputs[3]	2	4
Digital Alarm Outputs[3]	2	1
USB Type A host ports[3]	2	1
Console and AUX Port (RJ-45)	1	1

[1] Operating temperature range is impacted by choice of communication modules and battery backup options.
[2] Target Availability: 2H CY2012
[3] Interfaces built into platform hardware. Software support in future release

	CGR 1240 (Pole-mount)	CGR 1120 (Din-rail Mount)
SD Flash Slot (Memory)	1 (2 GB)	1 (2 GB)
Power Options		
Power Supply	AC Power supply: • 100 - 240 VAC	Integrated AC/DC power supply: • 3-phase AC power supply: 100 - 240 VAC • 9-60 VDC
Battery Backup Options[4] [5]	Integrated battery backup unit (BBU) and smart charging and monitoring system. • Run time: 8 hours • Estimated life: 5 years	N/A
Power Options for Third-Party Radios	The CGR 1240 provides support for powering third-party radios: • Voltage output: 12VDC ± 5 percent • Power output: 12 W (continuous)	N/A
Regulatory Compliance		
Environmental Compliance	• IEC-61850-3 • IEEE1613	• IEC-61850-3 • IEEE1613
Immunity	• EN61000-6-2 • EN61000-4-2 (ESD) • EN61000-4-3 (RF) • EN61000-4-4 (EFT) • EN61000-4-5 (SURGE) • EN61000-4-6 (CRF) • EN61000-4-11 (VDI) • EN 55024, CISPR 24 • EN50082-1	• EN61000-6-2 • EN61000-4-2 (ESD) • EN61000-4-3 (RF) • EN61000-4-4 (EFT) • EN61000-4-5 (SURGE) • EN61000-4-6 (CRF) • EN61000-4-11 (VDI) • EN 55024, CISPR 24 • EN50082-1
EMC	• 47 CFR, Part 15 • ICES-003 Class A • EN55022 Class A • CISPR22 Class A • AS/NZS 3548 Class A • VCCI V-3 • CNS 13438 • EN 300-386	• 47 CFR, Part 15 • ICES-003 Class A • EN55022 Class A • CISPR22 Class A • AS/NZS 3548 Class A • VCCI V-3 • CNS 13438 • EN 300-386
Safety	• USA: UL 60950-1 • Canada: CAN/CSA C22.2 No. 60950-1 • Europe: EN 60950-1 • China: GB 4943 • Australia/New Zealand: AS/NZS 60950.1 • Rest of World: IEC 60950-1 • UL certified to UL/CSA 60950-1, 2nd Ed. • CB report to IEC60950-1, 2nd Ed., covering all group differences and national deviations.	• USA: UL 60950-1 • Canada: CAN/CSA C22.2 No. 60950-1 • Europe: EN 60950-1 • China: GB 4943 • Australia/New Zealand: AS/NZS 60950.1 • Rest of World: IEC 60950-1 • UL certified to UL/CSA 60950-1, 2nd Ed. • CB report to IEC60950-1, 2nd Ed., covering all group differences and national deviations.

Table 6. Cisco Connected Grid Router Network Services: Features and Protocols Support

Protocols
IPv4, IPv6, Static Routes, Open Shortest Path First (OSPF)
Multicast: Internet Group Management Protocol (IGMPv3), Protocol Independent Multicast (PIM)

[4] Run time calculated based on router configuration with two (2) communications modules (WPAN and 2G / 3G). Actual battery time will vary depending on several factors, including traffic volume, the number of radios installed, temperature, and auxiliary device power draw.
[5] All measurements for battery capacity, run time and estimated life assume ambient temperature of 25ºC

IPSec, Generic Routing Encapsulation (GRE), DHCP
IEEE 802.15.4[6], IETF 6LOWPAN[6], IETF RPL[6], IETF CoAP[6]
Ethernet, Serial (RS-232/485)[6]
SCADA Protocol Support: IEC 60870-5-101/104[6]
Security
Encryption: IPSec VPN, Key-based Mesh Encryption, WPA2 for WiFi
Device Identity: IEEE 802.1AR
Role-based Access Control for Device Configuration
L3-L4 ACLs
Authentication, Authorization: EAP TLS
Mesh Security Solution[6]
QoS
Classification and Marking: ACLs, Layer3-IP Precedence, Differentiated Services Code Point (DSCP)
Congestion Management: Priority Queuing (PQ)
Embedded Management
Programmatic XML Interface (NETCONF), HTTPS, SSH
Secure Zero Touch Deployment
Battery Health Monitoring (n/a for CGR 1120)
Door Tamper Detection

For More Information

For more information on the Cisco 1000 Series Connected Grid Routers visit http://www.cisco.com/go/cgr1000

For more information on the Cisco Field Area Network solution visit http://www.cisco.com/go/fan

[6] Target Availability: 2H CY2012

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Data Sheet

Cisco 1000 Series Connected Grid Routers

The Cisco® 1000 Series Connected Grid Routers (CGR 1000 Series) are versatile communications platforms purpose-built to meet the communication infrastructure needs of electric, gas and water utilities. The multi-service capabilities of these platforms allow customers to converge multiple applications such as Advanced Metering Infrastructure (AMI), Distribution Automation (DA), Integration of Distributed Energy Resources (DER) and Remote Workforce Automation on to a single platform.

The CGR 1000 Series is the latest addition to Cisco's Connected Grid portfolio designed for utilities to provide a highly secure, reliable, and scalable communication infrastructure. These ruggedized products are certified to meet harsh environmental standards, including IEEE 1613 and IEC 61850. The CGR 1000 platforms supports wireless network interfaces such as IEEE 802.15.4 g/e wireless personal area network (WPAN), 2G/3G cellular and IEEE 802.16e WiMAX.

The Cisco CGR 1000 routers are powered by Connected Grid Operating System (CG-OS) that is built upon Cisco's world class networking technologies and adapted to the needs of energy utilities. This software delivers grid operators with the benefits of open standards-based, multi-service networking, strong network security, robust manageability, and high reliability. The distributed intelligence capabilities integrated into CG-OS software allows customers to run applications such as Supervisory Control and Data Acquisition (SCADA) protocol translation on the routers directly eliminating the need for additional device.

The Cisco CGR 1000 Series offers two platforms, shown in Figure 1. They include: The Cisco 1120 Connected Grid Router (CGR 1120), which is designed for indoor deployments; and the Cisco 1240 Connected Grid Router (CGR 1240), which is a weatherproof router in a NEMA Type 4 enclosure for outdoor deployments.

Figure 1. Cisco 1000 Series Connected Grid Routers

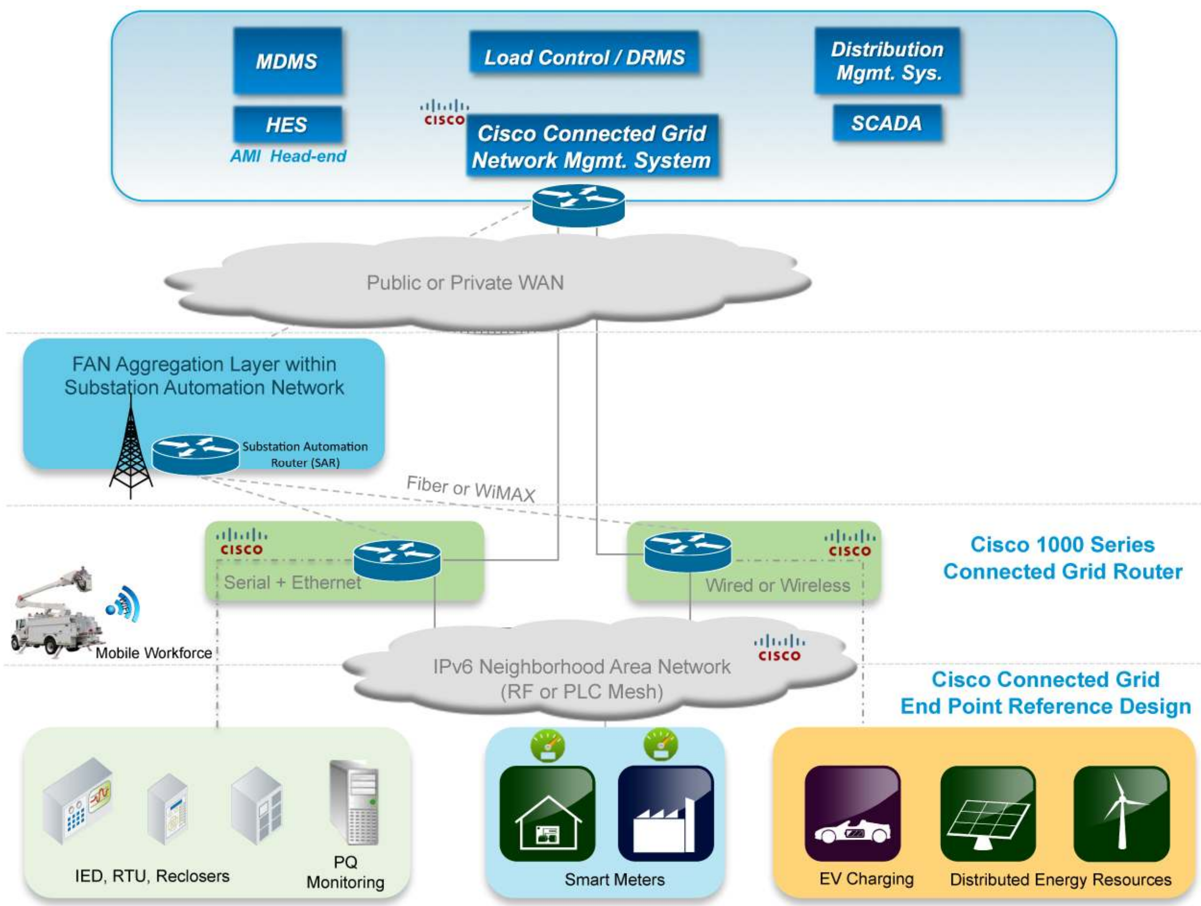
Connected Grid FAN Solution and CGR 1000 Series

Utilities all over the world are undergoing significant transition in their grids—from transmission to consumption. Regulatory mandates are advancing initiatives around smart metering, grid reliability, and integration of solar and wind farms into the distribution grid. This in turn, imposes a unique set of challenges for utilities to build a bi-directional communications field area network (FAN) that enables these diverse applications and also scales across millions of endpoints.

Cisco's Connected Grid FAN solution has been specifically developed to meet these challenges, using design principles from industry-leading Cisco GridBlocks architecture. Under the GridBlocks architecture, a typical communications network for the distribution grid is a two-tier architecture with Neighborhood Area Network (NAN) and Wide Area Network (WAN).

The NAN provides network connectivity to end points such as smart meters and DA devices. These endpoints form a mesh network based on radio frequency (RF) or power-line communications (PLC) technologies. The mesh network is aggregated at an intelligent device such as a field area router (FAR) mounted on pole-tops or in secondary substations. The WAN tier provides network connectivity from the FAR to the utility's control center over either a public 2G/3G network, or over a utility-owned (private) WiMAX or Ethernet fiber network. Figure 2 displays the solution's inclusion within the network.

Figure 2. Cisco Connected Grid Field Area Network Solution



The Connected Grid FAN solution comprises of the following products: Cisco 1000 Series Connected Grid Routers, Connected Grid Device Manager (CG-DM), Connected Grid Network Management System (CG-NMS) and Connected Grid End Point reference design (CG-EP), an open standards-based IPv6 networking stack that can be embedded in a variety of smart grid end points, such as smart meters.

Finally, CG-NMS is a software platform for managing multi-service communication networks and security infrastructure for smart grids. CG-NMS is a scalable, secure, modular open platform with pluggable architecture designed to help enable an ecosystem of multi-vendor capabilities for interoperability across not only communications networks, but also legacy and next-generation power grid equipment, over time.

Primary Business Benefits and Architectural Features

The CGR 1000 Series Routers leverage Cisco's core IP networking technologies with purpose-built hardware and software to create an open platform for utilities to build multi-service, secure and reliable Field Area Network that lowers their total cost of ownership.

Converged Multi-Service Network Architecture

The CGR 1000 Series is a flexible modular platform supporting various wired and wireless interfaces. The CGR 1000 Series router supports a 900 MHz IPv6 RF Mesh that can aggregate up to 5,000 end devices such as smart meters. The router has integrated ethernet and serial interfaces to connect to DA devices such as sensors, capacitor bank controllers, recloser controllers, and remote terminal units. SCADA protocol (serial to IP) translation features allow customers to easily integrate legacy (non-IP) devices on to an IP network. Integrated Wi-Fi port enables remote workforce automation and secure wireless console access while integrated GPS enables location mapping of the router. The modular design provides an easy upgrade path to future communication interfaces without platform replacement.

The CGR 1000 Series portfolio of routers offers platforms for both indoor and outdoor deployments. These platforms come with flexible mounting kits that allow utilities to deploy the routers on a broad array of existing assets such as distribution poles, walls, and inside pad-mounted enclosures. In addition, the CGR 1000 Series offers a wide range of external antenna choices to meet coverage, throughput, and range requirements.

Connected Grid OS provides a set of network and application layer services to help enable customers run multiple applications on a converged communication network. The network segmentation and quality of service (QoS) features allow customers to logically separate different application traffic and to apply specific constraints on each traffic flow. In addition, CG-OS is capable of integrating and hosting utility-specific third-party applications. This allows customers to eliminate cost, space, power, and complexity of deploying and managing single-purpose devices. Customers can also add more applications over time to meet future business needs.

Security

Cisco integrates security as a fundamental building block of the field area network (FAN) architecture. The CGR 1000 Series offers strong security capabilities that are based on Cisco's Connected Grid security principles and widely adopted cryptographic and security standards.

Security Principle	CGR 1000 Features and capabilities
Access Control	• Mutual authentication and authorization of all nodes connected to the network • IEEE 802.1x-based authentication, Role-Based Access Control • Certificate-based identity, strong username and passwords

Data Integrity, Confidentiality and Privacy	• Link-layer encryption in the NAN mesh (AES-128) • Network-layer encryption in the WAN (IPsec) • Scalable key management – generation, exchange & revocation of encryption keys
Threat Detection and Mitigation	• Network segmentation of users, devices and applications in NAN and WAN • Access-lists on field area router to filter traffic between users and devices • High-performance firewall in the control-center to protect critical assets
Device and Platform Integrity	• Tamper-resistant mechanical design, security alerts generated if compromised • Hardware chip to store router's X.509 certificate, other security credentials • Tamper-proof secure storage of router configuration and data

Network Reliability and High Availability

The CGR 1000 Series Routers have been designed with both device level and network level reliability to meet harsh physical environments. The CGR 1000 Series is built to meet stringent compliance standards such as IEEE 1613 and IEC 61850-3. The enhanced thermal design and conduction cooling with no moving parts allows support for extended temperature support. Additionally, the routers offer mechanisms for backup power to help ensure uptime for mission-critical applications in the event of power outages. Finally, the support for multiple WAN communication modules, and the network resiliency and routing features in CG-OS, allows utilities to deploy enterprise-class high availability in their communication networks for the distribution grid.

Network Management

A complete suite of network management tools is critical for lowering operating expenses (OpEx) while improving network availability. They do so by simplifying and automating many of the day-to-day tasks associated with managing such challenging network requirements. The embedded management features available in the CGR 1000 Series, Connected Grid Device Manager (CG-DM), and the Connected Grid Network Management System (CG-NMS) allow customers to effectively meet these requirements.

The Cisco FAN solution provides operators with extensive instrumentation and diagnostic information for geographic locations, wireless interfaces, battery management, and other grid-specific details. This information can be fed into the CG-NMS for day-to-day operations, operator dashboards, and real-time troubleshooting. Ease-of-use features such as secure zero touch deployment and a graphical field tool help enable non-IT field technicians to deploy and manage FAN communication equipment effectively. In addition to the utility-specific functionality, the Cisco solution provides customers with true enterprise-class fault, configuration, accounting, performance, and security (FCAPS) functionality such as a programmatic XML interface based on the Network Configuration Protocol (NETCONF) industry standard, Role-Based Access Control (RBAC), over-the-air software upgrades, and security management functionality.

Open Standards

Cisco's strategy is to encourage the creation and adoption of open communication standards for the smart grid. This in turn encourages the growth of an ecosystem of standards-based, interoperable devices and applications from different vendors while reducing the risk of adopting new technologies for utilities.

The Cisco Connected Grid solution is based on a series of open standards, many of them adopted from IP-based technologies such as IPv6. By use of these standards, customers are able to architect and design their network independent of the application layer or physical layer infrastructure. This protects any existing investment while lowering the total cost of ownership for the network over time.

Cisco Connected Grid Modules for CGR 1000 Series

There is not a single technology—wireless or wireline—that will be able to satisfy utilities' requirements for field area network applications. Different technologies may offer the best solution in terms of geography, performance, cost and other constraints, such as regulation, existing and planned infrastructure, coverage and SLA requirements. Customers also need the flexibility to upgrade to new communication technologies in the future while protecting their investment in the platforms deployed today. The CGR 1000 Series routers meet these requirements by use of module slots that accommodate Connected Grid Modules (CGM) offering a diverse range of connectivity options. Table 1 identifies Connected Grid Modules for the CGR 1000 Series.

Table 1. Connected Grid Modules for CGR 1000 Series

Connected Grid Module (CGM) Slots	• The CGR 1120 accommodates 2 modules • The CGR 1240 accommodates 4 modules
Connected Grid Modules (CGM) Families	• IEEE 802.15.4g/e WPAN (900 MHz RF Mesh) • Cellular: 2G/3G (Global System for Mobile Communications [GSM] and Code Division Multiple Access [CDMA]) • IEEE 802.16e WiMAX

Cisco's Connected Grid Wireless Personal Area Network (WPAN) Module

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- Code Division Multiple Access (CDMA) version is based on 3GPP2, and supports EVDO Rev A/Rev 0 and 1xRTT

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Cisco Connected Grid Module 3G CDMA Module: **CGM-3G-EVDO**	• CDMA 1xEV-DO Rev A (forward link up to 3.1 Mbps; reverse link up to 1.8 Mbps) • Backward compatibility: ◦ CDMA 1xEV-DO Rel 0 (forward link up to 2.4 Mbps; reverse link up to 153.6 kbps) • CDMA 1xRTT (forward link up to 153.6 kbps; reverse link up to 153.6 kbps)

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Output Power (Average)	23 dBm for 64QAM 5\6
Transport Options	• IP CS • ETH CS
Standards Based WIMAX Security	• PMKv2 • AES-128 • EAP-TLS • Support for X.509 digital certificates
QoS	Five (5) QoS classes: UGS, RT, eRT, nRT, BE
Modem Diagnostics	Tx power, received signal strength indication (RSSI), carrier-to-interference-plus-noise-reduction (CINR), modem state, base station ID (if connected), frequency (if connected)
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Rack Height	N/A	2 RU
Pole Mount	Yes	No
Wall-mount	Yes	Yes
Din-rail Mount	No	Yes
Typical Weight Fully Configured	23 lbs (10.4 kg) Unit weight includes base chassis with four communication modules, AC power supply, and 8-Amp-hr battery backup unit	8 lbs (3.6 kg) Unit weight includes base chassis with four communication modules, AC power supply, and 8-Amp-hr battery backup unit
Operating Temperature[1]	-40℃ to +70℃ (-40℉ to 158℉) with type test to 85℃ (185℉) for 16 hours	-25℃ to +60℃ (-25℉ to 140℉) with type test up to 85℃ (185℉) for 16 hours
Communication Modules		
IEEE 802.15.4 WPAN[2]	Yes	Yes
3.5G AT&T HSPA+/UMTS/GSM/GPRS/EDGE	Yes	Yes
3.5G (Non-US) HSPA+/UMTS/GSM/GPRS/EDGE	Yes	Yes
CDMA EV-DO Rev A/0/1xRTT—Verizon	Yes	Yes
CDMA EV-DO Rev A/0/1xRTT—Sprint[2]	Yes	Yes
CDMA EV-DO Rev A/0/1xRTT—Generic[2]	Yes	Yes
WiMAX: IEEE 802.16e- 2.3 GHz	Yes	Yes
WiMAX: IEEE 802.16e- 3.6 GHz[2]	Yes	Yes
WiMAX: IEEE 802.16e- 1.8 GHz[2]	Yes	Yes
WiMAX: IEEE 802.16e- 3.4 GHz[2]	Yes	Yes
WiMAX: IEEE 802.16e- 2.5 GHz[2]	Yes	Yes
On-board Interfaces		
Gigabit Ethernet Combination Ports (10/100/1000 Copper, 100/1000 SFP)	2	2
10 /100 Fast Ethernet Copper Ports	4	6
Wi-Fi (IEEE 802.11 b/g/n)	Yes (Autonomous)	Yes (Autonomous)
Serial (RS-232/RS-485)[2]	2	2
GPS for Location	Yes	Yes
IRIG-B[3]	BNC connector	No
Digital Alarm Inputs[3]	2	4
Digital Alarm Outputs[3]	2	1
USB Type A host ports[3]	2	1
Console and AUX Port (RJ-45)	1	1

[1] Operating temperature range is impacted by choice of communication modules and battery backup options.
[2] Target Availability: 2H CY2012
[3] Interfaces built into platform hardware. Software support in future release

	CGR 1240 (Pole-mount)	CGR 1120 (Din-rail Mount)
SD Flash Slot (Memory)	1 (2 GB)	1 (2 GB)
Power Options		
Power Supply	AC Power supply: • 100 - 240 VAC	Integrated AC/DC power supply: • 3-phase AC power supply: 100 - 240 VAC • 9-60 VDC
Battery Backup Options[4] [5]	Integrated battery backup unit (BBU) and smart charging and monitoring system. • Run time: 8 hours • Estimated life: 5 years	N/A
Power Options for Third-Party Radios	The CGR 1240 provides support for powering third-party radios: • Voltage output: 12VDC ± 5 percent • Power output: 12 W (continuous)	N/A
Regulatory Compliance		
Environmental Compliance	• IEC-61850-3 • IEEE1613	• IEC-61850-3 • IEEE1613
Immunity	• EN61000-6-2 • EN61000-4-2 (ESD) • EN61000-4-3 (RF) • EN61000-4-4 (EFT) • EN61000-4-5 (SURGE) • EN61000-4-6 (CRF) • EN61000-4-11 (VDI) • EN 55024, CISPR 24 • EN50082-1	• EN61000-6-2 • EN61000-4-2 (ESD) • EN61000-4-3 (RF) • EN61000-4-4 (EFT) • EN61000-4-5 (SURGE) • EN61000-4-6 (CRF) • EN61000-4-11 (VDI) • EN 55024, CISPR 24 • EN50082-1
EMC	• 47 CFR, Part 15 • ICES-003 Class A • EN55022 Class A • CISPR22 Class A • AS/NZS 3548 Class A • VCCI V-3 • CNS 13438 • EN 300-386	• 47 CFR, Part 15 • ICES-003 Class A • EN55022 Class A • CISPR22 Class A • AS/NZS 3548 Class A • VCCI V-3 • CNS 13438 • EN 300-386
Safety	• USA: UL 60950-1 • Canada: CAN/CSA C22.2 No. 60950-1 • Europe: EN 60950-1 • China: GB 4943 • Australia/New Zealand: AS/NZS 60950.1 • Rest of World: IEC 60950-1 • UL certified to UL/CSA 60950-1, 2nd Ed. • CB report to IEC60950-1, 2nd Ed., covering all group differences and national deviations.	• USA: UL 60950-1 • Canada: CAN/CSA C22.2 No. 60950-1 • Europe: EN 60950-1 • China: GB 4943 • Australia/New Zealand: AS/NZS 60950.1 • Rest of World: IEC 60950-1 • UL certified to UL/CSA 60950-1, 2nd Ed. • CB report to IEC60950-1, 2nd Ed., covering all group differences and national deviations.

Table 6. Cisco Connected Grid Router Network Services: Features and Protocols Support

Protocols
IPv4, IPv6, Static Routes, Open Shortest Path First (OSPF)
Multicast: Internet Group Management Protocol (IGMPv3), Protocol Independent Multicast (PIM)

[4] Run time calculated based on router configuration with two (2) communications modules (WPAN and 2G / 3G). Actual battery time will vary depending on several factors, including traffic volume, the number of radios installed, temperature, and auxiliary device power draw.
[5] All measurements for battery capacity, run time and estimated life assume ambient temperature of 25ºC

IPSec, Generic Routing Encapsulation (GRE), DHCP
IEEE 802.15.4[6], IETF 6LOWPAN[6], IETF RPL[6], IETF CoAP[6]
Ethernet, Serial (RS-232/485)[6]
SCADA Protocol Support: IEC 60870-5-101/104[6]
Security
Encryption: IPSec VPN, Key-based Mesh Encryption, WPA2 for WiFi
Device Identity: IEEE 802.1AR
Role-based Access Control for Device Configuration
L3-L4 ACLs
Authentication, Authorization: EAP TLS
Mesh Security Solution[6]
QoS
Classification and Marking: ACLs, Layer3-IP Precedence, Differentiated Services Code Point (DSCP)
Congestion Management: Priority Queuing (PQ)
Embedded Management
Programmatic XML Interface (NETCONF), HTTPS, SSH
Secure Zero Touch Deployment
Battery Health Monitoring (n/a for CGR 1120)
Door Tamper Detection

For More Information

For more information on the Cisco 1000 Series Connected Grid Routers visit http://www.cisco.com/go/cgr1000

For more information on the Cisco Field Area Network solution visit http://www.cisco.com/go/fan

[6] Target Availability: 2H CY2012

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MARIHUANA GROWING OPERATIONS IN BRITISH COLUMBIA REVISITED

1997-2003

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March 2005

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Marihuana Growing Operations in British Columbia Revisited (1997-2003)

by

Darryl Plecas, Aili Malm and Bryan Kinney

EXECUTIVE SUMMARY

This report contains the results of a comprehensive study of marihuana cultivation in British Columbia undertaken and completed in two parts. The first part, which covered the four-year period of 1997 – 2000 was completed in the summer and fall of 2001. The results from that time period were first reported in *Marihuana Growing Operations in British Columbia: An Empirical Survey (1997-2000)* by Plecas et al. (2002). The methodology of the second part of the project, covering the period from 2001 through 2003, remained unchanged. The second part of the project was conducted over the summer and fall of 2004. Overall, the project involved a review of all cases of alleged marijuana cultivation coming to the attention of the police from January 1, 1997 to December 31, 2003. In all, 25,014 cases from this seven-year period were reviewed. The main findings are summarised below.

First and foremost, the study re-confirms the main conclusion from the Plecas et al. (2002) study that British Columbia has a serious problem with marihuana growing operations. Although Statistics Canada has already published figures indicating that the rate of grow operations of 79 per 100,000 population in B.C. is nearly three times the national average of 27, this study provides more detailed evidence that these operations are increasing in size and sophistication and continue to be dipsersed throughout the province. Over the length of this project, a total of 15,436 founded cases were identified within 149 police jurisdictions across all regions of the province, although 10 specific jurisdictions accounted for slightly more than half (54%) of all of these instances. Generally, the number of individual incidents of marihuana grow operations increased by over 220% from 1997 to 2000, but appeared to level off over the period 2001 to 2003. However, the recent plateau in the number of incidents should not be taken as a signal that marihuana production in British Columbia has ceased to increase. On the contrary, from figures applied in the current study, the amount of marihuana produced each year in British Columbia is estimated to have increased from 19,729 kilos in 1997 to a seven year high of 79,817 in 2003.

Over the period studied, the evidence indicates that marihuana grow operations have become larger and increasingly sophisticated, involving more technological enhancements. For instance, the average number of plants seized in an indoor grow operation in 1997 was 149, but that average grew to 236 plants by 2003. Similarly, the average number of kilograms of harvested marihuana seized per grow operation tripled from 2.4 kilos in 1997 to 7.2 kilos in 2003. Further, the average number of high intensity lights seized per operation grew steadily from 9 in 1997 to 16 in 2003. This increase in the size of operations has led to an associated increase in the average amount of electricity theft per incident. Approximately one in five founded grow operations involved theft of hydro, a pattern of theft that has remained relatively stable over the past seven years. Where the hydro theft could be determined, the average cost associated per operation was approximately $2,880 in 1997 and $3,740 in 2003. Overall, it is estimated that growers stole more than $3,200,000 from BC Hydro in 2003 alone.

Aside from electricity by-passes, 15% of indoor grow operations contained at least one hazard (i.e. weapons, booby traps, explosives, chemical products, other drugs, and fire). The likelihood of a marihuana grow operation resulting in a fire was 24 times higher than it was for ordinary house fires. The hazards are of particular concern considering indications that children were present in 21% of indoor grow operations.

It is also important to note that the vast majority of cases coming to the attention of the police were as a result of public complaints, usually from anonymous complainants, landlords, neighbours, or, on occasion, from B.C. Hydro. Even those discovered by police were, in most cases, identified as a result of some unrelated police action, such as the serving of a warrant. In other words, the increase in marihuana cultivation cases in B.C. is not due to increased proactive police enforcement. The dynamics involved in cases coming to the attention of the police did not change over the entire seven-year period studied.

In terms of a profile of known offenders, 77% of the 15,588 suspects involved were male, 69% were Caucasian, and the mean age was 35 years old. Further, most suspects had a prior criminal history. On average, suspects had a 13 year criminal history which included seven prior convictions across multiple jurisdictions. Evidence presented in the report suggests that many suspects relocated to B.C. from other parts of Canada, as well as from outside the country. In particular, especially in the areas with the greatest rate of increase in the number of marihuana grow operations, there has been a significant increase in the number of suspects of Vietnamese origin.

Analyzing the criminal justice system's response to marihuana cultivation offences in B.C. is fraught with difficulty. Cases are complex, varying widely in size, value, and whether or not other related criminal activities are involved. They often involve multiple suspects and multiple charges and result in a wide array of dispositions (and combinations of same) at the court stage. Of the 25,014 cases coming to the attention of the police, 16,675 were fully investigated. Of these, 14,483 proved to be founded. About half of these cases (54%) were dealt with informally (i.e. as "no case" seizures), with this being a particularly likely outcome in smaller operations (i.e., under 10 plants). There was a positive correlation between the size of the grow operation, the severity of the penalty handed down in court, and, at the Crown decision-making stage of the process, there were significant numbers of stays of proceedings and plea bargains, both of which resulted in a considerable attrition of charges and suspects.

Overall, some 3008 of the founded cases led to at least one offender being convicted. More specifically, a total of 3364 offenders were convicted representing 52% of those charged and 22% of suspects initially associated with a founded operation. The majority of convictions, however, did not result in a custodial disposition. In fact, approximately 16% of offenders were sentenced to prison with an average sentence length of 4.9 months.

In the final analysis, the results of this study are more disconcerting than those presented through the Plecas et al. 2002 report. Indeed, as of 2003, the number of marihuana grow operations is still high and the overall estimated production associated to those incidents is four times higher in 2003 than in 1997. Despite this reality, and despite the fact that it has become increasingly apparent that grow operations pose a risk to public safety (especially through fire), the criminal justice system has become increasingly unable to respond. Specifically:

- police agencies overall are less likely to fully investigate incidents coming to their attention and less likely to move cases forward with recommended charges to Crown Counsel;
- prosecutors are less likely to accept charges recommended by police and less likely to move forward with charges; and
- judges are less likely to send an offender to prison for their participation in a grow operation, despite offenders becoming more prolific and more violent.

A recent announcement by the Premier of British Columbia (January 2005) to provide monies to law enforcement agencies to increase their capacity to respond to the risks posed by grow operations may assist in increasing the police's ability to respond. The relatively recent establishment of the R.C.M.P.'s Coordinated Marihuana Enforcement Team to direct a more strategic, intelligence driven approach to the problem also gives reason to be optimistic about a more effective law enforcement response in the future. However, the authors would expect that any enhancements to the law enforcement capacity will only translate into improved effectiveness where there is a corresponding improvement in the action taken at the prosecutorial and judicial level.

The main findings in the areas summarised above are described in detail in the report. The report includes a description of: incidents of marihuana grow operations coming to the attention of the police; the characteristics of marihuana growing operations; the suspects involved; the action taken by the police and the courts; and sentencing. Also included are the supporting data tables and other documentation.

ACKNOWLEDGEMENTS

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- The co-authors and principal researchers involved in the Phase One part of the study and the associated report. This includes Vivienne Chin, Yvon Dandurand, and Tim Segger.
- Our colleagues in the Department of Criminology and Criminal Justice at the University College of the Fraser Valley, and in particular, Dr. Irwin Cohen.
- Len Garis, Chief, Surrey Fire Service, who facilitated the researchers' access to data permitting a focused examination of the association between grow operations and the risk of fires.
- The sworn and civilian members from each of the departments and detachments visited over the course of this research. This includes those employees at 130 R.C.M.P. detachments, five R.C.M.P. district drug offices, and all 11 municipal police departments in British Columbia. Officers and staff at each location went out of their way to be helpful to the researchers at every visit.
- Assistant Commissioner Gary Bass, R.C.M.P. "E" Division, and other senior officers within R.C.M.P. "E" Division, including Chief Superintendent Dick Bent, Superintendent Carl Busson, and Inspector Paul Nadeau, each of whom were instrumental in the success of this project.

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Chapter 1

INTRODUCTION

There is no question that the issue of marihuana grow operations in Canada deserves serious attention. In fact, Anne McLellan, Canada's Deputy Prime Minister and Minister of Public Safety and Emergency Preparedness, in addressing the first National Conference on Illegal Marihuana Grow Operations[1], described illicit marihuana growing operations as one of the most serious problems faced in communities across the country. At the same time, the Minister cited the need for governments, the criminal justice system, and communities in general to do more to combat the problem.

In British Columbia, the province of focus for this report, the problem of marihuana grow operations has been particularly serious. According to Statistics Canada, 70% of all drug offences in Canada in 2003 involved cannabis[2] and 14% of all cannabis offences were for cultivation, the largest volume of which took place in British Columbia[3]. As illustrated in Table 1.1, 39% of all marihuana cultivation incidents reported to Statistics Canada are in British Columbia. Moreover, the rate of cultivation incidents in British Columbia (79 per 100,000 population) is nearly three times the national rate (27 per 100,000 population) (again see Table 1.1).

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[1] Held in Ottawa, Ontario on November 2nd and 3rd, 2004
[2] Cannabis includes both marihuana and hashish.
[3] Canadian Centre for Justice Statistics (2004). *Canadian Crime Statistics 2003.* Ottawa: Statistics Canada, December 2004, Catalogue no. 85-205-XIE.

This report, which describes the nature and extent of grow operations in British Columbia and the criminal justice system response to those operations, highlights the seriousness of the issue. It will also highlight the need to strengthen the response to the problem.

TABLE 1.1: MARIHUANA CULTIVATION INCIDENTS BY PROVINCE, 2003

Province	*Frequency*	*Percentage of Total*	*Rate/ 100,000 population*
BC	3274	38.75 %	79
NB	342	4.19 %	46
PQ	2939	34.79 %	39
TERR	15	0.18 %	39
NS	328	3.88 %	35
PEI	35	0.41 %	25
SK	132	1.56%	13
MB	142	1.68 %	12
NFLD	44	0.52 %	8
ON	990	11.72 %	8
AB	208	2.48 %	7
CANADA	8449	100.00 %	27

Source: CCJS; Canadian Crime Statistics 2004 Catalogue No: 85-205-XIE

This study builds upon the 2002 research conducted by Plecas et al.[4], where data on all marijuana grow operations coming to the attention of the police between 1997 to 2000 were collected and analyzed. The 2002 study indicated that there was a dramatic increase in the number and sophistication of marihuana growing operations. However, this increase in police awareness of marihuana growing operations was not primarily the result of proactive policing,

[4] Plecas, D., Dandurand, Y., Chin, V., & Segger, T. (2002). *Marihuana Growing Operations in British Columbia: An Empirical Survey (1997-2000)*. Abbotsford: University College of the Fraser Valley.

but as a result of information received from anonymous or confidential sources, such as neighbours, friends, relatives, and other members of the community.

The present study was conducted by the Centre for Criminal Justice Research, an ICURS[5] affiliate lab, at the University College of the Fraser Valley, in cooperation with the Drug Enforcement Branch, "E" Division, of the Royal Canadian Mounted Police. The study was funded by the R.C.M.P. and was based on the same methodology as the aforementioned Plecas et al. (2002) study. The present study includes all of the incidents of marihuana cultivation coming to the attention of the police for a seven year period, 1997-2003. As with the Plecas et al. (2002) study, this research was facilitated through the cooperation of every single police jurisdiction in the province. The data were collected during the summer of 2004 and analyzed the following fall.

The purpose of the present study is to identify the nature and extent of marihuana cultivation in British Columbia between 1997-2003. The report also reviews law enforcement and criminal justice responses to this issue. Specifically, the study was designed to: (1) describe the nature and extent of marihuana growing operations that came to the attention of the police in British Columbia during the seven-year period; and, (2) to describe the criminal justice system's response to these cases.

Method

Following the methodology of the Plecas et al. 2002 study, the current study involved reviewing every existing police file from every law enforcement jurisdiction in the province for information on marihuana cultivation. Actual site visits to police offices to conduct the review of files were carried out by a team of nine researchers. Those site visits were secured by R.C.M.P. "E" Division officials for both R.C.M.P. detachments and all municipal police departments in the province.

This study used the same three data coding instruments used in the Plecas et al (2002) study, each of which can be found in the Appendices. *Appendix 1* contains the incident data coding sheet, *Appendix 2* presents the coding sheet used to collect information on each suspect,

[5] The International Centre for Urban Research Studies is an international network of research facilities, with its core housed at Simon Fraser University.

while the criminal history coding sheet is presented in *Appendix 3*. The information coded included data about the suspect, the location of the growing operation, the nature and origin of the complaint, the police investigation, the size and type of the growing operation, the amount of marihuana seized, the presence of other drugs, the presence of various cultivation equipment, decisions made by the prosecution, and the sentencing outcome.

In addition to the information collected from the files, criminal histories were run on every suspect involved in the files based on their FPS number (fingerprint identification number). The information on the suspect's criminal record was coded and linked to the incident form using a unique identifier. After the data entry was completed and verified (i.e. "cleaned"), all identifiers were removed from the researcher's database. The primary database, an intelligence database including all suspect and incident identifiers, is held with R.C.M.P. "E" Division. The statistical analysis program, SPSS, was used to analyze the data.

It is important to briefly discuss the nature of police data and the information that can be gathered from grow operation case files. Police data rarely contain complete information for every variable of interest. For example, one of the variables of interest in this study is the number of children present at grow operations when the police were at the scene. Most detachments and departments do not consistently record this type of information for the file. However, when a systematic process is put into place, the numbers become far more reliable. For instance, Vancouver Police now record every instance that child protection attends a crime scene, thereby making the data for number of children present at grow operations more reliable. Due to the nature of police data, the authors believe that many of the numbers presented in this report, particularly surrounding the hazards of grow operations, are an underestimation.

Obtaining complete information on criminal histories is also a problem. In some cases, convicted offenders are not fingerprinted and, therefore, it is not always possible to confirm that a conviction exists. Further, there is a significant time lag between dates of conviction and the actual placement of that conviction on record. In the final analysis, the data presented in this report likely underestimates the reality of certain reported results.

Chapter 2

INCIDENTS OF ALLEGED MARIHUANA CULTIVATION COMING TO THE ATTENTION OF THE POLICE

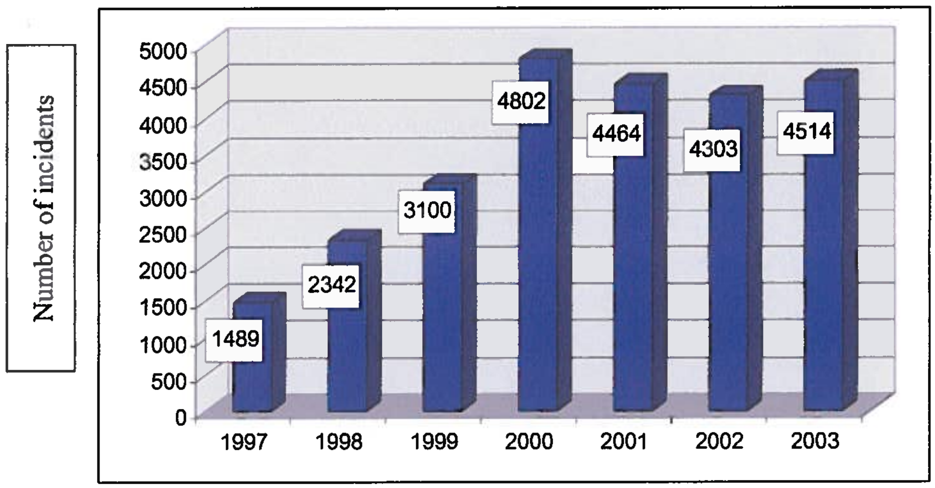
The number of incidents of marihuana cultivation coming to the attention of the police from 1997 to 2000 steadily increased; however, from 2000 to 2003, there appears to be a leveling off of marihuana growing operations in British Columbia. There are a number of possible reasons for this occurrence. One possible explanation is that marihuana growing operations are becoming more difficult to detect, while another is the impact of international security initiatives as a result of the terrorist attacks in New York and Washington on September 11th, 2001. These initiatives may have made it more difficult to export marihuana across the Canada - United States border. Another explanation is that current initiatives (i.e. green teams, Growbusters, etc.) in the criminal justice system have made it more difficult for marihuana cultivation to occur in British Columbia. Still another explanation could be that individuals are not reporting suspected marihuana cultivation as often as they were prior to 2000. However, the data presented in this research on source of complaint to the police does not support this explanation. It has also been speculated that the plateau in the number of marihuana growing operations may be due to a saturation of the retail market. However, as will be described in Chapter 3, given estimated production has not leveled off but has continued to increase, the authors would not agree that the market has become saturated. Finally, given police are getting to fewer incidents coming to their attention, and hence dismantling fewer grow operations, there is less need for growers to set up new operations.

The current study also shows that while the number of cases in the Lower Mainland increased from 1997 through 2000, and decreased since then, the number of cases in more rural areas of British Columbia actually increased. The top ten police jurisdictions, in terms of the number of marihuana grow operations, as found by the Plecas et al. (2002) study, continues to account for over half of all cases in British Columbia.

Suspected Cases of Marihuana Cultivation

A total of 25,014 incidents of alleged marihuana cultivation came to the attention of police in British Columbia between January 1997 and December 2003. As seen in Figure 2.1, the number of marihuana grow operation incidents increased each year from 1997 through 2001 and then remains relatively stable between 2000 and 2003. Despite the drop in incidents from 2000, the number of cases in 2003 was still more than three times that of 1997.

FIGURE 2.1: NUMBER OF MARIHUANA CULTIVATION INCIDENTS WHICH CAME TO THE ATTENTION OF POLICE AGENCIES IN BRITISH COLUMBIA BETWEEN JANUARY, 1 1997 AND DECEMBER 31, 2003



N = 25,014

Table 2.1 illustrates the frequency of marihuana cultivation cases in each of the eight development regions of the province: Mainland/Southwest, Vancouver Island/Coast, Thompson/Okanagan, Cariboo, Kootenay, North Coast, Nechako, and the Northeast. Not surprisingly due to population size, the Lower Mainland and Vancouver Island account for the majority of the grow operations in the province (72%). However, there seems to be a shift away from the Lower Mainland toward Vancouver Island and more rural areas. This is not surprising as the authors predicted the shift away from the urban centres of the lower mainland is related to the demand for larger properties to increase production and minimize police and community detection.

TABLE 2.1: CASES THAT CAME TO THE ATTENTION OF POLICE IN BRITISH COLUMBIA BETWEEN JANUARY 1, 1997 AND DECEMBER 31, 2003 (BY DEVELOPMENT REGION AND REGIONAL DISTRICT)

*Development Region / Regional District**	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*Increase since 1997*
Greater Vancouver	548	916	1299	2497	1787	1719	1929	252%
Fraser Valley	177	234	306	494	375	485	408	131%
Squamish-Lillooet	13	18	22	33	44	48	42	223%
Mainland/Southwest Overall	738	1168	1627	3024	2206	2252	2379	222%
Comox-Strathcona	84	131	173	212	224	211	198	136%
Sunshine Coast	20	59	52	50	78	47	49	145%
Mount Waddington	6	18	15	15	12	20	10	67%
Cowichan Valley	56	108	130	139	149	145	98	75%
Nanaimo	122	156	218	259	252	207	197	61%
Powell River	0	16	16	19	47	42	75	100%
Alberni-Clayoquot	21	21	25	35	50	63	70	233%
Capital	111	111	150	143	139	125	184	66%
Vancouver Is/ Coast Overall	420	620	779	872	951	860	881	110%
Northern Okanagan	30	53	50	91	126	99	95	217%
Thompson-Nicola	49	109	104	139	169	169	148	202%
Central Okanagan	40	63	90	96	322	281	260	550%
Okanagan-Similkameen	34	42	51	70	85	84	87	156%
Columbia-Shuswap	26	29	39	39	74	48	70	169%
Thompson/Okanagan Overall	179	296	334	435	776	681	660	269%
Fraser-Fort George	27	42	64	155	129	98	195	622%
Cariboo	25	57	50	92	54	42	34	36%
Cariboo Overall	52	99	114	247	183	140	229	340%
Central Kootenay	36	57	114	98	161	163	159	342%
East Kootenay	14	21	23	34	45	62	51	264%
Kootenay Boundary	13	43	52	26	39	45	49	277%
Kootenay Overall	63	121	189	158	245	270	259	311%
Kitimat-Stikine	10	13	12	28	42	18	46	360%
Central Coast	1	2	2	2	2	7	4	300%
Skeena-Qn. Charlotte	7	7	10	6	5	9	10	43%
North Coast Overall	18	22	24	36	49	34	60	233%
Bulkley-Nechako	14	8	13	21	28	29	22	57%
Stikine (region)	1	1	2	0	0	1	1	0%
Nechako Overall	15	9	15	21	28	30	23	53%
Peace River	4	6	12	7	26	36	23	475%
Northern Rockies	0	1	6	2	0	0	0	0%
Northeast Overall	4	7	18	9	26	36	23	475%
Province Overall	**1489**	**2342**	**3100**	**4802**	**4464**	**4303**	**4514**	**203%**

* Source of population statistics: Population Estimates 1996-2004, Ministry of Management Services, Government of British Columbia. Accessed January 5, 2005 from www.bcstats.gov.bc.ca/data/pop/pop/mun/Mun9604a.htm

In order to compare the regions and regional districts, Table 2.2 and Table 2.3 control for population by comparing the frequency of cases in 2003 to the population in each region. Figure

2.2 and Figure 2.3 compare the percentage variance from the provincial rate in each regional district in 2000 and 2003 in order to illustrate the changes in certain districts. As expected, the majority (53%) of marihuana cultivation cases in 2003 were in the Mainland/Southwest region.

TABLE 2.2: NUMBER AND RATE PER 1,000 POPULATION OF MARIHUANA CULTIVATION CASES KNOWN TO THE POLICE IN 2003 BY DEVELOPMENT REGION /REGIONAL DISTRICT. NUMBER OF CASES AS % OF THE NUMBER OF CASES IN BRITISH COLUMBIA

Development Regions and Regional Districts	*Population 2003**	*Total no. of cases in 2003**	*Rate per 1,000 population in 2003**	*No. of cases in 2003 as a percentage of total no. of cases in BC*	*Percentage of the total provincial population*
Greater Vancouver	2,113,699	1929	.91	42.7	50.9%
Fraser Valley	253,986	408	1.61	9.0	6.1%
Squamish-Lillooet	35,761	42	1.17	0.9	0.9 %
Mainland/Southwest Overall	2,403,444	2379	0.98	52.6	57.9 %
Nanaimo	136,122	197	1.45	4.4	2.5 %
Comox-Strathcona	101,882	198	1.94	4.4	2.5 %
Capital	344,299	184	0.53	4.1	8.3 %
Cowichan Valley	76,457	98	1.28	2.2	1.8 %
Sunshine Coast	27,388	49	1.79	1.1	0.7 %
Alberni-Clayoquot	31,813	70	2.20	1.6	0.8 %
Powell River	20,708	75	3.62	1.7	0.5 %
Mount Waddington	13,502	10	.74	0.2	0.3 %
Vancouver Isl. /Coast Overall	752,171	881	1.17	19.7	18.1 %
Thompson-Nicola	125,746	148	1.18	3.3	3.0 %
Central Okanagan	160,491	260	1.62	5.8	3.9 %
Northern Okanagan	77,854	95	1.22	2.1	1.9 %
Okanagan-Similkameen	81,044	87	1.07	1.9	2.0 %
Columbia-Shuswap	51,234	70	1.37	1.6	1.2 %
Thompson/Okanagan Overall	496,369	660	1.33	14.7	12.0 %
Fraser-Fort George	100,523	195	1.94	4.3	2.4 %
Cariboo	68,502	34	0.49	0.8	1.6 %
Cariboo Overall	169,025	229	1.35	5.1	4.0 %
Central Kootenay	60,125	159	2.64	3.5	1.4 %
East Kootenay	60,060	51	0.85	1.1	1.4 %
Kootenay Boundary	33,213	49	1.48	1.1	0.8 %
Kootenay Overall	153,398	259	1.69	5.7	3.7 %
Kitimat-Stikine	42,479	46	1.08	1.0	1.0 %
Central Coast	3,896	4	1.03	0.1	0.1 %
Skeena-Queen Charlotte	22,281	10	0.45	0.2	0.5 %
North Coast Overall	68,656	60	0.87	1.3	1.7 %
Bulkley-Nechako	42,565	22	0.52	0.5	1.0 %
Stikine (region)	1,374	1	0.73	0.0	0%
Nechako Overall	43,939	23	0.52	0.5	1.1 %
Peace River	59,168	23	0.39	0.5	1.4 %
Northern Rockies	6,119	0	0.00	0.0	0.1 %
Northeast Overall	65,287	23	0.35	0.5	1.6 %
Province Overall	**4,152,289**	**4514**	**1.09**	**100**	**100.0%**

* Source of population statistics: Population Estimates 1996-2004, BC Stats, Ministry of Management Services, Government of British Columbia. Accessed January 5, 2005 from www.bcstats.gov.bc.ca/data/pop/pop/mun/Mun9604a.htm

TABLE 2.3: MARIHUANA CULTIVATION CASES KNOWN TO THE POLICE IN 2003: RATES PER 1,000 POPULATION IN EACH DEVELOPMENT REGION AND REGIONAL DISTRICT OF BRITISH COLUMBIA AND LOCAL RATE VARIANCE FROM PROVINCIAL RATE

Development Regions and Regional Districts	*Rate per 1,000 population in 2003*	*Percentage variance from provincial rate of 1.09 per 1,000*
Greater Vancouver	0.91	-17
Fraser Valley	1.61	+48
Squamish-Lillooet	1.17	+7
Mainland/Southwest Overall	0.98	-10
Nanaimo	1.45	+33
Comox-Strathcona	1.94	+78
Capital	0.53	-51
Cowichan Valley	1.28	+17
Sunshine Coast	1.79	+64
Alberni-Clayoquot	2.20	+102
Powell River	3.62	+232
Mount Waddington	0.74	-32
Vancouver Island/Coast Overall	1.17	+7
Thompson-Nicola	1.18	+8
Central Okanagan	1.62	+49
Northern Okanagan	1.22	+12
Okanagan-Similkameen	1.07	-2
Columbia-Shuswap	1.37	+26
Thompson/Okanagan Overall	1.33	+22
Fraser-Fort George	1.94	+78
Cariboo	0.49	-55
Cariboo Overall	1.35	+24
Central Kootenay	2.64	+142
East Kootenay	0.85	-22
Kootenay Boundary	1.48	+36
Kootenay Overall	1.69	+55
Kitimat-Stikine	1.08	-1
Central Coast	1.03	-6
Skeena-Qn. Charlotte	0.45	-59
North Coast Overall	0.87	-20
Bulkley-Nechako	0.52	-52
Stikine (region)	0.73	-33
Nechako Overall	0.52	-52
Peace River	0.39	-64
Northern Rockies	0.00	-100
Northeast Overall	0.35	-68

* Source of population statistics: Population Estimates 1996-2004, BC Stats, Ministry of Management Services, Government of British Columbia. Accessed January 5, 2005 from www.bcstats.gov.bc.ca/data/pop/pop/mun/Mun9604a.htm

FIGURE 2.2: PERCENTAGE OF TOTAL CASES IN BRITISH COLUMBIA PER 1,000 POPULATION IN EACH DEVELOPMENT DISTRICT IN 2000 AND 2003

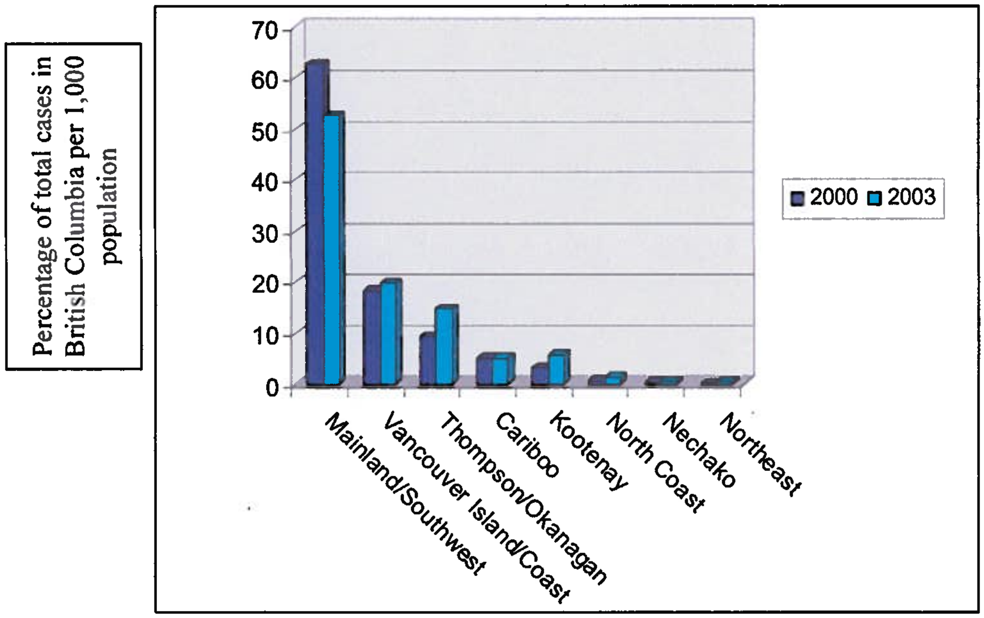
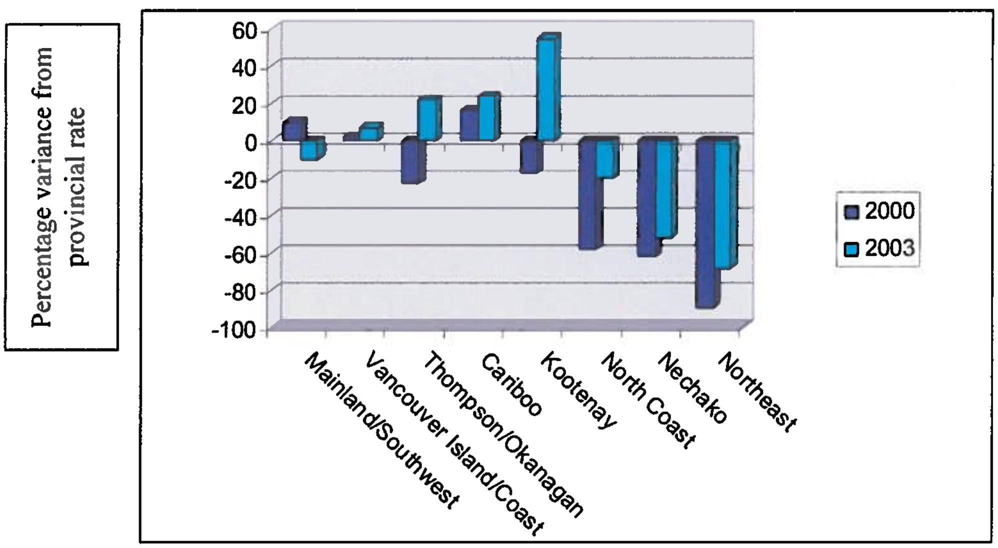


FIGURE 2.3: DEVELOPMENT DISTRICT PERCENTAGE VARIANCE FROM PROVINCIAL RATE IN 2000 AND 2003



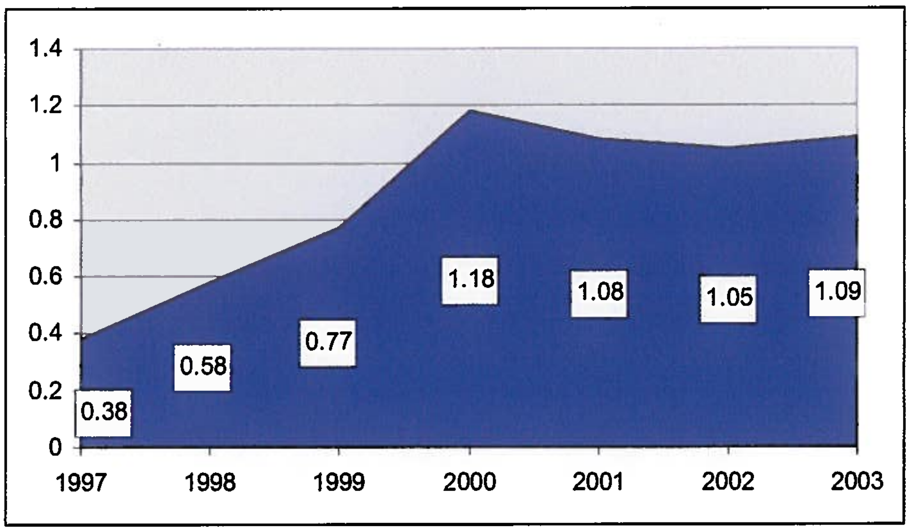
As indicated in Table 2.3, the district rates in the Lower Mainland, North Coast, Nechako, and Northeast are lower than the provincial rate when controlled for population. The five highest local rates, in comparison with the provincial rate, are shown in Table 2.4. Figure 2.4 charts the provincial rate per 1,000 population of marihuana cultivation in the seven year period. The dramatic rise from 1997 through 2000, and the plateau thereafter, is evident in this figure. Since 2000, the provincial rate of marihuana cultivation has remained over three times the rate seen in

1997. Figure 2.2 and Figure 2.3 show that marihuana cultivation cases have decreased in the Lower Mainland and increased in Vancouver Island/Coast, Thompson/Okanagan, and Kootenay areas since 2000. The rest of the jurisdictions are relatively stable from 2000 to 2003.

TABLE 2.4: MARIHUANA CULTIVATION CASES KNOWN TO THE POLICE 1997-2003: TOP FIVE REGIONAL DISTRICTS BY LOCAL RATE VARIANCE FROM PROVINCIAL RATE

Development Regions and Regional Districts	*Percentage variance from provincial rate 1997-2003*
Powell River	+232
Central Kootenays	+142
Alberni-Clayquot	+102
Fraser-Fort George	+78
Comox Strathcona	+78

Figure 2.4: RATE PER 1,000 POPULATION OF MARIHUANA CULTIVATION INCIDENTS KNOWN TO THE POLICE IN BRITISH COLUMBIA 1997-2003



As mentioned above, of the 149 jurisdictions in British Columbia, ten jurisdictions in British Columbia account for over 50% of all police cases in the province for the year 2003. Each of these jurisdictions have had at least a 150% increase in marihuana cultivation incidents from 1997. The average number of cases of marihuana cultivation in 2003 in each of the top ten jurisdictions was 245 (see Table 2.5). Notably, Surrey has surpassed Vancouver as the most prolific jurisdiction in the province. New entries (since 2000) to the top ten list include Kelowna, Prince George, and Ridge Meadows. The largest increases over the seven year period are in Prince George, Kelowna, and Coquitlam, each with increases of over 500%.

TABLE 2.5: JURISDICTIONS IN BRITISH COLUMBIA WITH HIGHEST VOLUME OF MARIHUANA CULTIVATION FILES OPENED IN 2003

RCMP Detachment/ Police Department	*Number of cases of marihuana cultivation in 2003*	*Percentage increase over the seven-year period*	*Number of files as a percentage of all files opened in BC in 2003*
Surrey	441	385 %	9.8 %
Vancouver	335	162 %	7.4 %
Coquitlam	297	624 %	6.6 %
Kelowna	260	550 %	5.8 %
Burnaby	218	169 %	4.8 %
Chilliwack	204	214 %	4.5%
Prince George	189	722 %	4.2 %
Richmond	180	339 %	4.0 %
Langley	170	170 %	3.8 %
Ridge Meadows	152	375 %	3.4 %
Average	**245**	**304 %**	**54 %**

As was the case in the Plecas et al. (2002) study, taken together, the top ten jurisdictions, based on a raw count of the number of marihuana cultivation cases, account for over 50% of the provincial total of marihuana growing operations; however, three of the top ten jurisdictions have rates, based on per 1,000 population, below the provincial rate. These are: Vancouver (47% below the per capita provincial rate), Richmond (5% below the per capita provincial rate) and Burnaby (2% below the per capita provincial rate). Table 2.6 shows the top ten jurisdictions and how they vary from the provincial rate of marihuana growing operations in 2003. Interestingly, the largest variance from the provincial rate can be seen in Chilliwack, Prince George, and Kelowna, each of these being relatively rural locations compared to the other jurisdictions in the top ten. In effect, Vancouver is currently 47% below the provincial rate, while in 2000 it was 1% above the per capita provincial rate. The jurisdictions of Delta, Nanaimo, and Abbotsford were in the top ten jurisdictions in 2000 and have since dropped off the list for 2003. An interesting note is that Delta, Nanaimo and Abbotsford have active 'green teams' to increase the enforcement against marihuana growing operations.

TABLE 2.6: JURISDICTIONS IN BRITISH COLUMBIA WITH HIGHEST VOLUME OF MARIHUANA CULTIVATION CASES IN 2003

RCMP Detachment or Police Department	Number of cases in 2003	Population*	Rate per 1,000 population	Percentage* variance from provincial rate (1.09)
Surrey	441	378,578	1.16	+ 6%
Vancouver	335	577,962	0.58	- 47%
Coquitlam	297	175,496	1.69	+ 55%
Kelowna[6]	260	110,167	2.36	+ 117%
Burnaby	218	202,852	1.07	- 2%
Chilliwack[7]	204	80,719	2.53	+ 132%
Prince George	189	76,597	2.47	+ 127%
Richmond	180	172,032	1.04	- 5%
Langley	170	117,366	1.45	+ 33%
Ridge Meadows[8]	152	84,933	1.79	+ 64%

* All percentages have been rounded to the nearest whole number.

Sources of Information

Table 2.7 outlines the source of information leading to the opening of a marihuana cultivation file in British Columbia. The 25,014 files reviewed for this report contained information on the source of that information in 87% of the cases. The majority of information derives from Crimestoppers or anonymous informants (57% over the seven year period). All of the categories have remained relatively stable across the seven year study period with the exception of reports coming from neighbours, which have increased by 7% between 1997 and 2003 (see Table 2.7). Reports from BC Hydro have decreased from 8% in 1997 to 2% in 2003. Notably, despite bylaws in many municipalities concerning landlord liability in rental growing operations, information received from landlords has not increased over the past seven years. There has been an increase in the number of calls from neighbours as a source, and this may suggest that public awareness campaigns, such as Growbusters, a Crimestoppers-like tip line

[6] In 2002, the Kelowna detachment was amalgamated to include Lake Country.
[7] In 2002, the Chilliwack detachment was amalgamated to include Aggasiz, Hope and Boston Bar.

used solely for the reporting of marihuana grow operations in Vancouver, have started to impact the number of grow operations in the province, specifically in the Lower Mainland.

TABLE 2.7: SOURCE OF THE INFORMATION LEADING TO OPENING OF MARIHUANA CULTIVATION FILE: PERCENTAGE* FROM EACH SOURCE BY YEAR IN BRITISH COLUMBIA 1997-2003

Source**	1997	1998	1999	2000	2001	2002	2003	Overall
Crimestoppers or anonymous informants	55 %	57 %	55 %	59 %	57 %	58 %	51 %	57 %
While responding to other crime	12 %	11 %	12 %	10 %	8 %	7 %	7 %	9 %
Landlord	7 %	7 %	8 %	8 %	7 %	7 %	7 %	8 %
Neighbour	3 %	4 %	3 %	6 %	7 %	8 %	10 %	7 %
General investigation	4 %	4 %	6 %	5 %	5 %	5 %	7 %	6 %
Routine check (including road stops)	5 %	6 %	6 %	5 %	4 %	4 %	2 %	4 %
While serving a warrant	3 %	3 %	4 %	2 %	2 %	2 %	5 %	3 %
BC Hydro	8 %	4 %	4 %	3 %	1 %	2 %	2 %	3 %
Other (e.g. fire, government officials)	3 %	3 %	3 %	3 %	8 %	8 %	8 %	5 %

N=21,762
* All percentages have been rounded to the nearest whole number.
** Information identifying a type of source was available in 87% of all cases.

Investigations

Marihuana cultivation cases are very complex and there are a number of variables that determine whether an investigation will proceed to charge. Search warrants demand solid grounds and there have been court decisions, most notably the decisions surrounding the use of the FLIR[9], that have affected police ability to obtain a search warrant in cultivation cases. Table 2.8 illustrates how the number of cases where the initial information received by the police did not lead to further action seems to have increased significantly over the seven-year period. Figure 2.5 shows how the percentage of cases in which the information received led to a full investigation (i.e. usually a search of the premises/property) has decreased steadily since 1997. This decrease in full investigations is mirrored by an increase in initial investigation and 'no action' cases.[10]

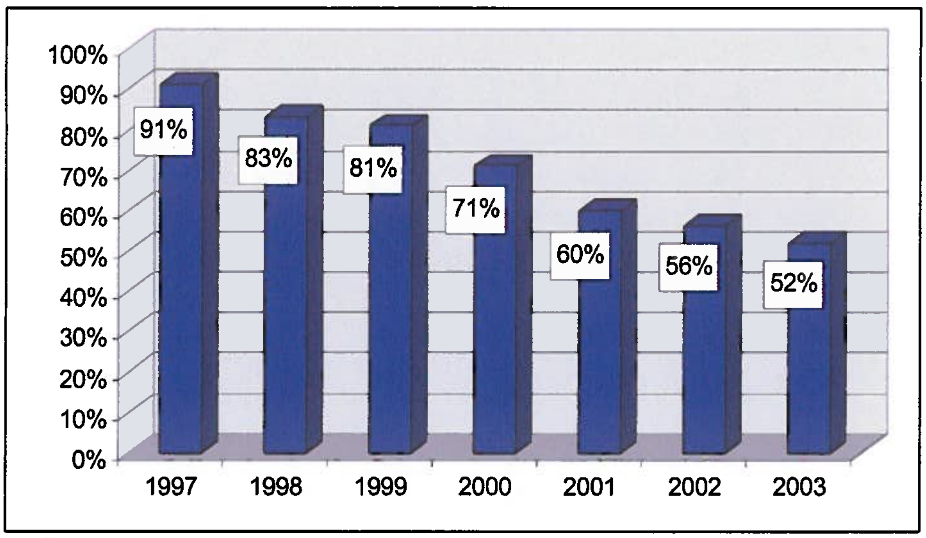
[8] Includes the municipalities of Maple Ridge and Pitt Meadows.
[9] Forward Looking Infrared device used for thermal imaging.
[10] Initial investigation would include the cases where there was insufficient evidence to obtain a search warrant. The classification 'no action' denotes cases for which no police investigation has occurred.

TABLE 2.8: ACTION TAKEN BY THE POLICE AFTER RECEIVING INFORMATION ON SUSPECTED MARIHUANA GROWING OPERATIONS AND THE PERCENTAGE OF CASES IN WHICH A FULL INVESTIGATION WAS CONDUCTED IN BRITISH COLUMBIA 1997-2003

YEAR		*Percentage of Cases Where Action was Taken After Information was Received*		
		Full investigation	Initial investigation only	No action taken
1997	**(*n* = 1489)**	91 %	2 %	7 %
1998	**(*n* = 2342)**	83 %	2 %	15 %
1999	**(*n* = 3100)**	81 %	4 %	15 %
2000	**(*n* = 4802)**	71 %	6 %	23 %
2001	**(*n*= 4464)**	60 %	25 %	15 %
2002	**(*n*= 4303)**	56 %	27 %	17 %
2003	**(*n*= 4514)**	52 %	26 %	22 %

N = 25,014

FIGURE 2.5: PERCENTAGE* OF FULL INVESTIGATION MARIHUANA CULTIVATION CASES IN BRITISH COLUMBIA 1997-2003



*All percentages rounded to the nearest whole number

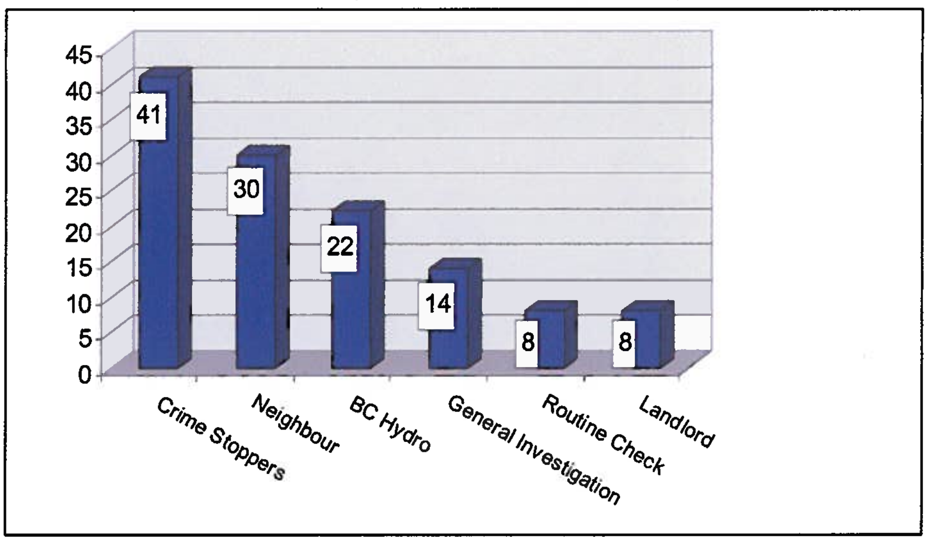
Table 2.9 indicates the average number of days elapsed from opening a marihuana production file to the date of search has decreased between 2000 to 2003, from 29 days to 18 days. The source of complaint to the police also affects the length of time between the complaint and police attending the scene. In Figure 2.6, Crimestoppers or anonymous informants have the longest length of time between report and attendance, with an average of 41 days across the seven year period. The average time elapsed for a neighbour report is also lengthy at 30 days.

Reports from BC Hydro, general investigation, routine check, and landlords are substantially shorter. A reason for this may be the increased time needed to collect evidence for a search warrant in cases involving an anonymous informant.

TABLE 2.9: AVERAGE NUMBER OF DAYS ELAPSED FROM OPENING MARIHUANA CULTIVATION FILE TO SEARCH BY YEAR IN BRITISH COLUMBIA 1997-2003

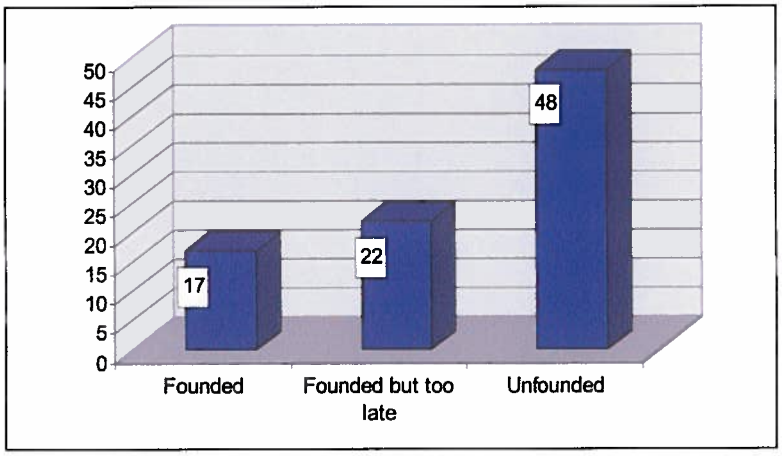
Year	Average Number of Days Elapsed
1997	17
1998	17
1999	24
2000	29
2001	21
2002	21
2003	18

FIGURE 2.6: AVERAGE NUMBER OF DAYS ELAPSED FROM OPENING OF A MARIHUANA CULTIVATION FILE TO SEARCH (BY SOURCE OF COMPLAINT) IN BRITISH COLUMBIA



Another important finding regarding police investigation of marihuana growing operations is the large amount of unfounded cases (see Figure 2.7). The fact that the days elapsed in getting to "unfounded cases" is nearly three times as long as the time elapsed for founded cases, and more than twice as long as cases "founded, but too late", may suggest that a large number of unfounded cases are perhaps not unfounded at all. Rather, a large number of unfounded cases may be nothing more than cases founded very, very late.

FIGURE 2.7: AVERAGE NUMBER OF DAYS ELAPSED FROM OPENING OF A MARIHUANA CULTIVATION FILE TO SEARCH (BY STATUS OF CASE) IN BRITISH COLUMBIA



* All figures rounded.

Founded Cases

During the seven years included in this study, 87% of the cases where a full investigation was conducted were founded cases. In a further 6% of the cases where a full investigation was conducted, there was evidence that a marihuana cultivation operation had taken place, but the search occurred too late to produce formal evidence. During the year 2003, 45% of all the cases that came to the attention of the police and 86% of the cases where a full investigation was conducted, proved to be founded. As mentioned above, the percentage of founded cases appears to be consistently declining 1997 through 2003 (see Table 2.10 and Table 2.11).

TABLE 2.10: PERCENTAGE OF ALL MARIHUANA CULTIVATION CASES THAT CAME TO THE ATTENTION OF THE POLICE WHICH PROVED TO BE FOUNDED IN BRITISH COLUMBIA 1997-2003

Year Cases brought to police attention	*Cases founded and marihuana was seized*	*Evidence of cultivation, but a search occurred too late*
1997 *(n =1,489)*	84 %	3 %
1998 *(n = 2,342)*	75 %	3 %
1999 *(n = 3,100)*	71 %	4 %
2000 *(n = 4,802)*	59 %	5 %
2001 *(n = 4,464)*	53 %	3 %
2002 *(n = 4,303)*	49%	4 %
2003 *(n = 4,514)*	45%	4 %

N = 25,014

* All percentages rounded.

TABLE 2.11: PERCENTAGE OF FULL INVESTIGATION WHERE THE CASE OF MARIHUANA CULTIVATION PROVED TO BE FOUNDED IN BRITISH COLUMBIA 1997-2003

Year Number of full investigation	*Case was founded, marihuana was seized*	*Evidence of cultivation, but a search occurred too late*	*Unfounded***
1997 *(n = 1345)*	93 %	3 %	4 %
1998 *(n = 1959)*	90 %	4 %	6 %
1999 *(n = 2509)*	88 %	5 %	7 %
2000 *(n = 3419)*	82 %	6 %	12 %
2001 *(n = 2667)*	88 %	5 %	7 %
2002 *(n = 2416)*	87 %	7 %	6 %
2003 *(n = 2360)*	86 %	7 %	7 %
Overall Average	87 %	6 %	8 %
N = 16,675	14,483	933	1259

* All figures rounded.

** Unfounded cases did not necessarily involve a formal search (i.e. search warrant). Some cases coming to the attention of the police were classified as "unfounded" by officers following, for example, a follow-up meeting with a landlord, or an inspection on crown land.

Chapter 3

DESCRIPTION OF MARIHUANA GROWING OPERATIONS

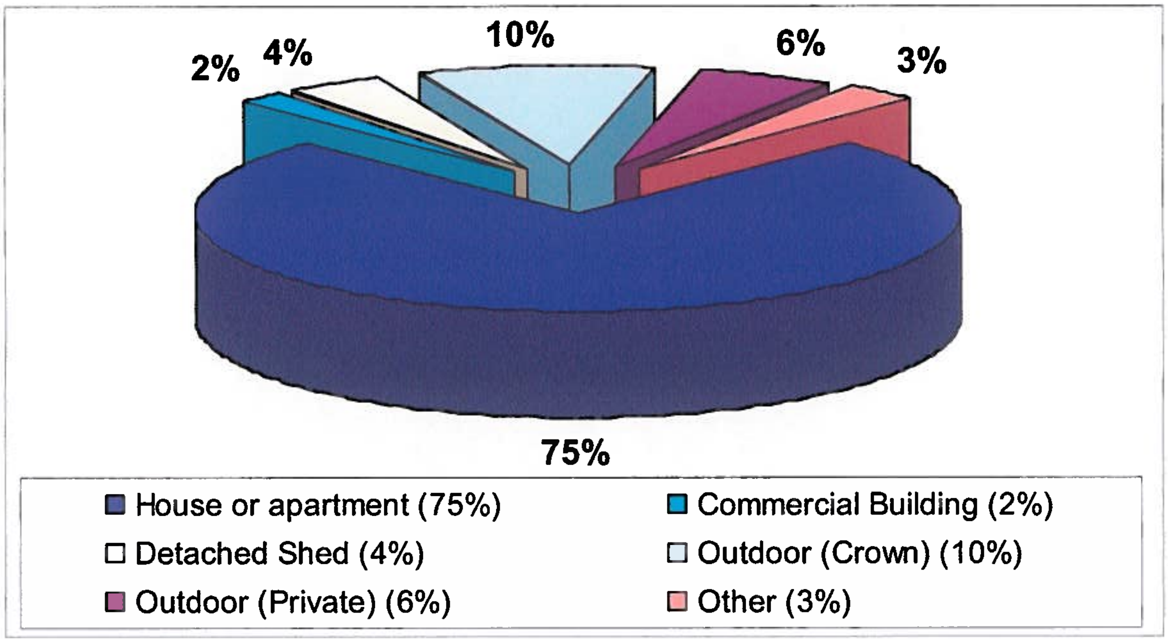
Between 1997 to 2003, more than 2.4 million marihuana plants and 19,325 kilograms of harvested marihuana were seized in British Columbia.. In general, the operations are becoming larger every year, as indicated by the number of plants and weight of harvested marihuana seized. With the increase in size and sophistication, communities are faced with progressively more harmful consequences related to marihuana growing operations. Specifically, grow operations result in an increased incidence of fires and children are present in 21%[11] growing operations.

Characteristics of Growing Operations

As was the case in the Plecas et al. (2002) study, the vast majority of the cases reviewed were indoor operations. As indicated in Figure 3.1 three quarters of founded grow operations are located within a house or apartment, while 16% are outdoors, located either on Crown (10%) or private (6%) land.

[11] Based on Vancouver data from 2003 due to incomplete recording in other jurisdictions.

FIGURE 3.1: TYPE OF FOUNDED MARIHUANA GROWING OPERATIONS IN BRITISH COLUMBIA 1997-2003



Note: For the period 1997 to 2000, 73% of cases were in houses or apartments, and 2% were in commercial buildings, 5% were in detached buildings, and 16% were associated to outdoor operations (See Plecas et al. (2002).

Table 3.1 describes the regional differences in outdoor growing operations. The Kootenay and Vancouver Island/Coast regions each have a large proportion of outdoor operations over the seven-year period. The Vancouver Island/Coast region has experienced a rise in the percentage of outdoor cases in 2002 and 2003. In part, this observed rise is due to the large number of outdoor eradications in this region. Eradications are large, coordinated policing initiatives aimed at locating and dismantling outdoor marihuana cultivation. The eradications are occasionally proactive, in the sense that many operations are spotted from air or sea without prior knowledge of the location. However, it is more common that the outdoor location comes to the attention of the police from informants, in a similar fashion to indoor growing operations.

TABLE 3.1: PERCENTAGE OF MARIHUANA CULTIVATION CASES INVOLVING AN OUTDOOR OPERATION IN EACH DEVELOPMENT REGION IN BRITISH COLUMBIA 1997- 2003

Development Region	*Percentage of cases involving outdoor cultivation*							
	1997	1998	1999	2000	2001	2002	2003	7 years
Kootenay	28 %	56 %	36 %	39 %	36 %	32 %	41 %	39 %
Vancouver Island/Coast	25 %	34 %	24 %	24 %	33 %	41 %	45 %	33 %
Thompson/Okanagan	20 %	32 %	26 %	23 %	25 %	21 %	23 %	25 %
North Coast	25 %	17 %	0 %	26 %	14 %	40 %	8 %	20 %
Cariboo	7 %	16 %	7 %	8 %	9 %	4 %	7 %	8 %
Northeast	0 %	17 %	8 %	0 %	1 %	0 %	0 %	5 %
Mainland/Southwest	7 %	7 %	5 %	6 %	4 %	5 %	5 %	5 %
Nechako	0 %	0 %	0 %	11 %	0 %	0 %	0 %	2 %
Province Overall	**15 %**	**22 %**	**15 %**	**13 %**	**15 %**	**16 %**	**19 %**	**16 %**

N = 25,014

The Size of Operations

The police case files indicate that marihuana was seized in both live plant and dried form. The average number of plants seized in marihuana growing operations has increased dramatically since 1997 (see Table 3.2). In fact, the average number of plants seized in indoor growing operations has increased each year since 1997. In 2003, the average number of plants per founded indoor grow operation was 236, an increase of nearly 60% from the average number per indoor growing operation in 1997.

Table 3.3 reports the number of kilograms of harvested marihuana seized in the province in each of the seven years studied. Notably, the average quantity of harvested marihuana seized has tripled since 1997 in both indoor and outdoor operations.

TABLE 3.2: AVERAGE NUMBER OF PLANTS INVOLVED WHEN PLANTS WERE SEIZED BY TYPE OF OPERATION IN BRITISH COLUMBIA 1997-2003

Type of Operation	*Average Number of Plants Seized in the Province*							
	1997	1998	1999	2000	2001	2002	2003	7 Year Average
Indoor	149	158	188	192	210	215	236	198
Outdoor	76	103	106	134	118	106	93	106
Other (bunker, trailer, vehicle)	162	118	220	166	78	134	224	128
All types combined	141	140	182	180	194	195	208	180

* All figures rounded.

FIGURE 3.2: AVERAGE NUMBER OF MARIHUANA PLANTS SEIZED PER INDOOR MARIHUANA GROWING OPERATIONS IN BRITISH COLUMBIA 1997-2003

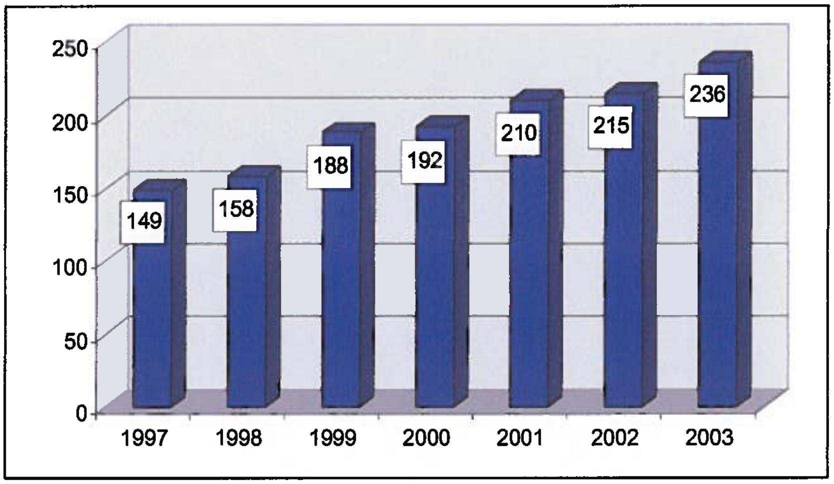


TABLE 3.3: AVERAGE NUMBER OF KILOGRAMS OF HARVESTED MARIHUANA SEIZED IN BRITISH COLUMBIA 1997- 2003

Type of Operation	*Number of kilograms of harvested marihuana seized*							
	1997	1998	1999	2000	2001	2002	2003	Total 7 years
Indoor	2.1	2.7	4.9	4.1	6.5	9.0	6.9	5.2
Outdoor	12.6	5.4	5.2	5.4	10.3	7.0	15.2	8.3
Other (e.g. bunker, trailer, vehicle)	2.1	1.8	3.9	3.3	1.3	3.5	1.7	3.2
All types combined	**2.4**	**2.7**	**4.8**	**4.0**	**6.6**	**8.5**	**7.2**	**5.1**

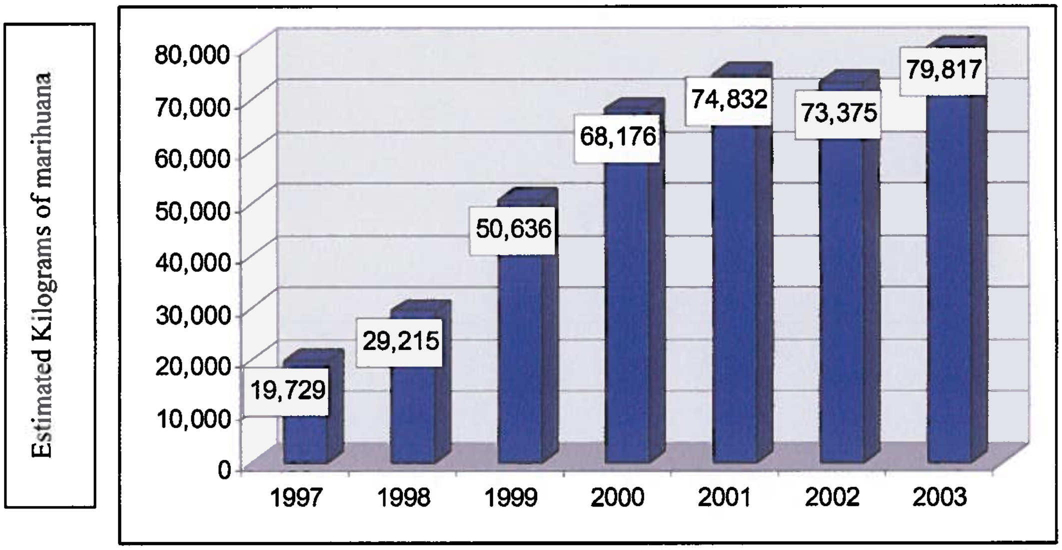
Table 3.4 shows the total quantity of marihuana seized between 1997 and 2003. The quantity of potentially harvestable substance per plant was conservatively estimated on the basis of 100 grams (or approximately 3.5 ounces) per plant.

TABLE 3.4: TOTAL QUANTITY OF MARIHUANA SEIZED IN BRITISH COLUMBIA 1997-2003

Form in which marihuana seized	*Estimated number of marketable kilograms of marihuana seized each year*							
	1997	1998	1999	2000	2001	2002	2003	Total
In plant form (100 gm / plant)	16,847	22,978	37,565	45,988	41,524	37,240	38,763	240,905
In bulk form already harvested	973	1,368	3,289	3,066	3540	4086	3002	19,325
Total Kilograms	**17,820**	**24,346**	**40,854**	**49,054**	**45,069**	**41,326**	**41,765**	**260,229**

In any case, the most realistic and useful figures on the amount of marihuana associated with cultivation cases in British Columbia over the 1997 to 2003 period are estimates of yearly production within the population of calls coming to the attention of police. Indeed, using such an estimate makes sense because the figures in the amount of marihuana actually seized is skewed downward by the fact that over the seven year period, the percentage of calls for service which led to a full investigation by police has steadily declined (refer to Table 2.8). As can be seen from Figure 3.3, using such an estimate shows that the estimated amount of marihuana produced each year has consistently increased to the point where the total volume in 2003, nearly 80,000 kilograms, is four times the nearly 20,000 kilograms produced in 2003. The total estimated volume produced over the seven year period is 395,780 kilograms, and in considering that figure, it is important to note that it is calculated from only the population of calls coming to the attention of the police.

FIGURE 3.3: ESTIMATED QUANTITY (IN KILOGRAMS) OF MARIHUANA PRODUCED FROM INCIDENTS COMING TO THE ATTENTION OF THE POLICE



* These estimates were derived using the following equation: (% founded cases in each year where full investigation occurred X total marihuana grow operations calls coming to the attention of police per year) X average quantity of marihuana seized in founded grow operations per year.

Value of Marihuana Seized

There are many different techniques to calculate what the average market value of confiscated marihuana is and on how to estimate it[12]. The same estimation procedure used in the Plecas et al. (2002) report was used in this study. The authors have conservatively estimated that marihuana plants could yield approximately 100 grams per plant, and that the average wholesale market value of a kilogram of dry British Columbia marihuana, when sold in quantities of over one kilogram has been at least $3,500 per kilogram.[13] Using this estimate, and based on the estimate of marihuana seized in British Columbia from January 1, 1997 through December 31, 2003 (see Table 3.4), at a cost of $3,500 per kilogram the value of the marihuana seized would yield a market value of approximately $910,801,500.

[12] See S. Easton's report for a full discussion of economic techniques on market estimation for marihuana production and distribution. Easton, S.T. (2004). *Marijuana growth in British Columbia*. Vancouver: Fraser Institute.

[13] Plecas, D., Dandurand, Y., Chin, V., & Segger, T. (2002). *Marihuana Growing Operations in British Columbia: An Empirical Survey (1997-2000)*. Abbotsford: University College of the Fraser Valley.

Growing Sophistication of Operations

Marihuana growing operations have not only grown in size over the past seven years, the sophistication of the operations also appears to be increasing. In the last three years of this study, it appears that more specialized equipment (i.e. timers, advanced hydroponic systems, electrical bypasses) are being used. The concept of increasing sophistication is not empirically measurable through the current file review study, however, the variables of electricity bypasses, number of hydroponic stores, and average number of lights per grow operation are indicative of increasing sophistication of measures.

This growth in sophistication and the number of grow operations is reflected in the increasing number of hydroponic stores in the province. In 2000, there were 101 different hydroponic stores in British Columbia.[14] In 2004, this number increased to 149 unique hydroponic locations.[15] The rate of growth in the number of hydroponic stores in British Columbia is six times higher than Washington State and nearly four times greater than Alberta, British Columbia's two closest neighbours (see Figure 3.4). This nearly 50% increase in hydroponic shops in British Columbia since 2000 is particularly interesting when considered against the apparent leveling off of the number of complaints coming to the attention of the police over the same time period.

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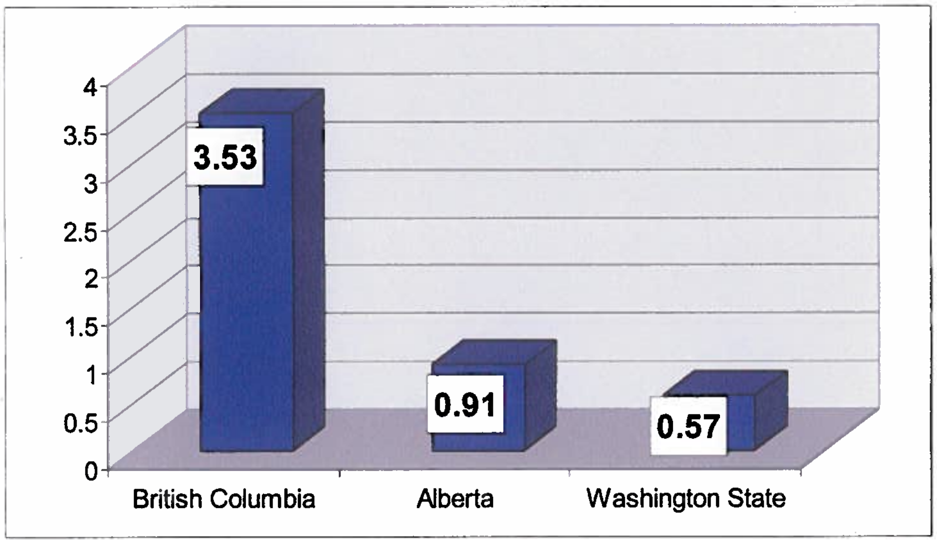
[14] Kirkpatrick, S., Hansom, D., Plecas, D., and Dandurand, Y., (2002). *Hydroponic Cultivation Equipment Outlets in British Columbia, Alberta and the State of Washington.* Vancouver/Abbotsford: International Centre for Criminal Law Reform and Criminal Justice Policy and the Department of Criminology and Criminal Justice, University College of the Fraser Valley, January 2002.

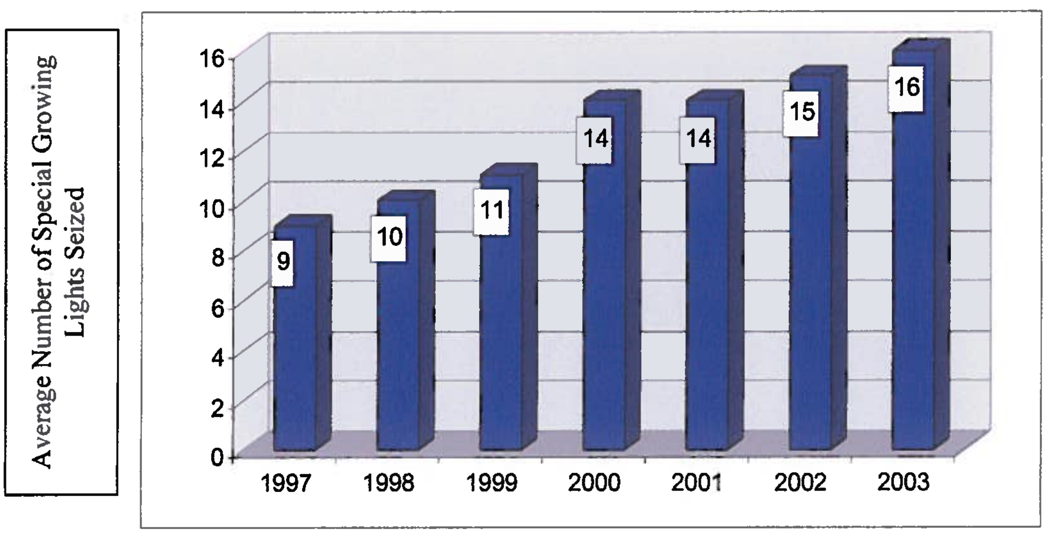
[15] Determined through systematic online review of 2004 telephone advertisements in British Columbia, Alberta, and Washington State.

FIGURE 3.4: RATE OF HYDROPONIC OUTLETS PER 100,000 POPULATION IN BRITISH COLUMBIA, ALBERTA AND WASHINGTON STATE 2004



Another variable that measures the increasing sophistication of growing operations is the use of special high voltage light bulbs. Figure 3.5 shows that the average number of special lights seized per growing operation has consistently increased over the seven-year study period.

FIGURE 3.5: AVERAGE NUMBER OF SPECIAL GROWING LIGHTS SEIZED FROM INDOOR MARIHUANA CULTIVATION OPERATIONS IN BRITISH COLUMBIA 1997-2003



* Includes some lights seized from trailers, bunkers, or lights boxed in vehicles.

Sophisticated indoor marihuana growing operations require large amounts of electricity to power high wattage lights which accelerate plant growth. In a few cases, special electric generators are used, while in others, particularly in small to medium size operations, electricity is consumed and paid for, but the operation is frequently moved to avoid detection. Operators often attempt to avoid detection as a result of their high consumption of electricity by stealing the electricity or by "diverting it", tampering with the meter, or by-passing it altogether. According to available information on file, the percentage of indoor marihuana growing operations involving the theft of hydro services remained relatively stable over the seven years. During this seven-year period, an average of 20% of founded cases involved theft of electricity. Table 3.5 summarizes the limited data collected on the incidence of theft of electricity during the period reviewed. The estimated value of electricity theft was known in only 47% of all cases involving a theft of electricity. The average estimated value of electricity theft has increased steadily since 2001 indicating that more electricity is being used through a single bypass and/or that the bypass is active for a longer period of time. This suggests operations that are either using more bulbs or operations with a larger number of plants. However, due to the decline in the percentage of indoor cultivation cases involving theft of electricity since 2000, the total reported sum of hydro theft has correspondingly decreased from $711,154 in 2000 to $489,909 in 2002 (see Table 3.5).

TABLE 3.5: THEFT OF ELECTRICITY INVOLVED IN CASES OF INDOOR MARIHUANA GROWING OPERATIONS IN BRITISH COLUMBIA 1997-2003

	1997	1998	1999	2000	2001	2002	2003
Percentage of indoor cultivation cases involving theft of electricity	21 %	14 %	20 %	26 %	16 %	21 %	21 %
Average value of hydro theft per operation *	$ 2,880	$ 3,145	$ 2,563	$ 2,784	$3,152	$ 3,699	$ 3,740
Total reported sum of hydro theft*	$ 250,596	$ 207,544	$ 392,166	$ 711,154	$ 438,083	$ 447,628	$ 489,909

* An assessment of the amount of electricity stolen was made in only 47% of the cases. The authors, extrapolating from what the data shows on founded cases and "no action" cases, estimate that the actual amount of hydro theft would have exceeded $3.2 million in 2003 alone.

The Potential Harm Associated with Indoor Growing Operations

Table 3.6 summarizes the information collected on some other characteristics of the founded marihuana cultivation cases investigated by the police in British Columbia between 1997 and 2003. Hazards were present in only 2.1% of founded cases, and its prevalence remained stable over the seven-year study time frame (see Table 3.6). The most common associated harm was the presence of a firearm (6.0%) which has increased since 2000. Overall, 15.3% of indoor grow operations had at least one harmful circumstance present (i.e. weapons, fire, other drugs) and that figure ignores electricity by-passes (i.e. 20% of cases), the presence of mold, and the chance of home invasions. The likelihood of harmful circumstances being present is particularly disturbing in view of the significant number of instances where children have been present at a grow operation. As Table 3.6 shows, children were recorded as being present in 21% of founded marihuana grow operations in 2003.

TABLE 3.6: OTHER CHARACTERISTICS OF MARIHUANA GROWING OPERATIONS IN BRITISH COLUMBIA 1997-2003

Circumstance	*Percentage of founded cases*
Hazards present (e.g., booby trap, explosives, dangerous chemical product)	2.1 %
Fire involved in indoor grows	3.7 %
Firearms seized	6.0 %
Other drugs seized (e.g. cocaine, heroin)	3.6 %
Other weapons seized (e.g., knives)	2.9 %
Children present (Vancouver 2003)	21 %*

* Due to the lack of consistent record keeping on children present in most other jurisdictions, this figure is based Vancouver 2003 data only.

Indoor growing operations are substantially more likely to catch fire than other residences. As Table 3.7 shows, there were 419 fires related to indoor grow operations in British Columbia between 1997 and 2003. Notably, the percentage of indoor grow operations associated to a fire has slightly increased year over year since 1999. In 2003, that percentage reached a seven-year high of 4.7%.

TABLE 3.7: NUMBER AND PERCENT OF FIRES OCCURRING IN FOUNDED INDOOR MARIHUANA GROWING OPERATIONS IN BRITISH COLUMBIA 1997-2003

	1997	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*Overall*
Number of Fires	32	48	51	69	72	67	80	419
Percent of Indoor Grow Operations Resulting in a Fire	3.5 %	4.1 %	3.1 %	3.4 %	3.5 %	3.7 %	4.7 %	3.7 %

Occurrences of fires, however, are not evenly dispersed among jurisdictions. In order to examine grow operation fires in more detail, the authors obtained data on all fires occurring in the City of Surrey, official incident reports on these fires, and the number of single family residences in the City of Surrey from January 1, 1997 through December 31, 2003. Their data are important because they allow for an analysis of the incidence of fires at grow operations relative to the incidence of fires in general. Equally important, both the official fire data and the individual fire reports allowed cross-referencing between the police-based database on grow operation fires to confirm that the analysis would only include those cases that made explicit reference to fires originating from an electrical problem associated to the presence of a grow operation within a single- family dwelling. Accordingly, the analysis excluded all individual reports of grow operation fires occurring in anything other than a single-family dwelling (i.e. sheds, barns, commercial buildings, apartments, or multiple family dwellings). The analysis also excluded any incident reports of grow operation fires if the suspected cause of the fire was not clearly and specifically tied to an electrical issue.

Using the data provided by the Surrey Fire Service, from 1997 to 2003, Surrey averaged 133 single family house fires per year. Given the number of single family homes in Surrey, this translates into an average of one fire per year per 525 homes (see Table 3.8). Given the likelihood of fire associated to grow operations is one in 22, it is fair to say that the probability of a fire in a home with a grow operation is 24 times as great as it is for a home in general.

TABLE 3.8: INCIDENCE OF FIRE AT SINGLE FAMILY RESIDENCES (SFR) IN SURREY FOR THE PERIOD 1997-2000

Year	*Population of SFRs*	*# of SFRs catching fire*	*Incident Ratio*
1997	**66,637**	**107**	**1 in 623**
1998	**68,152**	**128**	**1 in 532**
1999	**68,703**	**112**	**1 in 613**
2000	**69,703**	**135**	**1 in 514**
2001	**70,599**	**135**	**1 in 523**
2002	**71,777**	**142**	**1 in 505**
2003	**73,118**	**173**	**1 in 423**
Average	69,766	133	1 in 525*

*Includes fires involving grow operations. The incident ratio for fires among the population of grow operations at single family residences for data available for the 1997-2003 period is one in 22 (i.e. based on 23 fires within a population of 513 grow operations).

Table 3.9 describes the percentage of all fires in single family homes in the municipality of Surrey that appear to be directly attributable to an electrical problem associated with a grow operation. Out of a total of 173 fires in single family residences in Surrey in 2003, 8.7% involved electrical issues connected to marihuana grow operations. Equally noteworthy is that the average value of property loss in electrical fires involving grow operations in single family residences between 1997 and 2003 was nearly twice as high (i.e. $59,307) as for house fires in general in Surrey over that same time period (i.e. $31,282).

TABLE 3.9: TOTAL NUMBER OF FIRES AND PERCENT OF FIRES ASSOCIATED TO ELECTRICAL ISSUES INVOLVING GROW OPERATIONS IN SURREY, BRITISH COLUMBIA 1997-2003*

Year	# of Fires	% Involving Grow Operations
1997	107	.9
1998	128	6.3
1999	112	6.3
2000	135	5.2
2001	135	3.0
2002	142	1.4
2003	173	8.7
Average	932	4.7

*Figures based on a review of individual Surrey RCMP police files and cross-checked against individual fire incident reports from Surrey Fire Service. Only grow operations involving single family residences and only those fires confirmed to be associated with electrical issues were considered.

In considering the risk of fire associated to grow operations, it is important to keep in mind that not all fires involving grow operations are associated with an electrical by-pass issue. Rather, they can better be described as being associated with a number of electrical issues (including by-passes), most of which appear to be associated to a failure on the part of the individual(s) in control of the grow operation to comply with electrical standards.

Chapter 4

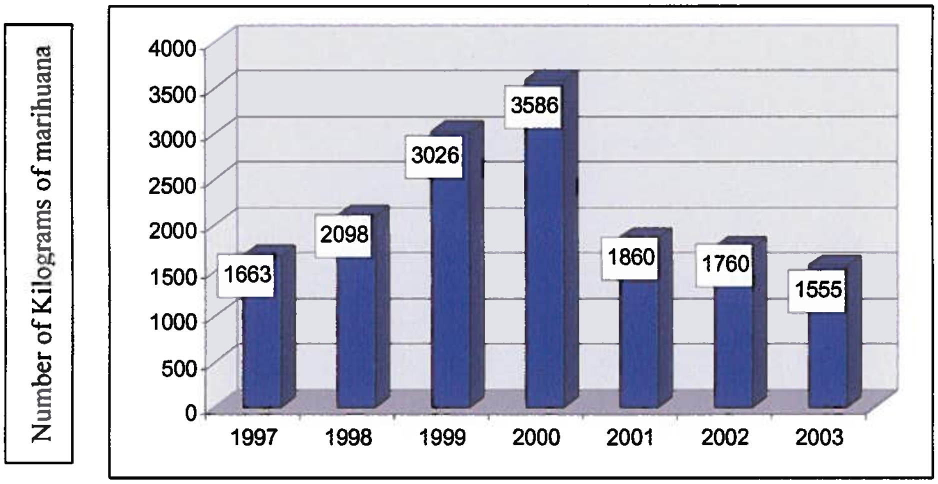
THE SUSPECTS

The researchers found just under 16,000 suspects involved in marihuana cultivation operations in British Columbia between 1997 and 2003. For BC as a whole, the majority of suspects were Caucasian males and in their mid-thirties. A more recent demographic shift has been the substantial increase in the number of Vietnamese suspects since 1997. Overall, the characteristics of suspects over the 1997 to 2000 period has remained relatively stable.

Description of Suspects

A total of 15,588 suspects were identified out of the 14,483 founded cases of marihuana cultivation. Figure 4.1 represents the constant rise in suspects from 1997 through 2000 and then a dramatic drop in the number of suspects in 2001 through 2003. The increase and subsequent drop in number of suspects can be related to the concomitant rise in the number of founded cases that proceeded to investigation from 1997 through 2000, and the subsequent rise in "no case" seizures (see Chapter 5) and "no action" files with no suspects 2001 through 2003. As mentioned earlier in this report, identical data collection methods were strictly adhered to in both phases of the research, thereby excluding the possibility of collection procedures influencing the number of suspects recorded over the two phases of the study.

FIGURE 4.1: NUMBER OF SUSPECTS IDENTIFIED IN RELATION TO FOUNDED MARIHUANA CULTIVATION OPERATIONS IN BRITISH COLUMBIA 1997-2003



Characteristics of the suspects involved can be seen in Table 4.1. Seventy-seven percent of all suspects were male, 2% of all the suspects identified were under the age of 18, and the average age of suspects was 35 years old.

TABLE 4.1: NUMBER, AGE, AND ETHNIC GROUP OF SUSPECTS INVOLVED IN FOUNDED MARIHUANA CULTIVATION OPERATIONS WITH SUSPECTS PRESENT IN BRITISH COLUMBIA 1997-2003

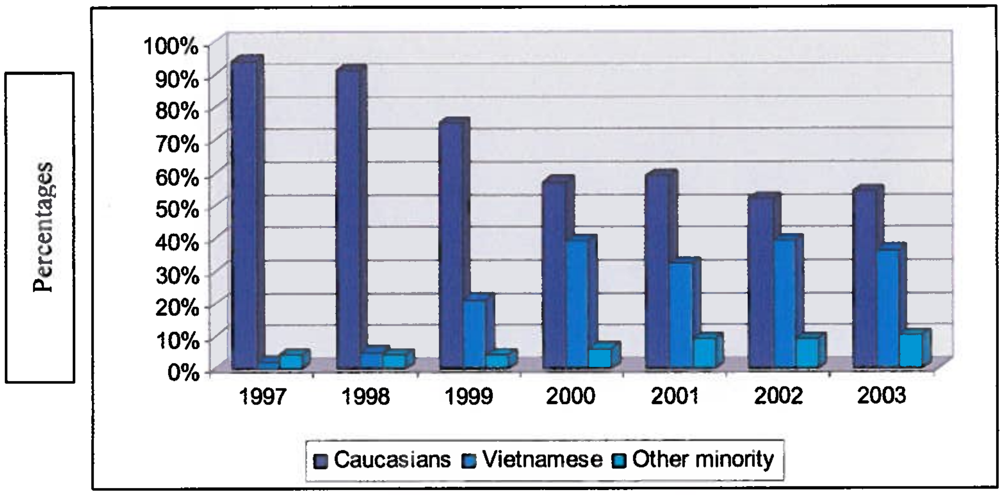
Characteristics	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*Overall*
Average number of suspects per case	2.1	2.1	2.3	2.3	1.9	2.0	2.1	2.1
Percentage of suspects who were male	79 %	80 %	78 %	75 %	77 %	74 %	77 %	77 %
Percentage of suspects who were female	21 %	20 %	22 %	25 %	23 %	26 %	23 %	23 %
Average age of suspects	34	34	34	35	35	36	36	35
Percentage of suspects under the age of 18	1 %	2 %	2 %	2 %	2 %	1 %	1 %	2 %
Percentage of suspects from any minority ethnic groups	6 %	9 %	25 %	43 %	41 %	48 %	46 %	31 %
Percentage of suspects of Vietnamese origin	2 %	5 %	21 %	39 %	32 %	39 %	36 %	26 %

N = 15,588

Figure 4.2 shows a steady decline in Caucasian suspects and a corresponding increase in Vietnamese suspects. For 1997 and 1998 and, to large degree, 1999, the most frequently occurring ethnicity reported in the suspect data is Caucasian. However, Vietnamese suspects.

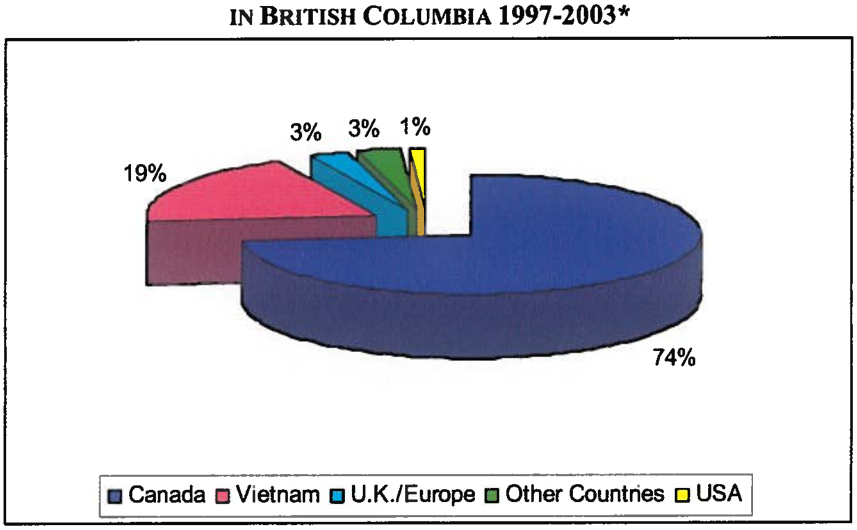
represented 2% of all suspects associated to growing operations, but by 2003, they represented 36%. Other minority groups have increased from 4% in 1997 to 10% in 2003, many of these from Mainland China. However, Caucasians remain the most common ethnicity.

FIGURE 4.2: ANNUAL PERCENTAGES OF SUSPECTS INVOLVED IN MARIHUANA CULTIVATION OPERATIONS BY ETHNIC GROUP IN BRITISH COLUMBIA 1997-2003



In terms of the distribution of suspects by place of birth, 74% percent of all known suspects were born in Canada (see Figure 4.3). As expected, due to their substantial increase as suspects since 2000, Vietnam is the second most common country of origin among suspects. Very few foreign born suspects were from the United States or Europe.

FIGURE 4.3: PLACE OF BIRTH OF SUSPECTS INVOLVED IN MARIHUANA CULTIVATION OPERATIONS IN BRITISH COLUMBIA 1997-2003*



*All percentages rounded to the nearest whole number

Criminal History of Suspects

Each of the 15,588 suspects were checked against the CPIC database to determine if he or she had a record of prior criminal convictions. For approximately 20% of these suspects, it was not possible to determine previous criminal history due to incomplete or unmatchable file information. The most common reason for not being able to match suspects was because of incomplete, missing, or erroneous recording of the suspect's name, date of birth, fingerprint identifier number (FPS), or, because there was more than one offender with identical details on file. In order to avoid double counting of suspects, imperfectly populated suspect forms were dropped from the criminal history analysis.

Marihuana cultivation suspects typically had a substantial criminal history. Excluding missing cases, 47% of all suspects had prior criminal convictions at the time of investigation. In total, 57% of all suspects had at least one prior conviction for a drug offence and 41% had a prior conviction involving some form of violence.

The percentage of suspects with a criminal record was lower for suspects of Vietnamese origin (28%), all other suspects (53%). A possible reason for this may be that many Vietnamese suspects are first generation, as indicated by their country of birth, and information on their criminal histories prior to arriving in Canada was not available.

TABLE 4.2: PERCENTAGE OF SUSPECTS WITH A CONFIRMED PRIOR CRIMINAL CONVICTION MARIHUANA CULTIVATION CASES IN BRITISH COLUMBIA 1997-2003

Category of suspects	*Percentage of suspects with at least one prior criminal conviction*
All suspects	47 %
All suspects excluding those of Vietnamese origin	53 %
Suspects of Vietnamese origin	28 %

N = 15,588

Table 4.3 presents a comparison between suspects of Vietnamese origin and other suspects. The average length of the criminal history of the former is a little less than one-half the average length of the criminal history of other offenders (6 years versus 13 years, respectively). Moreover, criminal histories involved, on average, approximately half as many offences for Vietnamese suspects. The criminal records of suspects of Vietnamese origin also have almost half the number of prior violent offences and are convicted in fewer jurisdictions than non-Vietnamese suspects. The average period of time between each conviction, however, is shorter among Vietnamese suspects than others. Regardless of country of birth, over one-half of all suspects, regardless of country of birth, were guilty of at least one Controlled Drugs and Substances Act offence prior to their suspected involvement with a marihuana production facility. The number of suspects involved in previous drug offences, particularly marihuana production, has increased since 2000, suggesting that many of the suspects are setting up another grow operation after they are initially caught. This will be explored in future research by the authors, examining the number of repeat offenders over the seven-year study period and the effect that the action taken by the criminal justice system has had on these offenders.

TABLE 4.3: COMPARISON BY ETHNIC AFFILIATION OF THE CRIMINAL HISTORIES OF SUSPECTS INVOLVED IN MARIHUANA CULTIVATION OFFENCES IN BRITISH COLUMBIA 1997-2003

Characteristic of suspects criminal record considered	*Suspects of Marihuana Cultivation*		
	All suspects	Non-Vietnamese	Vietnamese origin
Average length of criminal history	13 yrs	14 yrs	6 yrs
Average number of prior convictions	7	7	3
Percentage with prior drug convictions	57 %	59 %	54 %
Percentage with prior conviction for possession for the purpose of trafficking	27 %	27 %	33 %
Percentage with a prior marihuana cultivation conviction	22 %	22 %	27 %
Percentage with conviction for violent offence	41 %	43 %	23 %
Percentage with conviction for non-compliance offences*	28 %	30 %	16 %
Average number of jurisdictions in which suspects were convicted	2.3	2.5	1.5
Percentage of suspects convicted in Ontario, the most frequent province other than BC where suspects were previously convicted	11 %	10 %	20 %

* Non-compliance offences: (e.g., failure to appear, breach of probation, escape, parole violation, etc.).

Chapter 5

Action Taken

This chapter explores the criminal justice system's response to marihuana growing operations over the seven-year study period. Data on searches and seizures of growing operations, police charging of suspects, and court dispositions are discussed in order to better understand the way in which the system reacted to marihuana cultivation. An important caveat is that data could only be collected in cases where information was known at the time of data collection.

Searches and Seizures

Not all searches and seizures of marihuana growing operations have the same results. In most founded cases, police officers seize and dispose of all plants, harvested marihuana, and growing equipment from the location. However, differences occur in how suspects are dealt with. In some cases, after the equipment and marihuana is seized, no further action is taken against the suspect. These "no case" seizures are based upon police discretion and have been constantly increasing since 1997.

As indicated by table 5.1, more than half of all cases in the seven-year study period where marihuana was seized were dealt with as "no case" seizures. As in the previous study (Plecas et al. 2002), "no case" seizures were considerably less likely in cases where a suspect was present (35%). The number of plants present in a growing operation also effected the likelihood that a search would result in a "no case" seizure (see Table 5.2). Close to two thirds (64%) of cases with less than 10 plants resulted in a "no case" seizure. This percentage drops consistently as you increase the size of the growing operation. At the same time, it was found that different police jurisdictions use "no case" seizures at widely varying rates, ranging from 0 to approximately 75 % of all founded incidents.

TABLE 5.1: PERCENTAGE OF FOUNDED MARIHUANA CULTIVATION CASES CLASSIFIED AS 'NO CASE' SEIZURES IN BRITISH COLUMBIA 1997-2003

Year	Percentage Which Were "No Case" Seizures*	
	All founded cases	Founded cases where a suspect was identified
1997	35 %	23 %
1998	50 %	36 %
1999	43 %	30 %
2000	48 %	34 %
2001	62 %	38 %
2002	66 %	45 %
2003	64 %	42 %
Overall average	**54 %**	**35 %**

* All percentages have been rounded to the nearest whole number.

TABLE 5.2: PERCENTAGE* OF FOUNDED CASES THAT WERE CLASSIFIED AS 'NO CASE' BY THE NUMBER OF MARIHUANA PLANTS SEIZED IN BRITISH COLUMBIA 1997-2003

Year	Percentage* Which Were "No Case" seizures			
	<10 plants seized	10–49 plants seized	50–99 plants seized	100+ plants seized
1997	48 %	29 %	14 %	11 %
1998	59 %	42 %	29 %	21 %
1999	63 %	39 %	25 %	17 %
2000	70 %	37 %	32 %	23 %
2001	63 %	43 %	43 %	29 %
2002	71 %	54 %	52 %	36 %
2003	82 %	54 %	39 %	32 %
Overall average	**64 %**	**41 %**	**33 %**	**25 %**

* All percentages have been rounded to the nearest whole number.

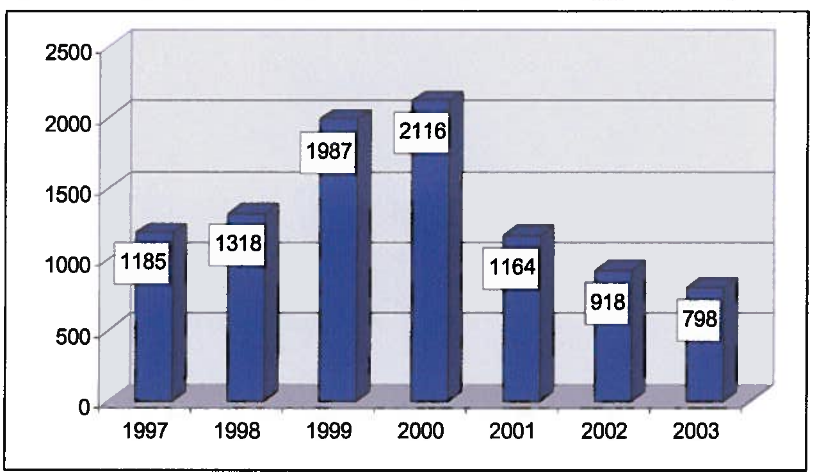
As indicated by Table 5.3, from 1997 through 2003, there was a consistently decreasing percentage of cases in which charges were laid. The number of cases where charges were laid dropped to 76% in 2003 from over 90% in 1997 through 2001. Figure 5.1 clearly demonstrates how the actual number of suspects charged has also dropped in 2001 through 2003. This is, however, relative to the decreasing number of suspects present at founded growing operations since 2001. Over the seven-year period of study, 9486 suspects in marihuana growing operations have been charged.

TABLE 5.3: PERCENTAGE* OF FOUNDED CASES THAT WERE NOT CLASSIFIED 'NO CASE' WHERE CROWN LAID CHARGES IN BRITISH COLUMBIA 1997-2003

Year	*Percentage* of Cases in Which Charges Were Laid*	Actual # of Cases in Which Charges Were Laid
1997	96 %	682
1998	94 %	717
1999	94 %	997
2000	94 %	1153
2001	92 %	824
2002	89 %	633
2003	76 %	553
Overall average	**91 %**	**5559**

* All percentages have been rounded to the nearest whole number.

FIGURE 5.1: NUMBER OF SUSPECTS CHARGED IN BRITISH COLUMBIA 1997-2003



Charges

If a founded growing operation does not become classified as a "no case" seizure, a report is submitted to Crown Counsel. Once a Crown Counsel report is submitted, the likelihood of formal charges being laid against one or more of the suspects is very high (91%). During the seven-year research period, 6,109 cases resulted in at least one charge being laid. The total number of charges relating to marihuana cultivation is presented in Table 5.4. All charges show a substantial decrease since 2001, due, in large part, to the increasing number of "no case" seizures.

TABLE 5.4 TOTAL NUMBER OF CHARGES RELATING TO MARIHUANA CULTIVATION INCIDENTS IN BRITISH COLUMBIA 1997-2003

Charge	*Charges laid in relation to marihuana cultivation incidents*							
	1997	1998	1999	2000	2001	2002	2003	Overall
Production/cultivation	1113	1241	1900	2028	1063	843	732	8920
P.P.T.*	835	992	1539	1626	819	659	531	7001
Simple possession	240	210	262	235	156	100	85	1288
Theft of electricity	177	137	348	432	182	154	81	1511
Firearms	100	112	107	100	36	34	22	511
Other Criminal Code	102	67	144	90	64	74	53	594
Total	**2567**	**2759**	**4300**	**4511**	**2320**	**1864**	**1504**	**19,825**

* Possession for the purpose of trafficking.

As illustrated in Table 5.5, the majority of the 9,486 suspects charged in British Columbia in relation to marihuana cultivation were given a primary charge of marihuana production (S.7 C.D.S.A). In the overwhelming majority (84%) of the cases, production was attended by other charges; the most frequent of these being possession for the purpose of trafficking. Only 194 suspects during the study period were charged solely with simple possession of marihuana. The average number of plants in the cases with a sole charge of possession was 83.

TABLE 5.5 PERCENTAGE OF CHARGED SUSPECTS BY TYPE OF CHARGES: MARIHUANA CULTIVATION OPERATIONS IN BRITISH COLUMBIA 1997-2003

Charge	*Percentage* of offenders charged*		
	By offence	In addition to a production charge	One offence and no other
Production	94 %	-	16 %
P.P.T.***	74 %	71 %	2 %
Simple possession	14 %	11 %	2 %
Theft of electricity	16 %	16 %	0 %**
Firearms	5 %	5 %	0 %**
Other Criminal Code	6 %	5 %	0 %**

N = 9486

* All percentages have been rounded to the nearest whole number.

** When combining theft, firearms related offences, and other Criminal Code offences, the total number of such of charges is 63, which is less than 1% of the total.

*** Possession for the purpose of trafficking

Due to the time frame of this research and the fact that not all suspects had completed their court appearance, 33% of the total number of charges (n= 6,487) were not yet disposed of at time of data collection. Therefore, the following analysis is based on 13,329 charges laid that had received a disposition at the time of data collection. These charges involved a total of 6,487 offenders.

Dispositions

If criminal charges were laid by Crown Counsel, in slightly less than half of the time (44%), the suspect received a stay of proceedings (see Table 5.6). Moreover, there does not appear to be a substantial difference in the likelihood of having all charges stayed based upon the number of charges laid. Gender appears to have an effect on the likelihood of receiving a stay of proceedings. As seen in Table 5.7, female suspects have their charges stayed two times as often as male suspects. As reported in the Plecas et al. (2002) study, in cases with multiple suspects, charges were maintained against the male suspects and stayed for the female suspect(s). In the current study, in cases where a female was the only suspect, the proceedings were stayed in 33% of the cases, whereas only 22% of the cases were stayed for male suspects.

TABLE 5.6: PERCENTAGE OF SUSPECTS WHOSE CHARGES WERE STAYED: MARIHUANA CULTIVATION CASES IN BRITISH COLUMBIA 1997-2003

Number of charges faced by suspect	*Percentage* of suspects** and stay of proceedings*		
	All charges stayed	Only some charges stayed	None of the charges stayed
One charge	42 %	--	58 %
Two charges	46 %	42 %	12 %
Three charges	43 %	48 %	9 %
Four charges	48 %	46 %	6 %
Five charges	35 %	59 %	6 %
Six charges	0 %	0 %	100 %
Total suspects	**44 %**	**36 %**	**20 %**

* All percentages have been rounded to the nearest whole number.
** Includes only suspects in cases where charges had been disposed of at the time of data collection.

TABLE 5.7: GENDER OF SUSPECTS IN WHOSE CASE PROCEEDINGS HAVE BEEN STAYED WITH RESPECT TO ALL CHARGES IN MARIHUANA CULTIVATION CASES IN BRITISH COLUMBIA 1997-2003

Number of charges faced by suspects	*Percentage* of suspects** for whom all charges were stayed*		
	Males	Females	Overall
One charge	34 %	66 %	42 %
Two charges	37 %	74 %	46 %
Three charges	35 %	70 %	43 %
Four charges	39 %	83 %	48 %
Five charges	17 %	80 %	35 %
Six charges	0 %	0 %	0 %
Overall	**36 %**	**72 %**	**44 %**

* All percentages have been rounded to the nearest whole number.
** Includes only suspects in cases where charges had been disposed of at the time of data collection.

Table 5.8 presents a comparison of action taken on the charges, accused, and files associated with cases approved by Crown Counsel in cultivation cases. A very low percentage (4%) of charges, accused, and files result in not guilty verdicts and only 30% of approved charges resulted in convictions, 52% of the accused connected to those charges were found guilty. However, 73% of the cases associated with those approved charges resulted in at least one accused being found guilty. In the final analysis, it would appear that Crown Counsel is trading off charges and the involvement of multiple accused to increase the likelihood of securing a conviction in individual cases.

TABLE 5.8: SUMMARY COMPARISON OF ACTION TAKEN ON THE CHARGES, ACCUSED, AND FILES ASSOCIATED WITH CASES APPROVED BY CROWN COUNSEL IN MARIHUANA CULTIVATION CASES IN BRITISH COLUMBIA 1997-2003

Status	*Charges Involved*	*Accused Involved*	*Files Involved*
Number approved	13,329	6487	4136
Number stayed	8748	2863	932
	(66%)	*(43%)*	*(23%)*
Number referred to court	4581	3624	3204
	(34%)	*(56%)*	*(77%)*
Number found not guilty	517	230	173
	(4%)	*(4%)*	*(4%)*
Number resulting in conviction	4064	3364	3008
	(30%)	*(52%)*	*(73%)*

*Percentage in brackets represents percentage of number approved.

Chapter 6

SENTENCING

The patterns of sentencing that emerge in relation to marihuana cultivation operations are difficult to accurately interpret. This difficulty is due to a number of complicating factors. The first of these factors, as discussed in Plecas et al. (2002), involves suspects who were accused in relation to their involvement in a marihuana cultivation operation and charged with multiple offences. The initial charges usually include a marihuana production charge, found in 94% of the cases, and a possession for the purpose of trafficking charge, found in 74% of the cases. Other charges often included with marihuana growing operation suspects include simple possession of marihuana, the possession of other controlled substances, theft of electricity, firearm related offences, and various other Criminal Code offences. The second difficulty surfaces because suspects frequently plead guilty to one or more charges, not necessarily the drug production charge, based on an agreement with the Crown. Consequently, some offenders were convicted of only one of the offences that they had originally been charged with, while others were convicted of two or three charges relating to the same marihuana cultivation operation. Another difficulty occurs because convicted offenders often receive multiple dispositions for the various related charges. The last difficulty involves an offender being sentenced to several dispositions for different charges, these sentences could be ordered served either concurrently or consecutively. Despite these difficulties, this chapter makes an effort to clarify the patterns of sentencing involved with marihuana growing operations in British Columbia from 1997 through 2003.

Type and Severity of Penalty Imposed

As shown in Table 6.1, the percentage of sentences that result in custody involving marihuana cultivation cases in British Columbia has dropped since 2000. Conversely, the percentage of conditional sentences has increased from 15% in 1997 to over 40% beginning in 2000. Firearms prohibition orders also increased dramatically from only 5% in 1997 to as high as 62% in 2002. Also, the proportion of conditional or absolute discharges doubled from 4% in 2000 to 8% in 2003.

TABLE 6.1: PERCENTAGE OF CASES WHERE SELECTED PENALTIES WERE AWARDED AS PART OF A SENTENCE FOR ANY OF THE CHARGES INVOLVED IN MARIHUANA CULTIVATION CASES IN BRITISH COLUMBIA 1997-2003

Disposition	*Percentage of cases**							
	1997	1998	1999	2000	2001	2002	2003	Overall
Prison	19 %	17 %	19 %	18 %	10 %	9 %	10 %	**16 %**
Conditional sentence	15 %	26 %	33 %	42 %	45 %	57 %	41 %	**34 %**
Probation	28 %	27 %	25 %	23 %	25 %	18 %	22 %	**25 %**
Fine	48 %	46 %	37 %	38 %	44 %	34 %	49 %	**42 %**
Community service order	5 %	6 %	6 %	9 %	2 %	3 %	2 %	**5 %**
Restitution	8 %	4 %	7 %	9 %	30 %	27 %	25 %	**12 %**
Firearms prohibition order	5 %	12 %	34 %	55 %	49 %	62 %	58 %	**34 %**
Conditional or absolute discharge	3 %	3 %	4 %	4 %	7 %	7 %	8 %	**5 %**

* All percentages have been rounded to the nearest whole number.

During the seven-year study period, conditional sentences increased. As was the case in the Plecas et al. (2002) study, these sentences were usually accompanied by other penalties. However, Table 6.2 indicates that a conditional sentence was the most serious disposition in 46% of cases in 2003, up from only 13% of cases in 1997. Since the percentage of cases where prison sentences were the most serious disposition has decreased from 18% in 2000 to only 10% in 2003, it would seem that a conditional sentence was being used as an alternative to prison sentences. Probation is utilized in 25% of charges involved in marihuana cultivation cases, however, the percentage of cases where probation was utilized as the most serious sentence dropped fairly consistently since 1997. Probation, as the most serious sanction, was imposed in only 12% of the cases in 2003, down from 18% in 1997. The use of fines has fluctuated from a low of 34% in 2002 to a high of 49% in 2003 (see Table 6.1). The use of fines as the most serious disposition decreased from 1997 (34%) through 2000 (18%), and then increased in 2001 (26%) and 2003 (32%).

TABLE 6.2: PERCENTAGE OF CASES WHERE PRISON OR ANOTHER PENALTY WAS THE MOST SERIOUS DISPOSITION AWARDED AS PART OF THE SENTENCE IN MARIHUANA CULTIVATION CASES IN BRITISH COLUMBIA 1997-2003

Disposition	*Percentage of cases**							
	1997	1998	1999	2000	2001	2002	2003	Overall
Prison	19 %	17 %	19 %	18 %	10 %	9 %	10 %	16 %
Conditional sentence	13 %	32 %	40 %	50 %	49 %	63 %	46 %	40 %
Probation	18 %	18 %	15 %	14 %	15 %	8 %	12 %	16 %
Fine	34 %	30 %	23 %	19 %	26 %	19 %	32 %	26 %
Community service order	0 %	0 %	0 %	0 %	0 %	0 %	0 %	0 %
Restitution	0 %	0 %	0 %	0 %	1 %	1 %	0 %	0 %
Firearms prohibition order	0 %	0 %	4 %	4 %	1 %	2 %	2 %	2 %
Conditional/absolute discharge	1 %	1 %	1 %	0 %	1 %	1 %	0 %	1 %

* All percentages have been rounded to the nearest whole number.

Table 6.3, Table 6.4, and Table 6.5 all illustrate the percentage of cases where a particular penalty was imposed for the offences of marihuana production, possession for the purpose of trafficking, and electrical theft, respectively. The penalties for marihuana cultivation have remained fairly stable over the seven-year study period. One noticeable trend is the reduction in the amount of restitution imposed since 1999 (see Table 6.3). The penalties for possession for the purpose of trafficking have also remained constant with the exception of a consistent increase in the length of conditional sentences and peaks in length of prison sentences in 2001 and 2003 (See Table 6.4). Table 6.5 reports that the penalties for theft of electricity have fluctuated over the seven-year study period, with substantial shifts in the length of conditional sentences (4.8 months in 1997, 16.0 months in 2003) and restitution ($1,885 in 1997, $13,046 in 2003). However, these numbers should be interpreted with the knowledge that there is a low number of cases that receive sentences for theft of electricity, therefore the numbers are susceptible to dramatic fluctuations based on extreme values.

TABLE 6.3: SEVERITY OF PENALTY IMPOSED FOR THE OFFENCE OF MARIHUANA PRODUCTION (C.D.S.A. S. 7) IN RELATION TO MARIHUANA CULTIVATION CASES IN BRITISH COLUMBIA 1997-2003

Type of Disposition	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*Overall*
Prison (months)	3.9	4.2	5.1	5.2	4.7	4.2	4.3	4.9
Conditional Sentence (months)	6.9	7.3	7.1	8.5	8.8	8.4	8.5	7.9
Probation (months)	14.1	13.8	12.9	13.0	11.4	10.3	10.2	12.9
Fine ($)	$2,499	$2,383	$2,427	$1,767	$1,807	$1,867	$2,368	$2,218
Community Service Order (hours)	70	95	66	65	59	104	33	73
Restitution ($)	$2,046	$2,066	$1,178	$1,64	$265	$609	$274	$886

TABLE 6.4: SEVERITY OF PENALTY IMPOSED FOR THE OFFENCE OF POSSESSION FOR THE PURPOSE OF TRAFFICKING (C.D.S.A. S. 5) IN RELATION TO MARIHUANA CULTIVATION CASES IN BRITISH COLUMBIA 1997-2003

Type of Disposition	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*Overall*
Prison (months)	4.2	3.3	5.4	5.2	8.7	3.5	7.5	4.8
Conditional Sentence (months)	7.0	9.3	7.1	8.8	9.0	9.4	12.8	8.7
Probation (months)	13.4	13.8	12.9	11.2	14.6	10.3	10.5	12.9
Fine ($)	$2,899	$2,329	$2,445	$1,495	$1,491	$765	$1,591	$2,075
Community Service Order (hours)	70	118	75	100	100	50	-	88
Restitution ($)	$1,525	$1,792	$795	$296	$266	$130	$4,582	$945

TABLE 6.5: SEVERITY OF PENALTY IMPOSED FOR THE OFFENCE OF THEFT OF ELECTRICITY (C.C.C. S. 326) IN RELATION TO MARIHUANA CULTIVATION CASES IN BRITISH COLUMBIA 1997-2003

Type of Disposition	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*Overall*
Prison (months)	3.7	1.9	2.5	3.8	1.0	6.0	-	2.9
Conditional Sentence (months)	4.8	8.7	8.4	6.6	9.2	10.4	16.0	8.5
Probation (months)	12.7	9.0	15.8	14.0	17.1	10.5	6.0	13.0
Fine ($)	$1,294	$618	$796	$840	$1,477	$2,126	$500	$1,100
Community Service Order (hours)	65	90	-	-	-	50	-	72
Restitution ($)	$1,885	$2,657	$1,718	$1,138	$822	$3,069	$13,046	$1,947

Severity of Penalties and Size of Cultivation Operations

The researchers conducted correlations in order to determine whether the size of growing operation, measured by number of plants seized and the amount of electricity theft, influenced the severity of penalties given. As indicated in Table 6.6, shows that the number of plants seized in a marihuana growing operation has been consistently related to the severity of the penalties imposed in every category except dollar value of restitution awarded. Notably though, it is only this category, restitution value, that is significantly correlated with amount of electricity theft.

TABLE 6.6: ZERO-ORDER CORRELATIONS BETWEEN THE SEVERITY OF THE PENALTIES IMPOSED AND THE SIZE OF THE MARIHUANA CULTIVATION OPERATION - OFFENDERS SENTENCED FOR MARIHUANA CULTIVATION (C.D.S.A. S.7) OPERATIONS IN BRITISH COLUMBIA, 1997-2003

Penalties	*Correlation between severity of penalties and*	
	Number of plants seized	Amount of electricity theft
Number of months prison awarded	.17*	.12
Number of months conditional sentence awarded	.26*	-.02
Number of months probation awarded	.16*	.14
Dollar value of fines awarded	.16*	.05
Number of hours of community service awarded	.26*	-.05
Dollar value of restitution awarded	.02	.51*

* Correlation is significant at the .05 level.

Severity of Penalty and Offenders' Criminal History

The authors compared the severity of the offenders' criminal history, as measured by the number of previous convictions and the number of previous drug convictions with the severity of the penalty imposed through sentencing. While the length of prison term does not seem consistent with the offenders' previous number of convictions or previous number of drug convictions, the likelihood of receiving a prison sentence does appear related. While the likelihood of receiving a prison term for an offence related to marihuana production was only 16%, this likelihood did increase as the length of criminal history increased (see Table 6.7). However, the length of prison sentence was not systematically affected by the number of prior offences in an offender's criminal history. On the other hand, as Table 6.8 shows, as the number of previous drug offence increased, so did the likelihood of receiving a prison sentence. However, the length of prison sentence was not consistently related to the number of previous drug convictions.

TABLE 6.7: PERCENTAGE OF THE OFFENDERS WHO RECEIVED A PRISON TERM FOR MARIHUANA PRODUCTION (C.D.S.A. S.7) AND AVERAGE LENGTH OF PRISON TERMS, BY AN OFFENDERS' NUMBER OF PREVIOUS CRIMINAL CONVICTIONS OF ANY TYPE IN BRITISH COLUMBIA 1997-2003

Offenders' number of previous convictions	*Percentage* of convicted offenders sentenced to prison*	*Average length of prison term (in months)*
None	13 %	4.0
1	8 %	6.2
2	12 %	5.1
3	13 %	7.1
4	18 %	4.1
5	17 %	7.9
6	24 %	7.4
7	22 %	3.0
8	24 %	6.8
9 or more	27 %	5.3
All offenders	**16 %**	**5.0**

* All percentages have been rounded to the nearest whole number.

TABLE 6.8: PERCENTAGE OF OFFENDERS WHO RECEIVED A PRISON TERM FOR MARIHUANA PRODUCTION (C.D.S.A. S.7) AND AVERAGE LENGTH OF PRISON TERMS, BY OFFENDERS' NUMBER OF PREVIOUS CONVICTIONS FOR DRUG TRAFFICKING OR PRODUCTION RELATED OFFENCES IN BRITISH COLUMBIA 1997-2003

*Offenders' number of previous drug related convictions**	*Percentage** of convicted offenders sentenced to prison*	*Average length of prison term (in months)*
1	11 %	5.0
2	19 %	5.1
3	24 %	7.1
4	27 %	4.1
5	43 %	7.9
6	31 %	7.4
7	25 %	3.0
8	43 %	6.8
9 or more	54 %	10.7
All offenders	30 %	5.7

* Refers to drug trafficking, cultivation, or production related convictions.
** All percentages have been rounded to the nearest whole number.

Table 6.9 compares offenders' criminal history and length of prison term for cultivation charges with the size of the marihuana cultivation operation measured by the number of plants. The offenders' likelihood of being sentenced to prison is significantly affected by whether they were involved in a growing operation where more than 100 plants were seized. This finding is constant regardless of criminal history. Similarly, the length of the prison term is also related to the number of plants seized. Again, this finding is consistent regardless of the offender's criminal history. In the Plecas, et al. (2002) this multivariate relationship produced a similar relationship.

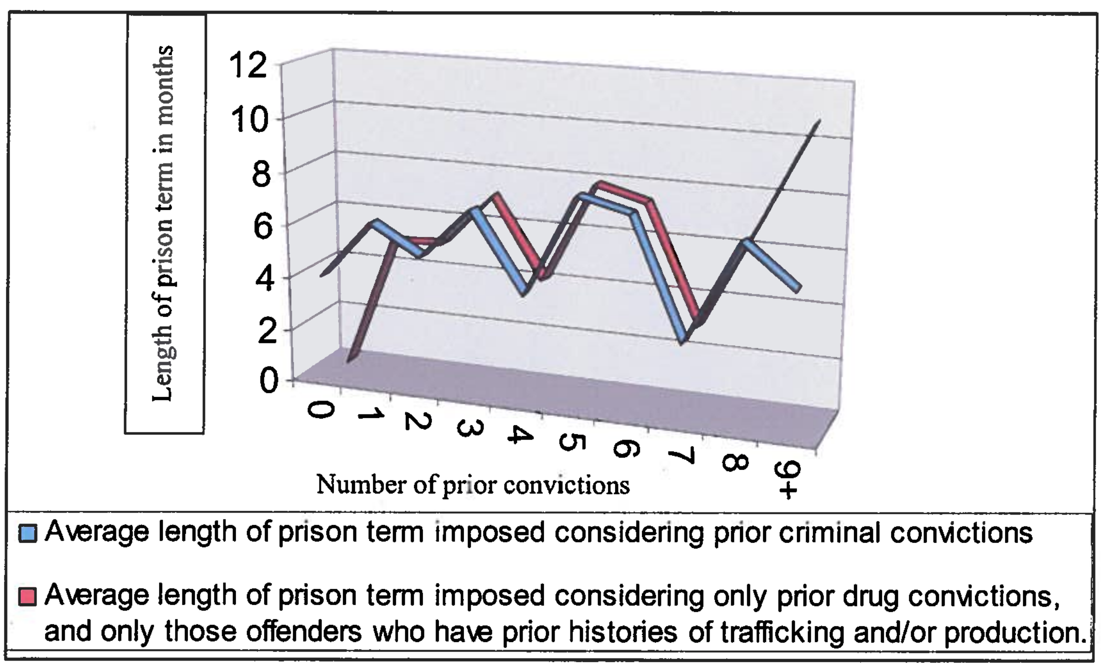
TABLE 6.9: PERCENTAGE OF OFFENDERS SENTENCED TO A PRISON TERM AND AVERAGE LENGTH OF PRISON FOR A CULTIVATION CHARGE (C.D.S.A. S.7) BY SIZE OF THE MARIHUANA CULTIVATION OPERATION IN BRITISH COLUMBIA 1997-2003

Offenders' number of prior convictions	*Cases involving less than 100 plants*		*Cases involving 100 plants or more*	
	Percentage* of offenders sentenced to a prison term	Average length of prison terms	Percentage* of offenders sentenced to a prison term	Average length of prison terms
None	8%	3.3	15 %	4.7
1-4 convictions	8%	4.1	12 %	4.6
5-7 convictions	14 %	5.2	20 %	6.1
More than 7 convictions	17 %	4.8	29 %	5.8

* All percentages have been rounded to the nearest whole number.

Figure 6.1 graphically depicts the information presented in Table 6.7 and Table 6.8. As can be seen, to some extent criminal history has an inconsistent effect on the length of prison sentence a suspect receives for a crime related to a marihuana growing operation.

FIGURE 6.1: AVERAGE LENGTH OF PRISON TERM IMPOSED IN MARIHUANA CULTIVATION CASES IN BRITISH COLUMBIA 1997-2003



In terms of sentencing, it is interesting to look at what would have happened to convicted marihuana growers in British Columbia if they had been sentenced in Washington State, where sentencing guidelines are in place. Under Washington State sentencing guidelines, 49% of the suspects convicted on marihuana production in British Columbia would have been sentenced to at least five years in prison (see Table 6.10). In British Columbia, no person was sentenced to five years or more in prison. Moreover, under the guidelines, 77% of suspects would have served a sentence of at least three months in prison. In British Columbia, only 7% of prison sentences were for three months or more. Given that there are hardly any marihuana grow operations in Washington State, and given that British Columbia has thousands of grow operations every year, it is difficult not to wonder if British Columbia might not be more effective in reducing the incident of grow operations by increasing penalties for individuals convicted for involvement in marihuana growing operations. In the final analysis, the consequences for involvement in a grow operation in British Columbia, even where a person receives a prison sentence, are likely insufficient to reduce or prevent participation in marihuana grow operations.

TABLE 6.10: PRISON SENTENCES THAT WOULD HAVE BEEN AWARDED UNDER SENTENCING GUIDELINES SIMILAR TO THOSE IN FORCE IN THE STATE OF WASHINGTON AS COMPARED TO SENTENCES IMPOSED IN BRITISH COLUMBIA: OFFENCES RELATED TO MARIHUANA CULTIVATION OPERATIONS IN BRITISH COLUMBIA 1997-2003*

*Sentencing Range***	*Percentage**** of offenders would have received prison sentence within range*	*Percentage of offenders whose actual prison sentence in BC fell within range*
Minimum 20 years	1 %	0 %
Minimum 10 years	16 %	0 %
Minimum 5 years	32 %	0 %
3 months – less than 5 years	28 %	7 %
0 – less than 3 months	23 %	93 %

* Includes only cases where at least one plant was seized and there was a conviction for marihuana cultivation.
** Note that under the Washington State Sentencing Guidelines, all prison sentences are accompanied by 12 months of community supervision. Washington State guidelines assessment here ignores enhancements concerning volume of drugs, weapons, and location of seizures. It also ignores prior trafficking and production offences.
*** All percentages have been rounded to the nearest whole number.

Appendix 1

INCIDENT FORM

Var. #	Code	Variable Description and Values
1		ID # (Use assigned numbers)
2		File Year (1=1997, 2=1998, 3=1999, 4=2000, 5=2001, 6=2002, 7=2003)
3		File Number
4		Police Force/Detachment (Use code sheet)
5		Street Number
6	Street Name:	
7	- -	Date offence reported (dd-mm-yy)
8	- -	Date offence attended (dd-mm-yy)
9		Time elapsed (days)
10		Source of complaint
11		Status of complaint (1=founded, 2=unfounded, 3=no action, 4=other, 5= founded but too late)
12		Type of facility
13		Rented (1=rented, 2=owned, 3=Crown, 4=other, 5=don't know)
14		Number of marihuana plants seized
15		Number of kg of marihuana seized
16		Other drugs seized (0=none, 1=cocaine, 2=heroin, 3=other)
17		Firearms seized (0=none, 1=prohibited, 2=restricted, 3=other, 4=mix)
18		Other weapons seized (1=yes, 0=no)
19		Equipment seized (1=yes, 0=no)
20		Number of lights seized
21		Amount of cash seized (Nearest C$, 1US$=1.5C$)
22		Number of children present
23		Fire involved (1=yes, 0=no, D.K.=3)
24		Other hazards present (1= booby trap, 2=explosive, 3=toxin, 4 =other, 5=mix)
25		Guard dog present (1=yes, 0=no, 3=DK)
26		Presence of hydro by-pass (1=yes, 0=no)
27		Amount of theft of Hydro (In Cdn $ - to nearest dollar)
28		Use of violence at time of arrest (1=yes, 0=no)
29		Type of seizure (1=case, 2=no case)
30	- -	Date of report to the Crown (dd-mm-yy)
31		Charges laid by Crown (1=yes, 0=no)
32		Number of suspects

REMARKS

Source of Complaint

1 = crime stoppers/informant
2 = routine check
3 = serving a warrant
4 = landlord
5 = other crime
6 = general investigation
7 = BC Hydro
8 = other
9 = missing
10 = neighbour
11= traffic violation /incident

Type of facility

1 = house
2 = apartment/multiple units
3 = warehouse/commercial
4 = detached building e.g. shed, barn.
5 = outdoors - Private
6 = outdoors – Crown land
7 = vehicle
8 = other
9 = missing

Conversions

1000 gm = 1 kg
28 gm = 1 oz
450 gm = 1 lb.

Appendix 2

SUSPECT SHEET **ID#**______________________

Number	Code	Variables Description and Values
1	Surname:	
2	First given name:	
3	Second given name:	
4		Number of aliases
5	- -	D.O.B. (dd-mm-yy)
6		Place of birth (town/city)
7		Gender (1=male, 2=female)
8		Ethnicity
9		Citizenship (1=Canadian, 2= Other)
10		**FPS Number**
11		**Production charge - CDSA s.(7)** (1= charged, 2=stay, 3=not guilty, 4=guilty), 5= warrant before charge, 6= warrant after charge
12		Prison (No. of months)
13		Conditional Prison (No. of months)
14		Probation (No. of months)
15		Fine ($ amount)
16		Community service order (No. of hours)
17		Restitution ($ amount)
18		Prohibition order (1=yes, 0=no)
19		Conditional or absolute discharge (1=yes, 0=no)
20		**Poss. for trafficking – CDSA s.(5)** (1= charged, 2=stay, 3=not guilty, 4=guilty)
21		Prison (No. of months)
22		Conditional Prison (No. of months)
23		Probation (No. of months)
24		Fine ($ amount)
25		Community service order (No. of hours)
26		Restitution ($ amount)
27		Prohibition order (1=yes, 0=no)
28		Conditional or absolute discharge (1=yes, 0=no)
29		**Simple possession – CDSA s.(4)** (1= charged, 2=stay, 3=not guilty, 4=guilty)
30		Prison (No. of months)
31		Conditional Prison (No. of months)
32		Probation (No. of months)
33		Fine ($ amount)
34		Community service order (No. of hours)
35		Restitution ($ amount)
36		Prohibition order (1=yes, 0=no)
37		Conditional or absolute discharge (1=yes, 0=no)
38		**Theft of Hydro - CCC s.326** (1= charged, 2=stay, 3=not guilty, 4=guilty)
39		Prison (No. of months)
40		Conditional Prison (No. of months)
41		Probation (No. of months)
42		Fine ($ amount)
43		Community service order (No. of hours)
44		Restitution ($ amount)
45		Prohibition order (1=yes, 0=no)
46		Conditional or absolute discharge (1=yes, 0=no)
47		**Firearms charges – CCC ss.84-96** (1= charged, 2=stay, 3=not guilty, 4=guilty)
48		Prison (No. of months)
49		Conditional Prison (No. of months)
50		Probation (No. of months)
51		Fine ($ amount)
52		Community service order (No. of hours)
53		Restitution ($ amount)
54		Prohibition order (1=yes, 0=no)
55		Conditional or absolute discharge (1=yes, 0=no)
56		**Other Criminal Code** (1= charged, 2=stay, 3=not guilty, 4=guilty)
57		Criminal Code Section Number
58		Prison (No. of months)
59		Conditional Prison (No. of months)
60		Probation (No. of months)
61		Fine ($ amount)
62		Community service order (No. of hours)
63		Restitution ($ amount)
64		Prohibition order (1=yes, 0=no)
65		Conditional or absolute discharge (1=yes, 0=no)

Ethnicity:
1= Caucasian
2=Oriental (except Vietnamese)
3=East Indian
4=Black/African
5=Aboriginal
6=Other
7=Vietnamese

Appendix 3

CRIMINAL HISTORY

VAR #	ASSIGNED CODE	VARIABLE DESCRIPTION AND VALUES
1.		ID #
2.		ID # Suspect
3.		Year of first offence (actual year)
4.		Type of prior drug offences
5.		Number of prior drug offences
6.		Number of violent offences
7.		Number of prior non-compliance
8.		Number of prior offences
9.		Total number of stays
10.		Number of jurisdictions on criminal record
11.		Most frequent jurisdiction on record
12.		Number of provinces on record
13.		Most frequent province on record
14.		Year of first offence in B.C.
15.		Year of cultivation # 1 (most recent)
16.		Jurisdiction of cultivation #1
17.		File # of cultivation # 1
18.		Year of cultivation # 2
19.		Jurisdiction of cultivation # 2
20.		File # of cultivation # 2
21.		Year of cultivation # 3
22.		Jurisdiction of cultivation # 3
23.		File of cultivation # 3

1 = possession
2 = trafficking
3 = cult/prod.
4 = 1 & 2
5 =1 & 3
6 = 2 & 3
7 = 1,2 & 3

NOTES

1.0 Reference: Exhibit B-1, p. 6-7 and Exhibit B-1, p. 78-79

"FortisBC's proposed AMI system consists of the following major components:

- Procurement of AMI system hardware and software including the meters, network devices, HES and MDMS;
- Design of the AMI system including the communications network and WAN backhaul;
- Installation of the HES and MDMS;
- IT Integration—connecting existing FortisBC 1 systems to the HES and MDMS;
- Deployment of the communications network infrastructure;
- Deployment of the AMI meters to replace existing meters; and
- Development and implementation of a customer information portal."

"Of the remaining meters, approximately 60 industrial customers are metered with the Itron MV-90 system, a cellular modem based system that captures metering data on an interval basis (similar to AMI). FortisBC is not proposing to replace the existing MV-90 metering system for these customers."

1.1 Please confirm that there are no components of the AMI Project that provide benefits to industrial customers?

<u>Response:</u>

All components of the AMI Project provide benefit to industrial customers.

Industrial customers will benefit from the following non-financial and operational benefits listed in Exhibit B-1, Section 3.2.5:

- Enhanced system modeling;
- Improved financial reporting, load forecasting and Cost of Service Analysis;
- Improved safety;
- Reduced GHG emissions; and
- Immediate notification of power outages and restoration.

Industrial customers will also benefit from the same financial benefits listed in Section 5 of Exhibit B-1 in the same way that all customers do.

All of the components listed in the question are required to achieve these benefits.

1.1.1 If not confirmed, please confirm that the benefits of the AMI Project are currently being provided to industrial customers?

Response:

Please refer to the response to ICG IR No. 1 Q1.1.

1.1.2 If not confirmed, please identify and provide a detailed description of the components of the AMI project that provide benefits to industrial customers?

Response:

Please refer to the response to ICG IR No. 1 Q1.1.

1.2 Please comment on whether or not cost-causation principles support the conclusion that the AMI Project costs should be allocated to residential and commercial customers?

Response:

Cost-causation principles would hold that any costs that are not clearly caused by, or incurred for, a certain rate class, should be allocated in some manner to all classes. In the case of the AMI project, costs (and benefits) cannot be isolated in such a fashion and should therefore be allocated to the Residential and Commercial classes, as identified in the question, along with all other classes.

In response to BCUC IR No. 1 Q118.1, FortisBC noted the following,

Consistent with all capital expenditures undertaken by the utility, the costs and benefits are included in the Company's Revenue Requirements and therefore are incorporated into all customer rates. In addition, the proposed FortisBC AMI project results in a net benefit to all customers as is evidenced by the financial analysis included as part of this Application.

Individual capital project costs are not directly assigned to any class(es) unless the costs and benefits are directly attributable to it.

FortisBC has stated that it intends to conduct a cost-of-service analysis in 2017 after it has a year of AMI data to incorporate. The Company anticipates that, given that class-inclusive nature of AMI expenditures and benefits, any costs associated with the project will be allocated on the basis of common allocation factors developed during the study.

1.3 Please comment on whether FortisBC anticipates that it will allocate all the costs of the AMI Project to residential and small commercial customers?

Response:

Please refer to the response to ICG IR No. 1 Q1.2 above.

1.4 If there are costs of the AMI Project that FortisBC does not anticipate that it will allocate to residential and small commercial customers, please provide a detailed description of those costs and provide a detailed explanation of why those costs might not be allocated to residential and small commercial customers?

Response:

Please refer to the response to Question 1.2 above.

2.0 Reference: Exhibit B-1, p. 18-19

"Benefits attributable to the AMI Project are summarized as follows:

1. Provides better and more energy consumption information allowing customers and the Company to efficiently manage electricity usage and the associated costs;
2. Consistency with British Columbia's energy objectives;
3. Is a prerequisite step in the evolution of the Company's long-term smart grid vision;
4. Provides numerous non-financial benefits to the Company's customers; and
5. Results in approximately $19 million in savings (on a net present value basis) as evaluated over a 20 year period (associated rate reduction of approximately 1 percent)."

2.1 Please confirm that all the benefits attributable to the AMI Project are benefits for residential and small commercial customers?

Response:

Not confirmed. The benefits listed accrue to all customers. Please also see the response to ICG IR No. 1 Q1.1.

2.1.1 If not confirmed, please comment on whether or all the benefits that can be quantified that have been included in the financial analysis of the AMI Project are benefits for residential and small commercial customers?

Response:

The financial benefits of the project do not accrue to individual customers, but to FortisBC customers as whole, including industrial customers.

2.1.2 If not confirmed, please provide a detailed description of, and quantify, all benefits attributable to the AMI Project for industrial customers?

Response:

Please refer to the response to ICG IR No. 1 Q2.1.1.

2.2 Please confirm that the need for the AMI Project is primarily driven by benefits to residential and small commercial customers?

Response:

Not confirmed. Please refer to the response to ICG IR No. 1 Q1.1 and the response to BCUC IR No. 1 Q2.1.

3.0 Reference: Exhibit B-1, p. 84

"The enhanced revenue protection program proposed in the Application is expected to increase the benefit to customers above the current status quo program."

"The enhanced program will provide a customer benefit with a net present value of approximately $38 million over the life of the Project."

3.1 Please confirm that the AMI-enabled revenue protection is expected to increase theft detection for service to customers with a meter installed pursuant to the AMI program, and no industrial customers?

Response:

Not confirmed. Industrial customers will benefit from the theft detection savings in the same manner as all customers. In addition, billing errors for these larger accounts can be detected as part of the energy balancing process which compares the total energy delivered with the total energy billed.

3.2 Please confirm that when sales are used to allocate costs in a COSA that billed sales, as opposed to gross sales, always have been used by FortisBC as allocators?

Response:

Confirmed. The revenues by class in the COSA come from the revenues forecast contained in the applicable Revenue Requirements Application

4.0 Reference: Exhibit B-1, p. 6, p. 31, and p. 36

"The need for an AMI system is primarily driven by the opportunity it affords both customers and the Company to have a greater ability to efficiently manage electricity usage and the associated costs.

"The proposed AMI system provides a number of non-financial benefits that are of importance to customers."

"One of the key benefits of AMI is that it would provide this data for all customer endpoints allowing more accurate future cost-of-service analyses."

4.1 Please comment on whether or not "residential and small commercial" could be inserted before "customer(s)" in each sentence quoted above and not change the intended meaning of the sentence?

Response:

FortisBC does not agree with the proposition.

The ability for FortisBC to efficiently manage electricity usage and the associated costs as described in Section 3.2.1 will benefit all customers.

Industrial customers (and others) will benefit from non-financial benefits as described in the response to ICG IR No. 1 Q1.1.

All customers will also benefit from more accurate future cost-of-service analyses.

5.0 Reference: Exhibit B-1, p. 9

"FortisBC believes that in order to ensure a thorough, comprehensive, and efficient review of the Company's proposed AMI Project, the Commission must consider potential participants' specific interest in the Application at the time of registration, and ensure that intervener status is limited to those individuals or groups that can adequately demonstrate they will be directly affected by the Application."

5.1 Please confirm that industrial customers will not be "directly affected by the Application"?

Response:

It is up to the Commission to determine whether individuals or groups are directly affected by the Application in the context of the reference.

FortisBC believes that ICG benefits, and is therefore affected, by the Application.

5.2 If not confirmed, please provide a detailed description of the industrial customers' interest in the Application?

Response:

Please refer to the response to ICG IR No. 1 Q5.1.

I note that the issue of Power Line Carrier AMI Systems in was rather summarily discarded with your notes form this section and section 4.2.2 mentioning that you did not specify in the RFP or receive and obtain a PLC proposal.

It is likely that you were and are currently aware of the public controversy involving the issues surrounding radio frequency (RF) broadcasts.

1. Given that climate, I would like to know why you did not seek this alternative in your RFP.

Response:

Please refer to the response to BCUC IR No. 1 Q38.3.

2. I would like to know why, other than the brief comments on page 115 you are discarding it, as it seems to me that the PLC alternative is a functional alternative that completely avoids the RF controversy. By way of example, I would like to ensure that it is on the record that Idaho Power in the State of Idaho, USA, considered this same question several years ago based on the controversy in California regarding RF systems and determined that they would be able to avoid any risk to their consumers by utilizing a wired AMI system. They installed 500,000 AMI meters using a PLC system, a much larger project than the FortisBC proposal, and they were able to serve their needs and not put any customers at risk. I have attached reference information in this regard as Attachment 1 and Attachment 2.

Response:

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

Please also refer to the response to NCGP IR No. 1 Q14.

Idaho Power, (2012), stated, “Smart meters being deployed in Idaho Power's service territory do not transmit radio frequencies. Our smart meters do not use any wireless communication media or generate any high-frequency signals. Our system uses only wired infrastructure to communicate to and from our smart meters utilizing the low-frequency 60 hertz (Hz) power line signal as the carrier for our communications. This may be of interest because some smart meter deployments in California have raised concerns that radio transmission, wireless transmission or high-frequency transmission may pose health risks. The technology we're deploying is fundamentally different from the technologies in question in California."

3. Given that the PLC alternative uses the same wired infrastructure that now exists to each residence with resulting cost efficiencies, why is that option not fully explored?

Response:

If the PLC alternative had exhibited greater cost efficiencies, FortisBC assumes that it would have received PLC proposals in response to its RFP.

Since FortisBC did not receive PLC proposals, the alternative was not as fully explored as those options for which FortisBC did receive proposals. Please also refer to the responses to BCUC IR No. 1 Q38.2 and Q38.3.

4. While some comments are available in the FortisBC response to BCUC IR1 Q106.1 to 106.5 and BCUC IR1 113.1 to 113.1.4, it would seem that a relatively safe and non-RF data system has been supplied by Fortis Alberta, similar to Idaho. Other than following what appear to be primarily reduced cost concerns, why is it absolutely necessary to subject B.C. residents to an RF system and why not utilize an alternate system supplier other than Itron?

Response:

Please refer to the response to Miles IR No. 1 Q2.

5. I would like to know what bearing the B.C. Hydro deployed metering system noted on Page 114 has to do with the data collection process for FortisBC. (I should note that any B.C. Governmental directions regarding smart meter installations as noted in 3.2.2 likely apply solely to B.C. Hydro, a Crown Corporation, and are not directly applicable to FortisBC as regards to the RF data collection method).

Response:

FortisBC assumes the page reference above should be to page 115.

As part of the utility Collaboration Objectives listed in Section 8.2.2 of the Application, FortisBC considered it important to be able to provide consistent advanced metering benefits to customers throughout the province. Since PLC systems were not able to cost-effectively provide the same services (as evidenced by the lack of PLC alternatives in the RFP process), FortisBC considered them unable to provide consistent advanced metering services.

6. While it appears to me that it is undesirable to use any RF distribution, I would like to know why you would not be able to provide a hybrid system with safe PLC data capture in residential areas and then, perhaps using an isolated RF bridging system that is removed to areas where there is likely to be no safety concerns, to transfer your data a central collection/processing facility.

Response:

Please refer to the response to BCUC IR No. 1 Q106.1 and Q106.2.

7. Notwithstanding your comments on PLC cost competitiveness on page 114, I would like to know how you can determine that that the health and safety of exposing 115,000 customers to any possible risk for negative effects from persistent RF exposure outweighs any extra costs of a fully safe PLC system.

Response:

FortisBC does not believe there are any risks associated with the proposed AMI system.

8.4.2 Page 133 - Electro Magnetic Fields:

With respect to the health concerns, by way of a personal example, I can mention that my wife has been disabled with Multiple Sclerosis, a neurological disorder, for many years. In your proposal, you will install the RF emitting device adjacent to our bedroom, as indicated in the attached photo, about four linear feet away from our bodies where we spend about 1/3 of our life sleeping. This is also about 10 ft. away from and adjacent to our neighbour's child's bedroom who is developmentally challenged. With respect to the original application, 8.4.2 ELECTRO MAGNETIC FIELDS, Page 133, I am unable to determine the risk for constant nighttime exposure while sleeping adjacent to the meter. I am unable to determine how to turn off the emitting source at the meter. I am unable to determine that there is consideration for removing the RF source to a more benign PLC-style data distribution at this location. I am unable to determine how to avoid any unnecessary risk at all.

8. Please advise related to 8.4.2, similarly to the question to you from Guy Leroux, Leroux Regulatory Consulting Ltd. Reference: APPLICATION Exhibit B-1, why we should be forced to permit potential risk to a known neurological condition at our home when PLC alternatives are available?

Response:

FortisBC does not believe that there is a risk to known neurological conditions. Please also see the response to Miles IR No. 1 Q7.

The problem at this location becomes even more significant at this location when it appears that directly across the street from our home and bedroom, infrastructure has already been installed for a device connection to facilitate concentrated RF transmissions collection. I have attached an image of the structure, also adjacent to the Middle School playground, which I presume will eventually serve to concentrate area RF transmission in our vicinity. I am unable to determine from your original application, 8.4.2 ELECTRO MAGNETIC FIELDS, Page 133, the additional net RF effect for signal capture at the collector.

9. Again, I would ask why we should be forced to permit any further potential risk to a known neurological condition at our home when PLC alternatives are available and what eventual options will be available to remove the concentrated RF signals in our vicinity?

Response:

The AMI system proposed by FortisBC complies with all Canadian laws and regulations designed to protect our health and regulate wireless emissions. In Canada, Health Canada is responsible for setting exposure limits, and has published information regarding smart meters and health risks at: http://www.hc-sc.gc.ca/hl-vs/iyh-vsv/prod/meters-compteurs-eng.php.

It writes, in part:

As with any wireless device, some of the RF energy emitted by smart meters will be absorbed by anyone who is nearby. The amount of energy absorbed depends largely on how close your body is to a smart meter. Unlike cellular phones, where the transmitter is *held close to the head and much of the RF energy that is absorbed is localised to one specific area, RF energy from smart meters is typically transmitted at a much greater distance from the human body. This results in very low RF exposure levels across the entire body, much like exposure to AM or FM radio broadcast signals.*

Survey results have shown that smart meters transmit data in short bursts, and when not transmitting data, the smart meter does not emit RF energy. Furthermore, indoor and outdoor survey measurements of RF energy from smart meters during transmission bursts were found to be far below the human exposure limits specified in Health Canada's Safety Code 6.

Based on this information, Health Canada has concluded that exposure to RF energy from smart meters does not pose a public health risk.

In BC, the BC Centre for Disease Control conducted measurements of the power density of RF waves emitted by Itron smart meters (and other common household devices) to compare the readings to the public exposure limits (uncontrolled environments) set by Health Canada Safety Code 6. That report, available at http://www.bccdc.ca/NR/rdonlyres/43EF885D-8211-4BCF-8FA9-0B34076CE364/0/452012AmendedReportonBCHydroSmartMeterMeasurements.pdf, showed that at 30 cm**,** the time-averaged power density from the meter was only 0.00037 percent of the Safety Code 6 limit (Table 3).

The very low levels of RF emitted by advanced meters (fractions of a percentage of the Health Canada limit even at only 30 cm) should assure customers of the safety of this technology.

Please also see the response to Miles IR No. 1 Q7.

10. Are you suggesting for ourselves and other consumers, where we cannot opt out of exposure planned for our electrical service because there is no other electricity supplier at our home, that the BCUC should approve your intervention to put us at any further risk when a PLC option does exist, as is the case in other jurisdictions, that would mitigate this type of concern? By way of reference regarding the above questions, I have attached (with permission) from May 26, 2012, as Attachment 3, a reasonably well substantiated document that is public correspondence from a local resident, Lizette Tucker, 1816 4th Ave, Trail BC. V1R 1T1. The document seems comprehensive in raising in the community, RF concerns, among others.

Response:

Please refer to the response to Miles IR No. 1 Q7.

8.4.3 Page 135 – Security

I am unable to locate in the BCUC IR1 responses to security concerns in the home to collector wireless distribution system, but, despite comments in your application of July 26, 2012 regarding monitoring and information exchanged, it appears to me that it would be relatively easy for 900 MHz airborne signal transmission and data relay to be compromised, either unintentionally or maliciously, notwithstanding security controls or software monitoring.

I would note from the PLC-type system comments by Idaho Power, (2012), that, Smart Meters Are Secure: Our smart meters do not communicate over public airways or the Internet. We employ cyber-security standards of encryption and isolation to ensure the integrity of the system. And we take effective precautions to protect our communication system physically. In our system, smart meter communications happen over the power line between each individual smart meter and a secure Idaho Power distribution substation.

Communication utilizes proprietary, secure equipment. There is no meter-tometer communication. It is physically impossible for smart meters to communicate with anything other than the substation. Typically, the meters communicate with the substation four times daily to collect usage information.

11. My question is, why put the RF data transmission service at risk when, with a PLC-type system or a hybrid system that could be wired to a localized collector, hijacking of the signal or data would be more easily frustrated, with no apparent loss of AMI functionality?

Response:

The AMI system proposed uses similar encryption methodologies to that described in the preamble to this question. It is just as difficult to break the encryption regardless of whether the medium is air (as is the case with RF), or power line electrical signals (as is the case with PLC). AMI meters will communicate only with collectors and other devices that possess the correct encryption keys regardless of the communication medium.

You may note that I am not technically skilled in all aspects of the BCUC intervention process and all of the subject matter. I request your patience in the format and presentation of my questions. The concerns I present are quite real and hopefully can be fairly considered. In general, I would resist the heightened intervention in our homes with AMI systems that provide lifestyle data to a corporation where my privacy will be diluted more significantly that it presently is. However, if it is inevitable those systems will be installed, then I would absolutely want it to be 100% safe and unassailable – on my terms, not simply accepting the well-being proposed by a single corporation.

12. In that regard, how will we as consumers have custody and control over the extra personal residential data being extracted from our homes by FortisBC Inc. such that it will not be misused, as in disclosure between other electrical companies, disclosure for marketing purposes, or disclosure to other Government and Municipal agencies? How will we have custody and control over personal usage data that is lost, retained forever, carried off-premises or otherwise distributed?

<u>Response:</u>

Please refer to Section 8.4.4 of the Application, as well as the supplemental filing dated October 19, 2012 (Exhibit B-9).

As noted in the above noted sections, FortisBC is not collecting any additional personal information by using AMI, FortisBC would be collecting the same information more frequently. The only personal information that is being wirelessly transmitted over the AMI system is a customer's electrical consumption information and meter number. This information is not linked to a customer name or address until it reaches FortisBC's internal system. There are extensive security features of the AMI system which are discussed in Section 8.4.3 of the Application.

To address the second portion of the question, the *British Columbia Personal Information Protection Act* (PIPA) governs the collection, use and disclosure of personal information by private sector organizations, such as FortisBC. The purpose of PIPA can be found in section 2 of that Act and states that it is to "govern the collection, use and disclosure of personal information by organizations in a manner that recognizes both the right of individuals to protect their personal information and the need of organizations to collect, use or disclose personal information for purposes that a reasonable person would consider appropriate in the circumstances". FortisBC has a privacy policy which lists the purposes for which it collects, uses and discloses personal information which can be found at www.fortisbc.com. In summary, FortisBC's customers can be assured that their personal information is collected, used, disclosed, secured and retained in accordance with PIPA.

1. Can FortisBC please explain, given that a number of Public Utility Districts in the United States Pacific Northwest are using a wired smart meter technology, why they have opted to use a former military version of wireless technology that was first designed and developed in the 1940's - for secure communications, not data collection?

Response:

As noted in section 4.2.2 of the Application as well as the response to BCUC IR No. 1 Q38.3, FortisBC did not specify any particular type (or consider the developmental origins) of AMI communication technology in its RFP; all proposals received were for systems employing RF technology. The fact that the majority of AMI manufacturers employ RF technology to facilitate meter communications is likely due to the cost-effectiveness, flexibility, security, and reliability afforded by such technology, particularly for connecting geographically dispersed networks such as FortisBC's. Indeed, the use of RF communications technology by some rural internet service providers is likely based on these same considerations.

2. Further, can FortisBC please explain why, if they and BC Hydro are using wired data transmission for commercial clients, they would not expand this to include all their customers?

Response:

FortisBC currently uses cellular modems to transmit consumption data for its large commercial, industrial and wholesale customers. The operating cost of this type of technology is not cost effective for the wide-scale deployment of communicating meters contemplated in the AMI Application, nor does it offer the functionality and attendant benefits of the proposed AMI system.

3. In addition, is it not true that wired back-haul could use IPv6 IP addressing at 20% of the cost of using IPv4 addressing?

Response:

As described in Exhibit B-1, Section 4.1, p 48, FortisBC intends to utilize available wired backhaul infrastructure wherever it is most economic.

The economics of using a wired fibre optic network compared to other alternatives depends primarily on having enough bandwidth utilization to offset the relatively high up-front capital costs. This is why the preliminary WAN design includes 11 sites directly connected by existing fibre optic lines that are already used for other purposes.

The use of IPv6 and IPv4 protocols does not depend on the type of backhaul chosen. FortisBC intends to deploy IPv6 for the LAN network, which can be encapsulated in IPv4 packets over the WAN if required.

4. Currently the Columbia Broadband Corporation, the Village of Kaslo and Kaslo InfoNetwork, for example, are teaming up to look at developing a fiber optic network. Can FortisBC, given development of similar fibre optic networks in South East Asia, the Middle East and Europe (for example Portugal), please explain why they are not teaming up with Telus and other large communication corporations to develop a single common carrier fibre optic network?

Response:

FortisBC has previously participated in fibre leasing arrangements (both as a lessee and a lessor) with other companies to meet its communications requirements and minimize costs. FortisBC will continue to look for these partnering opportunities to reduce WAN costs.

With respect to the LAN (meter to collector communications), utility-owned solutions such as PLC and RF networks that have relatively high collector costs, but low per meter costs, have dominated AMI installations.

The use of “fibre to the home” in North America has not been common due to the fact that there are sufficiently high-speed data options already available at most customer premises over existing infrastructure (telephony or cable). In these cases, it is less economic to install additional infrastructure (such as fibre) to individual premises, although fibre is often present “to the curb” or “to the neighbourhood” in urban areas, with the last mile using another non-fibre technology.

In more rural areas, it has simply been cost prohibitive for cable and telephony companies to extend fibre networks and high-speed data services to their customers. In these cases, the low bandwidth requirements of AMI would not sufficiently improve the economics of wired services.

There are significant issues with trying to leverage existing wired infrastructure to communicate with electricity meters:

- Establishing a wired link from an Ethernet source within the home or business (where available), or alternatively, providing multiple direct LAN connection options on the meter (telephone line, ADSL, cable and fibre); and

- Negotiating bandwidth contracts with multiple companies with sufficient cost and reliability guarantees.

Fibre-to-the-home projects have generally been in areas with state-controlled telephony providers, or where there is a government mandate to improve service in underserved areas.

In many areas that are underserved with wired high-speed data options, (such as portions of the FortisBC service territory), Internet Service Providers (such as those referred to in response to Shadrack IR No. 1 Q22) have offered wireless network options for their customers rather than wired options.

5. Can FortisBC please explain why it will be cheaper for their current customers, from a capital investment and operational cost point of view, to develop an isolated wireless network for themselves only, and specifically for their electrical customers, instead of paying an operational tariff for use of a common carrier fibre optic network?

<u>Response:</u>

Please refer to the response to Shadrack IR No. 1 Q4.

6. Has FortisBC compared the cost for utilities which have opted to collect smart meter information through such a common carrier operational tariff versus their decision to invest capital and operate a wireless network in isolation from other entities that are collecting and disseminating information?

<u>Response:</u>

Please refer to the response to Shadrack IR No. 1 Q4.

7. In preparing its application, did FortisBC hold any discussions in British Columbia with Telus or any other communication corporation about co-sharing fiber optic cable to collect their smart meter information? If not, why was this not considered?

<u>Response:</u>

FortisBC does propose to use direct connect fibre optic WAN backhaul wherever it is economic and available to do so, and where it may become economic and available in the future. Please also see the responses to Shadrack IR No. 1 Q3 and Q4.

The availability of fibre is still relatively limited for WAN backhaul purposes, and it is expected to be much longer before it is economic and available for LAN purposes. Please also refer to the response to Shadrack IR No. 1 Q4.

8. If FortisBC obtains approval from the Commission to build and operate a wireless network for its electrical customers, will it then be applying to build a separate wireless network for its natural gas customers, or will it use the same wireless network and just double up the collection of information?

Response:

FortisBC does not intend to build new networks where existing networks are more economic.

With respect to the LAN, existing networks providing data at customer premises are too diverse, and availability too limited, to be economic.

With respect to the WAN, FortisBC intends to rely on existing fibre optic, cellular, wireless or satellite networks where they are economic and available. Where existing networks are less economic or unavailable, FortisBC intends to install dedicated WiMAX WAN backhaul.

With respect to a possible future natural gas AMI network, FortisBC would use existing LAN and WAN options where economic and available. In the case of the FortisBC electric service territory, it is highly likely that the most economic available solution for natural gas AMI communications would be to use the existing electric AMI communications network infrastructure.

9. Has FortisBC had any discussions about co-sharing or working with BC Hydro around the development of its wireless network?

Response:

Exhibit B-1, Section 8.2 provides information on utility collaboration generally.

As noted in Exhibit B-1, Section 8.2.3, p 129, “Shared infrastructure savings were not possible because the AMI assets, with the exception of the software assets, must be located in the utilities’ respective service territories, which do not overlap.”

In the relatively small parts of the province where FortisBC and BC Hydro electricity customers are in close proximity to each other, one collector might be able to serve both companies. However, the infrastructure savings (estimated at less than $50,000 in total capital cost), would be more than offset by the operational complexity and expense of the additional hardware, software and contracts required to separate and return the data through the other company's WAN and software environment.

10. What specific advantage is there for FortisBC customers (residential, commercial and industrial) to have FortisBC adopt a wireless versus a wired smart meter technology?

Response:

FortisBC believes, based on the RFP results, that the proposed wireless LAN technology is the lowest cost solution that meets the Company's requirements.

11. The following URL contains an article that discusses how easy it is to hack wireless heart pacemakers:

    http://www.techhive.com/article/2012779/pacemaker-hack-can-kill-via-laptop.html
    Computer graph printouts of a BC Hydro smart meter being monitored from a home computer in real time on a minute-by-minute basis, with a readout and log of everything the meter was detecting, indicate that anyone has the ability to use an IR reader and capture data from the IR port. With the understanding that FortisBC is going to use the same meter from the same company, can FortisBC please explain, given that even a layman's eyes can detect when an appliance is turning on and off, why they think wireless smart meters are secure and will respect the personal right to privacy in the home?

Response:

FortisBC has not seen and is unable to locate the referenced "computer graph printouts", and has no comment as to its accuracy or validity. Please refer to Section 8.4.4 of the Application for details on privacy related to the proposed AMI meters.

FortisBC considers the security mechanisms inherent in the proposed AMI meters and system adequate to prevent unauthorized access to billing information. These include advanced authentication methods for access to the IR port, RF LAN and data repository as detailed in Section 8.4.3 of the Application.

12. Further, can FortisBC please explain why, if the signals emitted from a smart meter are intermittent, the program collecting information on a home computer from a smart meter shows a continuous flow of information on the graph printouts? Am I misunderstanding something here?

Response:

As stated in the response to Shadrack IR1 Q11, FortisBC was not provided the referenced video nor been successful at locating it, and is therefore unable to comment on its content.

13. FortisBC has stated that the amount of Electromagnetic Radiation (EMR) emitted by its smart meters are well within the Canada Health guidelines, and that other devices used by the public have higher EMR emissions. Has FortisBC found any studies that have looked at whether or not the cumulative amount of EMR from a cell phone and wi-fi, with a smart meter added in, still meet Canada Health guidelines?

Response:

In general, studies of population exposures to radiofrequency fields (Mantiply et al., 1997; Frei et al., 2009 ; Viel et al., 2009a ; Viel et al., 2009b Mantiply et al., 1997) indicate that the total exposure from cell phones, Wi-Fi, and other sources is so far below Safety Code 6 (or, for example, the limits set by the International Commission on Nonionizing Radiation Protection), that any small incremental exposure from an AMI meter would be insufficient to cause these guidelines to be exceeded.

http://www.ncbi.nlm.nih.gov/pubmed/19476932;

http://www.ncbi.nlm.nih.gov/pubmed/19336431;

http://www.ncbi.nlm.nih.gov/pubmed/19656570;

http://www.ncbi.nlm.nih.gov/pubmed/9383245

14. How many studies in total has FortisBC looked at that discussed the potential health impacts of EMR created by wireless devices, and over how long a time

frame were these studies undertaken and at what concentration among the population were the devices in circulation studied?

Response:

In general, FortisBC does not typically review individual studies of wireless devices and relies on authoritative reviews and evaluations of research by health and regulatory agencies such as Health Canada.

Please also refer to Appendix C-5 from the Application, as well as the response to Shadrack IR No. 1 Q13.

15. Of these studies how many of them looked at the cumulative health impacts for individuals and households using multi-numbers of these EMR emitting devices?

Response:

Please refer to the response to Shadrack IR No. 1 Q13.

16. Am I correct in understanding that FortisBC is proposing to use a "Frequency Hopping Spread Spectrum" (FHSS), originally created in 1942?

Response:

FortisBC confirms that the technology to be used for meter-meter-collector (LAN) communications for the proposed AMI Project implements a Frequency Hopped Spread Spectrum scheme.

17. In contrast is not true that the later developed "Direct Sequence Spread Spectrum" (DSSS), used in the original 802.11 and 802.11b versions of wireless, and the "Orthagonal Frequency Division Multiplexing (OFDM)", as used in the 802.11g versions of wireless, can work together?

Response:

DSSS and OFDM are modulation techniques that define how a digital signal is carried over a medium. In the case of Radio Frequencies this medium is air. These two modulation techniques will interfere with each other if their respective signals are transmitted on the same medium, at the same time and on the same frequency.

For these technologies to work together using the same frequency, some type of multiple access technique must be employed to determine which transmitting stations get exclusive access to the medium at any particular time. The referenced 802.11, 802.11b/g protocols employ a technique called Carrier Sense Multiple Access (CSMA) to allow multiple devices to cooperatively share the same frequency.

As stated in the question, 802.11b uses DSSS and 802.11g uses OFDM. It is known that 802.11b and 802.11g protocols work together. This does not by extension mean DSSS and OFDM work together. The compatibility of the 802.11 schemes are not a function of the modulation scheme, but of the multiple access technique they all use. There are systems that use these modulation schemes, but do not use the same multiple access techniques and these systems will interfere with each other.

18. The FHSS system, as originally designed (and up into the 1970s) will not share the bandwidth spectrum with any of the Spread Spectrum systems designed, because FHSS is an inefficient frequency hog, using 30Mhz to move less data than current systems which use 1.6Mhz. In short, is it not true that FHSS is not compatible with two later versions of wireless used by more recent applications (Wi-Fi, amateur radio, cordless phones, baby crib monitors, etc) and that FHSS will completely block those two newer versions for the duration of a FHSS transmission?

Response:

FortisBC assumes that the “two newer versions of wireless” referenced in the question are Direct Sequence Spread Spectrum (DSSS) and Orthogonal Frequency Division Multiplexing (OFDM) based on the previous question.

FortisBC does not share the views expressed in the question with respect to FHSS technology. Efficiency is a function of the modulation scheme used, and frequency hopping is not a modulation scheme. FortisBC considers frequency hopping to be a technique used to avoid potential interference and to allow users to efficiently share the same spectrum resource. FHSS may have an operating range over 28 MHz of spectrum, but it does not deny this spectrum for other users because it only transmits for a small amount of time on a small section of this band at any one time.

FortisBC does not agree with the statement that FHSS is not compatible with DSSS or OFDM. In fact, FHSS will co-exist with DSSS/OFDM with almost no impact to each other if the systems are designed using RF best practices.

19. Why should FortisBC be allowed to use this older FHSS technology that disrupts two newer versions found in other home products and services?

Response:

As discussed in Shadrack IR No. 1 Q21, FortisBC does not believe FHSS technology is disruptive to other users in the 902-928 MHz band. The equipment to be used in the proposed AMI project complies with Industry Canada RSS-210, which sets the standards for devices in this band.

20. When a FHSS-based smart-meter begins to transmit, it monitors the spectrum to determine if another system is transmitting. That being the case, smart-meters must have receivers built into them which can monitor the spectrum, or receive signals which would allow the hydro supplier to "cut-off" the customer, or vary smart-meter parameters while in use. Thus is it not true that the primary purpose for using this former military technology is so that utilities can eventually control the amount of power going to a particular customer and set time-of-use rates?

Response:

No, it is not true that the primary purpose for installation of advanced meters is to control the amount of power available to a customer (which is not a capability of the advanced meters), nor to allow FortisBC to implement time-of-use rates.

Please see Section 3 of the Application for a discussion on the drivers behind the proposed AMI project.

21. In its answer to 31.2 BCUC IR#1, FortisBC states that it: "anticipates very minor impact". Would FortisBC agree that where a smart meter disrupts one of their customer's ability to communicate using Wi-Fi, a ham radio, cordless phone, baby crib monitor, etc, that that disruption has a major impact on that customer's ability to use products that they had previously bought, installed and used?

Response:

FortisBC considers that all devices which share spectrum in the 902-928 MHz band impact each other to a certain extent. This includes all listed technologies, because each one has the ability to “disrupt” other devices in the frequency band.

FortisBC expects very minor impact on users in this band from its proposed AMI network, meaning that customers should not have any appreciable performance degradation for any of their devices. FortisBC does not agree that any disruption constitutes a major impact. All the listed devices and many others already “disrupt” each other with no noticeable impact to the customer. FortisBC contends that its proposed AMI infrastructure will be significantly less disruptive to other devices than many of these existing technologies.

Please refer to the response to BCUC IR1 Q31.2.4 and Q31.2.6 for further discussions detailing expected impacts on existing users.

22. In relation to its answer in 31.2.1 BCUC IR#1, does FortisBC know the number of Wi-Fi service providers in its service area using the 900 MHz communication band, and to how many customers in total these providers deliver service?

Response:

FortisBC has attempted to locate all Wireless Internet Service Providers (WISPs) in the area, and has also contacted the British Columbia Broadband Association for assistance creating a list. From this exercise FortisBC has identified 3 WISPs using 900 MHz in its service area. It is possible that some small providers using the band have not been identified.

FBC has contacted these WISPs to communicate its intent to install devices in the 900 MHz band during the deployment of the proposed project, and to discuss options for mitigating and minimizing any impact.

To date, these service providers have not shared information detailing the number or location of their customers. FortisBC has requested this information.

23. Is FortisBC aware of any disruptions caused by other pieces of equipment using the 900 MHz communication band, to, for example, Wi-Fi and ham radio, and/or cordless phones, and/or baby crib monitors, or is it just the introduction of wireless smart meters by FortisBC that is going to disrupt all these other devices

because it is not compatible, noting that all these devices are compatible with each other?

Response:

Please refer to the response to Shadrack IR No. 1 Q21. FortisBC is aware of numerous disruptions caused by and to other pieces of equipment in the 902-928 MHz band, including all the listed examples. FortisBC contends this disruption is not uncommon, and in almost all cases does not have major impacts on the use of the technology. To clarify, the referenced disruptions were not caused by advanced meters, or any other devices FortisBC employs but rather is referring generally to interference cause by other types of devices in the band.

24. Has FortisBC yet come up with any estimate of what it is going to cost to resolve the interference with Wi-Fi services and who is going to pay to fix it?

Response:

FortisBC assumes this question is referring to possible interference with Wi-Fi services provided by Internet Service Providers using 900 MHz wireless communications.

As stated in the response to BCUC IR No. 1 Q31.2.1, FortisBC does not believe that any appreciable interference with these services will result from the deployment of AMI, so the estimated cost is zero.

FortisBC cannot speculate on who may pay for unexpected mitigation costs, but suggests that the answer depends in part on any additional customer, utility and Internet Service Provider benefits that may result from mitigation (aside from the mitigation itself).

For example, mitigation may involve the Internet Service Provider moving to a different wireless frequency band or modulation technology that provides enhanced speed to customers.

25. In relation to its answer in 31.2.3 BCUC IR#1, it has been explained to me that the disruption to a ham radio by a smart meter comes in the form of a continuous pop, pop, popping sound. Does FortisBC agree that, for those who are slightly hearing impaired and/or aging, any disruption that causes the quality of sound to diminish or interrupts the continuous flow of sound is more than "minimal"?

Response:

FortisBC agrees that continuous pop, pop, popping sounds that cause the quality of sound to diminish or interrupts the continuous flow of sound is more than "minimal". FortisBC does not expect this to be the case, but would work closely with any customers that were impacted in this manner to mitigate negative effects.

26. In relation to its answer in 31.2.3 and 31.2.4, how will FortisBC deal with customers who discover that devices that they own and operate are being disrupted by installation of FortisBC smart meters?

Response:

As described in the responses to BCUC IR No. 1 Q31.2.3 and Q31.2.4 and Shadrack IR No. 1 Q24 and Q25, FortisBC will work with customers using the 900 MHz wireless band for other purposes to minimize any negative impact to customers. FortisBC expects very few issues based on conversations with other utilities that have implemented the Itron OpenWay solution.

27. In relation to its answer in 31.2.5, could FortisBC please explain why another company operating a device in the 900-928 MHz band prior to the arrival of FortisBC should have anticipated that FortisBC would use a device that is not compatible with other wireless devices currently being used in that band range?

Response:

FortisBC is unable to answer this question because it does not agree with the assertion that the proposed advanced meters are incompatible with other wireless devices currently being used in the 902-928 MHz band.

In fact, the AMI technology proposed operates in a similar manner to many other devices in the band, including baby monitors and cordless phones and will co-exist alongside these devices with little issue. Furthermore, the AMI RF technology is compliant with all technical parameters required under Industry Canada's RSS-210 standards.

28. In relation to questions 16 through 20 above, should not the onus be on FortisBC to purchase a wireless technology that is compatible with the other wireless products currently on the market and not vice versa?

Response:

Please refer to the response to Shadrack IR No. 1 Q21 and Q27. FortisBC considers the 900 MHz technology to be used in the proposed AMI Project to be compatible with other equipment in the band, and is compliant with required standards that ensure compatibility.

29. If these other devices are compatible with each other because they have been developed from more modern versions of wireless technology, why should FortisBC be allowed to use an earlier version of wireless technology that is so primitive it does not have compatibility with other wireless products?

Response:

Please refer to the responses to Shadrack IR No. 1 Q18 and Q27. In addition to not agreeing with the statement that the proposed technology is not compatible with other devices, FortisBC does not agree with the declaration that the technology is primitive. Though certain elements of the technology, in particular the concept of frequency hopping, were developed long ago, many facets of the technology are significantly newer. Regardless, the technology used in the proposed smart meters is well suited to its purpose and is similar to many other products continuing to use the 902-928 MHz band.

30. Section 2(a) of Part 1, Canadian Constitution Act, 1982, Canadian Charter of Rights and Freedoms, explicitly states that:

"*Everyone has the following fundamental freedoms: ...freedom of thought, belief, opinion and expression, including freedom of the press and other media of communication*"

Does FortisBC agree that its customers have a constitutional right to use previously installed Wi-Fi services, amateur radios, cordless phones and "*other media of communication*" that are not subsequently disrupted by installation of FortisBC's primitive smart meter technology?

Response:

FortisBC believes that the AMI project will be compliant with the applicable legal framework.

31. In relation to FortisBC's answers to 31.2.6 and 31.2.61 BCUC IR#1, as it relates to RSS-210 and RSS 210, Annex 8.1.b, is FortisBC aware that the Supreme Court of Canada has consistently struck down legislation and regulations, and administrative protocols, that fail to uphold a citizen's constitutional rights, especially where that legislation, and those regulations and administrative protocols fail to protect vulnerable citizens, such as those who are aging or have perceived handicaps?

Response:

FortisBC believes that the AMI project will be compliant with the applicable legal framework.

32. Why is FortisBC not using the designated International Telegraph Union channels previously accepted by Industry Canada for wireless smart meters?

Response:

FortisBC is not certain of the frequency bands being referred to in the question. However, it is assumed they refer to either the 1800-1830 MHz or 1492-1525 MHz frequency bands.

As discussed in Section 4.2.2 of the Application and in BCUC IR1 Q38.2, FortisBC did not specify a technology in its Request for Proposals. During this open RFP process, no submissions were received proposing equipment using these frequency bands. Furthermore, FortisBC is not aware of any commercially-available equipment available in these bands capable of meeting the requirements of an electric AMI system.

33. In relation to FortisBC's answer to question 33.1 BCUC IR#1, FortisBC explains that, prior to the introduction of Advanced Metering Infrastructure (AMI), the annual cost per customer of manually reading a meter is approximately $23 and will rise to $193 after AMI introduction. My 70 year old brother reads his own meter in England and phones it in to the company on a designated date. This is common practice for many utilities world wide. Why has FortisBC not previously considered introducing a self-read phone-in or Internet portal response meter program?

Response:

FortisBC is not opposed to the idea of customer self-reads, but believes they have limited application. In hard-to-read premises, FortisBC generally installs meters that can be wirelessly read from a distance with a handheld device.

In the case of AMI meters, a simple monthly meter reading does not provide the additional data that is obtained through the manual download process (hourly consumption, voltage, tamper alerts, etc). This data is required to preserve a portion of the quantifiable benefits described in the Application.

34. Can you please produce a modified Table BCUC IR1 Q33.1b as if the meters were self-read by the customer?

Response:

The table below is modified as requested to show a range of possible values depending upon the percentage of customers that elect to self-read the meter. The range covers 100% Company read (0% customer self-reads); 90% Company read (10% customer self-reads); 50% Company read (50% customer self-reads); and 0% Company read (100% customer self-reads).

Similar to the original table (BCUC IR1 Q33.1b), the information is presented for both the 1% of meters being manually read, and 5% of meters being manually read.

The Company notes that it has assumed that it will continue to read customer meters at least once per year to ensure accuracy. The “customer self-read” reflects the cost of doing that.

As indicated in the response to Shadrack IR1 Q33, customer self-reads will not allow the full benefits of AMI to be realized.

Table Shadrack IR1 Q34 – Manual Reading with Customer Self Reads

	Status Quo			Post - AMI						Post - AMI					
	Cost ($000)	100% manual reads	Cost per Customer	Cost ($000)	1% manual reads	Cost per Customer (0% Self Read)	If 10% uptake on self-reads, Cost per Customer for the 90% manually	If 50% uptake on self-reads, Cost per Customer for the 50% manually	Cost per Self-reading Customer	Cost ($000)	5% manual reads	Cost per Customer (0% Self Read)	If 10% uptake on self-reads, Cost per Customer for the 90% manually	If 50% uptake on self-reads, Cost per Customer for the 50% manually	Cost per Self-reading Customer
2016	$2,782	123371	$22.55	$238	1234	$193	$163	$60	$30	$792	6169	$128	$128	$34	$20
2017	$2,959	125581	$23.56	$246	1256	$196	$166	$61	$31	$821	6279	$131	$130	$34	$21
2018	$3,012	127798	$23.57	$255	1278	$200	$169	$62	$31	$850	6390	$133	$133	$35	$21
2019	$3,067	130024	$23.58	$264	1300	$203	$172	$63	$32	$880	6501	$135	$135	$36	$22
2020	$3,256	132188	$24.63	$273	1322	$207	$175	$64	$32	$911	6609	$138	$137	$36	$22
2021	$3,315	134357	$24.67	$283	1344	$210	$179	$65	$33	$942	6718	$140	$140	$37	$22
2022	$3,374	136518	$24.72	$292	1365	$214	$182	$67	$34	$974	6826	$143	$142	$38	$23
2023	$3,576	138650	$25.79	$302	1387	$218	$185	$68	$34	$1,007	6933	$145	$145	$38	$23
2024	$3,641	140812	$25.86	$312	1408	$222	$188	$69	$35	$1,040	7041	$148	$148	$39	$24
2025	$3,706	142955	$25.93	$322	1430	$226	$192	$70	$35	$1,075	7148	$150	$150	$40	$24
2026	$3,922	145078	$27.04	$333	1451	$230	$195	$71	$36	$1,110	7254	$153	$153	$40	$24
2027	$3,993	147181	$27.13	$344	1472	$234	$199	$73	$37	$1,146	7359	$156	$156	$41	$25
2028	$4,065	149280	$27.23	$355	1493	$238	$202	$74	$37	$1,183	7464	$159	$159	$42	$25
2029	$4,296	151367	$28.38	$366	1514	$242	$206	$75	$38	$1,221	7568	$161	$161	$43	$26
2030	$4,373	153420	$28.50	$382	1534	$249	$210	$77	$39	$1,274	7671	$166	$164	$43	$26
2031	$4,452	155448	$28.64	$394	1554	$254	$214	$78	$39	$1,314	7772	$169	$167	$44	$27
2032	$4,698	157481	$29.83	$406	1575	$258	$215	$79	$40	$1,354	7874	$172	$168	$44	$27

35. The Pine Ridge Water Utility Society uses a hand held device that reads a digital meter remotely. Has FortisBC ever considered using this technology?

Response:

FortisBC uses hand-held meter reading devices today to read hard-to-reach meters. FortisBC considered using this technology throughout the service territory in the Automated Meter Reading (AMR) project alternative described in Exhibit B-1, Section 7.2.

36. What frequency will FortisBC be using for its Radio Frequency (RF) Mesh collection system, and have they checked to make sure that this will not disrupt other previously installed "*media of communication*"?

Response:

As discussed in Section 4.1.2 of the original Application, and expanded on in several IRs including BCUC IR1 Q31.1, Q31.2, Q31.2.1, Q31.2.2, Q31.2.4, Q31.2.5, Q31.2.6, FortisBC plans on using the 902-928 MHz band for its proposed AMI system.

Please refer to the responses to BCUC IR No. 1 Q31.2.4 and Q31.2.6 for discussions detailing any expected impacts on existing users.

37. On August 7th, 2012, FortisBC advised that Itron has stated that it had never come across disruption of Wi-Fi services by their smart meter. Given that the Itron meter is disrupting certain Wi-Fi services across BC, has FortisBC considered asking its own engineers to do independent testing of this meter, and if not why not?

Response:

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.

38. Section 2(d) of the Canadian Constitution Act also guarantees "*freedom of association*". Has FortisBC considered granting any customer the right not to

have a wireless smart meter placed on their residential and/or business property?

Response:

Yes, the alternative of allowing for customers to "opt-out" was considered in Section 8.5 of the Application.

39. In one community in Area D the equivalent of all permanent residents in that community signed a petition opposing installation of smart meters. When the installers later showed up to install the meters in this same community, it is claimed that they threatened customers, some in their mid-80's, with disconnection of the utility service. In a number of rural communities around BC residents have simply blocked access to the community and refused to allow installers to enter. In larger urban centres citizens who have placed signs on their existing meters requesting that they not be swapped for smart meters have come home from school or work to find the sign crumpled up and lying on the ground and a smart meter installed.

    Can FortisBC please explain in exact detail how it intends to handle customers who refuse to accept installation of a smart meter on their property, and whether or not they will instruct the installer to replace the meter if the customer is away from their property at the time?

Response:

The FortisBC process for customers refusing the installation of an advanced meter is described in Exhibit B-1 Section 8.5.

Provided a customer has not clearly indicated to FortisBC their refusal to accept an advanced meter, FortisBC installers will be instructed to exchange meters if the customer is away from their property.

40. Will FortisBC instruct the installer to inform customers of the possibility of disconnection of service, and/or will FortisBC allow the installer to threaten customers with disconnection of service if they refuse to accept installation of a smart meter on their property?

Response:

FortisBC will instruct installers to inform customers of the potential for disconnection of their service if they refuse the installation of an advanced meter. FortisBC will not allow installers to threaten customers in any way.

41. It is understood that the existing meters will have to eventually be replaced due to old age, malfunction and claims by other regulators that they are not accurate enough, and that FortisBC does not intend to purchase or install new meters of the existing type. However, is it not also equally true that the new digital meters comply with accuracy requirements?

Response:

Confirmed. As noted in section 5.3.4 of the Application, solid state digital meters (AMI or otherwise) consistently exhibit better test results for accuracy, and as a result are typically granted longer seal extensions as compared to electro-mechanical meters. As well, it should be noted that a portion of the forecast savings related to avoided Measurement Canada compliance costs relates to the fact that the implementation of AMI will also allow the Company to optimize the size of compliance groups established for meter testing and verification, resulting in lower meter compliance costs than would otherwise be incurred were the existing meter population managed to the end of its life (i.e. replacing electro-mechanical meters that fail compliance testing with non-AMI digital meters).

42. Over the last six months I have received a number of phone calls from persons concerned about the health effects of wireless smart meters, including some who have moved to rural BC precisely to avoid coming into contact with EMR. Section 7 of the Canadian Constitution Act explicitly states:

Everyone has the right to life, liberty and security of the person and the right not to be deprived thereof except in accordance with the principles of fundamental justice

And, Section 15(1) also explicitly states:

"*Every individual is equal before and under the law and has the right to equal protection and equal benefit of the law without discrimination and, in particular, without discrimination based on...disability*"

Can FortisBC please explain, in detail, what provisions it has made for customers who have specific health issues, ie. allergic reactions, to devices that emit EMR?

<u>Response:</u>

Please refer to the response to CSTS No. 1 Q34.4.

Page 2, line 3 – Reduction of greenhouse gases

1. This is mentioned quite a few times. Please clarify what will happen to the vehicles that the meter readers use. Will they be sold, or just moved around?

Response:

Please refer to the response to BCUC IR No. 1 Q25.1.

Page 3, line 2

2. Please explain how the customer knows what information you will be sending out. What are the security specifications for AMI-SEC? Do customers have any say in what information is being sent out?

Response:

As noted in section 8.4.4 of the Application, AMI will allow FortisBC to collect the same personal information from customers that it currently collects today, with the only difference related to the frequency of collection of such information. This personal information will be collected, used and disclosed in accordance with the British Columbia *Personal Information Protection Act* (PIPA).

As noted in section 3.2.5 of the Application, AMI will also allow the Company to more frequently collect non-personal information related to a variety of operating exceptions including meter inversion, meter removal, reverse power flow and power outages. As well, information related to operating conditions that may impact power quality will also be more frequently collected, including information regarding reverse polarity, cross-phase and energy flow, phase voltage deviation, inactive phase current, phase angle displacement and current waveform distortion.

A copy of the AMI-SEC System Security Requirements is provided as Appendix F-1 to the Application.

Page 5

3. Please explain how a rate decrease of 1% over the life of the project (20 years) will be applied. How will the consumer know there is a rate decrease when rate increases are approved almost every year?

Response:

The Company stated that the:
"financial analysis of the Project, as evaluated over a 20 year period, shows that rates will be lower <u>than they would be without the AMI Project</u>, ... It is expected that advanced metering will provide a rate decrease of approximately 1 percent over the life of the Project…"

To clarify, this means that customer rates would be approximately one percent higher over the 20 year period in the absence of the AMI Project.

Please also see the response to BCUC IR No. 1 Q97.1 and Q97.3

Page 17, Line 11

4. Please explain what will be happening to the 80,000 meters when they are replaced.

<u>Response:</u>

All replaced meters, including the electro-mechanical meters referenced in the question, will be recycled or disposed of.

Page 17, Line 21

5. Please advise how many of the electronic meters installed in the last 6 years been AMI (smart) meters.

<u>Response:</u>

FortisBC has not installed any AMI meters.

Page 22

Smart Grid cost of and maintaining it

6. Please explain how you can have a smart grid all over BC? There are some regions that saimply cannot support it.

<u>Response:</u>

FortisBC is not proposing a smart grid all over BC. For the Company's electric service territory, FortisBC is proposing an AMI Project that will install:

- new software;
- a communications system enabling secure, automated transmission of data between the utility and AMI meters; and
- AMI meters.

Page 34, Line 17

7. Please advise if you have any record of a meter reader finding problems with a meter, but it is still reporting back.

<u>Response:</u>

FortisBC interprets "reporting back" to mean the meter is still recording electrical consumption. FortisBC meter readers have found problems with a meter (ex. broken glass), but the meter is still recording electrical consumption.

When a meter reader reports a meter problem, the problem is dispatched and investigated by an Operations employee. It is not until the investigation results come back into the Billing Department when FortisBC learns of the actual metering issue. The Company does not keep track of the number of occurrences in this regard (meter readers discovering a problem or issue with a meter).

Page 34, Line 29

8. Please advise how a smart meter will be able to tell if electricity is stolen before the meter.

<u>Response:</u>

Energy theft can occur both at the meter and before the meter. The advanced meters proposed in the Application will issue a tamper flag when the meter has been removed from the socket and trigger a site investigation. Premises where theft is potentially occurring before the meter can be identified by unexpected changes in voltage and through energy balancing at the feeder level. Please refer to the responses to BCUC IR No. 1 Q78.1 and Q88.1 for a discussion of feeder energy balancing.

Page 38, Line 18

9. Again, please advise what will be happening to the meter reader vehicles.

Response:

Please refer to the response to BCUC IR No. 1 Q25.1.

Page 39, Line 1

10. Please advise how the claim on lines 1 and 2 are justifiable and not completely subjective.

Response:

FortisBC believes that the referenced claims, although subjective, are explained in Exhibit B-1, Section 3.2.5, p 38 Line 22 through p 39 Line 10. Please also see the AMI CPCN Application, Section 6.3, pg 101 – 102 for future benefits related to outage management.

11. Please advise the average number of phone calls received when the power goes out.

Response:

The number of phone calls received when the power goes out depends entirely on the size, duration, and nature of an outage.

If a single customer's power goes out, the number of calls is at least one, and can be more than one (repeat calls from the same customer) depending on whether or not sufficient information was available from FortisBC at the time of their call.

Referencing larger outages, the number of calls depends on a number of factors, including the length of the outage and the time of year. Customers are understandably more likely to report an outage, and call more than once about an outage, if it occurs on a cold day and lasts longer than expected.

During a large outage, FortisBC places an information message at the front-end of its telephone system which provides, if known, awareness of the location of an outage, cause, crew response, and estimated time of restoration. In a large outage, most customers will hear this message and not elect to stay on the line to speak to a FortisBC representative.

Considering the myriad permutations of power outages, an "average number of phone calls received when the power goes out" is not specific enough a question to answer accurately.

12. Please advise the anticipated response time to an outage prior to installation of AMI.

Response:

Outage response time is dependent on the type of outage that occurs which can define how the Company is notified of the outage. Large outages that effect transmission lines, substations or substation feeders will notify the control room operator via the SCADA system. Smaller outages that occur downstream of these monitoring systems require effected customers to notify FortisBC. Response time to outages is also dependent on variables such as the time of the day or night, when affected customers call and other system problems affecting available resources.

13. Please advise the anticipated response time to an outage after installation of AMI.

Response:

FortisBC does not believe that the AMI system on its own will impact response time in a significant way. It will, however, help ensure that crews do not leave a problem area before all customers are restored. FortisBC is considering the implementation of an Outage Management System (OMS) following the implementation of the AMI system. The OMS will compile the AMI meter outage information and using the connectivity model of the distribution system from the Graphical Information System (GIS) will predict the individual outage groups and predict which customers are involved in each outage area. The OMS will also predict which device in the distribution system will most likely have operated to cause the outage. This information will assist control room operators in dispatching field personnel to the appropriate location.

Page 44 - IHD (Inhouse display)

14. Please advise the frequency of the outbound signals to Fortis if a customer has one of these devices.

Response:

Given that the IHD communicates with the meter and not the Company, FortisBC understands the question to mean "advise the frequency of the outbound signals to the customer's IHD".

There are two modes in which the IHD can communicate:

Binding: IHD subscribes to get updates such as messages and price changes. The frequency of these messages is fully determined by how often the messages are sent from the Company.

Polling: IHD polls the meter to get the messages and pricing in order to have near-real time data. For general operation, an IHD cannot poll any more often than once every 30 seconds. The IHDs are allowed to go into a Fast Polling mode where they can poll as often as once every 2 seconds for no longer than a 15 minute period of time.

15. What will the cost be for an IHD?

Response:

Please refer to the response to BCUC IR No. 1 Q28.1.

16. In order for customers to be able to determine their usage, they must purchase an IHD. So, to save money people have to purchase an additional piece of equipment. If one of the intents of having AMI meters is to conserve electricity, why not provide the IHD for free?

Response:

Customers will still get their monthly or bimonthly usage on their bills and can view more detailed consumption patterns on their premise through the secure customer information portal, at no cost. An IHD is simply another option for viewing more detailed and timely information. There are a variety of IHD's on the market and customers may wish to purchase more or less expensive models based on features that are important to them. FortisBC intends to provide incentives through its PowerSense program for the purchase of IHDs as described in the Application on page 44 and in the response to BCUC IR No. 1 Q28.1.

Page 45 LAN (Local Area Network)

17. Please advise if AMI meters in the system be able to communicate with their receivers (eg: rural areas) where the meters are far apart.

<u>Response:</u>

AMI meters in the proposed system will be able to communicate with each other when the meters are far apart. When distances are too great for direct meter to meter communications, pole mounted range extenders may be used. In cases where the distance between meters becomes so great, or the terrain too challenging, such that many range extenders are required, it may not be economical to use wireless technology, as contemplated in Section 4.1.3 of the Application.

Page 47, Line 4

18. The WiMAX system will have to be replaced due to upgrades and meter will be obsolete in 15 years due to battery life? Please explain how this is cost-effective?

<u>Response:</u>

FortisBC understands that some of the technologies that are to be used in the proposed AMI project may have limited technological lives, particularly communications infrastructure. All expected upgrades, battery replacements and device replacements have been accounted for in the financial analysis of the project.

Please see section 5 of the Application for details on how the project is cost effective, even considering the technological lives of some components.

Page 47, Line 17

The next rate increase in the future will be because we need to replace meters due to technology upgrades.

Page 47, Line 22

19. Satellite receivers can be cost effective – Explain?

Response:

In sparsely populated areas where no other third party services are available and FortisBC does not have existing communications infrastructure, using satellite transceivers to backhaul collector data is often less expensive than deploying a WAN network. Furthermore, as discussed in response to BCUC IR No. 1 Q32.1, as long as there are a sufficient number of customer meters being aggregated at the collector, using satellite may also be more economical than a manual meter reading process.

Page 55, Line 15

20. Explain the procedure for a remote connect/disconnect with an AMI meter.

Response:

Please refer to the Application (Exhibit B-1) at Sections 5.3.3. and 8.4.5, and the responses to BCUC IR No. 1 Q116.1-116.3.

Page 57, Design Phase and Build Phase

21. Including the capital costs at these phases, please advise what the rate increase is for these procedures alone.

Response:

Assuming the project expenditures are incurred as planned in 2013 (which include the Design and Build phases), the rate impact in 2014 would be approximately 0.5%.

22. Please advise how many new hires will be needed to implement the AMI system?

Response:

FortisBC does not contemplate requiring new permanent staff in order to implement the proposed AMI Project. Additional workforce is contracted, with designated internal project management staff drawn from existing Company personnel.

To operate the AMI system (after it has been installed/implemented), ensuring benefits realization as per the CPCN Application, the Company proposes to add 9.5 employees, offset by the reductions in the manual meter reading workforce.

23. Please advise the salary range for the new technicians hired – will those salaries be higher or lower than the meter readers you will be replacing?

Response:

The AMI Project proposes to add (post implementation) a total of 9.5 new employees. These consist of 6 Analysts (Business/Technical/System), a Communications Technician, a Telecom Engineer and 2 Revenue Protection staff. The compensation ranges from approximately $50,000/year to approximately $90,000/year, dependent upon the position.

The AMI Project proposes to eliminate manual meter reading. The meter reading workforce is comprised of 20 employees. The current average compensation for a meter reader is approximately $55,000/year.

Page 65, Lines 9 – 25

24. Please advise the justification for reducing meter readers and hiring project managers and AMI consultant.

Response:

The AMI Project proposes a prudent number of project management staff, inclusive of the AMI consultant, necessary to manage the implementation of the proposed project. Project management is budgeted at approximately $3.1 million. Upon conclusion of the implementation of the AMI project, and acceptance of the AMI system, the project management resources will be discontinued.

A benefit of AMI is the elimination of the ongoing operating expenses associated with the existing manual meter reading function. This represents a net customer benefit of approximately $23.8 million (NPV at 8%, 2012 – 2032) over the life of the proposed project.

Page 66 line 2

25. Prior to the AMI project, Fortis had one of the best processes of customer service, i.e. direct interaction with meter readers. Please explain how AMI meters will help customer service for Fortis.

Response:

As noted in section 3.2.5 of the Application, there are numerous benefits resulting from the implementation of AMI that are expected to improve customer service, including the following:

- The provision of enhanced billing information, including the ability to view through an online web portal or with an in-home display more detailed information about the timing and amount of energy consumed than currently possible;
- Improved billing accuracy and the elimination of bill estimates for monthly billed residential customers, as well as for customers for whom a manual meter reading cannot be reliably obtained;
- The ability to accommodate consolidated billing requests for customers with multiple electricity accounts;
- The ability to provide customers with a flexible billing date that best meets their needs;
- A reduced need to access customer premises;
- Immediate notification of power outages and restoration; and
- Improved power quality monitoring.

Although meter readers are one point of interaction between customers and Company, the primary point of contact between customers and FortisBC is through the Company's Contact Centre. Indeed, the customer service benefits attributable to AMI (enhanced billing information, improved billing accuracy, immediate notification of power outages) are expected to result in a decreased call volume related to billing inquiries and an increase in customer satisfaction resulting from the benefits listed above.

Page 67, Overview of Risks

26. Was the contract for communication network devices put to tender?

Response:

Yes, FortisBC issued competitive Requests for Proposals (RFPs) for the AMI system (which included the LAN network devices).

FortisBC is designing the WAN communications system internally. When the design is finalized, FortisBC intends to competitively tender for the hardware, software and services.

27. What were the results of those bids?

Response:

Itron Canada Inc. was selected as the vendor for the LAN communications system.

28. Have you signed a contract with the Communications network vendor?

Response:

Yes, with Itron Canada Inc. Please also see the response to Tatangelo IR No. 1 Q26.

29. Change requests are very expensive and in the first year electronics cost changes can be devastating. You indicate that "significant changes must be signed off by AMI Steering Team". Please clarify as to what Fortis considers to be a significant change.

Response:

Change requests that impact the proposed project scope, schedule or cost are considered significant if they result in:

- A change to the finalized project schedule;
- Addition or reduction of scope of the project; or
- Additional costs exceeding $100,000.

Page 68

30. You anticipate the AMI project will result in a reduction of 9.5 meter reader employees. Please advise the number of employees you will be hiring to proceed with the AMI Project.

Response:

The proposed AMI Project contemplates the elimination of existing meter reading operations, which currently employees 20 personnel. The proposed Project also contemplates the addition of 9.5 personnel to operate the AMI system, post-implementation.

Please also see the response to Tatangelo No. 1 Q22.

Page 69, Line 7

31. Does your 20 year study take into account that the electronic devices will only last for 10 years because of the 10 year limitation for the WiMAX technology?

Response:

Please refer to the response to Tatengelo IR No. 1 Q18.

Page 69, Line 4 - 13

32. As your cost and benefit summary states, the savings will pay for 30% of the costs of AMI for the next 20 years. How can you justify costs when you are not looking at the cost analysis of having to upgrade, which also very well may happen before the end of your 20 year analysis?

Response:

FortisBC is unable to determine where the Application states that savings will pay for 30% of AMI costs over 20 years. In fact, the summary table outlines a total net present value savings of approximately $18 million, after all costs.

As discussed in Tatangelo IR No. 1 Q18, all anticipated upgrades, battery replacements and device replacements have been accounted for in the financial analysis of the project.

33. Please provide your cost analysis of power theft and how you came up with the figure of 38,386 NPV

Response:

Please see Exhibit B-3 filed with the BCUC on August 17, 2012 and refer also to BCUC IR No. 1 Q87.1.

Page 70, Line 10

34. Please advise if the smart meters in use for the past 6 years have indicated theft in the system.

Response:

FortisBC has not installed any advanced (“smart”) meters.

35. Please advise how a smart meter is able to indicate power theft prior to meter.

Response:

Please refer to the response to Tatangelo IR No. 1 Q8.

Page 71, Line 6

36. Explain what you mean by “additional metering required to detect losses on the distribution system.” You have previously argued that AMI meters will be able to detect losses on their own.

Response:

Please see Tab 5.3.2, page 88 of the Application.

Page 74, Line 14

37. Please advise if you will have to install new meters to allow remote disconnect. Explain how this will be done with existing electronic meters.

Response:

Yes, new meters will have to be installed to accommodate the remote disconnect and reconnect functionality. These meters have been selected as part of the proposed AMI system. The existing electronic meters do not have remote disconnect and reconnect functionality and will be replaced during the deployment phase of the project.

Page 74, Line 17

38. On page 68 line 12 you claim you will reduce 9.5 meter readers but on this line you say Fortis will be hiring 9.5 staff at a higher wage bracket. Please explain where is the AMI cost saving.

Response:

AMI eliminates the need for existing meter reading operations, providing a net customer benefit of approximately $24 million (Exhibit B-1, Table 5.0). Total new operating expenses of the proposed Project, including those associated with the proposed new positions required to operate the AMI system post-implementation have a cost of approximately $14 million (NPV at 8%, 2012 – 2032).

Please also see the responses to Tatangelo IR No. 1 Q22 and Q24.

Page 77, Line 14

39. Fortis' stand on option for accounting options of disposal of existing meters is just hiding the figures in the bottom line and will not pass Measurement Canada's guidelines. Please advise the amounts that Fortis arrived at for options 1, 2 and 3.

Response:

Measurement Canada does not set accounting guidelines. FortisBC follows US Generally Accepted Accounting Principles (US GAAP). The three options each use the same assumption with regard to the net book value of the existing meters that will need to be written off. The difference in the three options is with regard to the period of time over which the meters would be written off. Option one is in accordance with US GAAP and would write off the meters over two years. Option two would write off the meters over seven years and Option three would write off the meters over twenty-one years and both would require approval of an accounting variance from the Commission.

Page 77, Line 29

40. Please justify this line. Meters reads have not been manually keyed in for years.

Response:

For clarity, the statement on page 77, line 29 of the Application refers to the manual keying of meter reads using the current portable handheld meter reading devices. Beginning in the early 1990s, FortisBC transitioned from collecting meter reads on paper (and transcribing them into the billing system), to inputting meter reads on a portable handheld meter reading device for subsequent electronic upload to the billing system. Despite this improvement in the method of collecting meter reads, inadvertent errors still occur due to meter readers reading the meter incorrectly or pressing the wrong button when entering a meter read into the portable handheld device. The implementation of AMI will eliminate these inadvertent errors.

As discussed in section 5.3.6 of the Application, off-cycle meter readings (soft reads) are required when a customer moves in or out of a premises, or to verify possibly inaccuracies in the reading. The collection of soft reads, are still performed using paper, with the read subsequently faxed to the Contact Centre and manually entered into the billing system. The implementation of AMI will result in cost savings resulting from reduced labour costs related to the manual entry of soft reads into the FortisBC billing system.

Page 78, Line 1

41. Your description of what a meter reader does is not complete. They find broken glass on meters that are still registering, find bad service wires, see power theft before the meter. They are the first contact that the customer has with the utility. They can talk to customers about their readings and consumption as well. Please advise how a smart meter will be able to fulfil any of these duties, if at all.

Response:

AMI meters will automate the collection of electrical consumption data and will significantly improve the Company's theft reduction capabilities. Further, tamper alarms will automatically alert the Company when certain types of tampering occur.

As is the case today, customers are always welcome to visit one of our offices or contact the Company using the telephone or email via FortisBC's contact center.

Additionally, post-AMI implementation, customers will be able to see, in near real time, their consumption history in much greater detail than is available today, accessing the information via either the secure customer web portal (which is part of the proposed AMI project) or a customer-purchased In Home Display (IHD).

Page 80, Line 1

42. In my opinion, Historical Meter Reading Costs could be reduced with the use of electric powered vehicles. Please justify why electric powered vehicles have not been utilized as this would reduce the production of greenhouse gases as well.

Response:

Electric vehicles are not used for meter reading purposes because they are not cost effective. The overall cost of an electric vehicle is significantly higher compared to conventional internal combustion engine vehicles due to the additional cost of the battery pack, the down time incurred to re-charge the vehicle and the need for electric charging stations. The combination of these factors makes electric vehicles less than optimal.

In addition, electric vehicles are generally not suitable for the unique requirements of the meter reader position. A meter reader requires a vehicle that can navigate through rugged, off-road conditions to reach customer premises. This is especially critical in FortisBC's rural and mountainous service area. Since existing electric vehicles cannot provide the versatility, clearance and the range required, gas and hybrid engine vehicles are used instead.

Page 81 Line 14

43. Is there any other way for you to justify the number of grow operations that occur within your territory? The report you referred to of Mr. Plecas only speaks to indoor grow operations. In previous reports of Mr. Plecas (i.e. "Marihuana growing operations revisited 1997 – 2003") he refers to both indoor and outdoor grow operations, and time and time again in those previous reports, outdoor grow operations occur at a higher number and percentage of plants grown in the Kootenays and Okanagan than in other regions. Your numbers used to justify smart meters is inherently flawed.

Response:

FortisBC is confident that its methodology correctly addresses only indoor marijuana grow operations. The Application considers indoor marijuana production sites only as these represent a risk of energy theft. This distinction is made in Tab 5.3.2, page 81, line 15. The 13,206 figure proposed by Dr. Plecas for 2010 are indoor sites only and legitimately forms the basis of the total marijuana sites estimated to exist in the FortisBC service area that use electricity in production.

FortisBC has carefully considered all known North American research on the subject as well as Company internal data in arriving at an estimated number of indoor production sites. Please also see the response to BCUC IR No. 1 Q74.1.

44. A meter reader can spot energy theft by noticing abnormalities of the premises or outside buildings, and reduced power consumptions. How will your smart meter notice any change in outdoor activity? A customer who operates a grow operation and does not bypass the meter is in fact not theft, as they are not stealing power but in fact buying it.

Response:

Please refer to the responses to Tatangelo IR No. 1 Q8, and BCUC IR No. 1 Q78.2, Q88.1, Q88.1.1 and Q88.3.1.

Page 89, Line 15

45. Please explain how a meter will disconnect a 200 amp service as we now have 600 volt meters self contained. Will smart meters that will be installed next year be able to do a remote disconnect or will a special smart meter be required? If so, what are the costs for those special smart meters?

Response:

The AMI Itron Centron OpenWay meters selected for the proposed AMI system will enable the remote disconnection (and reconnection) of service at a residential customer premise. Meters for a 200 amp, 600 volt self contained system will not be installed with remote disconnect and reconnect functionality.

Page 93

46. Your discussion of the changes that will occur due to the new Measurement Canada's requirements are only your supposition. You state that electrical mechanical meters have many moving parts, when in that they have FEW parts, and have lasted 40 - 50 years and passed seal extensions. Please advise what Fortis will do with the groups of passed electrical mechanical meters.

Response:

The electro-mechanical meters that will be replaced during FortisBCs proposed AMI project will be disposed of and recycled where applicable.

47. If a sample group failed, what happens to the group, as some types of meters cannot be manually calibrated in a shop.

Response:

If a sample group fails compliance testing, all meters belonging to the group are replaced with new meters prior to the expiration of their seals.

Page 96, Line 3

48. Please advise if a meter reader encountered a problem that the AMI would have missed on soft reads.

Response:

FortisBC understands the question to be about what meter problems a meter reader may observe during soft reads.

Meter readers can see, and will report, obvious signs of tampering. As stated in the response to Tatangelo IR No. 1 Q41, the AMI system will automatically alert the Company when certain types of tampering occurs.

Pages 99 – 101

49. Are not the cost savings you speak of on these pages not already done without AMI meters? You will require many different meters to carry out these scenarios.

Response:

The future potential benefit described in the referenced section of the Application refers to power grid voltage optimization. Table 6.2.a. sets out the estimated costs and potential benefits for the various voltage optimization options available. The potential benefits noted cannot be achieved with existing Company technology, and all would require additional investment, as estimated in the table.

Page 102

50. Again, these are unsubstantiated numbers. Please advise if you receive telephone calls when a specific customer loses power? Will a specific AMI meter identify to the control operator what is happening or just advise that the meter is not working? Does not currently the central operator screen light up on a block area power outage?

Response:

FortisBC believes that the information provided on Page 102 of the application is a reasonable estimate of the savings of an Outage Management System. These numbers will be validated through a regulatory process before FortisBC proceeds with the implementation of an OMS.

An OMS system will identify individual meters that have lost power and will also predict likely causes of failure based on the electrical system model.

Currently, system control screens will identify outages only at the distribution feeder level or higher.

Page 102, Line 17 – Pre-Pay Tariff

51. Is it reasonable to expect low income people to be able to pre-pay for their power usage when they are already considered poor pay and/or poor credit history? Why would you not be able to currently use prepay without AMI meters?

Response:

Optional pre-pay programs have proved popular with a variety of customers at other utilities. The programs are successful for a few important reasons:

- no deposit is required and no credit check is performed;
- customers can check their credit balance at any time; and
- customers can make multiple small payments.

Again, the Company would propose pre-pay only as an optional program. The program is not possible without AMI meters since continuous consumption data is required in order for customers to see their account balance.

FortisBC believes that AMI will provide many important tools that will help low or fixed-income customers to manage their consumption by providing the capability to:

- find current account balance at any time, either over the phone, online or with an optional in-home display;
- manage consumption with the pre-pay program; and
- select preferred billing dates.

Page 104

You are speculating that 8% of people will use prepay. Navigant's report says “potentially 3 and up to 8%” which is the same number in that report of in-home displays.

52. Is your intention that to use the prepay option will also require users to have a home display unit? Customers who are already considered poor pay and/or poor credit history will not be able to afford to prepay and pay or rent a home display unit.

Response:

FortisBC has not determined whether a pre-pay program requires an in-home display unit to be successful. The Company agrees that affordability could be an issue (if IHDs are required), and would propose customer cost mitigation measures as part of an application for a pre-pay tariff to address that issue. Please also see the response to BCUC IR No. 1 Q103.2.

53. How does Fortis believe that they will save money on prepay when you haven't even completely investigated this, as you yourself admit on Page 102, line 1 – 7.

Response:

FortisBC believes that customers will save money based on the findings in the Navigant report and from conversations with other utilities. Additionally, although it has not been quantified, it is considered likely that a pre-pay option for customers would reduce the administrative requirements of the Company related to the management of over-due accounts (since there are no overdue accounts with pre-pay).

Please refer to the response to BCUC IR No. 1 Q110.7 for information regarding the process for further assessing conservation rates.

Page 107, Line 8

54. Similar question already asked: what will happen if a large group of meters fail the compliance test?

Response:

Please refer to the response to Tatangelo IR No. 1 Q47. FortisBC does not take different actions for small versus large lot sizes – all meters are replaced regardless of lot size.

Page 112, Line 16

55. How can you justify spending 66 million dollars to replace 9.5 employees and hiring 9.5 employees at an increased labour rate to implement a AMI system that will probably be obsolete in 10 years and have to be replaced with newer technology?

Response:

Page 112, Line 16 of the CPCN Application is referring to the Power Line Carrier (PLC) AMI System that FortisBC investigated as an alternate to its proposed RF AMI system, and is estimated to have a capital cost of approximately $66 million. However, as is set out in Section 7.3 of the CPCN Application the PLC alternate was discounted as a viable alternative.

The economic life of the project is expected to be 20 years.

The Company's proposed AMI Project need is described in Section 3 of the CPCN Application, and the proposed costs and benefits are described in Section 5 of the CPCN Application.

Please also see the responses to Tatangelo IR No. 1 Q22 and Q30.

Page 130 – Project Challenges

NO WHERE is an issue that is important to many people covered off, and that is defective AMI meters.

56. What is Fortis' position on defective AMI meters?

<u>Response:</u>

The Company expects less than 0.5% of installed AMI meters will be defective, all of which will be replaced by the vendor during the warranty period. This failure rate is similar to that currently experienced by the Company with existing non-AMI digital meters.

Defective meters will generally be identified either by meter self-diagnostics or by a failure to communicate with the head-end system.

57. What percentage of residences that have AMI meters installed by Fortis have had a power surge, explosion, fire etc within 30 days of installation, regardless of whether the action occurred due to a faulty meter or not?

<u>Response:</u>

FortisBC does not currently have advanced meters installed on any residences within its service territory. Please also refer to the responses to BCUC IR No. 1 Q47.2 and Q47.3.

58. What percentage of residences that have electronic magnetic meters installed by Fortis have had a power surge, explosion, fire etc within 30 days of installation, regardless of whether the action occurred due to a faulty meter or not?

<u>Response:</u>

Please refer to the response to BCUC IR No. 1 Q47.3.

59. Are you able to answer the above question regarding the number of province-wide installed AMI meters?

Response:

As noted in a report prepared by Len Garis (Fire Chief for the City of Surrey, B.C.) and Dr. Joseph Clare (Strategic Planning Analyst for the Surrey Fire Service, Associate Professor in the Crime Research Centre, University of Western Australia), for the period July 2011 to June 2012 (during BC Hydro's SMI deployment), there have been two fires where the electrical igniting object was the panel board or switchboard (includes fuses, circuit breakers).

As discussed in the report, these types of fires are most closely related to the meter base. It should be noted that the report does not detail the period in which the fires occurred relative to when (or if) a smart meter was installed.

In comparison however, for the period July 2010 to June 2011 (prior to commencement of the BC Hydro SMI deployment), there were seven such fires in B.C. Based on this, the report concludes that there has been no significant difference in the number of fires caused by electrical distribution equipment in homes in the year before BC Hydro began installing smart meters as compared to the two years since BC Hydro started installing them. The report does note though that based on the analysis of residential fires, it is expected that electricity related fires may decline with the installation of the smart meters in B.C.

A copy of the report is provided as Appendix Tatangelo IR1 59.

60. Is each Fortis installer carefully examining each and every plate when an AMI meter is installed?

Response:

Yes, FortisBC installers will be examining each and every plate to make sure the meter being exchanged is the correct meter for the premises electrical service.

61. Has it been considered that there may be some reported power surge issues because of installed AMI meters?

Response:

FortisBC has been deploying digital meters at customer premises for over 15 years. An AMI meter is essentially a digital meter with a radio frequency transmitter module installed. The Company has no evidence of power surges caused by these meters.

62. How are you dealing with the reality that people may be having a power surge because of the installation of AMI meter, where no issue had surfaced earlier with electronic magnetic meters?

Response:

Please refer to the response to Tatangelo IR No. 1 Q61.

Appendix Tatangelo IR1 59

Assessing the Safety of Smart Meter Installations in British Columbia

Analysis of Residential Structure Fires in BC between July 2010 and June 2012

Fire Chief Len Garis and Dr. Joseph Clare

August 2012

UNIVERSITY OF THE FRASER VALLEY
SCHOOL OF CRIMINOLOGY & CRIMINAL JUSTICE

UNIVERSITY OF THE FRASER VALLEY
CENTRE FOR PUBLIC SAFETY & CRIMINAL JUSTICE RESEARCH

The Purpose of this Research

The purpose of this report is to analyze key questions raised in the deployment of smart meters by BC Hydro in the Province of British Columbia (BC). The deployment of smart meters commenced in mid-2011 and at the time of producing this report it is estimated approximately 1.5 million smart meters have been installed: approximately 83% of the total that will be installed upon completion of this exercise. A range of issues have been publicly discussed with respect to smart meters, the most recent of which has drawn links between these new apparatus and residential structure fires. As a result, two specific questions have emerged:

1. Has there been a noticeable change in the frequency of residential structure fires caused by electricity in the province that may be associated with the deployment of smart meters?

2. Has there been a noticeable change in the frequency of residential fires in the province in the presence of a marijuana grow operation?

In order to respond to these two questions, the scope of this research is as follows:

- Undertaking an analysis of relevant, available documentation including BC Hydro's smart metering and Infrastructure Program Business Case [1], and the University of the Fraser Valley (UFV) Research Note entitled, "The increasing Problem of Electrical Consumption in Indoor Marihuana Grow Operations in British Columbia" [2].
- Analyzing the Office of the Fire Commissioner's fire incident reporting data that covers a two year period from July 2010 to June 2012: providing a one year pre- and post-deployment for analysis of the impact of smart meters on residential structure fires.

Introduction

In June of 2011, BC Hydro commenced implementation of its Smart Metering Program, which involved converting every residential property in BC from legacy metering to wireless technology smart meters. This Smart Metering Program involves replacing an almost 1.9 million existing electrical meters that are now becoming obsolete, with a comprehensive wireless smart metering system. This process is scheduled to be completed by the end of 2012.

This development in BC mirrors similar activity in other areas, with a general shift by utilities companies from around the world towards upgrading their electricity systems and adopting smart meter technology. It is predicted that by 2015, 250 million smart meters will be installed worldwide [1, citing research undertaken by Pike Research, November 2009].

It is anticipated that BC Hydro's Smart Metering Program will modernize the electricity grid and pay for itself through reduced theft of electricity, energy savings, and operating efficiencies [1]. Electricity theft is an increasing problem in BC and can result in structure fires due to tampering with household wiring and with electricity grid infrastructure. Smart meter installation provides an opportunity to identify and address safety issues such as an overloaded service and electrical bypasses. It is expected that electricity-related fires, including those due to marijuana grow operations, may decline with the installation of the smart metering system in BC.

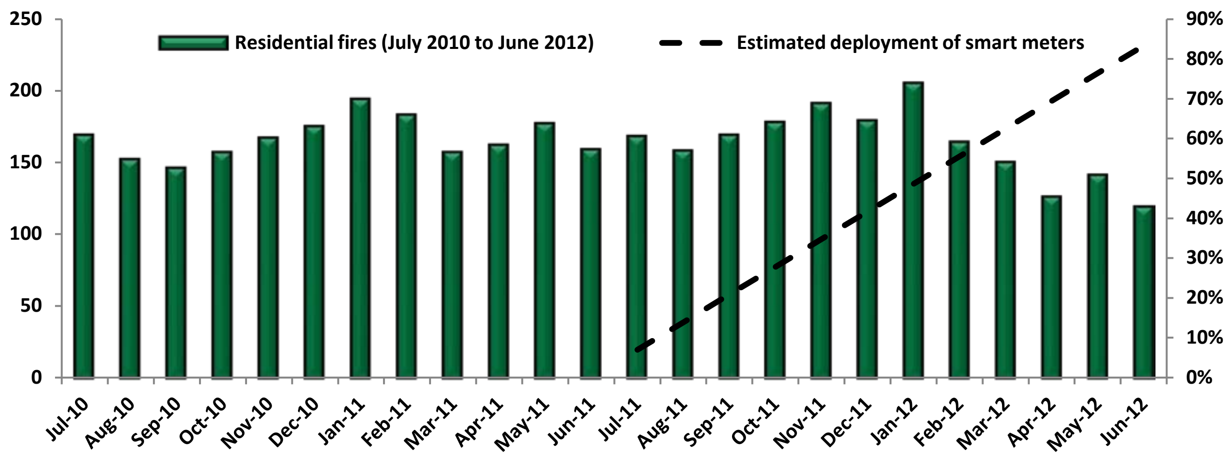
Analysis

The initial dataset that was examined contained 12,425 fires that had been reported to the BC Office of the Fire Commissioner and had occurred in BC between July 2010 and June 2012 (inclusive). Of these, 3,946 (31.8%) were residential structure fires. Table 1 demonstrates the reporting areas within BC that provided details about these residential structure fires, separated into two groups: pre-meters (which included fires that occurred between July 2010 and June 2011), and post-meters (fires that occurred between July 2011 and June 2012). For the purposes of this analysis, these two time periods have been compared to examine the broad impact of smart meters for fires. However, the authors realise that smart meters were not present in all residences from the start of the post-meter time period. The subsequent analysis should be considered with the graphical representation depicted in Figure 1 in mind. This demonstrates the estimated percentage of the province's residences that had smart meters installed over time, along with the monthly fire reports that have been examined.

TABLE 1. FREQUENCY OF FIRES BY REPORTING AREA FOR THE PRE-METER AND POST-METER TIME PERIODS – BC DATA, JULY 2010 TO JUNE 2012

Reporting Area	Pre-meters (July 2010 to June 2011)	Post-meters (July 2011 to June 2012)
Municipal areas	1,817	1,793
Non-municipal - fire protection	126	107
Non-municipal - no fire protection	30	23
First Nations Band area	25	25
Total	**1,998**	**1,948**

FIGURE 1. FREQUENCY OF RESIDENTIAL STRUCTURE FIRES IN BC PER MONTH (JULY 2010 TO JUNE 2012) WITH ESTIMATED DEPLOYMENT OF SMART METERS (% OF ALL RESIDENTIAL PROPERTIES IN BC)



The following analysis examines the frequency of fires in the pre- and post-meter groups, with a view to answering two main research questions:

1. What is the frequency of fires with respect to electricity?

2. What is the frequency of fires with respect to illegal activity associated with marijuana grow operations?

Frequency of Fires with Respect to Electricity

As can be seen from examination of Table 2, in both periods of interest (pre- and post-meters) residential structure fires made up approximately one-third of the total fires reported during that time. With respect to the question about the impact of smart meters on the frequency of residential structure fires, the following summarise the main findings displayed in the table:

- There has been a general decline in electricity-related residential structure fires reported where the form of heat was electrical (9.9% decline) and where electrical distribution equipment was the igniting object (2.3% decline).

- On a more specific level, electrical distribution equipment generally made up a very small percentage of the overall residential structure fires in both groups (0.4% and 0.1% in the pre- and post-meters, respectively). It is likely that these types of fires are most closely related to the meter base, which is directly relevant to the smart meters. Interestingly, in conjunction with the deployment program for smart meters, there has been a corresponding reduction in the frequency of these types of fires.

- To further examine any potential negative impact of the smart meters for fire safety the frequency of fires that occurred on an exterior wall where the igniting object was the electrical panel board/switchboard was examined. Only 1 of these incidents was recorded, which took place in the pre-meter time interval.

TABLE 2. ELECTRITY-RELATED FIRES – BC DATA, JULY 2010 TO JUNE 2012

	Pre-meters (July 2010 to June 2011)	Post-meters (July 2011 to June 2012)	% Change
Total Residential fires	1,998	1,948	-2.5%
% residential	30.1%	33.7%	12.2%
Form of heat is spark electrical (includes arc discharge)	171	154	-9.9%
% residential fires were form of heat was a spark, electrical	8.6%	7.9%	-7.6%
Electrical distribution equipment as igniting object	131	128	-2.3%
% residential where electrical igniting object	6.6%	6.6%	0.2%
Electrical distribution equipment - panel board, switchboard (includes fuse, circuit breakers)	7	2	-71.4%
% residential where electrical igniting object was panel board, switchboard (includes fuse, circuit breakers)	0.4%	0.1%	-70.7%
Fires where fire origin area was an exterior wall and the igniting object was an electrical panel board, switchboard	1	0	-100.0%
% residential where origin area was an exterior wall and igniting object was an electrical panel/switchboard	0.1%	0.0%	-100.0%

Frequency of Fires with Respect to Illegal Activity Associated with Marijuana Grow Operations

With respect to the question about the frequency of residential structure fires related to illegal activity associated with marijuana grow operations, the following main findings capture the results displayed in Table 3:[1]

- Fires that were recorded as having been caused by an act or omission associated with illegal operations declined by 35.7% over the period of interest.
- Fires where the igniting object was electrical a bypass (typically associated with theft of hydro associated with production of marijuana) reduced by 25%.
- There were no fires recorded in the post-meter time period where the igniting object was classified as a grow lamp and the activity was illegal. This declined from 5 such fires in the pre-meter time period.
- The only increase in any activity associated with electricity and marijuana was for fires caused by grow lamps where the activity was legal (an increase from 1 event in the pre- period to 2 in the post-period).

TABLE 3. ILLEGAL ACTIVITY-RELATED (MARIJUANA GROW OPERATION) FIRES – BC DATA, JULY 2010 TO JUNE 2012

	Pre-meters (July 2010 to June 2011)	Post-meters (July 2011 to June 2012)	% Change
Total residential fires	1,998	1,948	-2.5%
% residential	30.1%	33.7%	12.2%
Act/omission illegal operations/activities (e.g., grow ops, meth labs)	28	18	-35.7%
% residential fires where act/omission was illegal operations/activities (e.g., grow ops, meth labs)	1.4%	0.9%	-34.1%
Igniting object was electrical distribution equipment - electrical bypass (illegal operations)	8	6	-25.0%
% residential where igniting object was electrical bypasses (illegal operations)	0.4%	0.3%	-23.1%
Igniting object was grow lamps/lights (illegal)	5	0	-100.0%
% residential where igniting object was grow lamps/lights (illegal)	0.3%	0.0%	-100.0%
Igniting object was grow lamps/lights (legal)	1	2	100.0%
% residential where igniting object was grow lamps/lights (legal)	0.1%	0.1%	105.1%

[1] Some degree of caution is required when interpreting these results. The authors are not confident that fires caused by this type of illegal activity are always reported consistently. Having said this, these findings are the best current estimate available.

Locating Electrical Fires within the Broader Context for BC

To put these incidents within the broader context of residential fire activity in BC over the period of interest, it is important to examine the relative frequency of cooking related fires and fires that resulted from smoker's material, as displayed in Table 4. As can be seen, fires caused by electricity are relatively infrequent compared to those resulting from commonplace activities such as cooking (approximately 29% of fires in both time periods) and smoking (approximately 17% of fires in both time periods).

TABLE 4. FREQUENCY OF COOKING FIRES AND SMOKER'S MATERIAL FIRES – BC DATA, JULY 2010 TO JUNE 2012

	Pre-meters (July 2010 to June 2011)	Post-meters (July 2011 to June 2012)	% Change
Total residential fires	1,998	1,948	-2.5%
% residential (as a function of all fires reported)	30.1%	33.7%	12.2%
Cooking equipment fires	575	557	-3.1%
% residential where cooking equipment was igniting object	28.8%	28.6%	-0.6%
Smoker's material fires	321	340	5.9%
% residential where smoker's material was igniting object	16.1%	17.5%	8.6%

Conclusions

In conclusion, with respect to the two main research questions of interest, the following can be summarized:

- Available data does not indicate that there has been an increased frequency of residential structure fires associated with electricity since July 2010. If anything, there is a slight decline.
- Available data does not indicate that there has been an increased frequency of fires caused by electricity associated with illegal activity since July 2010. If anything, there is a slight decline.

Both of these findings need to be interpreted with caution, given the very small numbers of events that occur in these categories. However, having drawn attention to this issue, it should also be noted that the analysis presented here includes all fires reported for the whole of BC over the time period of interest. As a result, these are the best estimates available.

A final point worth emphasizing relates to the relative frequency of fires caused by electricity when compared to those that result from cooking and smoking. Without wishing to minimise any fire event, it is important to maintain perspective that these every day activities result in many more fires for BC than those caused by electricity.

References

[1] BC Hydro, *Smart metering and infrastructure program business case*, 2012, BC Hydro: Vancouver, BC.

[2] J. Diplock and D. Plecas, *The increasing problem of electrical consumption in indoor marihuana grow operations in British Columbia*, 2011, Centre for Public Safety and Criminal Justice Reserach, School of Criminology and Criminal Justice, University of the Fraser Valley: Abbotsford. p. 8.

Author Biographical Information

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1.0 Reference: Exhibit B-1, Application, Page 25 and Exhibit B-1, Application, Page 30 and Exhibit B-1, Application, Page 40

> FortisBC's evolutionary vision of a smart grid is to build upon a foundation of existing infrastructure to ensure a safe, reliable, cost-effective and environmentally-friendly electrical system which facilitates active customer participation, meets future demands and supports public policies and regulations.

> The technology of AMI is a fundamental prerequisite for FortisBC's smart grid vision since it includes deployment of a widespread communication network throughout the Company's service territory. The new network infrastructure associated with AMI has the potential to change the way that FortisBC operates its distribution infrastructure and how the Company interacts with its customers, and will help prepare the electrical infrastructure for new customer loads and technologies such as distributed generation and plug-in hybrid electric vehicles.

> - Install approximately 115,000 residential and commercial AMI meters capable of remote connection and disconnection of electric service;

1.1 Please confirm that in implementing AMI, FortisBC is achieving two outcomes:

a) A transition to communicating digital meters, which can be expected to continue indefinitely, and

b) Specific physical implementation of 115,000 meters with an expected life of 20 years.

<u>Response:</u>

FortisBC confirms that the outcomes noted above will be achieved by the proposed AMI Project. Further, it should be noted that these outcomes are inextricably linked to the significant financial and non-financial benefits (outcomes) that result from the proposed Project. It is these benefits, as identified in the Application, which drive the need for the implementation of AMI at this time.

Please also refer to the response to BCUC IR No. 1 Q2.1 for a discussion regarding the need for, and benefits attributable to, the proposed AMI Project, as well as the potential impact of any delay in the Project on the realization of these benefits.

2.0 Reference: Exhibit B-6, BCUC 1.1.1

> The Company has no current plan to complete a new depreciation study. However, the Company depreciation expert Gannett Fleming estimates that rates calculated in the most recent depreciation study are reasonable for a period of three to five years. As such, FortisBC will address the matter of a new depreciation study as part of a future revenue requirements application using year-end plant in service data from the year prior to that in which the study is conducted.

2.1 What changes would have to occur so that FortisBC would believe the existing depreciation rate was no longer reasonable?

<u>Response:</u>

There would have to be a significant change in the composition of the meter population through obsolescence, technological change or the like that would materially change either the useful life of new meters or the average life of the population.

3.0 Reference: Exhibit B-6, BCUC 1.1.1.1

Would Fortis BC consider not revising the depreciation rate and continuing with 5 percent over the 20-year period?

> Yes.

3.1 What advantages and disadvantages does FortisBC see in having the depreciation rate stay stable at 5% over 20 years?

<u>Response:</u>

The advantage of a stable depreciation rate is that it supports stable customer rates.

4.0 Reference: Exhibit B-6, BCUC 1.1.2 and Exhibit B-6, BCUC 1.46.1, Table 46.1

> Due to contractual sensitivities, information regarding the applicable warranties has been filed with the Commission in confidence.

Failures in integration work	1	4	Warranties related to equipment, software and all aspects of system performance are included in the contract.

4.1 Is FortisBC specifically prohibited by contract from providing certain information about warranties in the contract?

Response:

Yes, FortisBC is prohibited from providing specific information to any parties aside from the British Columbia Utilities Commission regarding the contract terms.

4.1.1 If so, what types of information may not be made public?

Response:

Information that may not be made public includes information that would reasonably be considered to be confidential, including information that is not generally known to parties outside the contract, and the terms of the contract.

4.1.2 If not, how has FortisBC determined what information is confidential and please provide a list of the types of information.

Response:

Please refer to the response to CEC IR No. 1 Q4.1.1.

4.2 Does Itron make any warranties regarding the life of the equipment provided?

Response:

Yes. As described in the response to BCUC IR No. 1 Q1.2, due to contractual sensitivities, information regarding the equipment warranties has been filed with the Commission in confidence.

5.0 Reference: Exhibit B-6, BCUC 1.1.2

> Itron CENTRON OpenWay meters are designed to have a service life of 20 years. Accelerated life testing performed by Itron on CENTRON OpenWay meters suggests that the great majority of those meters will last to or beyond the 20-year design life. Please also refer to the response to BCUC IR1 Q69.1.

5.1 Please explain if 'designed to have a service life of 20 years' refers strictly to functionality or whether this addresses the technologically useful life and/or economically useful life?

Response:

The statement is meant to address all three concepts. An economic useful life would be based on a functional life of 20 years that would not be limited by technological change. Depreciation rates are of course based on estimates. Technological change is not expected to limit the economic or service life of the meters.

5.2 Is 20 years typical of the service life of other digital meters?

Response:

Please refer to the response to BCUC IR No. 1 Q90.5.

6.0 Reference: Exhibit B-6, BCUC 1.1.2 and Exhibit B-6, BCUC 1.69.1

> Itron CENTRON OpenWay meters are designed to have a service life of 20 years. Accelerated life testing performed by Itron on CENTRON OpenWay meters suggests that the great majority of those meters will last to or beyond the 20-year design life. Please also refer to the response to BCUC IR1 Q69.1.

> *Meter Life Expectancy*
> Many meters will last beyond their 15 or 20 year life expectancy. Each stress test lasts the equivalent of the product lifespan. The tests show that the product must maintain a <= 0.5% yearly failure rate over the product life expectancy. In other words, if we have 0.5% * 20 years = 10% of the meters can fail, but 90% are still operational. From the accelerated life testing, we calculate what the yearly failure rate; we can validate that the failure rate is less than the 0.5%.

6.1 Please confirm that over 90% of the meters can be expected to last 20 years or beyond?

Response:

The Centron meter product was introduced to the marketplace in 1998, so no Centron meters have yet been operating in the field for 20 years. However, based upon accelerated life testing, Itron confirms that the average constant failure rate for OpenWay Centron meters is 0.5 percent per year over the 20 year lifespan of the meter. This testing includes, but is not limited to: High temperature test, temperature cycling test, and high temp/high humidity test.

6.2 Can Itron or others specify what the estimated failure rate is based on their testing?

Response:

Please refer to the response to CEC IR No. 1 Q6.1.

6.2.1 If so, what is it?

Response:

Please refer to the response to CEC IR No. 1 Q6.1.

6.3 Is there a price premium associated with longevity? For example, are there Smart Meters available that have equivalent functionality, at a cheaper price, that are designed with a shorter lifespan?

Response:

No, FortisBC does not believe that there is a price premium associated with longevity for the proposed Itron AMI meters. Further, FortisBC is not aware of advanced meters that have been designed with a shorter lifespan in order to reduce costs.

7.0 Reference: Exhibit B-6, BCUC 1.3.1

> FortisBC must decide prior to August 1, 2013 whether to proceed with the Itron contract. FortisBC may exit the contract prior to that date if it does not receive a decision or if it receives a decision with conditions that are unacceptable to the Company.
>
> FortisBC is requesting a decision by July 20, 2013 in order to provide sufficient time for the Company to evaluate the decision prior to August 1, 2013.
>
> The contract does not contemplate, 1) FortisBC failure to exit the contract prior to August 1, 2013 without proceeding with the contract after that date or 2) renegotiating any terms of the contract prior to August 1, 2013. The outcome in both of these circumstances is therefore uncertain.

7.1 Please confirm that there are no penalties associated with FortisBC exiting the contract prior to August 1, 2013.

<u>Response:</u>

Confirmed, providing that FortisBC decides not to proceed with the Itron contract before August 1, 2013 because the BCUC has not approved the Application or because a BCUC decision is received with conditions unacceptable to the Company.

A break fee is payable to Itron if FortisBC exits the contract prior to August 1, 2013 for any other reason.

7.2 Are there other conditions by which FortisBC may exit the contract beyond either not receiving a decision or receiving a decision with conditions that are unacceptable to the company?

<u>Response:</u>

FortisBC may exit the contract at its discretion.

7.3 What conditions would FortisBC contemplate as being either acceptable or unacceptable to the Company?

<u>Response:</u>

The Company is unable to speculate on what conditions could be considered acceptable or unacceptable given the variety and combination of conditions that could be imposed by a decision. FortisBC will evaluate the decision, including any conditions attached, at the time of receipt prior to making a determination as to whether such conditions are acceptable or unacceptable for the Company to proceed with the Project.

7.4 Please confirm that if FortisBC fails to exit the contract prior to August 1, 2013 it remains contracted to proceed under the existing terms of the contract?

Response:

FortisBC is required under the contract to issue a notice to commence work after August 1, 2013, unless prior to August 1, 2013 FortisBC: 1) exits the contract, 2) does not receive approval, or 3) receives approval with unacceptable conditions.

7.5 Is FortisBC contracted to minimum numbers of smart meters and other equipment to be purchased and/or installed over a certain period of time? If so, please provide the minimum numbers of each type of equipment FortisBC is contracted to purchase/install and over what period of time.

Response:

FortisBC is not contracted to purchase a minimum number of meters or other equipment.

8.0 Reference: Exhibit B-6, BCUC 1.3.1

> Approximately $21 million of total project costs relate to the Itron contract for AMI – including unit costs for meters and network devices, software, and contract costs for professional services. The contract was negotiated in 2011, and prices will be held firm provided that FortisBC receives CPCN approval and agrees to any conditions contained in the BCUC decision by August 1, 2013.

8.1 Are there portions of the contract with Itron in which the prices will not be held firm?

Response:

No.

8.2 In the event that prices decline, is there any mechanism by which FortisBC can capitalize on the reduced prices?

Response:

No.

9.0 Reference: Exhibit B-6, BCUC 1.3.1

> Internal costs will be impacted by a delay in project start since staff continuity cannot be assured. These costs cannot easily be quantified, but relate to sourcing, obtaining, training and orienting new project personnel after a positive decision for the project is obtained.

> Itron has experienced resources available in British Columbia until mid-2013 that could be quickly deployed to the FortisBC project, which would help ensure the project schedule was met and capitalize upon the synergies of implementing FortisBC's AMI project near the time of BC Hydro's Smart Metering implementation.

9.1 What is the maximum delay that FortisBC could expect to reasonably accommodate without impacting internal costs?

Response:

If the project start date was delayed in a predictable manner, personnel decisions could be made with clarity, allowing FortisBC to allocate internal resources appropriately, and limiting delay costs. If the time delay is unknown or uncertain, FortisBC will have to release personnel to other projects with variable assignment terms, potentially hindering a restart of the project and/or increasing costs.

9.2 Can internal costs potentially be reduced by proceeding more quickly than anticipated in the application?

Response:

The proposed preliminary Project Schedule and Project Plan (refer to the response to BCUC IR No. 1 Q40.1) provides the optimum matching of resources to tasks while minimizing the costs of those resources. Accelerating the proposed project schedule would require additional resources and increase project risks.

9.3 Specifically what experienced Itron resources are available in British Columbia until mid-2013 that would help ensure the project schedule was met?

Response:

Itron currently has an experienced project team working at BC Hydro on its SMI implementation that could be available to FortisBC until mid-2013. FortisBC and Itron have not identified any specific individuals.

9.4 What is the anticipated cost savings or other advantages that would accrue from utilizing these resources?

Response:

As stated in the reference, the advantage of using these resources is that they could be quickly deployed to the FortisBC project. However, Itron is contractually required to meet project schedule and cost requirements regardless of the availability of these resources.

9.5 What constitutes ‘near the time of BC Hydro’s Smart metering implementation’?

Response:

Implementing the Company’s proposed AMI Project as per the preliminary Project Plan (refer to BCUC IR No. 1 Q40.1), which would see implementation commence in Q3 2013, is approximately nine months after the expected substantial completion of BC Hydro’s implementation.

9.6 Please confirm that the above statement contemplates a timing in which the Itron resources being deployed have completed their work with BC Hydro SMI project and then move to commence work with the FortisBC project.

Response:

Confirmed.

9.7 If not, is there expected overlap and over what period of time?

Response:

Please refer to the response to CEC IR No. 1 Q9.6.

9.8 If the final completion date of the BC Hydro SMI project were delayed for any reason, would FortisBC consider delaying the AMI project?

Response:

No.

9.8.1 If not, what impact would that have on the ability of FortisBC to capitalize on the resources and synergies of implementing immediately after the BC Hydro project?

Response:

Please refer to the response to CEC IR No. 1 Q9.4.

10.0 Reference: Exhibit B-1, Application, Page 1

> The FortisBC AMI Project is consistent with provincial government policy. The *Clean Energy Act* directly supports the implementation of "smart metering" and "smart grid" technologies, and the Project proposed in this Application is consistent with the regulations made pursuant to the Act.

10.1 Has FortisBC considered the possible impact of a change of provincial government policy on legislation affecting smart meters?

Response:

The CPCN Application assumes a stable regulatory and legislative environment. The Company believes the additional considerations related to the decision to proceed with the Application at this time as articulated in the responses to BCUC IR No. 1 Q2.1 and BCPSO IR No. 1 Q4.1 clearly underscore the fact that the proposed Project ought to be considered as being in the public interest.

10.1.1 If so, what changes could FortisBC anticipate that might be problematic?

Response:

Please refer to the response to CEC IR No. 1 Q10.1 and the response to CSTS IR No. 1 Q73.1.

11.0 Reference: Exhibit B-6, BCUC 4.1.1

Festival Hydro Inc.	Y			
FortisBC	Y			
Greater Sudbury Hydro Inc.	Y	Y	Y	Y
Grimsby Power Incorporated (FortisON)	Y	Y	Y	Y

11.1 Does FortisBC anticipate using Util-Assist Inc. for purposes other than procurement such as Implementation and Project Management, Business Process Development or Testing?

Response:

Yes, FortisBC anticipates using Util-Assist Inc for additional support, primarily in testing the backoffice (MDMS/HES) functionality.

11.2 If so, has FortisBC entered into any further agreements with Util-Assist Inc?

Response:

FortisBC's existing contract with Util-Assist contemplates the anticipated usage noted in the answer to CEC IR No. 1 Q11.1. Costs associated with anticipated Util-Assist work are included in the proposed Project costs as submitted in the CPCN Application.

12.0 Reference: Exhibit B-6, BCUC 1.6.1

> FortisBC confirms that electro-mechanical meters are no longer available to be purchased new on the market from the two main meter manufacturing venders currently being used - Itron and Elster.

12.1 Please confirm that 'currently being used' means currently being used by FortisBC.

<u>Response:</u>

Itron and Elster are the main meter vendors currently being used by FortisBC.

12.2 Are there other vendors supplying new electro-mechanical meters in North America?

<u>Response:</u>

FortisBC is not aware of any vendors supplying new electro-mechanical meters in North America.

12.2.1 If so, please identify those vendors and the products available.

<u>Response:</u>

Please refer to the response to CEC IR No. 1 Q12.2.

12.2.2 How long might these vendors be expected to keep manufacturing electro-mechanical meters?

<u>Response:</u>

These vendors no longer manufacture electro-mechanical meters and have changed all of their production to digital meters.

12.3 Please identify when Itron and Elster stopped manufacturing new electro-mechanical meters.

Response:

Itron produced their last electro-mechanical meter in 2005. It is expected that Elster would have stopped production around the same time to allow them to compete with the other vendors.

12.4 When is the conversion of the market to digital meters expected to be nearly permanent in FortisBC's estimation? Can this be expected to occur within the next 5, 10, 15 or 20 years?

Response:

Please see the Application (Exhibit B-1) at Section 5.3.4, Page 93.

The Company anticipates that under the new Measurement Canada S-S-06 regulations that FortisBC would be fully converted to digital meters in a 21 year period if the AMI project did not proceed.

13.0 Reference: Exhibit B-6, BCUC 1.6.5.1

> This alternative has not been pursued as it would negate much of the benefit of an AMI system. For example, the main financial benefits of an AMI system – decreasing meter reading costs and reducing theft – both require a full deployment of AMI meters in an area to be realised. Since the current digital meters are not concentrated in a geographical area, these efficiencies would not be realised across the entire FortisBC service area.

13.1 Please confirm that 'full deployment' with respect to reducing theft refers to 100%, and that 100% deployment of AMI is required in order for the maximum theft reduction benefits to be realized.

Response:

Confirmed. Please note that 100% deployment includes AMI meters that are not connected to the LAN network but are manually downloaded (Exhibit B-1, p49).

13.2 If deployment is less than 100% will the theft reduction benefits to be realized be diminished from the maximum?

Response:

Given the significant deterrent effect of the proposed AMI-enable theft reduction program, the associated benefits may or may not be impacted if deployment is less than 100 percent.

13.2.1 Please provide the curve/scale at which theft reduction benefits can be realized in relation to the proportion of deployment.

Response:

FortisBC cannot prepare such a scale since the amount that the benefit is diminished will depend on the location of the theft on the electrical grid and the effect on deterrence resulting from the incomplete deployment.

13.3 At what level of deployment does FortisBC estimate that it would be unable to achieve 80% and 50% of the theft reduction benefits respectively?

Response:

Please refer to the response to CEC IR No. 1 Q13.2.1.

13.4 Please confirm that 'full deployment' with respect to decreasing meter reading costs refers to 100% deployment.

Response:

Confirmed. Please also refer to the response to CEC IR No. 1 Q13.1.

14.0 Reference: Exhibit B-6, BCUC 1.6.8

> If FortisBC did apply for temporary permission pursuant to the Measurement Canada Policy on Granting Temporary Permission to Use Electricity Meters Without Reverification, it would not be without cost. The policy states that an electricity contractor must:
>
> a. ensure that the integrity and accuracy of electricity meters are maintained;
>
> b. provide objective evidence to support a decision to keep electricity meters in service without reverifying the subject meter types, models and/or groups of meters; and
>
> c. provide a plan that will include conditions to mitigate the risk of inaccurate meters remaining in service.

14.1 What costs does FortisBC anticipate it would incur in meeting the conditions specified above.

Response:

At this time, FortisBC has not performed an analysis to determine the costs to meet the conditions listed, however the Company estimates the costs would be no less than $50,000.

Based on discussions with Measurement Canada representatives, the Company anticipates that a considerable amount of time and expense would be involved in developing a plan to mitigate the risk of inaccurate meters remaining in service. Further, Measurement Canada representatives have indicated that the process of applying for dispensation would be iterative and take several months to ensure a sufficient level of comfort that the measurement devices in the field are performing as required.

Measurement Canada felt that based on discussions with the Company regarding the timelines for the implementation of the AMI Project, it would be prudent to avoid applying for temporary dispensation.

14.1.1 Please quantify each of the costs specified.

Response:

Please refer to the response CEC IR No. 1 Q14.1.

14.2 How would these costs change over time?

Response:

Please refer to the response CEC IR No. 1 Q14.1.

15.0 Reference: Exhibit B-6, BCUC 1.8.1

> *The most frequent customer dispute is a high bill. They complain about the meter reading being wrong. In truth there are enough meter reading errors that high bills are a fact of life. But the ability to check the current meter reading directly from the meter while the customer is on the phone and re-calculate the bill if the bill was high, and to end the post call investigation, by being able to directly validate the customer dispute reduces the time to clear a complaint that is nonphone time and it reduces the call handling time of the life of the dispute. It is not unusual that the initial call time goes up, since the CSR has to explain how they are getting the information and may have to have the customer walk to the meter while on the phone and verify the numbers that show on the meter. This has reduced monthly disputes with chronic callers over a period of 3 to 6 months in most utilities that have this ability.*

> It is difficult to predict the impact on customer satisfaction of having accurate and frequent meter readings readily available to customers. However to the extent that the availability of such information addresses customer concerns related to high bills and estimated bills, it is probable that customer satisfaction will improve. The use of bill estimates is the unavoidable result of the current manual meter reading process, and drives many of the complaints received. As well, the current high bill process also suffers from a lack of data to assist customers with identifying when their consumption increases and how increases may relate to temperature. This gap is addressed with AMI.

15.1 Does the above information relate only to residential customers?

Response:

Commercial services are still subject to manual meter reading errors which AMI would eliminate.

The ability to discuss detailed usage patterns on the phone (or through the customer information portal or with an in-home display) would assist all customer classes, including commercial customers, in identifying patterns of usage and possible explanations for high bills.

15.2 Are complaints received from commercial customers relating to high bills also related to the manual meter reading process?

Response:

Yes. Commercial services are at least as likely to experience an erroneous manual meter reading as residential customers. Due to the higher frequency of readings for larger commercial services that are read monthly instead of bimonthly, and the fact that the additional reading component of demand is recorded, it is safe to say that commercial services are proportionately more likely to suffer from an erroneous manual reading than residential services.

15.2.1 If not, please specify the types of complaints FortisBC receives from commercial customers with respect to high bills.

Response:

Please refer to the response to CEC IR No. 1 Q15.2.

15.3 Are there other areas in which customer satisfaction is expected to improve other than those related to high bills?

Response:

While the impact on customer satisfaction is hard to quantify or even guarantee, it stands to reason that increased options, flexibility and information for customers should have a positive effect on customer satisfaction. Some of these include:

- Flexible billing dates (especially useful for customers whose cheques arrive at a set time of the month and currently don't match FortisBC's due dates which are tied to manual meter-reading billing cycles);
- Consolidated billing which would allow customers who have premises in different locations (and therefore on different billing cycles) to receive a single detailed bill instead of multiple bills with different due dates;
- More detailed information on energy consumption patterns over time and at different times of the day, allowing for better decision making around energy efficiency choices;
- In the event of an outage, FortisBC will be aware of exactly which customers are out of power, and therefore be able to restore power more quickly by being able to interpret the most-likely cause of the outage affecting the larger group. Better outage location information will allow FortisBC to have more accurate and timely information messages at the Trail Contact Centre, meaning that customers won't have to wait in the outage phone queue to speak to a representative for that same information. FortisBC will often

be aware of smaller distribution outages even before the first customers call to report it, thereby also saving time in sending crews to respond; and

- Instant reconnection of power (either after a non-pay disconnection or due to someone moving into a vacant premise).

15.4 Has readily available access to accurate and frequent meter readings been found to influence customer electricity usage without time-of-use pricing?

Response:

FortisBC believes that better access to information can influence consumption behaviour even without time varying price signals.

The Navigant Study, (attached as Appendix C to the Application), discusses in a number of places the added benefit provided by combining improved customer information that supports conservation rates. It is clear however that the impacts of both components are separable and have some impact on their own. For example, the BC and Newfoundland real time feedback pilot, mentioned in Table 4 of the Navigant Study, is an instance where no price or conservation incentives were given to sample participants. Therefore, the conservation results observed in the pilot are interpreted as the minimum to be garnered in the absence of other possible conservation incentives.

This conclusion is supported by a recent Brattle Group study which concluded, "… that consumers who actively use an IHD can reduce their consumption of electricity on average by about seven percent when prepayment of electricity is not involved. When consumers both use an IHD and are on an electricity prepayment system, they can reduce their electricity consumption by about twice that amount."

The full text of this study can be found at http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1407701.

15.5 How many meter reading errors does FortisBC uncover every year? Please specify for commercial and residential customers.

Response:

FortisBC does not track how many meter reading errors occur every year. An estimate was used based on the number of manual error corrections that were completed for bills in 2011.

In 2011, meter reading errors for residential customers were estimated to be 5,480 and for commercial customers meter reading errors were estimated to be 630.

15.6 What is the average amount in dollars of a meter reading error?

Response:

The estimated cost of a meter reading error is approximately $6. This is based on the cost of a billing operations employee manually completing the correction.

15.7 How often does FortisBC attribute temperature fluctuations as a reason for high bill inquiries?

Response:

As part of a high bill call, the same period in the previous year(s) is often compared in order to see if the current consumption is similar. Any differences are discussed with the customer in regard to temperature in the current year versus the previous year. Since the comparison period is generally two months in length, it is difficult to definitively attribute usage changes exclusively to temperature fluctuations.

As part of AMI implementation, FortisBC intends to provide daily (or more frequent) temperature data correlated with daily (or more frequent) consumption. This will provide a more obvious comparison of any link between usage and temperature.

FortisBC does not track the proportion of high bill calls that are attributed to temperature fluctuations, since such a metric would be subjective and possibly misleading.

15.8 What other reasons are typically attributed for high bill inquiries?

Response:

Possible reasons for bills being higher than expected include:

- Customer misses the fact that there is a balance forward (forgot to pay, missing payment, etc…);

- Billing period is longer than usual (i.e. if a monthly bill gets cancelled due to a high previous estimate and is rebilled as part of a two-month bill to the actual verified reading. Also, the customer's first bill may have been shorter than a full bill cycle due to a customer's move-in date, thereby making the second bill appear larger in comparison);
- Equal Payment Plan reconciliation;
- Customer is comparing the current high bill to the previous one which may have occurred in a completely different climate, instead of comparing to the same period in previous years;
- Weather is significantly colder or warmer than the previous year;
- Customer's usage has changed significantly due to differences in appliances (i.e. new hot tub, switch in heating type, faults, etc…), number of occupants, or lifestyle;
- The current reading is estimated too low which may result in a high catch-up bill once an actual reading is obtained;
- The current reading is estimated too high which may later result in a low catch-up bill once an actual reading is obtained;
- The current or previous actual readings were incorrectly read by a meter reader, resulting in the same high bill scenarios as the previous two points;
- Customer is comparing bills to their previous or neighbour's premises (i.e. different residences);
- The bill may contain other charges that are unrelated to consumption (Heat Pump Loan, Connection charge, Deposit request, etc…); and
- Power theft without a power diversion (neighbour plugging into the outside plug while customer is away).

16.0 Reference: Exhibit B-6, BCUC 1.8.2

FortisBC has rated customer demand for IHD and portal features on a scale of 1 to 10 based on the forecast adoption rates.

IHD/Portal Feature	Forecast Adoption Rate	Demand (1-low, 10-high)
Pre-pay	3-8%	1
In-home display (purchased by customer with PowerSense incentive)	30%	3
Use of customer portal to monitor consumption	15%	2

16.1 Please confirm that the above information relates to residential customers only.

<u>Response:</u>

The forecast adoption rate, and therefore the demand calculated from it, was derived primarily from residential studies. However, it is not unreasonable to assume (for IHDs and the customer information portal) that adoption rates for commercial customers would be in similar proportion to the residential rates.

16.2 Does FortisBC have knowledge of the manner in which commercial enterprises in their area do or could utilize higher resolution time-based consumption information to manage their electricity usage?

<u>Response:</u>

Commercial users can use the information to help manage their consumption in the same manner that residential customers can: by changing their consumption behaviour (turning lights off when not in use, for example) or by investing in energy efficiency equipment (more efficient lighting).

Commercial customers that are subject to a demand charge can use hourly (or more frequent from an in-home display) information to find out when their power use is highest to try and reduce their peak use and thereby manage their bill.

16.2.1 If so, please provide a description of the manner in which commercial enterprises could utilize the above information.

<u>Response:</u>

Please refer the response to CEC IR No. 1 Q16.2.

16.3 Has FortisBC received requests from commercial enterprises for higher resolution time-based information about their electricity usage?

Response:

Yes, through requests made to the Commercial PowerSense representatives. It is useful information that helps customers mitigate demand spikes (and thereby helps them manage their bills).

17.0 Reference: Exhibit B-6, BCUC 1.9.1 and Exhibit B-6, BCUC 1.9.1.2 and Exhibit B-6, BCUC 1.9.2

Yes, FortisBC's five wholesale customers are signatories to the British Columbia Climate Action Charter.

Yes, the Company considers the approximately 47,000 customers served by the five wholesale customers to be indirect customers of FortisBC.

Although the Smart Meters and Smart Grid Regulation under the *Clean Energy Act* (CEA) is generally applicable to BC Hydro, section 17 (6) of the CEA also states:

> If a public utility, other than the authority, makes an application under the *Utilities Commission Act* in relation to smart meters, other advanced meters or a smart grid, the commission, in considering the application, must consider the government's goal of having smart meters, other advanced meters and a smart grid in use with respect to customers other than those of the authority.

17.1 Does FortisBC believe that the 47,000 customers it considers indirect would also be covered under the government's goal of having smart meters, other advanced meters and a smart grid in use?

Response:

The definition of "public utility" as provided in the *Utilities Commission Act* does not include a municipality or regional district in respect of services provided by the municipality or regional district within its own boundaries. As FortisBC's approximately 47,000 indirect customers are served by municipalities which the Company provides wholesale service to, by definition, section 17 (6) of the *Clean Energy Act* cannot apply to those service providers. Despite this, it is conceivable that the government still desires the implementation of smart meters and a smart grid for all residents of BC, including those customers served directly by municipalities, however this support has not been articulated through legislation. It is important to note that of the five municipalities for which FortisBC provides wholesale service to three have already implemented a form of advanced metering (AMR).

18.0 Reference: Exhibit B-6, BCUC 1.10.1

> Once AMI meters are installed it would be possible to conduct energy loss measurements on a per-feeder basis. This would be done by subtracting the total energy consumed at customer end-points from the energy supplied to a distribution feeder (as measured by the substation advanced meters). Prior to completion of the DSAP, a large number of distribution feeders would not have had the advanced substation meters necessary to support this calculation.

18.1 Please provide a list of the substation distribution feeders and identify the number of customer endpoints on each.

Response:

Please refer to Table CEC IR1 18.1 below.

Table CEC IR1 18.1

Region	Feeder	Customers
Boundary	CHR1	1394
Boundary	GFT1	1624
Boundary	KET1	870
Boundary	KET2	408
Boundary	KET5	1
Boundary	KET6	1259
Boundary	RUC1	1
Boundary	RUC5	471
Kootenay	AAL1	709
Kootenay	AAL2	1076
Kootenay	AAL3	522
Kootenay	BEP1	749
Kootenay	BEP2	726
Kootenay	BLU1	781
Kootenay	BLU2	1121
Kootenay	CAS1	797

Region	Feeder	Customers
Kootenay	CAS2	1550
Kootenay	CAS3	128
Kootenay	COF1	343
Kootenay	COT1	19
Kootenay	CRA1	336
Kootenay	CRA2	532
Kootenay	CRA3	155
Kootenay	CRA4	296
Kootenay	CRE1	1017
Kootenay	CRE2	1433
Kootenay	CRE3	961
Kootenay	CRE4	899
Kootenay	CSC1	332
Kootenay	CSC2	1234
Kootenay	CSC3	716
Kootenay	FRU1	1338
Kootenay	FRU2	135
Kootenay	GLM1	53
Kootenay	GLM2	1791
Kootenay	GLM3	1007
Kootenay	HER1	235
Kootenay	KAS1	476
Kootenay	KAS2	525
Kootenay	OOT1	1317
Kootenay	OOT2	648
Kootenay	PAS1	265
Kootenay	PAS2	399
Kootenay	PLA1	887
Kootenay	PLA2	1016
Kootenay	PLA3	495
Kootenay	SAL1	965
Kootenay	SAL2	227
Kootenay	STC1	1463
Kootenay	STC2	697
Kootenay	TAR1	1
Kootenay	VAL1	757
Kootenay	VAL2	1

Region	Feeder	Customers
Kootenay	YMR1	255
Kelowna	BEV1	2515
Kelowna	BEV2	572
Kelowna	BEV3	1279
Kelowna	BEV4	991
Kelowna	BLK1	1370
Kelowna	BLK2	303
Kelowna	BLK3	1494
Kelowna	BWS1	1037
Kelowna	BWS2	1030
Kelowna	BWS3	9
Kelowna	DGB1	2103
Kelowna	DGB2	2100
Kelowna	DGB3	567
Kelowna	DUC1	367
Kelowna	DUC2	896
Kelowna	ELL1	71
Kelowna	ELL2	451
Kelowna	ELL3	927
Kelowna	ELL4	319
Kelowna	GLE1	1383
Kelowna	GLE2	683
Kelowna	GLE3	213
Kelowna	GLE5	2334
Kelowna	GLE6	748
Kelowna	GLE7	407
Kelowna	HOL1	508
Kelowna	HOL2	1073
Kelowna	HOL3	2394
Kelowna	HOL4	2393
Kelowna	HOL5	2206
Kelowna	HOL7	1563
Kelowna	JOR1	455
Kelowna	LEE1	3174
Kelowna	OKM1	1391
Kelowna	OKM2	1345
Kelowna	OKM3	1345

Region	Feeder	Customers
Kelowna	OKM4	708
Kelowna	OKM5	712
Kelowna	SEX1	1359
Kelowna	SEX2	2703
Kelowna	SEX3	1221
Kelowna	SEX4	600
South Okanagan	AWA1	375
South Okanagan	AWA2	717
South Okanagan	HED2	403
South Okanagan	HED3	23
South Okanagan	HED4	531
South Okanagan	HUT2	0
South Okanagan	KAL1	1152
South Okanagan	KER1	1569
South Okanagan	KER2	1501
South Okanagan	NKM1	510
South Okanagan	NKM2	893
South Okanagan	NKM3	115
South Okanagan	NKM4	515
South Okanagan	OKF1	863
South Okanagan	OKF2	182
South Okanagan	OKF3	1000
South Okanagan	OLI1	915
South Okanagan	OLI2	771
South Okanagan	OLI3	258
South Okanagan	OSO1	1757
South Okanagan	OSO2	0
South Okanagan	OSO3	1303
South Okanagan	PIN1	1234
South Okanagan	PIN2	630
South Okanagan	PIN3	1340
South Okanagan	PRI1	4
South Okanagan	PRI2	586
South Okanagan	PRI4	1475
South Okanagan	PRI5	1615
South Okanagan	RGA1	102
South Okanagan	TRC1	4

Region	Feeder	Customers
South Okanagan	WEB1	972
South Okanagan	WEB2	542

18.2 Is there a maximum number of customer endpoints that can be accommodated on a distribution feeder?

Response:

There is no specific maximum number of customer endpoints that can be served from a distribution feeder. This is because the count varies depending on the expected customer load at each endpoint. Since commercial customers tend to have higher consumption than residential customers, feeders supplying residential areas are typically able to supply more customers. These limits occur because of the practical limitations involved in ensuring that all customers receive minimum acceptable voltage levels.

Furthermore, distribution feeders with very high customer counts are undesirable as a single feeder outage results in a large number of customers being without power. On average, this would result in reduced customer reliability levels.

18.2.1 If so, what is the maximum and what is the criterion by which this maximum is established?

Response:

As shown in the response to CEC IR No. 1 Q18.1, the largest FortisBC distribution feeder supplies 3,174 customer endpoints. While FortisBC has no defined maximum number of customers per feeder, a practical and cost-effective limit is reached at approximately 3,500 customers. This threshold is driven by the voltage and reliability implications discussed in the response to CEC IR No. 1 Q18.2.

19.0 Reference: Exhibit B-6, BCUC 1.10.2

> With respect to the cost reductions associated with reducing system losses, FortisBC is unable to quantify the expected financial benefit at this time. As discussed in the response to BCUC IR1 Q10.1, this is because FortisBC cannot accurately estimate and locate distribution system losses without AMI, and therefore cannot quantify or identify areas of opportunity until AMI is implemented. Further, FortisBC will need to conduct a cost/benefit analysis for any given loss reduction initiatives to ensure that the benefits of the associated loss reduction exceed the cost of any infrastructure upgrades. Hence, these savings have not been reflected in the project costs analysis. Any future financial benefits will be reflected in reduced power purchase costs and potentially reduced growth capital infrastructure investments.

19.1 What types of loss reduction opportunities does FortisBC anticipate being available with AMI that would not otherwise be available?

Response:

The primary loss reduction opportunity made available with AMI that cannot be achieved with current systems is the enhanced theft detection program. Please refer to the response to BCUC IR No. 1 Q15.1 which shows the estimated NPV benefit and BCUC IR No. 1 Q76.1.1 for a discussion of the potential energy savings.

Other loss reduction opportunities would include system infrastructure upgrades such as feeder re-conductoring, load rebalancing and the installation of capacitors for voltage support. However, until specific loss problems are identified, FortisBC is unable to determine which of these measures would be employed and to what degree.

19.2 What types of infrastructure upgrades would be necessary to address these opportunities?

Response:

Please refer to the response to CEC IR No. 1 Q19.1

19.3 Are the infrastructure upgrades anticipated currently installed elsewhere in Canada, the United States or other jurisdictions?

Response:

The infrastructure upgrades described in the response to CEC IR No. 1 Q19.1 (feeder re-conductoring, load rebalancing and installation of capacitors) are techniques which are already routinely used at FortisBC and all other electric utilities. The primary benefit provided by AMI is that the need for these upgrades can be more easily identified. Further, once identified, the upgrades can be deployed more tactically to maximize the energy savings when compared to the cost of the upgrade.

19.4 How long after the implementation of AMI can FortisBC expect to have the necessary information to conduct the above cost/benefit analysis?

Response:

FortisBC expects to have the necessary information to conduct a cost/benefit analysis 18 months after the completion of the AMI Project.

19.5 What would be the benefit of 0.5% and 1% reductions in losses across the system respectively?

Response:

Based on the before DSM and Other Customer Savings load forecast, in 2015 the savings from a reduction in losses of 0.5% is approximately 20 GWh and $1.7 million. At 1.0% it is approximately 39 GWh and $3.3 million per year.

This is based on a Long Range Marginal Cost of power of $85. This is in nominal dollars and therefore the rate is a flat rate that does not change over time. There is a small volume increase from year to year as the load (and therefore loss savings) gradually increases. By 2025 the savings would increase by about 6% due to the load increase.

19.6 Is FortisBC aware of the system losses reduced in other jurisdictions due to the implementation of loss reduction initiatives fostered by AMI implementation?

Response:

Currently there is no definitive information available, but FortisBC and its industry expert continue to monitor industry papers for results that would quantify the reduction in losses resulting from the installation of smart meters.

19.6.1 If so, please provide estimates of the system losses that are being reduced.

Response:

Please refer to the response to CEC IR No. 1 Q19.6 above.

20.0 Reference: Exhibit B-6, BCUC 1.10.1 and Exhibit B-6, BCUC 1.10.2 and Exhibit B-6, BCUC 1.78.3

> Once AMI meters are installed it would be possible to conduct energy loss measurements on a per-feeder basis. This would be done by subtracting the total energy consumed at customer end-points from the energy supplied to a distribution feeder (as measured by the substation advanced meters). Prior to completion of the DSAP, a large number of distribution feeders would not have had the advanced substation meters necessary to support this calculation.

> With respect to the cost reductions associated with reducing system losses, FortisBC is unable to quantify the expected financial benefit at this time. As discussed in the response to BCUC IR1 Q10.1, this is because FortisBC cannot accurately estimate and locate distribution system losses without AMI, and therefore cannot quantify or identify areas of opportunity until AMI is implemented. Further, FortisBC will need to conduct a cost/benefit analysis for any given loss reduction initiatives to ensure that the benefits of the associated loss reduction exceed the cost of any infrastructure upgrades. Hence, these savings have not been reflected in the project costs analysis. Any future financial benefits will be reflected in reduced power purchase costs and potentially reduced growth capital infrastructure investments.

> Since customers are on different read cycles and billing meters are read at different times over a multiple-month period, it is not possible to capture a "snap-shot" of the total system consumption. Consequently it is not currently possible to accurately determine system losses for any specific point in time. AMI deployment will enable the accurate and timely collection of more granular information on system losses. Please refer also to the responses to BCUC IR1 Q10.1 and Q78.3.2 with respect to the improved ability to measure and calculate losses.

20.1 What level of granularity does FortisBC believe is necessary to calculate losses on a 'per feeder' basis?

Response:

To calculate losses on a per-feeder basis, FortisBC needs to know the power supplied into the feeder ($P_{supplied}$), as well as the power consumed by all customers connected to that feeder

(P_{billed}). With that information, instantaneous power losses can be simply calculated as: $P_{losses} = P_{supplied} – P_{billed}$.

While $P_{supplied}$ is presently known accurately for almost all feeders, FortisBC has no accurate information on P_{billed}. This is because the existing meters are manually read at varying times over a two month period. As a result, the readings are not time-synchronized (they do not cover the same time interval) and thus cannot be summed to determine P_{billed}.

In contrast, the AMI meters will record time-stamped interval readings at all customer end-points. With this information, P_{billed} can be calculated by summing the time-synchronized readings for a given interval. Since the meters are already collecting data for billing purposes on a one hour interval, it will also be possible to calculate losses for each hour (or any longer interval). This is considered sufficiently granular for loss detection purposes.

Note that full deployment of AMI metering is required to produce meaningful loss information. Any endpoints not equipped with AMI meters would not be included in the calculation of P_{billed}, and would be indistinguishable from – and hence considered to be – losses.

20.2 Why is it necessary for FortisBC to calculate system losses at a specific point in time?

Response:

Once loss information is calculated (as described in the response to CEC IR No. 1 Q20.1) it can be further investigated to determine the cause. System losses result from a number of causes:

- Technical losses (electric energy converted to heat as it passes through electrical equipment);
- Company-use load (electricity necessary to operate substation and generating facility equipment);
- Unbilled customer load (such as street lighting and cable television amplifiers);
- Meter inaccuracies; and
- Energy theft.

While many of these losses do not vary significantly over short intervals, losses due to theft are more easily detected with more granular information. This is because some types of loads cycle on and off during the day; having hourly loss information makes the identification of these losses easier.

20.3 Please confirm that annual or other long time scale calculations of aggregate losses on the system do not allow FortisBC to determine loss at specific points on the system.

Response:

Confirmed.

21.0 Reference: Exhibit B-6, BCUC 1.11.1

> At present, FortisBC has only installed metering devices at the distribution substation level (i.e. electrically at the point where the distribution feeder leaves the substation). These devices measure and record both the real-time and historical readings of power, energy, current, voltage, and harmonics. Metering at this level is not sufficient to identify or locate sites involving theft of energy. Please see the response to BCUC IR1 Q54.1 describing the downstream distribution metering proposed to be installed.

21.1 Are the current metering devices at the distribution substation level able to identify potential theft of energy within a geographic area?

Response:

On their own, the current metering devices at the substation level are not able to identify theft. The current metering devices installed at the feeder exit points from the substation can identify the total amount of energy supplied to feeders independent of the feeder size or the geographic area served by the feeder. However, the identification of energy theft requires the additional deployment of advanced meters at customer premises in order to balance the amount of energy delivered with the total energy billed to customers between two precise points in time. Please refer also to the responses to BCUC IR No. 1 Q82.4 and Q84.1.

21.1.1 If so, what is the approximate size of geographic area in which the current metering devices are able to identify areas of potential theft?

Response:

FortisBC has approximately 130 feeders which serve areas of varying geographic size and customer density. The metering devices will provide the total energy delivered to the feeder independent of the number of customers or the length of the feeder. On its own, this metering is unable to identify any areas of theft. Please refer also to the response to CEC IR No. 1 Q20.1.

22.0 Reference: Exhibit B-6, BCUC 1.11.1 and Exhibit B-6, BCUC 1.54.1

> At present, FortisBC has only installed metering devices at the distribution substation level (i.e. electrically at the point where the distribution feeder leaves the substation). These devices measure and record both the real-time and historical readings of power, energy, current, voltage, and harmonics. Metering at this level is not sufficient to identify or locate sites involving theft of energy. Please see the response to BCUC IR1 Q54.1 describing the downstream distribution metering proposed to be installed.

> The proposed distribution metering system that enables the detection of electricity theft through energy balancing consists of three types of meters:
>
> - 300 permanent feeder meters at a unit cost of $2,500. This provides for one meter per feeder phase as well as allowances for additional meters on high load feeders. These meters will help analyse specific losses per feeder and enable the identification of feeders with a high risk of energy theft.
> - 225 transformer meters at a unit cost of $800. These meters will be deployed to strategic areas of the targeted feeders to narrow the area of focus for the use of the portable meters. They will be redeployed throughout the system depending on which feeders are being analysed.
> - 50 portable meters at a unit cost of $1,000. These meters are designed for easy deployment and redeployment along targeted areas of a feeder to identify a selection of premises where energy theft is indicated.

22.1 Will the anticipated theft identification equipment enable FortisBC to identify and locate individual customer sites where energy theft is indicated?

<u>Response:</u>

The coordinated use of the feeder and transformer meters with the downstream AMI meters will identify variances between energy delivered and energy billed in each section of a targeted feeder under analysis. When losses are identified for a group of customers, portable meters will be deployed to facilitate energy balancing at each transformer. When theft is identified at a specific transformer a field investigation will be performed for each customer served by the transformer to identify the theft site.

22.1.1 If not, within how many premises/customer sites does FortisBC expect to be able to narrow their identification of potential theft?

Response:

Please refer to the response to CEC IR No. 1 Q22.1.

22.1.2 What is the approximate size of geographic area that could be identified?

Response:

The geographic area will vary depending on customer density on the feeder. Initial investigation on urban feeders will target approximately groups of 150 sites. For rural feeders the proposed target is groups of 50 sites.

22.1.3 Are the above transformer meters and portable meters capable of working with the existing distribution system? Please explain if they require the proposed AMI project to be undertaken in order to be deployed.

Response:

The deployment of the proposed distribution metering to assist in identifying energy theft is not effective in the absence of advanced meter deployment at the customer premise. Energy balancing requires the simultaneous reading of feeder and customer meters to identify losses. This is not possible with the current meter technology which is manually read on a 60 day cycle. Please refer to the response to BCUC IR No. 1 Q78.3.1 and Q82.4.

23.0 Reference: Exhibit B-6, BCUC 1.12.3

For the remaining items, FortisBC would like to reiterate that the components listed in the table do not typically represent stand-alone "projects". In many cases they are actually technology sectors or initiatives and would be driven based on the uptake levels of customer-driven projects. For example, Distributed Generation and Electric Vehicle Integration will be driven by customer adoption rates. As well, these components will likely ramp up over a long period of time. Thus, there is no "Year Planned" or "Forecasted Cost" that can be provided for these components. In some cases, there is either no identified need for the project (such as for Demand Response control, Work Management System, or Real-time transmission line rating) or the technology is simply not applicable to FortisBC's operation (Energy Management System).

Key Components	Forecast Cost	Year Planned
Advanced Metering Infrastructure (AMI)	$47.7M	2015
Automated Vehicle Location (AVL) - *	Already deployed	
Computerized Maintenance Management System (CMMS) - *	Already deployed	
Conservation Voltage Reduction (CVR)	~ $9M	Power purchase/cost driven
Customer information portals	Included with AMI	
Cyber-security infrastructure - *	Already deployed	
Dispatch system - *	Already deployed	
Distributed Generation (DG) integration	Customer driven	
Distribution Automation (DA)	Unknown	Ongoing
Demand Response (DR) control	No identified need	
Distribution Management System (DMS)	No identified need	
Electric (EV) or plug-in hybrid (PHEV) vehicle integration	Customer driven	
Energy Management System (EMS)	Not required	
Fibre-optic communications networks - *	Already deployed	
In-Home Displays (IHD)	Included with AMI	
Meter Data Management System (MDMS)	Included with AMI	
Outage Management System (OMS)	~ $1M	~ 2016
Phasor Measurement Units (PMU) - *	Already deployed	
Real-time transformer monitoring - *	Already deployed	
Real-time transmission line rating	No identified need	
Supervisory Control and Data Acquisition (SCADA) - *	Already deployed	
Substation Automation - *	Already deployed	
Wide-area (wireless) communications networks	Included with AMI	
Work Management System	No identified need	
Total Forecast Cost	~ $57 M	

23.1 Please confirm that Electric Vehicle Integration and Distributed Generation integration have not been assessed nor incorporated into the application cost/benefit analysis because FortisBC does not have sufficient information about customer demand for these components.

Response:

FortisBC confirms that no specific provisions to facilitate Electric Vehicle integration or Distributed Generation have been included in the financial analysis appearing in the Application as there is insufficient evidence at this time of future customer demand.

23.2 Does FortisBC anticipate that these components may be developed over the next 20 years?

Response:

FortisBC assumes that some level of uptake of electric vehicles and distributed generation will occur in the service area over the next 20 years. As previously discussed, FortisBC has no growth projections for either technology as there is little solid information on which to base a forecast. FortisBC expects that there will be some level of customer demand for these applications and consequently, systems to incorporate them into the distribution grid will need to be developed.

23.3 Please confirm that Conservation Voltage Reduction has not been assessed nor incorporated into the application cost/benefit analysis because FortisBC does not have a prediction as to the costs of purchasing power over the next 20 years.

Response:

Not confirmed. As discussed in Section 6.2 of the Application, Conservation Voltage Reduction (CVR) has been assessed; however, at this time all forms of CVR show an overall negative payback for customers at this time. On that basis, CVR is not considered to currently be in the interest of ratepayers and was thus not included in the financial analysis for the proposed AMI Project.

23.4 Would FortisBC accept that BC Hydro's Resource Options Report may be an adequate source of the cost of new energy?

Response:

The BC Hydro Resource Options Report is useful in considering FortisBC's cost of new energy and capacity supply. However, differences in existing resources and loads plus the location of new resources that may be available to FortisBC mean that the numbers in the BC Hydro report do not directly apply to FortisBC.

The 2010 BC Hydro Resource Options Report can be found at the link below as part of the draft 2012 BC Hydro IRP. Tables 2.2 and 2.3 provide an estimated cost of new energy and capacity resources available to BC Hydro.

http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/iep_ltap/2012q2/draft_2012_irp_appx_3A_1.Par.0001.File.DRAFT_2012_IRP_APPX_3A_1.pdf

The FortisBC 2010 Resource Options Report is included as part of the FortisBC 2012 Long Term Resource Plan as Appendix C and can be found at the following link:

http://www.fortisbc.com/About/ProjectsPlanning/ElecUtility/ElecResourcePlanning/Pages/default.aspx

23.5 Please confirm that Demand Response control, Distribution Automation, Distribution Management Systems and Work Management Systems have not been assessed nor incorporated into the application cost/benefit analysis because FortisBC does not anticipate a need for the above.

Response:

FortisBC confirms that there is no currently anticipated need for Demand Response control, a Distribution Management System or for a Work Management System, and these have not been included in the financial analysis for the proposed AMI project.

FortisBC views Distribution Automation as a very broad category, and is continuing to assess the benefits from improved communications to distribution grid devices (and on that basis has been noted as “Ongoing” in the cited table). Distribution Automation has been excluded from the financial analysis for the proposed AMI project because no specific DA devices are planned for installation by the project and no firm date for installation has been established in the future.

23.6 Does FortisBC have forecasts as to the expected adoption rate of Electric Vehicles over the next twenty years?

Response:

Pike Research released a report in 2012 stating that plug-in electric vehicles (PEVs) are forecast to reach 400,073 annual sales in the United States and 107,146 in Canada by 2020. In

Canada, the provinces of Ontario, Quebec, and British Columbia, which account for 75% of the Canadian population, will represent 97% of Canadian PEV sales by 2020. Toronto, Montreal and Vancouver will lead Canadian PEV sales. The report is consistent in its conclusion that large metropolitan areas will likely see the highest adoption rates. Since FortisBC does not serve any large metropolitan cities, at this time the Company only expects a very small fraction of vehicles purchased to be used within the service area.

23.6.1 Please provide any forecasts FortisBC has with respect to this adoption.

Response:

Please refer to the response to CEC IR No. 1 Q23.6.

23.6.2 If FortisBC does not have an estimate would FortisBC accept that BC Hydro's estimates may be a useful proxy?

Response:

No, FortisBC does not agree that BC Hydro estimates are necessarily a valid proxy. As discussed in the response to CEC IR No. 1 Q23.6, the Pike Research report expects that vast majority of EV adoption to occur in major metropolitan centres. BC Hydro's service area includes two major metropolitan areas: Metro Vancouver/Fraser Valley and the Capital Region on Vancouver Island. Combined, these two areas represent approximately 2/3 of the population – yet cover only 2 percent of the land area – of British Columbia. In contrast, FortisBC's service area includes less than 10 percent of the population of British Columbia. Thus, given the different nature of the service territories (primarily urban vs. primarily rural) and the relative population coverage of each, FortisBC would be concerned about making projections of EV adoption based on BC Hydro estimates. FortisBC expects to have much lower EV adoption as compared to BC Hydro.

23.7 Does FortisBC have forecasts as to the anticipated adoption of distributed generation over the next twenty years?

Response:

No, FortisBC does not have any forecasts for the anticipated adoption of distributed generation.

Based on the low uptake rates under the FortisBC Net Metering tariff (only seven residential customers to date), the Company is not expecting any significant adoption of distributed generation in the near term.

23.7.1 Please provide any such forecasts that FortisBC has available.

<u>Response:</u>

No forecasts are available. Please the response to CEC IR No. 1 Q23.7.

23.8 Please clarify what Demand Response control refers to.

<u>Response:</u>

Demand Response control refers to the ability for the utility to dynamically push information on power purchase pricing or system capacity constraints to customers in order to modify their consumption patterns. A simple example would be the ability to send critical-peak pricing information to a customer's thermostat (via the AMI meter and wireless HAN) to automatically increase the temperature setpoint during the summer peak hours when high power purchase costs were being experienced.

Please also refer to the responses to BCSEA IR No. 1 Q15.6.8 and Q15.6.9.

24.0 Reference: Exhibit B-6, BCUC 1.14.1 and Exhibit B-1, Application, Page 31

> Non-financial customer service benefits are detailed in Exhibit B-1, Tab 3.0, Section 3.2.5: Conservation Rate Structures, Enhanced Billing Information, Improved Billing Accuracy, Consolidated Billing for Multiple Customer Locations, Flexible Billing Date and Reduced Need to Access Customer Premises.

> choices), which could potentially result in a reduced electricity bill. A choice between RIB and a time-based rate may, dependent upon a customer's consumption habits and preferences, allow customers an opportunity to achieve real bill reductions based on whether they are able to reduce overall consumption (under RIB), or simply shift consumption into lower cost periods (under time-based rates).

24.1 Please confirm that Conservation Rate Structures available with AMI can translate into financial benefits for customers.

Response:

Confirmed. Some individual customers may be able to reduce their total annual billings if they are able to alter their consumption patterns to take advantage of the conservation rate structures. Customers in general may benefit if the aggregate customer response results in cost savings to the utility.

24.2 What amount of reduction does FortisBC estimate to be a possible 'real bill reduction' for customers who might use the full capability of the HMI system?

Response:

FortisBC assumes the question refers to the "AMI" system. Please refer to the response to CEC IR No. 1 Q15.4 for information on customer response due solely to improved information availability in the absence of time-varying rates.

FortisBC estimated in its 2009 COSA and RDA on page 23, Section 3.1, that TOU rates have the effect of reducing peak demand by 5.7 percent during the "critical peak hour" and energy use by 6.0 percent annually.

In order to provide potential savings (in terms of capacity and energy) that may be expected with AMI enabled programs, FortisBC commissioned a report from Navigant Consulting. The study, attached as Appendix C to the Application provided the following results

Table ES-1: Per Participant Savings for Possible AMI Future Programs

Program Type		Peak	Energy	Source
Conservation Rates	TOU	11%	5.5%	BC Hydro CRI[1]
	CPP/CPR	10%	0	
	Inclining	1.8%	1.8%	BC Hydro CRI[2]
Pre-Pay		5.8%*	11.7%	Woodstock Hydro 2004[3]
Load Control		13.3%	0	FERC 2009
In-Home Displays		2.7%	5.4%	ACEEE 2010

* Assumed that the peak period savings are half of the annual savings

Individual customer bill impacts cannot be estimated as potential savings are heavily influenced by existing usage amount and pattern, as well as characteristics of the rate itself including the spread in price between the various time periods.

25.0 Reference: Exhibit B-6, BCUC 1.14.1 and Exhibit B-1, Application, Page 38 and Exhibit B-1, Application, Appendix E-3 and Exhibit B-6, BCUC 1.25.1

Non-financial operational benefits are detailed in Exhibit B-1, Tab 3.0, Section 3.2.5: Enhanced System Modeling, Improved Financial Reporting, Load Forecast and Cost of Service Analyses, Improved Safety, Reduced GHG Emissions, Immediate Notification of Power Outage and Restoration and Improved Power Quality Monitoring.

With FortisBC meter reading vehicles driving approximately 500,000 kilometers per year and consuming approximately 80,000 litres of gasoline, GHG emissions (CO_2e) are estimated at 191,000 kilograms or 191 tonnes per year. AMI will dramatically reduce this source of emissions as a component of FortisBC's overall GHG emissions.

We are also pleased to learn that this will improve worker health and safety by reducing meter-reading risks and concretely avoid 180 tonnes of GHG emissions, 80,000 litres consumed in 18 meter-reader vehicles.

The meter reading vehicles will be permanently eliminated from the vehicle fleet.

25.1 Please confirm that the AMI program will 'concretely avoid 180 tonnes of GHG emissions, 80,000 litres consumed in 18 meter-reader vehicles'. If not, please identify the amount of GHG emissions that will be concretely avoided.

<u>Response:</u>

It is estimated that the AMI Project will result in approximately 171 tonnes of GHG emissions that will be concretely avoided.

25.2 Please confirm that FortisBC has not calculated the financial benefits of Reduced Greenhouse Gas emissions and that they have not been included anywhere in the financial analysis of the Application.

<u>Response:</u>

Confirmed. It should be noted, however, the financial benefit related to the reduction in fuel costs has been captured in the Project financial analysis as a component of the reduced manual meter reading O&M costs.

26.0 Reference: Exhibit B-6, BCUC 1.18.1

> FortisBC does consider it a requirement of TOU and CPP rates that the AMI meter has hourly interval data availability at minimum.
>
> This data can be used to support customer service calls, load research, future time-based rates (such as TOU and CPP), and other applications. Interval data simply represents the most flexible receipt of data, allowing rate calculations to be made and easily changed within the MDMS and billing system. The meter configuration described above (multiple registers) would present FortisBC with challenges and associated costs when it comes time to adapt and reconfigure the meters or system to support new rates and programs. Interval data ensures flexibility for changing business and customer needs and future requirements.

26.1 Is the above response reflective of the ability of the customer to respond to TOU and CPP pricing signals?

Response:

The key point in the original response is that hourly interval data provides the most flexibility in the design of rates that could best by tailored to the needs of FortisBC and its customers and provides the granularity of data necessary for assessing the impact of those rates.

The response does not discuss the ability of customers to respond to rates, but FortisBC believes that providing near-real time electricity consumption feedback to customers is critical to obtaining maximum response to time-varying rates. This conclusion is supported by the Navigant report provided in Exhibit B-1, Appendix C-1.

26.1.1 If so, does the above response apply to residential customers or commercial customers?

Response:

More detailed and real-time access to information is important to residential and commercial customers alike. As such, metering that records interval data is better for both groups.

26.2 Would commercial customers making use of TOU and CPP rates likely benefit from shorter than hourly interval data?

Response:

Regardless of whether interval data is available on an hourly basis or shorter time increments, the time periods defined in both TOU and CPP rates are typically set in hour blocks. The AMI technology that FortisBC is putting in place is capable of recording and reporting on shorter time intervals which could theoretically factor into shorter blocks in a CPP or TOU rate. Such rates may or may not be of greater benefit to Commercial customers and the Company anticipates that the cost and benefit related to interval length would likely be a consideration in an application for such rate structures should it be brought forward for consideration by the Commission.

Commercial customers may benefit from consumption data provided more frequently than the TOU or CPP time intervals to help manage their costs. If so, commercial customers may choose to purchase a Zigbee-enabled display device, from which they can obtain detailed consumption information directly from their meter at intervals of less than one minute.

26.3 If so, at what level of interval data would commercial customers be most likely to maximize their cost benefits?

Response:

Please refer to the response to CEC IR No. 1 Q26.2

27.0 Reference: Exhibit B-6, BCUC 1.20.1

6 For 2011, the total number of billing-related calls was approximately 45,500. Of these calls,
7 approximately 39,500 are estimated to be related to residential inquiries.

27.1 Please confirm that there were 6,000 billing related calls from commercial customers in 2011.

Response:

Approximately 4,500 billing related calls were from Commercial customers in 2011. The remaining calls (approximately 1,500) are from other rate classes.

27.2 Please provide the total number of residential and commercial customers and define ‘customer’ as the customer premise or the meter, whichever is most applicable.

<u>Response:</u>

Residential: 98,781

Commercial: 11,727

In the context of this question, ‘customer’ is defined for Residential as <u>each meter</u>, and for Commercial as either <u>each meter or each service connection</u> (since a service connection such as a streetlight is billed on a flat-rate and is not metered).

28.0 Reference: Exhibit B-6, BCUC 20.1 and Exhibit B-6, BCUC 20.1.1

> For 2011, the total number of billing-related calls was approximately 45,500. Of these calls, approximately 39,500 are estimated to be related to residential inquiries.

> FortisBC does not track calls specifically related to estimate usage. However, calls are tracked for more general categories such as Customer Meter Read, Budget Billing, High Bill Inquiries and Bill Escalations. A proportion of calls within these categories may be attributed to estimated usage. For 2011, the calls within the above noted 4 categories totalled approximately 6,800. Of these, approximately 87% or 5,900 calls are estimated to be related to residential billing.

28.1 Please confirm that there were approximately 38,700 billing-related calls that did not fall into the categories of Customer Meter Read, Budget Billing, High Bill Inquiries and Bill Escalations.

<u>Response:</u>

The numbers quoted above are slightly misstated. The number of calls in the categories of Customer Meter Read, Budget Billing, High Bill Inquiries, and Bill Escalations are approximately 8,100, of which approximately 87% or 7,000 calls are estimated to be related to residential billing.

Therefore, FortisBC confirms that approximately 37,400 calls did not fall into the categories of Customer Meter Read, Budget Billing, High Bill Inquiries, and Bill Escalations.

28.2 Please identify the categories of billing-related calls and the numbers of calls within each, for both commercial and residential customers.

Response:

Please see the following table:

Table CEC IR1 Q28.2

2011 Billing-related calls (rounded to nearest 100)				
	All	Res.	Comm.	Other
Update Acct Info	5,500	4,800	600	100
Billing Error	100	100	0	0
Budget Billing	3,500	3,000	400	100
EFT	2,300	2,000	200	100
Account Balance	11,400	10,000	1,100	300
High Bill Inquiry	4,200	3,700	400	100
Transfers & Adjustments	2,000	1,700	200	100
Account Information Request	11,200	9,800	1,100	300
Credit Card Payments	2,900	2,500	300	100
Payment Inquiry	2,000	1,700	200	100
Rate Increase Inquiry	100	100	0	0
Customer Meter Read	300	300	0	0
Totals	45,500	39,700	4,500	1,300

29.0 Reference: Exhibit B-6, BCUC 1.21.1

FortisBC does not keep records of consolidated bill requests. However, FortisBC does receive requests and can occasionally accommodate them (provided that the meters for each service being consolidated are read on the same meter reading route). FortisBC contact centre personnel estimate that 20-30 customers per month inquire regarding consolidated billing and cannot be accommodated.

29.1 Approximately how often is FortisBC able to accommodate consolidated bill requests in comparison to those it cannot accommodate?

Response:

In comparison to the estimate of 20-30 that it cannot accommodate, FortisBC contact centre personnel estimate that less than 1 per month can be accommodated, due to the premises not being geographically close enough to be on the same meter reading cycle, as well as not being on the same billing rate (i.e. are both monthly, or both bi-monthly).

30.0 Reference: Exhibit B-6, BCUC 1.23.1

> In other words, future feeder rebalancing work does not represent incremental effort that is required or results from the AMI Project. Instead, AMI meters will offer an additional source of data to be used in future modelling exercises. Until actual data is received from the AMI system, it is unknown to what extent the additional data provided by the system will improve existing system models. Thus, FortisBC is unable to provide an estimate at this time of the incremental improvement that the additional AMI data will provide to these future rebalancing projects.

30.1 Please confirm that FortisBC has not included a financial benefit from future feeder rebalancing based on AMI in the application.

Response:

Confirmed.

30.2 Does FortisBC have awareness of any incremental improvements experienced by other jurisdictions from the additional information provided by AMI.

Response:

Many jurisdictions are either still in the process of AMI deployment or only just recently completed their full deployment. Consequently, beyond the theoretical benefits that FortisBC has indicated, the Company has no knowledge of specific incremental improvements resulting from feeder rebalancing at other utilities.

31.0 Reference: Exhibit B-6, BCUC 1.27.1

> Further, during implementation of the proposed AMI system (and consistent with current meter exchange practices), meter deployment personnel will inspect the meter bases to observe indications of problematic service. Any potential issues discovered will be reported by the AMI system to FortisBC for appropriate action.

31.1 What action does FortisBC currently take when meter bases are observed to have indications of problematic service?

Response:

Currently FortisBC logs any metering issue as an incident in its URM (Utility Risk Management) system. When entered into this system, incidents are deemed high priority and are dealt with in a timely manner.

If a meter base has been observed to be problematic (depending on the nature of the issue) the meter base will be repaired by a qualified electrician before a meter is reinstalled. As a best practice, FortisBC employees or contractors will not leave a damaged energized service unattended.

Please also refer to the response to BCUC IR No. 1 Q47.3.

31.2 What costs are borne by the customer when potential issues are discovered based on FortisBC's current practice?

Response:

The costs borne by customers during an exchange include those related to meter base installations found disconnected or pulled away from the wall or enclosed such that it is not possible to exchange. Also included are any installations with exposed wiring, evidence of tampering or compromised insulation.

32.0 Reference: Exhibit B-6, BCUC 1.27.1.1

> Itron OpenWay meters are capable of reporting temperature conditions from the meter over the network. Itron is currently making necessary enhancements to the HES to receive temperature data from the meter. If overheating is detected, the system will be able to remotely disconnect the meter and service. FortisBC expects this functionality to be enabled (at no additional cost) prior to meter deployment.

32.1 Does the above response imply that overheating is associated with faulty meter bases?

Response:

Yes, the above response does imply that the Itron meters will be able to detect overheating associated with faulty meter bases (provided of course that such overheating exceeds the temperature limit set in the AMI system).

32.2 Is FortisBC aware of whether this enhancement is currently in place and being used in other jurisdictions?

Response:

No, FortisBC is not aware of this enhancement being currently in place and used in other jurisdictions.

The response to BCUC IR No. 1 Q27.1.1 noted, “Itron is currently making necessary enhancements to the HES to receive temperature data from the meter.”

32.3 What temperature conditions would constitute ‘overheating’?

Response:

The Itron OpenWay meters operate in temperatures up to 85˚C in the base. The temperature increase in the base versus ambient (outside) temperature is approximately 10˚C, leading to a maximum ambient temperature of approximately 75˚C for correct operation. As the ambient temperature rises above 75˚C, or if the temperature within the base rises above 85˚C, the meter will fail.

As temperature approaches the noted limits, the expected functionality referenced in the response to BCUC IR No. 1 Q27.1.1 would alert the Company.

32.4 Can or will the system automatically disconnect if overheating is detected?

Response:

No, the meter will not automatically disconnect in an overheating condition. However, given the functionality noted in BCUC IR No. 1 Q27.1.1, the meter will alert the Company about an overheated condition giving FortisBC the opportunity to remotely disconnect the meter. If the temperature reaches the levels noted in the response to CEC IR No. 1 Q32.3 then the meter will fail.

32.5 Is this functionality guaranteed to be enabled at no additional cost prior to meter deployment?

Response:

FortisBC expects, but cannot guarantee, that this functionality will be enabled (simply because it has not yet been implemented in the field). If it is enabled, it will be at no additional cost.

32.6 Will this functionality add any additional operating or other expenses if utilized?

Response:

FortisBC expects the number of over temperature warnings to be zero, or at worst very small, so any additional expenses incurred to investigate these occurrences are expected to be immaterial.

32.6.1 If so, please clarify any additional costs FortisBC anticipates may be incurred.

Response:

Please refer to response to CEC IR No. 1 Q32.6.

32.7 Are there conditions other than overheating that are associated with faulty meter bases and may impact the AMI program? If so, please explain the conditions and their effect.

Response:

FortisBC assumes that this question is excluding meter base issues that arise during AMI meter installation.

FortisBC has not identified any other conditions associated with a faulty meter base that would impact the proposed AMI project.

33.0 Reference: Exhibit B-6, BCUC 1.28.1

> Preliminary research indicated a price range of $80-$150 per In-Home Display (IHD) device. The approved 2012-13 DSM Plan includes a nominal $50 incentive or up to half the cost, of eligible IHDs. The net Customer Portion of Cost would be $40-$100 of the price range indicated above.

33.1 Does FortisBC consider that a 'nominal $50 incentive or up to half the cost' means the lesser of the two. If so, why?

Response:

Confirmed, the incentive would be the lesser of the two. The policy complies with the FortisBC Electric Tariff Schedule 90 which limits the available incentive to the lesser amount. The remaining customer portion of the measure cost ensures the customer is better motivated to make use of the device.

34.0 Reference: Exhibit B-6, BCUC 1.28.1.1

> The customer's payback on their net IHD cost of $100 (after $50 DSM incentive) is approximately 1.5 years, assuming the average usage per customer (UPC).

34.1 Has FortisBC considered making IHD devices available on a rental basis at a considerably lower cost to individual customers? If not, why not?

Response:

FortisBC has considered this, and is also considering the associated implications of owning IHD devices. At this time, FortisBC is not planning to implement a rental program.

34.2 What is the average usage per customer (UPC)?

Response:

A UPC of 12.7 MWh/yr was used in the payback calculation.

35.0 Reference: Exhibit B-6, BCUC 1.28.1.2

> The IHD devices will be piloted in 2014, with availability to customers expected in 2015.

35.1 Would FortisBC be able to make IHD devices available to customers earlier than 2015 if they instituted a rental program?

Response:

No. FortisBC wants to be able to pilot IHD devices in the field in 2014 to ensure that they work as expected, and that the process for pairing devices with the AMI meters is straightforward for customers, before making a program generally available.

36.0 Reference: Exhibit B-6, BCUC 1.30.1

> FortisBC is proposing that the advanced meters include HAN functionality at implementation. This functionality is important in order to give customers near real-time access to consumption information through in-home displays and simplifies the implementation of conservation rates such as CPP and pre-pay. Please see the Application (Exhibit B-1) at Tab 4.0, Section 4.1.1.

36.1 Would FortisBC agree that delay in the provision of technological advancements to customers enabling near real-time access to consumption information would contribute to further delay in customer understanding and uptake of the technology and still further delay in customer adoption of conservation practices?

Response:

Yes, FortisBC would agree. The Navigant study (Exhibit B-1, Appendix C-1) clearly indicates the conservation benefits of using IHD devices in combination with conservation rates.

37.0 Reference: Exhibit B-6, BCUC 1.30.2.1

> Zigbee has a dominant market share in North America, and is currently the only standards-based protocol (Smart Energy Profile) offered by the major AMI vendors. None of the alternative protocols listed in this question are available in Measurement Canada-certified meters. As well, the Zigbee protocol was chosen by BC Hydro and FortisBC believes it is in the provincial interest that home automation devices capable of connecting to electric meters in BC use the same protocol.

37.1 Why does FortisBC believe that it is in the provincial interest that home automation devices capable of connecting to electric meters in BC use the same protocol?

Response:

FortisBC believes that there will be a higher adoption rate of HAN devices such as in-home displays if retailers can make products available across BC that interoperate with meters from both of the major public electric utilities. A single protocol means less retail inventory, less customer confusion and more portability of devices when customers move.

38.0 Reference: Exhibit B-6, BCUC 1.30.3

> FortisBC has not forecast customer penetration of in-home displays beyond 30 percent (not a majority of customers), and has not forecast the use of other HAN devices. 30 percent penetration of IHDs is expected to occur between 2015 and 2020 (assuming BCUC approval of the AMI Project is received by July 20, 2013).

38.1 Does FortisBC consider cost to be a factor in customer implementation of IHD?

Response:

FortisBC does not consider cost a significant impediment to adoption of IHD devices. As well, prices should decline as manufacturing volumes increase.

As noted in Section 4.1.1 of the Application, FortisBC does intend, through its PowerSense program, to offer incentives to customers for the purchase of IHDs. It is expected that such incentives will further remove any cost barriers that certain customers contemplating the purchase and use of an IHD may face.

38.2 If so, does FortisBC believe that substantially reduced customer costs associated with IHD's could stimulate customer penetration beyond 30%?

Response:

FortisBC agrees that lower costs will result in higher customer IHD penetration. If IHD penetration would have otherwise reached 30% (as FortisBC expects), then IHD penetration would be higher than 30% with substantially reduced customer cost.

39.0 Reference: Exhibit B-6, BCUC 1.32.2

> collectors would require satellite backhaul. It should be noted that third party cellular providers have planned coverage enhancements in 2012 and 2013 that would provide backhaul for 15 of these 35 collector locations servicing approximately 3,520 meters. If all of the planned coverage enhancements are completed prior to the AMI rollout, satellite backhaul will be required for only 20 collectors servicing approximately 2,830 customer meters.

39.1 Does FortisBC believe that planned cellular coverage enhancements will be made beyond 2013 that could provide backhaul coverage for the remaining 20 collectors?

Response:

FortisBC does not have knowledge of any planned coverage enhancements in addition to those discussed in the referenced IR response. However, FortisBC has been in contact with cellular service providers who have communicated a longer term strategy to deploy cellular service in smaller communities and along major transportation routes, some of which may overlap areas where satellite backhaul is currently planned.

40.0 Reference: Exhibit B-6, BCUC 32.2.4

> FortisBC has not identified any technical or operational barriers or showstoppers that would preclude an installation using either PLC or AMR technology, and will continue to look at alternative LAN options such as these. However the cost of satellite backhaul bandwidth that would be avoided is not sufficiently high to make either option more economical than the proposed RF mesh system in locations with sufficient population. As discussed in section 4.1.3 of the Application, FortisBC is continuing to evaluate WAN options as technology changes, and both options have been and will continue to be considered in these areas.

40.1 Does FortisBC believe that costs of the proposed RF mesh system will decline over time relative to PLC or AMR technology?

Response:

It is difficult to predict whether RF systems will evolve by enhancing networking capabilities, reducing costs or both. However, the pace of change is likely to be higher with RF systems (including mesh) than it is with PLC or AMR technologies.

The difference in the pace of changes in the technologies is due to a higher level of investment in RF AMI installations than other technologies, and from the standardization of the mesh technologies.

Neither PLC nor AMR deployments will benefit to the same extent from these economies of scale due to the lower deployment level.

40.2 If so, does FortisBC anticipate that the sufficient population required to make the proposed RF mesh system economical will decline?

Response:

No, FortisBC does not expect that the expected economies of scale referred to in CEC IR No. 1 Q40.1 will make the RF mesh system significantly more economical for very sparsely populated areas. This is because the cost of the Radio Frequency equipment is a small component of the total installation cost. The majority of the deployment costs for the RF LAN mesh are related to installation, operation and WAN backhaul costs, none of which benefit from these economies of scale.

Is it more likely that alternative technologies such as direct connect cellular or PLC will prove economical in "hard to reach" areas.

40.3 What does FortisBC anticipate in population growth for the next 5, 10, 15 and 20 years in areas in which the satellite backhaul technology will be used?

Response:

FortisBC is not aware of population growth statistics specifically for these areas. However, to the extent that growth occurs there is a higher probability that more economical WAN options will become available.

40.4 What is the minimum population size required to make the RF mesh economic?

Response:

The economic viability of the RF mesh is a function of the number of meters that can be aggregated at a single collector for backhaul. To be economic, the cost to install the RF mesh, to install the satellite system and to pay the ongoing costs of operating the system would have to be less than or equal to the cost of manually meter reading the same number of meters.

For backhaul, satellite was assumed to be the technology used as this was both the worst and expected case assumption for sparsely populated areas.

As discussed in section 4.1.2 of the Application, the RF mesh consists of meters, collectors and range extenders. In very sparsely populated areas, repeaters will be required and will increase the number of meters needed for the RF mesh to be economic. A conservative planning estimate of when a repeater would be needed is when residences are more than 300 meters apart.

The RF mesh in the proposed AMI project is economically viable when there are a minimum of between 18 and 28 meters (depending on the number of repeaters) that can form a mesh and connect to a satellite backhaul collector.

41.0 Reference: Exhibit B-6, BCUC 1.33.1b

Table BCUC IR1 Q33.1b

	Status Quo			Post - AMI			Post - AMI		
	Cost ($000)	100% manual reads	Cost per Customer	Cost ($000)	1% manual reads	Cost per Customer	Cost ($000)	5% manual reads	Cost per Customer
2008	$2,145	109719	$19.55						
2009	$2,107	110853	$19.01						
2010	$2,232	112249	$19.89						
2011	$2,430	111407	$21.81						
2012	$2,474	114232	$21.66						
2013	$2,518	116484	$21.62						
2014	$2,684	118809	$22.59						
2015	$2,733	121135	$22.56						
2016	$2,782	123371	$22.55	$238	1234	$192.69	$792	6169	$128.46
2017	$2,959	125581	$23.56	$246	1256	$196.11	$821	6279	$130.74
2018	$3,012	127798	$23.57	$255	1278	$199.60	$850	6390	$133.06
2019	$3,067	130024	$23.58	$264	1300	$203.03	$880	6501	$135.36
2020	$3,256	132188	$24.63	$273	1322	$206.64	$911	6609	$137.76
2021	$3,315	134357	$24.67	$283	1344	$210.29	$942	6718	$140.20
2022	$3,374	136518	$24.72	$292	1365	$213.98	$974	6826	$142.65
2023	$3,576	138650	$25.79	$302	1387	$217.83	$1,007	6933	$145.22
2024	$3,641	140812	$25.86	$312	1408	$221.67	$1,040	7041	$147.78
2025	$3,706	142955	$25.93	$322	1430	$225.57	$1,075	7148	$150.38
2026	$3,922	145078	$27.04	$333	1451	$229.55	$1,110	7254	$153.04
2027	$3,993	147181	$27.13	$344	1472	$233.63	$1,146	7359	$155.75
2028	$4,065	149280	$27.23	$355	1493	$237.77	$1,183	7464	$158.51
2029	$4,296	151367	$28.38	$366	1514	$241.95	$1,221	7568	$161.30
2030	$4,373	153420	$28.50	$382	1534	$249.10	$1,274	7671	$166.07
2031	$4,452	155448	$28.64	$394	1554	$253.51	$1,314	7772	$169.01
2032	$4,698	157481	$29.83	$406	1575	$257.97	$1,354	7874	$171.98

Annual cost per customer for manual meter reading prior to AMI implementation is approximately $23.

Post-AMI, manual meter reads for 1% of customers will be approximately $193 per customer per year. The growth in cost per customer is directly related to the fact that average travel time between reads will increase substantially from the current state.

For a more direct comparison to the BC Hydro numbers cited in the preamble, FortisBC has also included the estimated manual meter reads costs for 5% of customers. FortisBC expects the cost to be approximately 5.7 times higher compared to pre-AMI costs. This ratio may be higher than BC Hydro's due to lower customer density in the FortisBC service territory.

41.1 Please provide the calculations FortisBC used to estimate the cost of meter reading at both the 1% and 5% levels.

<u>Response:</u>

Manual meter reading costs in a post-AMI state include all labour, non-labour (such as time away costs, and travel expenses), handheld support, and vehicle expenses.

Varying this average cost by the number of customers being served by manual meter reading assumed the following:

Read Time:

The actual "read" time[1] would change from the existing average of approximately 1 minute per read to a new average read time of 3 minutes per read in order to accommodate the requirement to download interval data manually from the AMI meter.

Travel Time:

The significant variable is the travel time between reads. Given that the Company cannot determine the geographic dispersion of the manually read customer premises, it was first assumed that the reads were equally distributed over the Company's service territory. The service territory (in km^2) was divided by the number of customers to determine an average distance between reads. Given an average travel speed between reads, this produced an average travel time for each read. Then it was assumed that the affected premises were largely located in widely dispersed, rural, harder to reach sites, thereby requiring substantially longer travel times between premises – and that those travel times were not easily approximated based upon an equal dispersion of customers throughout the Company's service territory. Therefore, a factor of 1.8 was applied to approximate the extended travel times applicable in these cases.

The travel time was added to the average "read" time of 3 minutes. Thus, dependent upon the number of customers to be served, an average total read + travel time for each read was determined. To this result the hourly cost of manual meter reading was applied, resulting in cost per read applicable to the number of customers being manually read.

The resultant cost per read was multiplied by the average reads per customer per year, and by the number of customers being served, to result in the total cost to provide manual meter reading to the percentage of total customers indicated to determine the annual cost per customer.

The same methodology was used for both the 1 percent and 5 percent levels described in the response to BCUC IR No. 1 Q33.1b.

[1] This refers to the time required by the meter reader, while standing at the meter, to "read" the consumption data.

41.1.1 Please provide a complete breakdown of the types of costs included with a description of each and the assumptions used to derive this data.

Response:

Please refer to the response for CEC IR No. 1 Q41.1.

41.2 Would FortisBC agree that the per customer cost of meter reading can be expected to decline in a non-linear manner from 0% to 1% to 5% and more, with the number of customers receiving manual meter reading?

Response:

FortisBC agrees that the cost of meter reading declines in a non-linear manner.

41.3 Please provide the scale/curve that FortisBC estimates meter reading costs would decline per percent of customers receiving manual meter reading.

Response:

Please refer to the below table.

% of Customers read manually	Cost per Read	Cost per Customer
5.00%	$20.17	$128.46
4.00%	$20.92	$133.23
3.00%	$22.16	$141.18
2.00%	$24.49	$156.00
1.00%	$30.20	$192.39

41.4 Please identify any assumptions that FortisBC may employ in making the above estimations.

Response:

Please refer to the response to CEC IR No. 1 Q41.1.

42.0 Reference: Exhibit B-6, BCUC 1.35.3

> Role-based security will be used which will ensure only authenticated users have access to the system. Additionally, users will be assigned to roles or security groups that will limit the functions they can perform or data they are authorized to view.

42.1 Does FortisBC currently have established security levels limiting the authorization to view data? If so, please identify the levels of authority, functions and the types of data authorized for viewing at each level.

Response:

FortisBC does employ role-based security to limit access to view data. Role-based security is configurable and customized based on each application's uniqueness and security requirements. Although the role-based security design is not finalized until the project is started, the broad areas in which users will be assigned are as follows:

- Administration group – could access administration/configuration data
- Operators – could access operation data, where applicable
- Inquiry – could access (read-only) data, where applicable

During the design phase of the AMI project, the security model will be refined to ensure authorized users within the above groups have access to only the information required to perform their job function.

42.1.1 If in place, does FortisBC intend to utilize the same security levels?

Response:

Please refer to the response to CEC IR No. 1 Q42.1.

42.1.2 If not, what security group levels does FortisBC intend to implement?

Response:

Please refer to the response to CEC IR No. 1 Q42.1.

42.1.3 What, if any, background checks does FortisBC expect to employ for the various authorized users?

Response:

FortisBC completes reference checks for every new hire into the Company. Criminal record checks are completed if it is applicable to the position. Once FortisBC is satisfied with all background checks a new employee will have access to any systems that are required for them to do their job. The employee will be assigned to the appropriate role or security group based on their job function prior to accessing the systems.

43.0 Reference: Exhibit B-6, BCUC 1.36.1.2

> FortisBC has embedded in its contract with Itron that Itron shall submit all proposed forms of procurement documents, including forms of subcontract, to FortisBC for review. Itron is required to ensure that all competitive procurement process(es) give preference to unionized contractors whose unions are recognized by the British Columbia Federation of Labour and provide meaningful First Nations employment opportunities in connection with work to be performed on First Nations territories. FortisBC has oversight on Itron's final selection of a deployment subcontractor. As such, the risk of discrimination is minimized or avoided.

43.1 Are there additional requirements other than those identified above that FortisBC has embedded into its contract with Itron regarding selection of the deployment subcontractor?

Response:

FortisBC has also embedded in its contract with Itron that Itron shall employ publically advertised, fair and competitive procurement process(s).

43.2 Does review of the proposed forms of procurement documents mean approval of those documents prior to implementation?

Response:

Review of the proposed form of procurement documents means that FortisBC assures itself that all terms of the contract pertaining to procurement are met.

43.3 Does ‘oversight on Itron’s final selection’ mean that FortisBC has final approval?

Response:

FortisBC has the right to dispute Itron’s selection of subcontractor.

43.3.1 If not, please clarify what oversight would entail.

Response:

Please refer to the response to CEC IR No. 1 Q43.3.

44.0 Reference: Exhibit B-6, BCUC 1.38.3

> 1. AMI communications technologies are continuously evolving, so it was prudent to test the market with business requirements, not technology requirements; and
> 2. FortisBC AMI requirements are unique to its operating environment.

44.1 Does FortisBC agree that communications technologies will continue to evolve and that testing these technologies against business needs is the best method of determining what technologies should be employed and when they should be implemented?

Response:

FortisBC agrees that communications technologies will continue to evolve and that analyzing the capabilities and economics of new technologies in response to business needs is a good method of determining what technologies should be employed and when they should be implemented.

44.2 What FortisBC AMI requirements are unique to its operating environment?

Response:

The referenced statement "FortisBC AMI requirements are unique to its operating environment" was intended to highlight that each utility has different business requirements and that for many reasons, the technical solution chosen by others may not be the best solution for FortisBC. For example, some utilities did not have a requirement to facilitate remote disconnects/reconnects, or may not have required the same granularity with respect to interval reads. Also, many utilities did not identify the same need for theft detection as FortisBC.

While the business needs defined the needed functionality of the system, FortisBC's unique service territory was also important. 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.

FortisBC felt its RFP process provided the market with the opportunity to propose the best technical solution based on its business needs while considering the constraints placed on technologies by its service area. FortisBC submits that with differing business requirements, and different system constraints, that the best solution for each utility **will** be different. For this reason, the RFP was constructed to be technology agnostic to allow any responder to propose the technology they considered best for FortisBC.

45.0 Reference: Exhibit B-6, BCUC 1.39.1 and BCUC 1.39.2

> Itron has no incentive to re-use removed electromechanical meters as they are considered obsolete and will be salvaged for scrap value. Itron is required to apply any potential value from the digital meters against the cost of recycling/disposing of the meters.

> The cost of meter disposal is included in the meter deployment cost estimate, and is assumed to be offset entirely by the scrap value of the meter.

45.1 Please confirm that all the electromechanical meters will be salvaged for scrap value and that recycling will not be considered for any of these meters?

Response:

It is the intent that electro-mechanical meters will be salvaged for scrap or recycled, whichever provides the greatest value for customers.

45.2 Does FortisBC believe that the digital meters could be resold or refurbished and resold?

Response:

Based upon information currently available to FortisBC, there is not currently a market for the resale and/or refurbishment of digital meters. However, FortisBC would resell the digital meters if it provided more value to customers than scrapping or recycling the digital meters.

45.2.1 If so, what is the current market rate for used digital meters?

Response:

Please refer to the response to CEC IR No. 1 Q45.2.

45.3 Is FortisBC required to apply any potential scrap value from the electromechanical meters against the cost of disposal?

Response:

Yes. FortisBC's accounting practise is to apply any potential scrap value from the electromechanical meters against the cost of disposal.

45.4 Does FortisBC believe it is possible that the total scrap value of the meters could exceed the cost of disposal?

Response:

Although it is possible that the total scrap or recycled value of the meters could exceed the cost of disposal, the Company is of the opinion that it is not likely. Further, there is virtually no market for used non-AMI meters so the value is based primarily on scrap metal prices.

45.5 What incentive does Itron have to maximize the scrap value of the electromechanical meters or any residual value from the digital meters; or otherwise minimize the cost of disposal and maximize any salvage value from either the electromechanical or digital meters? Please explain.

Response:

The Company's contract with Itron requires that Itron be responsible for disposal of existing meters as they are removed from service. This includes disposal via scrap or recycling. FortisBC will work with Itron to ensure that the sub-contract for scrap/recycling provides the best value to ratepayers in terms of minimizing total project cost (which includes credits for scrap/recycling).

45.5.1 Would FortisBC agree that maximizing the value of either the electromechanical meters or the digital meters would necessitate extra work on the part of Itron or a subcontractor?

Response:

There is up-front work required by Itron and FortisBC to ensure an optimal scrap/recycling contract is established. Please refer to the response to CEC IR No. 1 Q45.5. Once the contract and recycling process is established, there would no additional work for Itron or subcontractors.

45.6 Does FortisBC have an estimate of the scrap value of the electromechanical meters and the potential value from the digital meters? If so, please provide the estimates.

Response:

FortisBC understands that there currently is no market for the resale/refurbishment of digital meters. The Company further understands that the existing scrap value for existing meters falls within the range of $0.25/lb to $1.50/lb.

45.7 Would FortisBC agree that any increase in the value received from either the electromechanical or digital meters would benefit FortisBC but not Itron? If not, why not?

Response:

Please refer to the response to CEC IR No. 1 Q45.5.

45.8 Does FortisBC have any input into the salvage methods undertaken by Itron?

Response:

Yes, FortisBC will review and approve Itron's finalized proposals with regards to meter disposal. Please also refer to the response to CEC IR No. 1 Q45.5.

46.0 Reference: Exhibit B-6, BCUC 1.42.1

> As the costs are "sustaining" in nature and will continue after the project is complete, FortisBC chose to keep these expenditures separate from the proposed AMI project capital costs on Line 27. The sustaining capital expenditures are still included in the overall AMI project financial analysis, so the overall NPV and rate impacts would not be affected if the sustaining capital expenditures were instead added to project capital expenditures.

46.1 Please confirm that FortisBC has sustaining capital and non-capital costs for its current metering processes.

Response:

Confirmed.

46.2 Please confirm that capital and non-capital 'sustaining' costs including those associated with meter growth and replacement, IT hardware, licensing and support costs can be expected to continue for as long as any type of meter is in place, including after the 20 year project analysis time frame.

Response:

Confirmed.

46.3 Please confirm that FortisBC will continue accounting for the capital and non-capital sustaining costs after the 20 year analysis time frame is over.

Response:

Confirmed.

47.0 Reference: Exhibit B-6, BCUC 1.42.2

> The larger Equipment/Hardware/Servers expenditures in 2017, 2022 and 2027 relate to adding additional capacity to the storage area network (SAN). The smaller annual expenditures in this category are for ongoing replacement of field communications and network devices.

47.1 Will the additional capacity added to the SAN be available for use beyond 20 year planning horizon?

Response:

SAN storage will be available for use beyond 20 year planning period provided sustaining capital continues to be invested.

48.0 Reference: Exhibit B-6, BCUC 1.42.2.1

> Based on the above, FortisBC has applied 50 percent of the forecast IT Support Costs that are referenced in Exhibit B-3 as Capital Costs, and 50 percent as Operating Expenses (as part of New Operating Costs as referenced in Exhibit B-3).

48.1 Why has FortisBC selected 50/50 as the split between Capital and Operating?

Response:

Please refer to the response to BCUC IR No. 1 Q42.1.1.

49.0 Reference: Exhibit B-6, BCUC 1.43.1

Delays in operational benefits related to meter reading, remote disconnect/reconnect, contac centre, and theft reduction were included in the analysis.

The Company did not include meter exchanges or avoided cost benefits associated witl Measurement Canada compliance, since those benefits are realized by the installation of th AMI meters.

See the table below for the financial impact of a six month delay in the realization of the state operational benefits:

	NPV ($000s)	
	AMI proposal (errata 1)	6 month delay in operational benefits
Meter Reading	-$23,785	-$22,383
Remote Disconnect/Reconnect	-$5,466	-$5,158
Contact Centre	-$441	-$410
Theft Reduction	-$38,386	-$37,491
Project NPV	-$17,629	-$14,992

49.1 Please confirm that a six month delay in operational benefits would result in a net loss to FortisBC of $2,637,000 (PV). If so, what is the rate impact of such a delay?

Response:

Not confirmed. A six month delay in operational benefits would not result in a loss to FortisBC's customers. It would however, result in the reduction in the NPV of customer benefits of $2,637,000, resulting in a change to the cumulative rate impact of the AMI project from a decrease of 1.02% to a decrease of 0.99%.

49.2 Does the cost of delay in the operational benefits increase in a linear manner on a monthly basis for each? Please explain why or why not?

Response:

The costs of delay do not vary linearly with time due to the fact that certain benefits are not linear with time (such as the Measurement Canada Compliance benefit) and that present-value discounting is not linear with time.

49.2.1 If not linear, please provide the expected curve by which costs would accrue over time including a three month, nine month and one year delay.

Response:

The Company notes that the table from BCUC IR No.1 Q43.1, referenced above, contains a typographical error. The "Project NPV" for a 6 month delay in operational benefits should read -15,992, not the -14,992 indicated.

FortisBC notes that its AMI financial models are completed on an annual basis, making it difficult to derive sub-annual forecasts. Therefore, annualized benefits have been prorated to produce the approximate customer benefits reductions noted in the table below:

Table CEC IR1 Q49.2.1

	AMI proposal (errata 1)	3 month delay in operational benefits	6 month delay in operational benefits	9 month delay in operational benefits	12 month delay in operational benefits
Meter Reading	-$23,785	-$23,587	-$22,383	-$21,622	-$21,170
Remote Disconnect/Reconnect	-$5,466	-$5,352	-$5,158	-$4,997	-$4,795
Contact Centre	-$441	-$431	-$410	-$398	-$381
Theft Reduction	-$38,386	-$37,820	-$37,491	-$36,191	-$33,861
Project NPV	-$17,629	-$16,741	-$15,992	-$12,759	-$11,211

49.3 Does FortisBC predict that a BC Human Rights tribunal ruling relating to the BC Hydro SMI program in favour of the Citizens for Safe Technology could result in a delay or otherwise necessitate a change in FortisBC's AMI implementation? Please provide a rationale.

Response:

FortisBC believes that a ruling requiring a change in the BC Hydro SMI implementation is unlikely.

Please also refer to the response to CSTS IR No. 1 Q4.1.

49.3.1 If so, has FortisBC developed possible means of addressing such changes?

Response:

No. Considering that in its decision dated August 28, 2012, the BC Human Rights Tribunal directed that any amended complaint brought forward by CSTS is to be restricted to a class comprised of persons allegedly diagnosed with electro-hypersensitivity (a medical condition not generally recognized by the medical and scientific community), FortisBC reasonably expects any possible changes stemming from a future Tribunal decision on an amended complaint unlikely to have a material impact on the Project.

49.3.2 If the BC Human Rights Tribunal hearing has not provided a ruling prior to the August 2013 deadline to proceed with the Itron contract, will FortisBC proceed with the Itron contract?

Response:

Yes, however the Company's decision to proceed with the Project will ultimately be based on the decision provided by the BCUC.

50.0 Reference: Exhibit B-6, BCUC 1.46.3 and Exhibit B-1, Application, Page 143

> FortisBC believes that the "Project Challenges" identified in Exhibit B-1, Tab 8.0, Section 8.4 could be considered emerging risks in that they are potentially significant but not fully understood since they are not necessarily based on actual risks. The nature of these challenges makes the development of risk response strategies difficult.

> - Advanced metering benefits can be eroded by "opt-out" customers.

50.1 Please clarify what FortisBC means by 'opting out' and the technology, information characteristics or other elements that would characterize an opt-out.

Response:

"Opt-out" in the context of this question represents a range of formal program options for customers to not participate in some manner in the AMI Project.

Opt-out programs can range from programs that allow the customer to select the type of meter they prefer to the installation of advanced meters that have their RF radios turned off.

50.2 If 'Opt Out' has a potentially multi-dimensional definition how many variations would FortisBC expect may be possible and what does FortisBC believe would be the implications of trying to manage this?

Response:

Please refer to the response to CEC IR No. 1 Q50.1. Managing multiple opt-out programs would be more time-consuming and costly than managing one.

50.3 If 'Opt Out' is dependent upon customer approval does this mean that FortisBC would forever have meter implementation as an individual customer choice?

Response:

The benefits associated with the Project are dependent on the robust and cost-effective communications functionality of the AIM system. Given the significant benefits afford by AMI, FortisBC does not believe customer choice on this issue is appropriate. If metering selection becomes a customer choice, it establishes a precedent that will limit the ability of the utility to effectively manage the electric grid, lower costs, improve reliability and safety, and enhance other services to customers.

FortisBC does not agree in principle with providing choices to individual customers that have a clearly demonstrable negative financial impact to other customers. Offering individual customers the extreme case "opt-out" option of having a manually-read meter of their preference without paying for the related incremental costs and lost benefits to other customers violates this principle.

FortisBC agrees with the principle of providing customers with choices, which is one of the main reasons for proposing the implementation of multiple ways of receiving consumption information (in-home displays, customer portal, mail, calls to the contact centre) and different billing options (consolidated billing, flexible billing dates, pre-pay tariff).

50.3.1 If so, what would be the implications of 'opt out' customers moving to sites in which AMI was already installed, or moving away from sites where they had 'opted out'?

Response:

If an "opt-out" meter was installed at a particular location, FortisBC would propose that the meter location revert to an AMI meter installation once the "opt-out" account holder moved to a different location. Presumably a formal "opt-out" program would allow the account holder to request an "opt-out" meter, at their expense, at their new premises (if in the same service territory).

50.4 To what extent does FortisBC believe that customers are likely to request to 'opt-out'?

Response:

FortisBC understands that the participation rate in "opt-out" programs is dependent on whether there is an associated fee and how well the utility communicates the benefits of not "opting-out".

As discussed in the response to CEC IR No. 1 Q50.3, FortisBC believes that "opt-out" customers must pay for the incremental costs and lost benefits related to their choice in order to mitigate the clearly demonstrable negative impact to other customers.

50.5 Please identify all the ways in which advanced metering benefits can be eroded by opt-out customers.

Response:

The erosion of AMI benefits depends on the nature of an opt-out program. In the extreme case, a no-cost opt-out program that allows customers to choose a manually read meter at no cost would negatively impact all quantifiable benefits:

- Higher meter reading costs, by requiring high cost (due to the low density of "opt-out" meters) manual meter reads;
- Reduced theft reduction, by negatively impacting the ability to perform feeder energy balancing and not receiving tamper alerts;

- Higher disconnect/reconnect costs, by requiring FortisBC personnel to drive to premises to disconnect and reconnect meters;
- Higher Measurement Canada compliance costs, due to the need to more frequently test and replace less accurate analog meters;
- Higher meter exchange costs, since "opt-out" meters would continue to require test sampling; and
- Higher contact centre costs, by requiring contact centre personnel to continue manually entering "soft reads" from manually read meters.

Public and employee health and safety is also negatively impacted due to more electricity theft, more vehicles on the road and higher GHG emissions. As well, the ability to implement and/or fully realize potential future benefits (outage management system, conservation voltage) is also impacted.

50.6 Does FortisBC have an estimate of the cost per customer that would be incurred if customers were permitted to 'opt –out' as defined by FortisBC other than the meter reading cost of 'opt out'? If so, please provide the cost estimates and how they were derived.

Response:

Any "opt-out" program needs to ensure that the benefits of the AMI program are not diluted. In order to minimize the benefit reduction that "opt-out" customers would have to pay for, FortisBC has assumed that "opt-out" customers would receive a radio-off AMI meter. This allows the Company to receive the same data that it would through the RF LAN, less frequently, through a periodic manual download process. The availability of the same data preserves many of the financial benefits of the AMI project.

On the above assumptions, the radio-off option fees would be:

A per-manual download fee of approximately $22, assuming that 0.5% of customers elect the radio-off option. If more customers select radio-off, the per-download cost would be lower. If fewer customers select radio-off, the per-download cost would be higher.

A one-time fee of approximately $110. This fee recovers incremental costs associated with:

- additional collectors and repeaters, as required, to ensure the integrity of the RF mesh network; and

- administrative costs associated with processing radio-off requests and maintaining an inventory of radio-off meters.

50.6.1 Please identify if these costs would be incurred in a straight line with respect to the numbers of people opting out. Please provide the relationship or curve under which opting out would generate costs for FortisBC.

Response:

The one-time fee noted in the response to CEC IR No. 1 Q50.6 would remain the same for each "opt-out" customer in the scope of the analysis. Please also see the response to CSTS IR No. 1 Q4.5.

The table below provides the cost per read incurred by those customers electing to opt out, depending upon the percentage of customers electing to do so.

Percent Opt Out	Cost / Read	Set-up Cost
0.1%	$ 43	$ 110
0.2%	$ 32	$ 110
0.3%	$ 27	$ 110
0.4%	$ 24	$ 110
0.5%	$ 22	$ 110
1.0%	$ 17	$ 110
1.5%	$ 15	$ 110
2.0%	$ 14	$ 110

50.7 If a customer were permitted to 'opt-out' for reasons related specifically to the exposure to RF signals, what changes would FortisBC need to be undertake to enable the customer access to electricity without exposure to RF signals?

Response:

FortisBC would need to install a meter without RF radios or a meter with RF radios that are inactive.

50.7.1 What would be the cost of these changes?

Response:

Allowing customers to retain their existing meters or to have "radio inactive" meters would result in a higher project cost due to the need to manage "opt-out" meter locations separately.

Ongoing incremental costs and reduced benefits would also occur as described in the response to CEC IR No. 1 Q50.5.

50.7.2 Would the ratepayers be responsible for these costs and if so, why?

Response:

FortisBC does not believe ratepayers who have not "opted-out" should be responsible for the costs related to customers who "opt-out". Please also see the response to CEC IR No. 1 Q50.3.

50.7.3 Does FortisBC believe that eliminating the RF signal from a Smart Meter would enable a person to eliminate RF signals from their personal environment? Please explain.

Response:

FortisBC does not believe it is possible for any customer to eliminate RF signals from their personal environment, even those in rural environments. Both natural (from earth and even human bodies) and man-made RF signals are constantly present all around us.

50.7.4 To what extent would this reduction likely limit an individual's exposure to RF signals throughout a year? Please quantify.

Response:

Considering the extremely low level of RF emissions associated with AMI, it is difficult to quantify to what extent the provision of an opt-out option may potentially reduce an individual's exposure, however based on these extremely low levels, and considering the multiple sources of natural and man-made RF signals, it is clear that that such a reduction from an AMI meter would not significantly reduce an individual's total exposure.

51.0 Reference: Exhibit B-1, Application, Page 45 and Exhibit B-6, BCUC 1.46.4

> manage their electricity usage. Products are in development that will enable customers, should they wish to do so, to optionally connect appliances such as washers, dryers, furnaces and air conditioners and with technology emerging today in home automation, control these devices from their home network. For clarity, the visibility, automation and control of these devices will reside solely in the hands of the customer, and not with the utility.

> FortisBC believes there is only a minor risk associated with the home automation communication protocol choice made by home appliance manufacturers since economic solutions are likely to be available. Please also see the response to BCUC IR1 Q30.2.1.

51.1 Please identify the types of home automation devices that are currently available, that can be installed at the customer's discretion, and are facilitated by the Zigbee or other wireless communication protocols?

Response:

The ZigBee™ Alliance website[2] states: ZigBee Home Automation offers a global standard for interoperable products enabling smart homes that can control the following product categories:

- Appliances;
- Audio;
- Cards & Readers;
- Closures, e.g. window shades;
- Energy Efficiency;
- Health & Fitness;
- Information Systems;
- Lighting;

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[2] http://www.zigbee.org/Standards/ZigBeeHomeAutomation/Overview.aspx

- Networking Devices;
- Payment Equipment; and
- Security

Their website offers a searchable directory of certified products that meet the Alliance standards and protocol.

51.2 Is FortisBC aware of other types of home automation devices under development in addition to those identified above? If so, please provide a list of such products.

Response:

Please refer to BCSEA IR No. 1 Q1.3 and Q24.3.

51.3 Does FortisBC believe that the development and adoption of home automation devices will be increasing over the next twenty years and beyond the 20 year analysis period?

Response:

Yes, it is quite probable as the current market offerings are based on a market that is still developing.

51.4 Please confirm that AMI is a key facilitating technology of “Smart Home” applications.

Response:

Confirmed, assuming that “Smart Home” applications require a HAN (Home Area Network) that can provide electricity consumption and pricing information.

52.0 Reference: Exhibit B-6, BCUC 1.27.1 and Exhibit B-6, BCUC 1.47.1.1

> Further, during implementation of the proposed AMI system (and consistent with current meter exchange practices), meter deployment personnel will inspect the meter bases to observe indications of problematic service. Any potential issues discovered will be reported by the AMI system to FortisBC for appropriate action.

> The meter deployment training document will be reviewed once it is created during the define and design stage of the project by:
>
> - Supervisor, Meter Reading
> - Director, Network Services
> - Manager, Technical Trades

> The following topics will be outlined in the deployment training manual:
> Pre-Installation Site Inspection
> 1.0 Assess acceptability of site for installation by looking for:
> 1.1 Generally unsafe meter conditions,
> 1.1.1 Water visibly present near meter socket or,
> 1.1.2 Exposed wiring
> 1.2 Evidence of tampering,
> 1.2.1 Missing meters,
> 1.2.2 Incorrect meter in socket,
> 1.2.3 Upside down meter (in conjunction with broken seal)
> 1.2.4 Drilled holes in meter glass
> 1.3 Compromised insulation
> 1.3.1 Burn marks in and around the meter,
> 1.3.2 Discoloured metal,
> 1.3.3 High temperature socket

52.1 When does FortisBC require the meter deployment training document to be completed?

Response:

FortisBC requires the meter deployment training document to be completed during the Define/Design stage of the proposed AMI Project.

52.2 Please confirm that FortisBC currently follows the same procedures when exchanging meters as it or the subcontractor will under the AMI exchange.

Response:

FortisBC confirms that the meter exchange process that will be used during installation of a meter during the proposed AMI project will be consistent with its current practices.

52.2.1 If not confirmed, what differences does FortisBC expect from its existing methods?

Response:

Please refer to CEC IR No. 1 Q52.2.

52.2.2 If not confirmed, does FortisBC consider that the proposed exchange procedures will be an improvement over the existing exchange procedures? Please explain.

Response:

Please refer to the response to CEC IR No. 1 Q52.2.

52.2.3 If an improvement, would FortisBC consider this to be a customer benefit of the AMI program?

Response:

Please refer to the response to CEC IR No. 1 Q52.2.

52.3 At what average interval would FortisBC expect that an individual customer's meter would be exchanged/replaced for any reason and so result in an inspection of the meter base?

Response:

FortisBC assumes that the question refers to the average time interval between meter base inspections after the population has been replaced under the proposed AMI project. FortisBC estimates that the average customer meter base would be inspected every 17 years.

52.4 What would be the maximum length of time an individual's meter base would reside without inspection under the status quo?

Response:

Under Measurement Canada guidelines, it was possible that an individual meter base may never be inspected if its compliance group continued to get long seal extensions. Therefore, in the status quo, the maximum time interval before a replacement or exchange activity triggers a meter base inspection is equal to the total life-span of the meter.

53.0 Reference: Exhibit B-6, BCUC 1.47. 1

- Jumpers/unusual Wiring;
- Broken or missing Government seal;
- Unusual lug wear combined with broken or missing seal;
  - Broken or cracked meter base lugs;
- Neutral wire is properly connected in meter base (note: this applies to network and poly phase metering only);
- Verify meter compatibility with socket (voltage/current/number of elements);
- Voltage check on all meter bases looking for;
  - Continuity (or load side resistance);and
  - Standard FBC residential voltage.

53.1 Do FortisBC meter readers currently examine meter bases for the above conditions at the time of meter reading?

Response:

FortisBC meter readers do a cursory visual inspection of the meter during meter reading activities, but because the internal portions of the meter base are not visible it is not possible to identify the referenced conditions.

53.2 If so, does FortisBC believe that the tamper, failure or any other automated detection capabilities of the AMI system can more accurately identify damage to meter bases than would occur during manual meter readings?

Response:

Please refer to the response to CEC IR No. 1 Q53.1. FortisBC believes that the integrated tamper detection and other types of reporting available from the AMI system (frequent short disconnections that aren't reported, for example), will be more effective in identifying tampering than the current bi-monthly inspection of the seals.

53.3 Under what conditions would an existing socket not be compatible with the new meter?

Response:

FortisBC has identified several potential scenarios where a new AMI meter may not be compatible with existing meter service, including:

- Direct wired service (No socket);
- Faulty, damaged or broken socket; and
- Older, obsolete meter bases.

53.3.1 Is there a particular type of meter base in FortisBC territory that has incompatible sockets? Please explain.

Response:

FortisBC has identified two types of service installations that will not be compatible with the new meters to be installed by the proposed AMI project:

- "A" base meter sockets; and
- Hard-wired meter installations.

53.3.2 If so, can FortisBC identify where these meter bases are located prior to installing the new meters?

Response:

Yes, FortisBC has already identified the locations of incompatible meter bases.

53.4 How often does FortisBC expect to find incompatible sockets?

Response:

FortisBC has identified approximately 4,500 incompatible meter sockets. The majority of these sockets can be made compatible with AMI meter types using a conversion kit, which is budgeted as part of the $47.7M capital cost. FortisBC expects less than 5% cannot be converted using a kit.

54.0 Reference: Exhibit B-6, BCUC 1.47.3

> If any deficiencies are found, the deployment procedures will specify what measures must be taken to correct these deficiencies prior to installation completion. These measures may include the replacement of a faulty meter base by a qualified electrician at no cost to the customer.

54.1 Does FortisBC currently replace faulty meter bases at no cost to the customer?

Response:

No, FortisBC does not currently replace faulty meter bases at no cost to the customer.

54.2 Are there conditions under which FortisBC would expect to charge the customer if a faulty meter base is identified?

Response:

Yes, if a metering installation is so old that it cannot easily accept a modern meter form then the customer may be required to pay for all or a portion of a wiring upgrade.

Also, if the customer's electrical service has been tampered with, FortisBC would require the customer to hire an electrician to bring the service up to code and provide an affidavit prior to meter installation.

55.0 Reference: Exhibit B-6, BCUC 1.47.3

> FortisBC performed 54,640 meter installations, removals or replacements in the period from 2006 through 2011. During this period there were 13 reported meter incidents where some form of meter base damage occurred or was identified. Further, FortisBC has checked its records and has found no evidence of any damage to customer property (other than the meter base) that has occurred as a result of a meter installation, removal or replacement.

55.1 Does '2006 through 2011' include all of 2006 and all of 2011 for a total of 6 years?

Response:

Yes, the referenced phase "2006 through 2011" is inclusive and covers 6 years.

55.2 Please provide the number of incidents year by year.

Response:

Please refer to the table below for a breakdown of the number of metering incidents occurring per year for the period 2006-2011.

Meter Base Incidents	
Year	Count
2006	2
2007	0
2008	1
2009	3
2010	6
2011	1
	13

55.3 Please clarify whether the 13 reported meter incidents of 54,640 meter installations, removals or replacements were all as a direct result of the meter installation/exchange activity, or if these 13 incidents included pre-existing damage to meter bases.

Response:

All the reported meter incidents were discovered during installation/exchange activity. It is not known if the damage was pre-existing, or was caused during the removal process.

55.3.1 If the 13 reports were restricted to damage that occurred at the time, please identify how many meter bases FortisBC finds already damaged in its routine observations.

Response:

Please refer to the response to CEC IR No. 1 Q55.3.

55.3.2 If the 13 reported meter incidents includes meter base damage that was pre-existing at the time of the incident, does FortisBC believe that there are currently damaged meter bases which are currently undetected in its service area?

Response:

Based on historical experience and the significant number of installed meters, FortisBC believes there are likely undetected damaged meter bases in its service territory. The replacement of all meters as contemplated in the AMI project is expected to identify these damaged meter bases.

55.3.3 Would FortisBC expect to detect these in the meter exchange as part of AMI?

Response:

Yes, FortisBC would expect to detect and fix these faulty meter bases during the proposed AMI project meter deployment.

56.0 Reference: Exhibit B-6, BCUC 1.47.3

> FortisBC has conservatively budgeted for over 1,000 meter base replacements as part of the AMI project budget to help ensure that any identified issues with customers' meter bases can be repaired with minimal customer inconvenience.

56.1 Please confirm that if FortisBC's prior experience is an appropriate basis for estimating one would expect about 30 meter base replacements.

Response:

FortisBC does not confirm that 30 is an appropriate estimate for meter base replacements resulting from the proposed AMI project. Meter base replacements will occur when the bases are faulty or damaged, but also due to incompatibility. FortisBC does agree that 30 meter base replacements are appropriate if only faulty meter bases are considered.

56.1.1 If FortisBC's experience is not an appropriate basis for estimating please explain why.

Response:

Please refer to the response CEC IR No. 1 Q56.1.

56.2 Does budgeting for 1,000 meter base replacements enable FortisBC to do a better job of defective base replacement than it currently does?

Response:

No, budgeting for 1000 meter base replacements does not allow FortisBC to do a better job of defective base replacement than it currently does. As discussed in CEC IR No. 1 Q56.1 the total number budgeted for meter replacements includes both faulty and incompatible bases.

56.3 If so, would FortisBC consider advanced defective meter base replacement to be a benefit to the customer?

Response:

FortisBC would consider the replacement of defective meter bases as a benefit to the customer as the customer's meter base is made safe sooner than it otherwise would have been and the customer avoids future replacement costs.

57.0 Reference: Exhibit B-6, BCUC 1.47.4.1

> The meter vendor has provided information that the product is designed to accept twice the normal line voltage indefinitely (i.e. 480 volts for the single-phase meter); this ensures that the device is unaffected by most overvoltage events. A metal-oxide varistor (MOV) surge protector is used to protect the meter hardware (power supply and voltage sensing inputs) from transient over-voltage surges. In the event of a long-duration, extreme over-voltage situation, a current-

57.1 How does the ability of the AMI meters to withstand surcharge compare to those currently in place?

Response:

FortisBC assumes that the word “surcharge” in the question was intended to read “surges”. The surge withstand capability of the Itron AMI meters is essentially the same as the digital (non-AMI) revenue meters which FortisBC has been successfully deploying at some customer premises for the past 15 years and exclusively since 2006.

58.0 Reference: Exhibit B-6, BCUC 1.50.1.1

> 2012 AMI Application costs incurred to date are $2,365,000, or 860 percent, higher than the 2007 AMI Application costs.

> Commission Order G-168-08, denying a CPCN for the 2007 AMI Application, stated, among other things, that “the Commission Panel considers that the risk of exposure to unknown costs of future elements of the program outweighs the value of any savings associated with the current AMI Project application” (page 22).

> In order to address this concern FortisBC consulted experts (such as Util-Assist, Navigant, and Exponent), and employed two RFP processes to identify the AMI solution presented in this 2012 AMI CPCN Application. Ultimately, FortisBC selected Itron Canada as the vendor for the major components of the AMI Project, and negotiated a firm contract for a substantial portion of project costs. Finally, FortisBC ensured that a comprehensive consultation process was followed in order to ensure that the Company understood its Stakeholders views on AMI.

58.1 Please explain specifically how the ‘risk of exposure to unknown costs’ as stated by the Commission has been or will be mitigated by the above $2,365,000 consultation process.

Response:

The risk of exposure to unknown costs has been mitigated through the negotiation of a contract for the AMI system that makes firm a significant portion of project costs. Please also see the responses to BCUC IR No. 1 Q49.1 and CEC IR No. 1 Q58.2.

58.2 Please identify which potential costs have been reduced or made more firm because of this process.

Response:

Please refer to the response to BCUC IR No. 1 Q49.1. Approximately 55% of proposed Project costs, totaling approximately $26 million are firm.

59.0 Reference: Exhibit B-6, BCUC 1.52.3

> The 20 year study period was chosen in order to reflect the 20 year economic life of the meters (which are the most significant project expense).

59.1 Would FortisBC agree that the AMI meters could well last beyond the 20 year economic life established?

Response:

Yes, FortisBC agrees that the AMI meters could well last beyond the 20 year economic life established. Please also refer to BCUC IR No. 1 Q89.2.

59.2 Would FortisBC agree that if a new and superior technology were made available within the 20 year period, FortisBC would consider adopting that technology if it could be done so with a positive and significant Net Present Value?

Response:

FortisBC agrees, assuming an analysis of all costs and benefits related to a new and superior technology, including the write-off of any remaining net book value of assets being replaced, indicates a positive and significant benefit in Net Present Value terms.

59.3 Would FortisBC agree that future replacements of the digital meters installed in its AMI project will include all the functionality of the currently selected Itron meters and would very likely include significantly enhanced functionality?

Response:

Yes. Itron OpenWay products are designed to be upgradable and FortisBC expects that they will continue to be enhanced in the future.

59.4 Would FortisBC agree that the transition to digital metering being made possible by the AMI project will not terminate at the end of 20 years and that the benefits of digital metering will continue into the future? If not, please explain.

Response:

Yes. FortisBC agrees that digital metering will continue to be the standard beyond the 20 year life of the meters, providing ongoing benefits to customers after that time.

59.5 Would FortisBC agree that the transition to increased resolution of information made possible by the AMI project will not terminate at the end of 20 years, and that the benefits of the increased granularity will continue into the future? If not, please explain.

Response:

Yes. FortisBC agrees that the transition to increased resolution of information made possible by the AMI project will not terminate at the end of 20 years, and that the benefits of the increased granularity will continue into the future.

59.6 Would FortisBC agree that the transition to automated meter reading will not terminate at the end of 20 years and the benefits will continue into the future? If not, please explain.

Response:

Yes, FortisBC believes that advanced (non-manual) metering reading will be industry standard at the end of 20 years and will continue to be into the future.

59.7 Would FortisBC agree that the ability to remotely disconnect and reconnect can be expected to continue beyond the 20 years? If not, please explain.

<u>Response:</u>

Yes, FortisBC believes that the remote connecting and disconnecting of electric services will be industry standard at the end of 20 years and will continue to be into the future.

59.8 Would FortisBC agree that the technology associated with identifying, deterring and catching energy theft will not terminate at the end of 20 years and the benefits will continue into the future? If not, please explain.

<u>Response:</u>

Yes, FortisBC agrees that theft detection benefits will not terminate at the end of 20 years and the benefits will continue into the future.

60.0 Reference: Exhibit B-6, BCUC 1.53.2.2

> The 2008 Application assumed a useful life of the meters to be 25 years. As noted in Exhibit B-1, Tab 5.0, Section 5.3.3, p. 76 of the current Application, the Company has revised its estimate of the economic life to 20 years, partly based on information from the meter manufacturer that was not available in the 2008 Application, hence the decrease in the time-period.

60.1 What information became available from the meter manufacturer that was not available in the 2008 Application that resulted in the decreased time period?

<u>Response:</u>

Please refer to the response to BCUC IR No. 1 Q69.1.

61.0 Reference: Exhibit B-6, BCUC 1.53.1.1

> No. The Application provides the costs and benefits associated with the AMI Application; however a change in the assumptions included in the Application could improve the benefits associated with the Project.

61.1 Please specify what changes in the assumptions could be reasonably foreseen as likely to occur and how they might improve the benefits associated with the Project?

Response:

FortisBC believes the assumptions it has provided in the Application as related to the benefits associated with the implementation of AMI are reasonable. However, changes in the following assumptions could be reasonably foreseen as potentially likely to occur. In each case below, the assumption is made while also assuming that all other variables within the proposed AMI Project remain constant:

- As discussed in the response to BCUC IR No. 1 Q87.2.1, an increase from the 2 percent annual growth rate of marijuana production sites to 5 percent and a decrease in the deterrence rate from 75 percent in 2012 to 60 percent by 2019 for the status quo theft reduction scenario. Such a change increases the NPV of the net benefit related to theft reduction from $38 million to $47 million;

- As discussed in the response to BCUC IR No. 1 Q87.2.7, that grow operations diverting electricity are 50 percent larger on average compared to grow operations not diverting electricity. Such a change increases the NPV of the net benefit related to theft reduction from $38 million to $50 million;

- As discussed in Section 5.3.2 of the CPCN Application (page 85), an increase in the annual growth rate of marijuana production sites from 2 percent to 3 percent in the Status Quo model from 2013 to 2017, plus an increase from 30 to 36 lights per site in both the Status Quo and AMI-potential models, and the theft deterrence factor continues to increase above 95 percent beyond 2021 in the potential AMI forecast. Such a change increases the NPV of the net benefit related to theft reduction from $38 million to $52 million;

- As discussed in the response to BCUC IR No. 1 Q52.2.1, a change in the discount rate from 8% to 6%. Such a change increases the NPV of the net benefit to customers from $17.6 million to $23.6 million;

- As discussed in the response to BCUC IR No. 1 Q58.1.2.2, and CEC IR No. 1 Q66.3.1, currently FortisBC is forecasting customer growth based upon PEOPLE35 from BC Stats (PEOPLE = Population Extrapolation for Organizational Planning with Less Error). If, instead, PEOPLE36 were adopted, the forecast customer growth rate would drop from approximately 1.8% (starting in 2016) to approximately 1.2% (starting in 2016) with the impact being a decrease in the NPV of the net benefit to customers from $17.6 million to $15.9 million;

- As discussed in the response to BCUC IR No. 1 Q96.2, if New Operating Costs were to grow at 3% instead of the 1.8% assumed in the model, the NPV of the net benefit to customers decreases from $17.6 million to $16.5 million. However, also noted in the same response was the unlikelihood that New Operating Costs would appreciate at a rate unlike that used to escalate all other model costs. If it is assumed that 3% replace 1.8% for all model inflationary escalations, the NPV of the net benefit to customers improves from $17.6 million to $20.7 million;
- As discussed in the response to BCUC IR No. 1 Q16.1, if the proposed AMI Project financial analysis took into account the potential savings resulting from customer use of the Customer Information Portal (CIP), the NPV of the net benefit to customers improves by approximately $3.8 million to $21.4 million; and
- As discussed in the response to BCSEA IR No. 1 Q44.2, if the proposed AMI Project financial analysis took into account the potential savings resulting from customer use of the In-Home Display (IHD), the NPV of the net benefit to customers improves by approximately $9.8 million to $27.4 million.

61.1.1 Please quantify the potential improvements where possible.

Response:

Please refer to the response to BCSEA IR No. 1 Q61.1

62.0 Reference: Exhibit B-6, BCUC 1.43.1 and Exhibit B-6, BCUC 1.53.11

In this response, FortisBC assumes that the proposed AMI project is implemented as per the preliminary project plan, but operational benefits are delayed by six months.

Delays in operational benefits related to meter reading, remote disconnect/reconnect, contact centre, and theft reduction were included in the analysis.

The Company did not include meter exchanges or avoided cost benefits associated with Measurement Canada compliance, since those benefits are realized by the installation of the AMI meters.

See the table below for the financial impact of a six month delay in the realization of the stated operational benefits:

	NPV ($000s)	
	AMI proposal (errata 1)	6 month delay in operational benefits
Meter Reading	-$23,785	-$22,383
Remote Disconnect/Reconnect	-$5,466	-$5,158
Contact Centre	-$441	-$410
Theft Reduction	-$38,386	-$37,491
Project NPV	-$17,629	-$14,992

Table BCUC IR1 Q53.11 – Cost Sensitivity Analysis of Project Implementation Delay

Net AMI	Errata 1	6 month delay	1 year delay	2 year delay
Project Start Date	3Q2013	2Q2014	3Q2014	3Q2015
Activity	($000s)			
AMI Project Development and Regulatory Costs	2013 - 2032	2013 - 2033	2013 - 2033	2013 - 2034
Total	$4,915	$4,915	$4,915	$4,915
CAPEX				
Total Capital Expenditure	$42,773	$45,126	$45,126	$45,938
Sustaining Capital				
Meter Growth and Replacement	$4,286	$4,880	$4,880	$5,652
Handheld Replacement	-$1,149	-$1,149	-$899	-$1,257
IT Hardware, Licensing, and Support Costs	$12,767	$12,882	$12,997	$13,227
Measurement Canada Compliance	-$18,555	-$17,864	-$17,864	-$17,493
Total Sustaining Capital	-$2,651	-$1,251	-$886	$129
Operating Expenses				
New Operating Costs	$32,196	$32,486	$32,776	$33,355
Meter Reading	-$58,116	-$60,620	-$59,574	-$61,976
Disconnect/Reconnect	-$13,267	-$14,245	-$14,245	-$14,953
Meter Exchanges	-$1,802	-$1,087	-$1,087	-$883
Contact Centre	-$1,157	-$1,212	-$1,212	-$1,254
Total Operating Expenses	-$42,146	-$44,678	-$43,342	-$45,711
Theft Reduction	-$93,705	-$99,376	-$97,867	-$101,519
Total	-$90,814	-$95,264	-$92,054	-$96,248
Project NPV	-$17,629	-$16,316	-$13,162	-$11,979

62.1 Please confirm that the NPV discounting has used the rate of 8%.

Response:

Confirmed.

62.2 Please identify whether inflation has been captured in the 6 month or the 1 year calculations.

Response:

Inflation has been captured in all instances.

62.3 Please confirm that the above calculations capture both anticipated growth and inflation.

Response:

Confirmed.

63.0 Reference: Exhibit B-6, BCUC 1.53.14.2

> No. Consistent with all capital projects undertaken by the Company, the benefits would be incorporated into Revenue Requirements either as cost reductions or incremental revenue as they are forecast to be realized. Attempting to accumulate the benefits in a "holding" deferral account would be inconsistent with the treatment of other capital, would provide no incremental benefit to customers and would add additional administrative burden to the utility. The Company has forecast loss reductions of 2 GWh associated with theft reduction due to AMI in its 2012 – 2013 Revenue Requirements Application.

63.1 How does FortisBC intend to match benefits to on-going costs and smooth them for rate payers at present and in the future?

Response:

The Company does not intend to match benefits to on-going cost and smooth them. The Company will incorporate benefits and costs into Revenue Requirements as they are forecast to arise.

64.0 Reference: Exhibit B-1, Application, Appendix C-4, Page 22 of 44 and B-6, BCUC 1.53.15

> "Theft Detection - These costs are for additional metering required to detect losses on the distribution system." [Ref: B-1, p. 71]
>
> Theft Analytics—A suite of software tools that support enhanced electricity network modeling methods, as well as the business rules required to analyze measurement data captured from new distribution system meters and the end-user advanced meters. [Ref: B-1, App. C-4, p. 22 of 44]

> Theft reduction benefits are a combination of power purchase reductions and revenue increases, and so have been separated from capital and operating expenses.

64.1 Please identify whether the theft values are just for direct energy loss or use as opposed to being inclusive of system losses and reserve capacity requirements.

Response:

Theft reduction benefits calculation do not include an estimate of technical system losses but do incorporate power purchase costs that are borne by FortisBC customers and not paid for by the customers using the energy. For a detailed discussion on how the theft benefit is calculated please refer to Exhibit B-3 filed with the BCUC on August 17, 2012 and the response to BCUC IR No. 1 Q87.1 and revised BCUC IR No. 1 Q97.2.1 (Exhibit B-6-5).

65.0 Reference: Exhibit B-6, BCUC 1.56.3 and Exhibit B-6, BCUC 1.56.5

Table BCUC IR1 Q56.3 – Financial Benefit Realization

Benefit Description	Monitoring Plan
Meter reading cost	Compare actual meter reading expenses to the forecast on Line 47 of the *Gross AMI* worksheet filed as part of Exhibit B-3
Theft reduction	Compare actual number of theft sites identified to the number of theft sites forecast on Row 26 of the *Theft Reduction* worksheet filed as part of Exhibit B-3 Compare actual revenue recovered from theft sites to the revenue forecast on Row 29 of the *Theft Reduction* worksheet filed as part of Exhibit B-3
Remote disconnect/reconnect	Compare cost of manual disconnects and reconnects to the forecast on Line 48 of the *Gross AMI* worksheet filed as part of Exhibit B-3
Measurement Canada compliance	Monitor whether 100% of electromechanical and small-batch digital meters are replaced with AMI meters.
Meter exchanges	Compare actual Measurement Canada-related compliance meter exchange expenses to the forecast on Line 49 of the *Gross AMI* worksheet filed as part of Exhibit B-3
Contact centre	Monitor whether the Contact Centre needs to manually enter any soft reads into the billing system once the AMI project is complete.

FortisBC proposes to report on the above items annually to the BCUC for a period of five years once the AMI project is complete.

FortisBC plans to continuously review and monitor the AMI project and manage risks as they are identified. Please also see Exhibit B-1, Tab 4.0, Section 4.3.5, pp. 66-67 and the responses to BCUC IR1 Q46.1 - Q46.3.1.

FortisBC notes that the Project as proposed in the Application is viable. As a prudent utility operator, FortisBC will ensure project risks are managed as is done for all capital projects undertaken for the benefit of customers, however no ongoing monitoring of project viability is planned.

65.1 Please identify at what stage FortisBC will consider the AMI project to be complete and will report on the above items to the BCUC for a period of 5 years.

Response:

FortisBC expects the project to be complete when all contractual acceptance tests are complete in the latter half of 2015. Therefore, FortisBC would expect to report on the above items from 2016 through 2020.

65.2 Will FortisBC report on the above items prior to project completion?

Response:

FortisBC does not expect to report on the above items prior to project completion since these benefits do not begin to be fully realized until the project is complete.

66.0 Reference: Exhibit B-6, BCUC 1.57.1 and BCUC 1.58.12.2

> All meter reading expenses are inflated at 1.8 percent per year. However, in order to maintain the average annual reads per meter reader at approximately 36,000 reads per year, the

> Company has forecast (in the Status Quo scenario) that an additional meter reader will be required in each of 2014, 2017, 2020, 2023, 2026, 2029, and 2032. Each of these additional meter readers are accompanied by an associated increase in non-labour support, vehicle and handheld support. As a result, savings attributed to the Company's proposed AMI Project grow disproportionally (more than the 1.8 percent inflation rate) in those years as noted in the question.

> The Company assumed that labour escalation costs would not exceed general inflation over the study period and that customer growth would remain at a historical average of below two percent.

66.1 What is the average and maximum number of meter reads accomplished in a day by one meter reader? If necessary, please break down by geographic area.

<u>Response:</u>

FortisBC has readers working out of 7 different offices throughout its territory. Due to the different headquarters which present diverse challenges in each region, on average a meter reader reads approximately 160 meters per day. The maximum number a reader could read in a day would be 1,100 meters.

66.2 Please explain why FortisBC requires an additional meter reader every three years in order to maintain the average annual meter reads per meter reader.

<u>Response:</u>

The 36,000 reads per year per meter reader noted in the response to BCUC IR No. 1 Q57.1 was an approximation used for estimating meter reading requirements. More precise data is provided below.

For the period 2008 -2011, FortisBC meter readers have read, on average, 37,233 reads per year.

The forecast for 2012 – 2013 shows the average growing to approximately 38,675 reads per year.

With an additional meter reader added in each of the years noted above, the annual average meter reads per meter reader in each period are shown in the following table. The forecast additional meter readers are required to maintain a consistent average number of reads per meter reader per year.

Time Period	Customer Growth	Additional Reads from Customer Growth	Average Reads per Meter Reader
2014 - 2016	6887	43870	38572
2017 - 2019	6653	42380	38766
2020 - 2022	6494	41367	38902
2023 - 2025	6437	41004	38997
2026 - 2028	6325	40290	39064
2029 - 2031	7986	50871	39244

The additional reads are attributable to forecast customer growth.

66.3 If the need for additional meter readers is entirely due to anticipated population/customer growth, does FortisBC believe that the population in its service area is expected to continue to grow by approximately 36,000 meter reads every three years?

Response:

Please refer to the response to CEC IR No. 1 Q66.2.

66.3.1 Please identify the population forecast that FortisBC has utilized.

Response:

The population forecast is based upon PEOPLE 35, which stands for Population Extrapolation Organizational Planning with Less Error. This report is from BC Stats. .

66.4 Please identify the number of meter reads per month per customer FortisBC uses for its average estimate of 36,000 meter reads per year per meter reader.

Response:

Please refer to the response to CEC IR No. 1 Q66.2.

- 38,675 meter reader per year per reader, multiplied by
- 19 readers, divided by
- 12 months in a year, divided by
- 114,232 customers

Equals 0.54 meter reads per month per customer

66.5 Does the number of meter reads that can be read by a meter reader vary depending on the geographic dispersion of the meters being read? Please explain the variations and how they affect the number of meter reads possible.

Response:

Yes, the number of meter reads that can be read by a meter reader is driven by the geographic dispersion of the meters being read. While the act of "reading the meter" takes roughly the same amount of time at each location, the differentiator is the time spent traveling between reads. FortisBC's service territory encompasses a mix of both urban and rural customer density.

In terms of meter reading, urban settings can be characterized by multiple reads from one vehicle location. In other words, the meter reader drives to a block, parks the vehicle, and reads multiple meters. In the Company's rural service territory, with its many long single distribution feeders, meter readers frequently have long traveling time between each meter.

66.5.1 If so, does FortisBC anticipate that population growth in its service area will be geographically consistent with the existing population?

Response:

FortisBC uses PEOPLE 35, provided by BC Stats. It is noted that the 2011 BC Stats report discusses only the demographic changes in the FortisBC region, not any potential geographical changes.

Based upon current information, the Company anticipates that population growth in its service area will be geographically consistent with the existing population.

66.5.2 Does FortisBC anticipate any population migration either to or from urban centres based on retirement or other factors? If so, please explain.

Response:

FortisBC does not know how, or if, the underlying population statistics include these factors.

67.0 Reference: Exhibit B-6, BCUC 58.2

> The Company considers 1.8% to be a conservative scenario, and notes that if in the overall NPV analysis the inflation assumption was changed to 3.0% (for all costs in both the AMI and Status Quo cases), the NPV benefit of the AMI project would increase to $26.688 million.

67.1 Does FortisBC consider 3.0% inflation to be a more likely scenario than 1.8%?

Response:

No, although a higher inflation rate increases the net present value benefit of the project.

67.2 What rate does FortisBC consider to be the most likely scenario as opposed to a conservative scenario and why?

Response:

The Company is of the opinion that the 1.8 percent rate is a likely scenario and also the most conservative scenario.

67.2.1 What would be the anticipated NPV benefit at the most likely rate?

Response:

The NPV of the benefit would be the same as filed in the CPCN of approximately $17.6 million based on a rate of 1.8 percent.

68.0 Reference: Exhibit B-6, BCUC 59.2

> The interest rate applied to the non-rate base deferral account is forecast to be approximately six percent.

68.1 Please provide the rationale for the six percent interest rate forecast to be applied to the non-rate base deferral account.

Response:

The six percent interest rate forecast represents the Company's forecast weighted average cost of debt.

68.2 What is the non-rate base deferral account amortization period?

Response:

The deferral account is not yet being amortized. If the AMI CPCN were to be approved, the Company is requesting that the deferred amount be included in the capital cost of the project and the deferral amount would be amortized over approximately nineteen years. If the AMI CPCN were not approved, the Company would apply for disposition of the account in a subsequent regulatory proceeding.

68.3 Please provide the period of time over which interest is expected to be applied to the non-rate base deferral account.

Response:

Interest will be applied on the balance of the deferral account until the Company receives approval for the AMI CPCN after which the account balance including the accumulated interest will be transferred to the Project. If the Company does not receive approval for the AMI CPCN, the Company will apply for disposition of the account balance including the accumulated interest in a subsequent regulatory process.

69.0 Reference: Exhibit B-6, BCUC 60.2

> Based on the experience of FortisBC's industry consultant, it is expected that 2 business analysts would be required to manage the events for a utility of FortisBC's size.

69.1 Please confirm that the industry consultant to whom FortisBC is referring is Util-Assist.

Response:

Confirmed, the industry consultant that FortisBC is referring to is Util-Assist.

70.0 Reference: Exhibit B-1-1, Errata Updated, Page 70, Table 5.1-B and B-6, BCUC 1.66.1, Table 5.1-B

Table 5.1.b – Summary of All Incremental Non-Project Costs and Benefits

AMI	2013	2014	2015	2016	2017 – 2032	Total
Sustaining Capital						
Meter Growth and Replacement	-	99	100	85	4,001	4,286
Handheld Replacement	-	(250)	-	-	(899)	(1,149)
IT Hardware, Licensing, and Support Costs	-	292	568	578	11,329	12,767
Measurement Canada Compliance	(146)	(909)	(903)	(1,478)	(15,119)	(18,555)
Total Capital	**(146)**	**(767)**	**(234)**	**(815)**	**(688)**	**(2,652)**
Operating Expenses						
New Operating Costs	-	875	1,529	1,556	28,236	32,196
Meter Reading	-	-	(998)	(2,544)	(54,574)	(58,116)
Disconnect/Reconnect	-	(133)	(414)	(544)	(12,176)	(13,267)
Meter Exchanges	-	(349)	(331)	(408)	(713)	(1,802)
Contact Centre	-	20	7	(20)	(1,163)	(1,157)
Total Operating Expenses	-	413	(208)	(1,961)	(40,390)	(42,146)
Theft Reduction	(383)	(987)	(1,711)	(2,835)	(87,789)	(93,705)

The table below shows the expected impact of the Kelowna municipal utility becoming part of the FortisBC service area, including City of Kelowna, and changes arising from Errata No. 1.

Table BCUC IR1 Q66.1 – Impact of City of Kelowna

	Dec-13	Dec-14	Dec-15	Dec-16	Total 2017 - 2032	Total
AMI						
Capital						
Sustaining Capital					-	-
Meter Growth and Replacement	-	(198)	(179)	(262)	2,705	2,066
Handheld Replacement	-	(250)	-	-	(899)	(1,149)
IT Hardware, Licencing, and Support Costs	-	297	573	583	11,411	12,864
Measurement Canada Compliance	(146)	(1,005)	(997)	(1,652)	(16,689)	(20,490)
Total Capital	(146)	(1,155)	(604)	(1,332)	(3,472)	(6,709)
Operating Expenses						
New Operating Costs	-	884	1,538	1,565	28,412	32,400
Meter Reading	-	-	(1,151)	(2,887)	(60,711)	(64,748)
Remote Disconnect/Reconnect	-	(152)	(475)	(624)	(13,952)	(15,202)
Meter Exchanges	-	(384)	(363)	(450)	(705)	(1,902)
Contact Centre	-	18	3	(27)	(1,312)	(1,317)
Total Operating Expenses	-	366	(447)	(2,422)	(48,268)	(50,771)
Theft Reduction	(431)	(1,110)	(1,925)	(3,190)	(98,762)	(105,418)

70.1 Please confirm that the impact of the City of Kelowna becoming part of the FortisBC service area is, on a preliminary basis, expected to create a 50% drop in meter growth and replacement sustaining capital, a 20.5% decrease in Operating Expenses and a 12.5% increase in Theft Reduction to the incremental non-project total operating costs by the year 2032.

Response:

FortisBC notes that the table provided in response to BCUC IR No. 1 Q66.1, (shown above) contained the same error as noted in Errata 1 (Exhibit B-1-1) relative to Meter Growth and Replacement Sustaining Capital. The corrected table is below:

	Dec-13	Dec-14	Dec-15	Dec-16	Total 2017 - 2032	Total
AMI						
Capital						
Sustaining Capital					-	-
Meter Growth and Replacement	-	111	114	97	4,620	4,941
Handheld Replacement	-	(250)	-	-	(899)	(1,149)
IT Hardware, Licencing, and Support Costs	-	297	573	583	11,411	12,864
Measurement Canada Compliance	(146)	(1,005)	(997)	(1,652)	(16,689)	(20,490)
Total Capital	(146)	(846)	(310)	(973)	(1,558)	(3,834)
Operating Expenses						
New Operating Costs	-	884	1,538	1,565	28,412	32,400
Meter Reading	-	-	(1,151)	(2,887)	(60,711)	(64,748)
Remote Disconnect/Reconnect	-	(150)	(466)	(613)	(13,709)	(14,938)
Meter Exchanges	-	(384)	(363)	(450)	(745)	(1,942)
Contact Centre	-	18	3	(27)	(1,312)	(1,317)
Total Operating Expenses	-	368	(439)	(2,411)	(48,065)	(50,546)
Theft Reduction	(431)	(1,110)	(1,925)	(3,190)	(98,762)	(105,418)

Given the corrected data, FortisBC confirms that, on a preliminary basis, the impact of the City of Kelowna becoming part of the FortisBC service area is, with AMI net of Status Quo, for the period 2013 - 2032:

- Meter Growth and Replacement Sustaining Capital increases $0.655 million, or 15%;
- Total Sustaining Capital (including avoided Measurement Canada compliance costs) reduces $1.182 million, or 45%;
- Operating Expenses reduces $8.4 million, or 20%. and
- Theft Reduction benefit increases $11.7 million, or 12.5%.

In summary, the Company anticipates that the addition of the City of Kelowna improves the overall customer benefit to approximately $23 million.

70.2 Please provide the assumptions FortisBC used in calculating the above.

Response:

Please also refer to the response to CEC IR No. 1 Q70.1.

Meter Growth and Replacement

The customer growth forecast from a base inclusive of the approximately 15000 additional City of Kelowna customers equates to additional customer growth and exchanges in a Status Quo state. AMI, net of Status Quo, applies the incremental cost of the AMI meters to the related increased growth costs.

Operating Expenses

Net AMI, with City of Kelowna included, eliminates the additional City of Kelowna related Status Quo O&M costs for manual meter reading, the disconnect/reconnect process, meter exchanges and the soft read component of contact center costs. This elimination improves the net AMI benefit by approximately $3.6 million.

New Operating and Maintenance

The addition of City of Kelowna adds new O&M costs of approximately $9,000 per year for additional WAN costs starting in 2014.

Meter Reading

The Company estimates that to extend its current meter reading operation into the City of Kelowna area, reading on a bimonthly basis, will require an additional 2.5 full time meter readers (and the associated non-labour support, such as vehicles). AMI eliminates this additional City of Kelowna-related requirement, improving the net AMI benefit, as evaluated on a net present value basis, by approximately $2.7 million.

Remote Disconnect/Reconnect

FortisBC has estimated an increase in operations costs related to the disconnect/reconnect process based upon the percentage increase in customers represented by City of Kelowna. AMI eliminates this additional City of Kelowna-related cost, improving the net AMI benefit, as evaluated on a net present value basis, by approximately $0.7 million.

Meter Exchanges

The addition of approximately 15,000 meters as part of the City of Kelowna acquisition results in additional O&M costs incurred for the necessary compliance sampling and retesting of those meters. The implementation of AMI eliminates this additional City of Kelowna-related O&M expense until 2021, improving the net AMI benefit, as evaluated on a net present value basis, by approximately $0.13 million.

Contact Centre

Consistent with FortisBC's AMI application, the only contact centre costs that will be impacted by AMI are those costs related to soft reads[3]. The estimate of costs is based upon the percentage increase in customers represented by City of Kelowna. AMI eliminates this additional City of Kelowna related cost, improving the net AMI benefit, as evaluated on a net present value basis, by approximately $0.07 million.

Theft Reduction

With the inclusion of the approximately 15,000 customers presently served directly by the City of Kelowna, the Company's percentage of total provincial customers increases from approximately six percent to approximately seven percent (6.1% to 6.75%). The Net AMI analysis presumes that the Company extends its Theft Reduction program, with the improved capabilities provided by AMI, into the City of Kelowna area. FortisBC estimates that Theft Reduction will improve by approximately $4.8 million as evaluated on a net present value basis.

70.3 Please explain why adding the City of Kelowna would decrease the Meter Growth and Replacement Sustaining Capital.

[3] Soft reads are defined in the AMI CPCN.

Response:

As noted in the response to CEC IR No. 1 Q70.1, Meter Growth and Replacement sustaining capital costs would increase with the City of Kelowna addition since there would be a larger population of meters.

71.0 Reference: Exhibit B-1, Application, Page 77 and Exhibit B-6, BCUC 72.3 and Exhibit B-6, BCUC 72.4 and Exhibit B-6, BCUC 72.4.1

1. In accordance with generally accepted accounting principles, the existing meters would be written off over the 2014 to 2015 period as they are removed from service; or
2. Depreciate the existing meters based upon the depreciation rate from the 2011 Depreciation Study included in the 2012-13 Revenue Requirements Application. This would mean the existing meters would continue to be depreciated at the rate derived from the life estimate of approximately 7 years as determined in the 2011 Depreciation Study; or
3. Depreciate the existing meters over a period longer than those proposed in the first two options. In the absence of the AMI Project, the Company would be writing off approximately 88,000 of its meters under Measurement Canada's new sampling plan (S-S-06) over 21 years beginning in 2014.

Option 1 was considered the most appropriate as it is in accordance with US GAAP accounting guidance and therefore does not require the Company to apply to the Commission for an accounting variance.

Yes, the Company does propose to recover the accelerated depreciation of the existing meters from ratepayers.

In all three options, the recovery of the cost of the existing meters would be included as a charge to depreciation expense in the year in which the meters are removed from service.

71.1 Is this the only reason FortisBC selected Option 1?

Response:

Yes, the the Company selected Option 1 as it is in accordance with US GAAP and would not require the Company to apply to the BCUC for an accounting variance.

71.2 Please explain the advantages and disadvantages of each option.

Response:

Please refer to the below table.

Option	Advantage	Disadvantage
One	• Would not require an accounting variance from the BCUC	• Has the highest rate impact of the three options
Two	• Has a lower rate impact than Option One	• Would require an accounting variance from the BCUC • Would have a higher rate impact than Option Three
Three	• Has the lowest rate impact of the three options	• Would require an accounting variance from the BCUC

71.3 What effect would Option 2 and Option 3 have on customer rates versus Option 1?

Response:

Both Option 2 and Option 3 would result in lower customer rates as compared to Option 1.

72.0 Reference: Exhibit B-6, BCUC 1.72.5

> The write-down of $8.59 million only includes the existing meters. The Company will still be required to perform manual meter reads, consequently all of the related property, plant and equipment including computer equipment and software and other equipment will be retained as used and useful.

72.1 Please provide an estimate of the above property, plant and equipment that will be retained as used and useful.

Response:

The property, plant and equipment that will be retained as used and useful is estimated at approximately thirty thousand dollars (gross book value).

72.2 For how long does FortisBC intend to retain in a used and useful state the above property, plant and equipment?

Response:

The Company will retain the assets as long as it is required to perform manual meter reads.

72.3 Does FortisBC intend to write the above property, plant and equipment off at a later date?

Response:

No. The property, plant and equipment will continue to be required as long as the Company performs manual meter reads.

72.4 If so, at what date does FortisBC intend to do so?

Response:

Please refer to the response to CEC IR No. 1 Q72.3.

73.0 Reference: Exhibit B-1, Application, Page 81 and B-6, BCUC 1.75.1

- An amendment to the provincial *Safety Standards Act* in 2006 obligates utilities, on request, to provide municipalities with a report identifying premises with consumption exceeding 93 kWh per day. This regulation is the basis for safety-focused initiatives in various BC municipalities whereby, based on abnormal electric consumption, municipal safety teams can inspect and shut down premises that exhibit unsafe conditions.

683 residential accounts have used greater than 93 kWh/day every billing period since September 2010.

73.1 Does the Safety Standards Act apply to commercial enterprises as well and if so, what threshold mechanism is used for commercial operations?

Response:

The 2006 Amendment to the Safety Standards Act is specific to residential accounts only and does not apply to electric customers on commercial rates.

73.2 If not, does FortisBC have a means of tracking potential energy theft in commercial sites?

Response:

FortisBC has not developed specific criteria to identify theft for marijuana production in commercial sites as the majority of theft detected to date has been in residential premises. The size of commercial services varies greatly, depending on the customer connected load at the premise and it would be very difficult to establish a meaningful threshold of expected consumption for a commercial premise. Standard consumption edits in the Billing system are applied each billing period to commercial services and identify unusual changes in consumption or demand which are investigated for potential unbilled energy.

FortisBC will be able to detect energy theft in the manner described in Section 5.3.2 of the Application for all metered customer classes, including commercial customers.

73.3 What proportion of residential accounts do these represent for each year?

Response:

This figure represents approximately 0.7 percent of the average number of residential customers for the years 2011-2012.

74.0 Reference: Exhibit B-6, BCUC 1.76.1.1

Table BCUC IR1 Q76.1.1

	2013	2014	2015	2016	2017	2018	2019
Reported Estimated System Losses(MWhs)	320,512	326,788	332,545	336,688	340,846	345,539	350,086
Status Quo Scenario							
Total estimated theft sites	218	231	244	257	270	276	281
Annual Estimated losses per site(kWhs)	151,200	151,200	151,200	151,200	151,200	151,200	151,200
System Losses due to Theft (MWhs)	33,032	34,939	36,884	38,869	40,893	41,710	42,545
AMI Probable Scenario							
Total estimated theft sites	206	191	177	158	137	106	82
Annual Estimated losses per site(kWhs)	151,200	151,200	151,200	151,200	151,200	151,200	151,200
System Losses due to Theft (MWhs)	31,162	28,919	26,836	23,938	20,707	16,048	12,437

	2020	2021	2022	2023	2024	2025	2026
Reported Estimated System Losses(MWhs)	354,687	359,574	364,470	369,158	374,079	378,976	383,850
Status Quo Scenario							
Total estimated theft sites	287	293	299	305	311	317	323
Annual Estimated losses per site(kWhs)	151,200	151,200	151,200	151,200	151,200	151,200	151,200
System Losses due to Theft (MWhs)	43,395	44,263	45,149	46,052	46,973	47,912	48,870
AMI Probable Scenario							
Total estimated theft sites	64	49	45	46	46	46	47
Annual Estimated losses per site(kWhs)	151,200	151,200	151,200	151,200	151,200	151,200	151,200
System Losses due to Theft (MWhs)	9,639	7,470	6,816	6,885	6,953	7,023	7,093

	2027	2028	2029	2030	2031	2032
Reported Estimated System Losses(MWhs)	388,819	393,737	398,777	403,772	408,351	413,175
Status Quo Scenario						
Total estimated theft sites	330	336	343	350	357	364
Annual Estimated losses per site(kWhs)	151,200	151,200	151,200	151,200	151,200	151,200
System Losses due to Theft (MWhs)	49,848	50,845	51,862	52,899	53,957	55,036
AMI Probable Scenario						
Total estimated theft sites	47	48	48	49	49	50
Annual Estimated losses per site(kWhs)	151,200	151,200	151,200	151,200	151,200	151,200
System Losses due to Theft (MWhs)	7,164	7,236	7,308	7,381	7,455	7,529

74.1 Please explain why FortisBC's annual estimated losses per site are expected to remain stable at 151,200 kWhs over 19 years under both the Status Quo scenario and the AMI probable scenario and why under the AMI scenario the losses per site would not shrink below the threshold for detection.

Response:

FortisBC assumes that the "threshold of detection" cited in the question refers to the 93 kWh/day under the Safety Standards Act. FortisBC does not consider this a likely scenario as municipal engagement under the Act is not anticipated at FortisBC. Please refer to the response to BCUC IR No. 1 Q87.2.3 for the most probable outcome that FortisBC expects in this scenario (in which the NPV of the theft benefit rises to $48.5 million).

74.2 What is the threshold amount of theft which FortisBC expects to be able to detect, and please explain why this is the threshold.

Response:

FortisBC expects the threshold of detection to be less than 1% of the total load being measured. For the purposes of calculating a representative detection threshold, FortisBC has assumed that a section of a distribution feeder with 50 residences has been targeted for analysis. The 50 residences represent an annual estimated load of approximately 600,000 kWh. Based on the 1% threshold stated, this would imply a detection threshold of less than 6,000 kWh annually in total for the assumed 50 residences on the section of distribution feeder. As the estimated annual consumption for a single marijuana production site is 151,200 kWh, the 6,000 kWh threshold will be exceeded if one or more sites are present among the 50 selected. Unexpected losses above the 6,000 kWh threshold will generate further investigation to identify the specific site(s). 6,000 kWh represents a significantly reduced grow operation size than is operating today and FortisBC believes that grow operators will find it uneconomic to increase the number of grow operations to accommodate this decrease as a substantial increase in grow sites means higher costs and risks for grow operators. .

75.0 Reference: Exhibit B-6, BCUC 1.77.1

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
	$000s													
Status Quo Revenue Protection	$ 235	$ 244	$ 248	$ 253	$ 257	$ 262	$ 267	$ 272	$ 276	$ 281	$ 287	$ 292	$ 297	$ 302
AMI Incremental	0	0	0	$ 118	$ 241	$ 245	$ 249	$ 254	$ 258	$ 263	$ 268	$ 273	$ 277	$ 282
Annual Total	$ 235	$ 244	$ 248	$ 371	$ 498	$ 507	$ 516	$ 526	$ 534	$ 544	$ 555	$ 565	$ 574	$ 584

	2024	2025	2026	2027	2028	2029	2030	2031	2032
		$000s							
Status Quo Revenue Protection	$ 302	$ 308	$ 313	$ 319	$ 325	$ 330	$ 336	$ 342	$ 349
AMI Incremental	$ 282	$ 288	$ 293	$ 298	$ 303	$ 309	$ 314	$ 320	$ 326
Annual Total	$ 584	$ 596	$ 606	$ 617	$ 628	$ 639	$ 650	$ 662	$ 675

75.1 What does the FortisBC cost for Status Quo Revenue Protection involve the company doing?

Response:

Please refer to the response to BCUC IR No. 1 Q85.1, Q85.3.2 and Q85.4.

75.2 What is the current FortisBC likely threshold for theft detection and why is it at this level?

Response:

Theft at individual sites is confirmed through a manual process in which the load recorded on an individual meter and load measurements before the meter are compared. To account for the risk of error in this manual process, the current threshold above which FortisBC will report theft to the RCMP is 5,000 watts. This is not a kWh measure but an instantaneous load measure. This method is not as accurate or as granular as the method proposed under AMI. Please refer to the response to CEC IR No. 1 Q74.2 and Q77.2.

75.3 Please explain how the level of theft detection threshold will change with AMI and why.

Response:

Please refer to the responses to CEC IR No. 1 Q 22.1, Q74.2, Q75.2 and Q77.2.

76.0 Reference: Exhibit B-6, BCUC 1.78.2 and Exhibit B-6, BCUC 1.83.3

> FortisBC customers financially benefit from marijuana grow operations that do not engage in the theft of service due to the increased number of billed kWh over which fixed utility costs are divided. This benefit is the same as the benefit received from any paying customer.

> FortisBC has limited experience with paying marijuana grow operations since it is interested primarily in detecting and deterring theft. FortisBC does not request information from the RCMP for marijuana sites that have been busted and are paying for electricity.

76.1 Does FortisBC believe that the energy conservation derived from detecting and deterring energy use by paying marijuana grow operations will have a positive benefit to legitimate customers?

Response:

If the energy conservation results from grow operations that are stealing, all other customers will benefit. If the energy conservation results from grow operations that are paying, all other customers will be harmed (due to lost marginal revenue margin).

76.1.1 Would it be reasonable to anticipate that uncertainty regarding the presence of grow ops in residences and the damage caused by grow ops could negatively impact the value of homes and neighbourhoods?

Response:

FortisBC is not qualified to assess the impact of residential marijuana production on real estate values.

76.1.2 Does FortisBC consider the presence of grow ops to be a hazard to the community?

Response:

Potential hazards associated with indoor marijuana production are detailed in the 2005 Plecas et al Report filed as Appendix CSTS IR1 77.7. The report cites a 24 fold increase in the risk of fire for indoor marijuana sites which is why FortisBC is motivated to identify those sites with altered wiring (i.e. diversions). AMI deployment will increase the number of theft sites identified and reduce the risk of electrical fires for FortisBC communities. Please also refer to Exhibit A2-7 filed by Commission staff on September 14, 2012.

77.0 Reference: Exhibit B-6, BCUC 1.78.3 and Exhibit B-6, BCUC 1.78.3.1

> Since customers are on different read cycles and billing meters are read at different times over a multiple-month period, it is not possible to capture a "snap-shot" of the total system consumption. Consequently it is not currently possible to accurately determine system losses for any specific point in time. AMI deployment will enable the accurate and timely collection of

> Estimates of total system losses have been used historically in the Company's Revenue Requirements and Cost of Service Analysis Applications. While these estimates are adequate for power purchase and cost allocation purposes, they are not as granular or as detailed as the network losses which could be measured following the installation of AMI meters. These more detailed loss measurements would allow FortisBC to proactively locate and address specific loss problems. Time-synchronized customer billing meter readings are required to make more detailed loss calculations. FortisBC's proposed AMI system is capable of producing these time-synchronized meter readings.

77.1 Please confirm that the AMI project is the only viable means of capturing the necessary "snap-shot" of total system consumption in order to determine system losses for a specific point in time.

Response:

Confirmed. FortisBC is not aware of other means of obtaining the necessary "snap-shot".

77.2 How much more granularity does FortisBC require in order to locate specific loss problems and at what level does the granularity produce diminishing benefits?

Response:

FortisBC intends to adjust the "granularity" by deploying more theft detection metering on the portions of the electric system with the highest unexplained losses.

From a prioritized ranking of high-loss feeders (determined using existing distribution substation automation equipment and data from the new AMI meters), FortisBC will strategically deploy feeder metering devices on feeders with the highest unexplainable losses. The feeder will then continue to be divided into more granular sections using feeder metering until the source of loss is precisely identified at a particular meter.

FortisBC considers that its proposed methodology of using fixed and re-locatable transformer and feeder meters (as described in Section 5.3.2 "Phase II -Theft Detection Improvements" of the Application) will provide detailed information in high-loss areas while being cost-effective.

78.0 Reference: Exhibit B-6, BCUC 1.79.1

> Two percent is the forecast customer growth between 2011 and 2013 as filed in the FortisBC 2012-2013 Revenue Requirements Application, Table 3C. FortisBC chose to use this figure for inflating marijuana grow operation numbers through 2032 since it is based on current forecasts.
>
> If FortisBC instead used the P.E.O.P.L.E. 36[3] estimate of 1.2 percent average annual population growth between 2011 and 2036 for the Status Quo marijuana operation growth, the NPV of the theft benefit would increase to $42.1 million.

78.1 Please explain why FortisBC believes the forecast in the 2012-2013 Revenue Requirements Application, Table 3C is a superior forecast to the P.E.O.P.L.E. estimate of 1.2 percent annual average for this purpose.

Response:

FortisBC does not assert that the two percent forecast used in the 2012-2013 Revenue Requirements Application is superior to the P.E.O.P.L.E. forecast. They are merely different models and the Company chose the one which yielded a more conservative benefit.

78.2 Does FortisBC believe that marijuana grow operations can be expected to increase proportionately with the population. If so, please explain why.

Response:

It seems reasonable to expect a proportionate increase in the number of marijuana production sites relative to population growth for the following reasons:

- Domestic demand will increase proportionate to population growth as there is no reason to expect that the incidence of use is declining;
- The return on investment for producers is unchanged; and
- The market price of the product is not anticipated to decline.

79.0 Reference: Exhibit B-6, BCUC 1.79.2, Table and BCUC IR 1 Q.79.2 – Number of Lights

Table BCUC IR1 Q79.2 – Number of Lights

	Number of Lights 2005-2006	Number of Lights 2007-2011
	30	28
	6	63
	21	12
	2	37
	51	33
	56	42
		10
		10
		38
		32
		27
		19
		24
		34
		16
		114
Average	29.23	29.03

79.1 Why did FortisBC use thirty lights instead of the above indicated 29 lights as the estimate per site?

Response:

FortisBC does not enter the customer premise to directly observe the number of lights and equipment wired to the meter bypass but must rely on information received from other parties whose primary focus is not the amount of energy theft but rather the number of plants and the overall safety of the premise. The information received from the RCMP or the electrician is not necessarily exhaustive in nature as the light ballasts and exhaust fans associated with indoor marijuana production also consume energy that is not included in the light estimate. The average number of lights reported to FortisBC from theft sites in 2012 as of the application date has increased from 29.03 to 32.75. In consideration of these additional factors and the Plecas research indicating 36 lights it seemed reasonable to round the light average up to thirty lights per site.

79.2 Please provide the information in Table BCUC IR1 Q79.2 – Number of Lights separately for each year from 2005 to 2011 inclusive.

Response:

Table CEC IR No. 1 Q79.2 below has been updated to include light data from ten additional sites identified in 2011.

Table CEC IR1 Q79.2 - Number of Lights

2005	2006	2007	2008	2009	2010	2011
30	14	28	67	40	20	16
26	24	21	24	38	24	114
38	46	24	20	16	63	12
26	26	24	36	31	12	24
31	15	20	36	42	37	30
21	41	26	33	21	33	32
24	20	24	38	19	42	48
54	20	24	33	21	10	22
10	24	42	32	10	10	37
24	30	30	14	8	36	20
	53	25	28		32	42
	24	40	25		27	29
	11	25	32		19	
	14		21		24	
	12		18		34	
	28		36			
	27		24			
	24		15			
	16					
	34					
	20					
	100					
	30					
	45					
	30					
	45					
	30					
	12					
	32					
	30					
	32					
	46					
	28					
	6					
	21					
	2					
	51					
	56					

79.3 Please confirm that the data in the above table is inclusive of all the years indicated, and that it indicates a total of 48 grow op sites caught stealing electricity over the two year period of 2005 and 2006; and a total of 58 sites caught stealing electricity over the five year period from 2007 and 2011.

Response:

The number of lights table was compiled early in 2011 and contained 2011 data from two theft sites only. Table CEC IR1 Q792 has been updated to reflect the additional 10 sites identified in 2011. The table now contains all available light data for the years 2005-2011 inclusive.

A distinction must be made between the number of sites in the table and total number of theft sites identified. As indicated in the response to BCUC IR No. 1 Q79.2, the number of lights is not consistently available and the table contains the only available light data. The total number of sites where we have light data is 48 for 2005-2006 and 68 for 2007-2011. The total number theft sites identified for the same period is 57 for 2005-2006 and 92 for 2007-2011.

79.4 Are the numbers of lights per site identified in the table above depicted in chronological order?

Response:

Yes. The light data in Table BCUC IR1 79.2 are recorded in chronological order.

80.0 Reference: Exhibit B-1, Application, Page 83

> FortisBC has had a revenue protection program in place since 2006. Based on a three year average for the period 2009 – 2011, the program has identified an average 25 percent of known or suspected marijuana sites as diverting energy, which equates to a 75 percent deterrence factor as a result of FortisBC's current revenue protection activities. Applying the 75 percent deterrence factor to the estimated 824 grow sites in FortisBC's service territory in 2012 indicates that 206 grow sites are diverting electricity while the remaining 618 sites are assumed to be paying customers.
>
> Revenue protection investigations have discovered an average of 8 percent of the total estimated theft sites annually. This implies that in 2012, 16 of the estimated 206 sites engaged in theft will be identified and the remaining 190 sites will be undetected representing an annual revenue loss of $3.7 million in 2012.

80.1 Please explain how the above revenue protection program has calculated that it has identified on average 25% of known or suspected marijuana sites as diverting electricity.

Response:

The 25 percent theft ratio presented in the Application is derived from the following inputs:

Theft Sites- defined as marijuana sites that are confirmed to be diverting energy.

High Load Paying Sites - defined as sites where marijuana production is confirmed or suspected and the customer is paying for all energy consumed.

The theft ratio for each year is calculated as (# Theft Sites divided by (the # Theft Sites plus the # High Load Paying Sites)). The average of the annual figures for the years 2009-2011 was calculated as 25 percent of known or suspected marijuana sites were diverting energy. Please refer to the response to CEC IR No. 1 Q80.2 and BCUC IR No. 1 Q85.3.

80.2 Please provide the annual number of known or suspected marijuana sites diverting energy for each of the years 2009, 2010 and 2011 and the number identified by the revenue protection program and the source of the numbers.

Response:

The numbers contained in the following table are derived from analysis of FortisBC theft investigation files.

Table CEC IR1 Q 80.2

Year	Diversions	High Load Paying	Total #	Theft Ratio
2006*	57	71	128	45%
2007	21	21	42	50%
2008	28	27	55	51%
2009	13	32	45	29%
2010	18	52	70	26%
2011	12	49	61	20%

*2006 data includes 2005 as the program began in October 2005.

80.3 Please explain why FortisBC estimate of theft as a percentage of grow operations is so much less than the 50% estimate in the Plecas studies.

Response:

Please refer to the response to BCUC IR No. 1 Q85.3.1. The uncertainty of predicting customer behaviour for a covert activity dictates that the Company take a conservative approach in estimating the theft reduction benefit from AMI deployment.

80.4 Please explain FortisBC's 25% theft estimate versus the estimates used by BC Hydro and explain why there is a difference if any.

Response:

The BC Hydro Smart Metering Infrastructure Program Business Case cites losses of $100 million annually due to energy theft. FortisBC has no visibility of any detail behind this number that may relate to theft ratios specific to marijuana production. The Company is unable to complete the requested comparison.

81.0 Reference: Exhibit B-1, Application, Page 85

- The average number of lights recorded by FortisBC at licensed sites shut down by the RCMP for illegal production is trending well above the 36 reported by Plecas. If

81.1 Please provide the trend that FortisBC has identified.

Response:

FortisBC has become aware of five licensed marijuana production sites that have been shut down by the RCMP in 2012 for exceeding their licensed quota. The light data provided by the RCMP is presented in the following Table CEC IR1 Q81.1.

Table CEC IR1 Q 81.1

	Light Count
	85
	10
	146
	5
	23
Average	**53.8**

82.0 Reference: Exhibit B-6, BCUC 1.81.1

> In light of these evolving detection risk considerations, FortisBC considers it reasonable that there would be both an increase in paying sites and an increase in the use of alternative energy sources. Both of these responses by illegal marijuana grow sites are logical given the increased risk of the theft detection and the stable risk of paid consumption detection.

82.1 Does FortisBC consider that the use of alternative energy would be more costly for a grow operation than paying FortisBC?

Response:

Yes. However, producers will balance the cost of operation and the risk of detection in an effort to remain in business. Please refer to response to BCUC IR No. 1 Q87.2.5 and Q87.2 as well as the Easton Policy Paper filed by BCUC as Exhibit A2-1.

83.0 Reference: Exhibit B-1, Application, Page 89 and Exhibit B-6, BCUC 1.82.1 and Exhibit B-6, BCUC1.86.2

> The savings from energy theft reduction will be realized in accordance with the two phases discussed above. The Company expects to increase detection of energy theft from 8 to 15 percent in 2014 -2015 due to the productivity gains and improved data analysis associated with initial deployment. The introduction of energy balancing beginning in 2015 is expected to increase the deterrent impact to 84 percent by 2016, and improve detection capabilities to 25 percent by 2016. The progression of recoveries for the life of the Project is detailed in the table below.

> The theft benefit per customer of FortisBC AMI deployment is estimated at $330 ($38 million NPV benefit divided by 115,000 customers) which compares favourably with the BC Hydro theft benefit of $406 ($732 million NPV benefit divided by 1,800,000 customer) as estimated from data in the published Business Case, which suggests similar assumptions are used.

> The detailed methodology used in identifying electric theft and the subsequent results is necessarily sensitive in nature. FortisBC confirms that it has discussed with BC Hydro their approach to identifying electricity theft and their successes/challenges to date under a Non - Disclosure Agreement. The benefit of this discussion is reflected in FortisBC's approach to theft reduction in Tab 5.3.2 of the Application and it is expected that collaboration will continue as more experience is gained by both parties.

83.1 Does the information obtained from BC Hydro relate particularly to the FortisBC estimate of expected benefits to be obtained in 2014 and 2015 based on the initial deployment?

<u>Response:</u>

No. The information shared relates to the field methods employed to detect energy theft.

83.2 Given that FortisBC's estimate of $330 in net theft benefit per customer is approximately 20% lower than BC Hydro's estimate of $406 per customer has FortisBC identified particular challenges that have led FortisBC to reduce assumptions regarding the effectiveness of the theft reduction program?

<u>Response:</u>

There are no specific challenges identified leading to the calculation of $330 in net theft benefit for FortisBC customers. As stated in several places through the information request responses, FortisBC has attempted to provide conservative but reasonable estimates of benefits.

The comparison with BC Hydro is based on a simple calculation which divides the estimated theft benefit by the number of customers in each utility. The comparison was made to suggest generally that similar assumptions were applied in evaluating the cost of energy theft for customers.

83.3 Please compare the assumptions used by BC Hydro and FortisBC.

Response:

FortisBC has no visibility of specific BC Hydro assumptions referred to in BCUC IR No. 1 Q82.1 used in the Smart Meter Business Case and is unable to respond to this question. Discussion regarding detailed methodologies on theft detection is covered by a Non-Disclosure Agreement. Please also refer to the response to CEC IR No. 1 Q83.1, Q83.2 as well as BCUC IR No. 1 Q82.1, page 183, line 15 and BCUC IR No. 1 Q82.2, page 183, line 33.

84.0 Reference: Exhibit B-1, Application, Page 88 and Exhibit B-1, Application, Page 89, and Exhibit B-6, BCUC 1.82.7

> Feeder meters, as distinct from those to be installed at customer homes or businesses, will be installed at key points on FortisBC distribution feeders. These meters monitor cumulative electricity loads on an hourly or more frequent basis and will measure the total electricity supplied to a specific area. Based on the data supplied by the feeder meters, AMI-

> This AMI feature is expected to increase theft detection to 25 percent by 2016 and gradually increase deterrence from 75 to 84 percent by 2016. Results from this initial approach will be reviewed to determine if additional capital investment will generate satisfactory incremental returns and if warranted, FortisBC will seek approval of new capital and operational investment in a separate filing.

> The Application states in several sections the intent to collect hourly consumption data from advanced meters installed at customer premises (please refer to pages 3,19, 46, 51 and 55 from the Application). There is no intent at this time to collect consumption data at half-hourly intervals.

84.1 Would theft detection from energy balancing be improved by having information at the customer and feeder meters being collected at less than hourly intervals?

Response:

Theft detection from energy balancing is not expected to improve with more frequent data collection.

84.1.1 Please explain why or why not.

Response:

Theft detection from energy balancing requires time-synchronized collection of customer and feeder consumption data. Theft can be identified effectively using consumption data that are separated by more than an hour, and FortisBC sees no additional benefit to more frequent measurement. In addition, the processing, storage and analysis of increased volumes of data associated with more frequent collection will increase costs (with no corresponding increase in benefit).

84.2 Would FortisBC require different feeder meters in order to measure electricity supplied to a specific area at half-hourly intervals?

Response:

The feeder meters proposed in the Application are still in development. However, the prototypes under consideration are capable of collecting data at half-hourly intervals as well as hourly intervals.

84.2.1 If so, what would be the cost of feeder meters that could collect consumption data half-hourly or more frequent intervals?

Response:

They are the same meters so there would be no additional cost. Please also see the response to BCUC IR No. 1 Q54.1.

84.2.2 If not, what is the shortest interval for which the feeder meters can measure the total electricity supplied to a specific area?

Response:

The feeder meters proposed in the Application are capable of collecting data in intervals as low as 5 minutes.

84.3 What is the shortest interval for which customer meters can measure the electricity supplied to their premises?

Response:

The shortest interval for which customer meters can measure the electricity with the system that FortisBC is proposing is 5 minutes. This is configurable remotely or locally at the meter.

If a customer chooses to purchase an "in-home" display, they will be provided electricity data on a shorter time interval, likely less than 30 seconds. The capability of the IHD will determine how much of that information can be stored and retrieved.

84.4 Reference: Exhibit B-1, Application, Page 37 and B-6, BCUC 1.92.2 and Exhibit B-6, BCUC 1.92.2.1

> kilometres driven when locating the source of unplanned power outages. As well, the remote disconnect/reconnect functionality of the AMI system will eliminate the need to drive to customer premises to complete a disconnection or reconnection of service.

> The charge for Normal working hours is $100.00. The charge for Overtime hours is $132.00 and the charge for Callout hours is $339.00.

> Once the AMI project is completed, the marginal cost of a remote reconnection is likely to be less than $10, meaning that in theory the reconnection fee could be dropped substantially. However, FortisBC proposes to maintain the current reconnection charge until the next COSA in order to better understand all costs associated with the new processes.
>
> The reconnection charge also deters disconnections, the costs of which are borne by all customers. Although disconnection process costs would go down with the AMI project, there are still related costs such as site visits for 50% of vacant sites and 100% of non-pay sites (Exhibit B-1, Section 5.3.3, p60) and the contact centre processes related to non-pay disconnects.

84.4.1 Please confirm that the AMI system could eliminate the need to drive to customer premises to complete either a disconnection or reconnection of service except for 50% of vacant sites and 100% of non-pay sites.

Response:

Confirmed.

84.4.2 When does FortisBC anticipate that the next COSA will be?

Response:

In order to complete a COSA with the most complete information possible, the Company will require the load data that the AMI-enabled metering will provide. Assuming full deployment of AMI by the end of 2015, the Company would collect at least one full year of data and perform a full cost of service study in 2017.

84.4.3 What years did FortisBC submit its last three COSAs?

Response:

FortisBC submitted COSAs in 1993, 1997, and 2009.

84.4.4 How often does BC Hydro submit COSAs to the Commission?

Response:

FortisBC is not aware of any set interval that BC Hydro maintains between COSA submissions. BC Hydro last filed detailed COSAs with the Commission in 2007 and 1991 as part of the Rate Design Applications that were filed at that time. As well, BC Hydro annually files (December) a less detailed annual COS compliance filing that shows revised Revenue-to-Cost ratios for all customer classes and complies with specific directives from BCUC Order No. G-111-07 and G-10-08.

84.4.5 Please identify and quantify the existing disconnection process costs and the expected disconnection process costs under AMI.

Response:

Please refer to Exhibit B-1, Table 7.1a, which quantifies the costs of the Status Quo disconnect process.

Please refer to Exhibit B-1, Table 7.4a, which quantifies the costs of the AMI disconnect process.

84.4.6 Please explain how FortisBC defines Call Out and explain under what circumstances FortisBC would apply either the $339.00 Call Out charge or the $132 overtime charge if the AMI program were implemented.

Response:

The callout charge is applicable to customers requesting a meter reconnection after 2:30 pm.

Following the implementation of AMI, FortisBC will only charge the $100 fee for reconnection for customers with an AMI meter. Customers whose meters are still manually read will still be subject to the standard charge, or overtime or callout charge as applicable. Please also refer to the response to BCUC IR No. 1 Q92.2.1.

84.4.7 Would FortisBC agree that in the event Opt Out were permitted it would be appropriate to charge substantially different disconnection and reconnection charges to customers who had “Opted Out” than to customers who have remote disconnect and reconnect capability under the AMI program?

Response:

Yes, the Company agrees that if an opt-out program were permitted, it would be appropriate (and consistent with cost-causation principals) to ensure that the costs of disconnecting and reconnecting opting out customers are appropriately set to ensure no cross-subsidization between customers with an AMI meter, and customers who choose to opt-out.

84.5 Reference: Exhibit B-1, Application, Page 98 and B-6, BCUC 1.100.1

> to maintain a power factor of not less than 90 percent lagging, FortisBC is only able to practically apply this requirement to commercial customers subject to a demand component as part of their billing. Moreover, as commercial customers subject to demand billing are billed on demand as measured in kVA (apparent power), customers exhibiting a poor power factor are automatically penalized by an increased demand charge (providing additional revenue to mitigate system impacts) than would otherwise be realized with an improved power factor. The current metering used for the majority of FortisBC's customers does not permit any determination of power factor (and thus the application of section 7.4 of the Electric Tariff), greatly limiting any potential for the Company to address poor power factor on the distribution network.

> For clarity, the discussion in Section 6.1 of the Application refers to the ability of the AMI system to determine power factor at all customer end-points. While this does include residential customers, FortisBC's expectation is that low power factor concerns are more likely with other customer classes such as commercial and irrigation customers. This is because the latter often have large electric motor loads as compared to residential customer loads which are primarily resistive (lighting and heating).

> However, as discussed in the response to BCUC IR1 Q100.1, it is expected that low power factor issues will be more probable with other customer classes, and that residential power factor is not expected to be a significant concern.

84.5.1 Please clarify and quantify if those commercial customers subject to demand billing and exhibiting a poor power factor are penalized by the increased demand charge more than the cost associated with the poor power factor.

<u>Response:</u>

FortisBC submits that the referenced paragraph from the Application could be restated for clarity as:

> *Moreover, as commercial customers subject to demand billing are billed on demand as measured in kVA, customers exhibiting a poor power factor are automatically penalized by an increased demand charge relative to a billed demand charge based on a good power factor.*

The increased kVA-based demand charge related to a poor power factor is the cost associated with the poor power factor.

84.5.2 How many commercial customers does FortisBC have that are and are not subject to a demand component as part of their billing?

<u>Response:</u>

As of October 1, 2012, FortisBC has approximately 1,840 commercial customers that are subject to a demand component as part of their billing and 9,800 commercial customers that are not subject to a demand component as part of their billing.

We also have 155 irrigation customers that are subject to a demand component as part of their billing and 935 irrigation customers that are not subject to a demand component as part of their billing.

84.5.3 Please explain how a commercial customer not currently subject to demand billing but found to have a poor power factor with the information obtained in the AMI program will be affected.

Response:

AMI meters have the ability to measure watts, volt-ampere hours and watt hours for all customers, so power factor can be calculated for all customers. Accurate measurement of customers' power factor (irrespective of whether demand billing is applied) will allow the Company to apply section 7.4 of the Electric Tariff as required.

84.5.4 Does FortisBC expect that low power factor impacts will be a 'significant' issue with respect to some commercial customers?

Response:

FortisBC does not expect that low power factor will be a 'significant' issue with commercial customers.

FortisBC expects that some commercial customers will have low power factors. For those that do, there are often relative low-cost, high-payback solutions that increase power factor and lower customer bills (for those customers that are demand-metered).

84.5.4.1 If so, please supply any estimates that FortisBC has with respect to the incremental savings that may be derived from commercial customers where power factors can be improved.

Response:

Poor customer power factor has the effect of unnecessarily consuming FortisBC system capacity. This effect can be significant at peak load times when system usage is highest and hence some portions of the system are almost fully utilized. Resolving the resulting system capacity constraints could drive costly generation, transmission, substation or distribution upgrades. Ensuring that customers maintain a power factor of 90 or greater helps ensure that unnecessary infrastructure projects to support customers with poor power factor are not undertaken.

Notwithstanding this, FortisBC sees no indications which suggest that wide-scale problems with poor customer power factor are present. Even during peak loading conditions, power factor readings at FortisBC substations are 90 or greater (and in most cases are greater than 95). Additionally, the Company has not had to add unusual amounts of reactive equipment (capacitors) to its distribution feeders to maintain these power factor levels. On this basis, FortisBC expects that any problems with customer power factor will be localized and hence have a limited impact on the system. Until AMI is fully deployed and individual customer power factor readings are available, the Company cannot provide an estimate of any savings or system benefits that will result from customers improving their power factor.

85.0 Reference: Exhibit B-1, Application, Page 102 and Exhibit B-1, Application, Appendix C-4, Page 12 of 44

Table 6.3.a – Potential Savings from Outage Management System Deployed in 2014

	Forecast Savings ($000s)						
Outage Management System	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	-	830	(68)	(138)	(141)	(143)	(146)
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	(148)	(151)	(154)	(157)	(159)	(162)	(165)
	2027	**2028**	**2029**	**2030**	**2031**	**2032**	
	(168)	(171)	(174)	(177)	(181)	(184)	

FortisBC expects to finalize the development of a business case for the implementation of an OMS for inclusion as part of a future regulatory application with submission possibly in 2015.

	Outage Management Efficiencies	$10	$5–$15

85.1 Why did FortisBC elect to address Outage Management system as a separate regulatory application instead of including it in the business case for AMI as did BC Hydro in the SMI project?

Response:

The Company believes it is prudent to take a measured approach to the implementation of future “smart grid” technologies (like an outage management system). As noted in the Application, the deployment of future smart grid technologies will be evaluated to determine whether such a deployment is both cost-effective and in the best interests of customers. FortisBC believes it needs more experience with the AMI system before it can fully quantify the benefits and costs of an Outage Management System.

86.0 Reference: Exhibit B-6, BCUC 102.3

> FortisBC is considering the acquisition, in 2014/2015 of an Outage Management software System (OMS) that will leverage the information from the AMI meter, CIS (Customer Information

86.1 In considering the acquisition of an Outage Management software system, what factors would FortisBC believe would detract from the purchase of OMS?

Response:

The Outage Management software system will consolidate outage phone calls or AMI meter outage information and then predict the electrical device in the field that operated to isolate the area of outage. This provides benefits from an operational efficiency perspective and by providing better information to the customer.

FortisBC continues to review all projects and only apply for BCUC approval on projects deemed to have the greatest benefit to the customer in an effort to mitigate rate increases. Therefore, the only factor that can be considered to detract from the purchase and implementation of an OMS is the cost and associated rate impact in consideration with all other projects.

86.2 Please identify all circumstances in which FortisBC does not believe it would proceed with the purchase of an OMS system.

Response:

Please refer to response CEC IR No. 1 Q86.1.

86.3 Reference: Exhibit B-6, BCUC 1.105.1

> Please see the table below which provides the unit cost for digital and electro-mechanical meters currently in use by FortisBC. Due to contractual sensitivities, the unit cost of the proposed AMI meter has been filed with the Commission in confidence.

Meter Type	Unit Cost
Single phase electromechanical meter	$36.84
Single phase digital meter	$30.11

86.3.1 Please confirm that the single phase electromechanical meter is not still and will not be available for purchase throughout the 20 year study period.

Response:

Confirmed, to the best of the Company's knowledge. Please also refer to the response to CEC IR No. 1 Q12.3.

87.0 Reference: Exhibit B-1, Application, Page 32 and Exhibit B-6, BCUC 1.16.1 and 107.1

> to better understand their bills and manage their consumption. Increased awareness and access to more information has proven an effective tool that allows customers to modify their usage habits in an effort to lower their bills and save energy as detailed in the Navigant report provided as Appendix C-1. As part of its 2012 Long Term Resource Plan, FortisBC has included estimated savings of 2.3 GWh beginning in 2015 and increasing to 8.9 GWh by 2025 related to the behavioural changes enabled by the FortisBC online web portal.

> portal savings range from 2.2 in 2015 to 5.3 GWh in 2025.. The corrected customer information portal savings, by year, and the dollar value of each is shown in the following table. The incorrect figures do not affect the application as the customer information portal benefits were not factored in (please see the response to BCUC IR1 Q16.2 response).

87.1 Would the 2012 Long Term Resource Plan need to be revised in the event that the AMI project did not proceed and the online web portal was not available?

Response:

No. The 2012 Long Term Resource Plan identifies resource options and related strategies to address resource gaps considering a range of long term load forecasts. In the short to medium term, any changes to load requirements that may occur in the event that the AMI project did not proceed are expected to be captured within this range of forecasts. Any longer term impacts would be addressed in future Long Term Resource Plans. As directed by the Commission in its August 2012 decision related to FortisBC's 2012-2013 Revenue Requirements and the 2012 Integrated System Plan Application, FortisBC anticipates filing its next Resource Plan no later than June 30, 2016.

87.2 Why did FortisBC not include any portion of the customer information portal benefits in the AMI application?

Response:

Please refer to the response to BCUC IR No. 1 Q16.2.

88.0 Reference: Exhibit B-1, Application, Pages 44 and 45

> IHDs. A recent survey[9] by the US Department of Energy and CenterPoint Energy of participants in a smart meter In-Home Display pilot program showed positive results with 71 percent of participants reporting that they changed their electricity consumption behaviour
>
> habits. These savings will be included in future PowerSense DSM applications to the extent that the Company provides a related incentive.

88.1 Why will FortisBC limit the potential for consumption savings to PowerSense DSM applications in which the company provides a related incentive?

Response:

FortisBC agrees that savings that are directly related to the implementation of AMI (such as the IHD savings) could be included in the AMI project benefits as well as PowerSense DSM savings provided that the savings are not "double-counted" in revenue requirements.

89.0 Reference: Exhibit B-1, Application, Appendix C-1, Page 40 of 65 and Exhibit B-6, BCUC 107.1

> The Hydro One TOU pilot had 13% of the customers solicited agreeing to the TOU rates, of these, 72% said that they would like to stay on the TOU rates implying long-term participation rates of 9%. The NewMarket Hydro TOU pilot was run as an opt-out program. Approximately 37% of the customers opted out.

- Delaying requirement for new generating facilities and transmission and distribution infrastructure, lowering costs for all customers;
- Reducing future power purchase expense (as shown in Table 6.5a);
- Inasmuch as some market-based power supply alternatives may be fossil fuel based, a reduction in any reliance on such resources provides an environmental benefit.

These drivers are relevant to FortisBC now, which is why the Company has contemplated the implementation of time-varying rates in the AMI CPCN.

89.1 Does FortisBC agree that customer adoption of conservation practices will likely increase with familiarity of conservation rate programs and the technology that supports them?

Response:

Yes.

89.1.1.1 Does FortisBC have a forecast as to how adoption of conservation practices may increase from year to year after implementation of IHD and conservation rate structures? If so, please provide.

Response:

FortisBC does not have such a forecast.

89.1.1.2 What measures can FortisBC take to enhance and increase response rates over time?

Response:

If the question is referring to the participation rate in TOU programs, FortisBC believes the most effective means to increase customer participation is education and the implementation of DSM programs designed to help customers take advantage of the pricing periods.

If the question is referring to the response (in terms of conservation) from customers that are on TOU rates, then the Company is of the opinion that promoting the use of “in-home” displays is the best way to enhance response. This is clearly articulated in the Navigant report in Exhibit B-1, Appendix C-1.

89.2 Does FortisBC agree that a delay in the adoption of technologies such as AMI that support conservation rate structures will contribute to delays in the adoption of conservation practices and the achievement of related benefits such as those above?

Response:

Yes. The availability of detailed and timely consumption data is a key component in maximizing the benefits associated with conservation measures. Delays in the availability of such information will lead to a delay in achieving those benefits.

90.0 Reference: Exhibit B-6, BCUC 1.109.1.2

The availability of a CPP option could be beneficial today in unusual contingency events.

90.1 What unusual contingency events would make the availability of a CPP option beneficial today and how frequently might each occur based on past experience or general utility experience?

Response:

There are certain contingencies such as the loss of multiple lines or unusually severe winter weather where supplies of electricity to customers remain available, but perhaps not as much as would normally be demanded. If this were to occur, any program or rate that served to smooth out or reduce customer load patterns might assist in maintaining reliable supplies without resorting to emergency measures such as public emergency conservation requests or even rolling blackouts.

It is generally assumed in utility planning that an outage due to inadequate electrical supply is acceptable to occur about once every ten years. The Company estimates that the transmission events would have a similar probability, therefore, on the balance of probability a contingency event that may lead to an outage but can potentially or partially be mitigated by reducing demand could be expected to occur once or twice every ten years. In most cases supply shortages would be short lived lasting only an hour or two, while transmission contingencies could last much longer.

90.2 What might be the impact in quantitative ($) terms of each of the possible contingency events as an average expected impact?

<u>Response:</u>

There would be no dollar savings associated with mitigating the transmission system contingencies described in the response to CEC IR No. 1 Q90.1. The impact would be improved service reliability in that some customers would continue to receive service when they would otherwise have had an outage.

However, in addition to the reliability benefits, the potential savings to power supply costs could be substantial if expensive market based power is not needed. At this time, the peak price of power that the Company is exposed to is around $1,000 per MWh. In the future, this number could be substantially higher. If a prolonged period of regional shortage occurs again such as occurred during the California crisis a little over ten years ago, total exposure could be very large and measured in the millions of dollars.

A more likely event would be a short-term shortfall related to cold weather where the Company could be spending $100,000 or more a day buying power on peak hours. This could potentially last for several days or even weeks. A reasonable cost estimate could therefore be $500,000 or more. This type of event would happen more frequently, perhaps 3 or 4 times in the ten year period.

91.0 Reference: Exhibit B-6, BCUC 1.109.1.2

> FortisBC is not forecasting very high critical peak period prices in its resource plan, but in the event that they occurred, the effect could be viably mitigated through a residential CPP rate structure.

91.1 What price would FortisBC consider as ‘very high critical peak period prices’?

<u>Response:</u>

FortisBC believes the correct reference to be BCUC 1.109.1.3.

The Company does not have a set price that if exceeded, it suddenly becomes a critical price. Much more important than the price on any one hour is the number of hours that a critical event may last. The current maximum rate the Company is exposed to is $1,000 per MWh. This would certainly be a critical peak price. However, if the event only lasts one hour, then the impact on the Company is about the same as an event that lasts five hours but only costs $200 per MWh.

91.2 Does FortisBC have a risk factor and/or trigger event identified by which the above very high critical peak period prices could occur?

Response:

FortisBC believes the correct reference is to BCUC 1.109.1.3.

Generally speaking, there are three main types of events that could cause concern:

1. Loss of generation or transmission that creates a severe shortage of regional power. This is what happened in Alberta over this past summer. It could also happen in the Pacific NorthWest in a very poor water year;

2. Load growth being much higher than anticipated in the regional long term Resource Planning. This would likely mean that reserve margins are being squeezed throughout the region and the most costly units set the price of power on a regular basis. The price may not reach extreme levels all the time, but as other events occur, there will be regular periods of extreme prices. However, even if no periods of extreme prices result, everyday high prices occurring repeatedly for years while new cheaper supplies are brought on-line could have a severe impact over time; and

3. The weather is extremely cold or hot.

The truly extreme events most likely only occur if two or more of these happen at the same time. For example, if load growth is suddenly much higher than anticipated for a few years, then a hotter than normal summer and a critical water year all occur at the same time, extreme prices for an extended period of time could result.

92.0 Reference: Exhibit B-1, Appendix C-1, Page 31 of 65 and Exhibit B-6, BCUC 1.110.2

Table 14: BC Hydro's Commercial and Industrial Elasticity Forecast Estimates lists estimates for elasticity of commercial and industrial customers used by BC Hydro in their 2006 and 2007 load forecast. C&I sectors have higher elasticities (-0.1 to -0.2) than the residential sector (roughly -0.05) which suggests C&I industries are more responsive to price changes. For example, during high price periods, industrial customers are more likely to shift demand to off-peak periods in order to reduce costs.

Table BCUC IR1 Q110.2a - Commercial

	Participation Rate	Per Participant Savings (Capacity) Incremental to RIB	Per Participant Savings (Energy) Incremental to RIB	2016 Power Purchase Savings ($000s)	2020 Power Purchase Savings ($000s)	2030 Power Purchase Savings ($000s)
TOU	20%	10.50%	3.60%	486	523	643
CPP	20%	9.50%	0.00%	63	84	164
PrePay	8%	5.30%	9.80%	369	386	431

92.1 Please explain why FortisBC has adopted the same participation rates for Commercial, Industrial and Wholesale customers as those for residential when commercial and industrial customers have been found to have higher elasticities than the residential sector?

Response:

FortisBC has adopted the same participation rates for Commercial, Industrial and Wholesale customers as those for residential customers because there is limited data available for non-residential customers. FortisBC agrees that the participation rates could be higher for customers with higher elasticity of demand for electricity and therefore increase the benefits of conservation rates.

93.0 Reference: Exhibit B-6, BCUC 1.111.4

> Yes, FortisBC considers that a significant uptake of electric vehicles could result in additional supply infrastructure necessary to support this un-forecast load growth. The potential impact is highly dependent on a number of factors:
>
> - The rate of customer uptake of electric vehicles;
> - The geographic distribution of customer adoption (i.e. are the vehicles clustered in specific areas of the FortisBC service area); and
> - Whether the vehicles are charged during on-peak or off-peak times.

93.1 Why did FortisBC not forecast the load growth associated with electric vehicles?

Response:

Please refer to the response to CEC IR No. 1 Q23.6.

93.2 Would FortisBC consider the BC Hydro forecast of electric vehicle requirements an adequate proxy as a forecast for the growth of electric vehicles? If not, why not?

Response:

Please refer to the response to CEC IR No. 1 Q23.6.2.

94.0 Reference: BCUC 1.111.1.4.1

> Technology available in today's electric vehicle charging stations allows for "economy charging" without the assistance of AMI networks. If customers purchase charging stations with Time-of-Use metering installed on the EV circuit, the charging station can be configured to charge only when the power rates are at their lowest. Economy charging requires no action, other than plugging in the electric vehicle. At least two vendors offer charging equipment with this functionality.

94.1 Please identify the types of customer benefits for economical charging of electric vehicles that would be available under the AMI program that would not be available by 'economy charging' without the assistance of AMI networks, if any.

Response:

Immediately after AMI implementation and the implementation of time-based rates (if applied for by FortisBC and approved by the Commission), an AMI system would allow electric vehicles to be charged at lower electricity rates during non-peak hours. AMI is required for this for the same reasons it is required for time-based rates generally (as described in Exhibit B-1, p31-32).

In the future, AMI could economically allow a separate vehicle tariff through sub-metering connected through the Zigbee HAN module. This type of sub-metering would reduce customer (and utility) costs associated with a separate tariff since it would not require the installation of a separate electrical service at the customer premise.

AMI could also provide "reverse-charging" signals to electric vehicle charging stations that would trigger (with customer permission) the vehicle battery to discharge into the electric system, providing energy to the utility at desirable times and offsetting customer electricity charges.

94.1.1 Please distinguish between advantages for residential customers and commercial fleet customers if applicable.

Response:

The first and third paragraphs in the response to CEC IR No. 1 Q94.1 describe benefits that would accrue to commercial fleet customers as well as residential customers.

95.0 Reference: Exhibit B-6, BCUC 1.116.1

> Direct contact with customers via a site visit to the premises is the most frequently-used form of contact for an account being disconnected for non-payment. The FortisBC process is to contact a customer either by hanging a 48-hour door tag at the premise or speaking to them via phone. FortisBC believes that these notifications, and the internal policy that requires at least two points of contact with the customer, provide adequate notification for making payments or arrangements. This policy is also compliant FortisBC Electric Tariff guidelines.

95.1 Please confirm FortisBC always has or tries to have direct contact with the customer either through a site visit or telephone call prior to disconnection.

Response:

Confirmed, FortisBC always attempts to contact the customer either through a site visit or via phone.

95.2 Does FortisBC consider leaving a voicemail as a point of contact with the customer?

Response:

Yes, if unable to speak directly to the customer, FortisBC considers leaving a voicemail as a point of contact. In this situation, a call back deadline is provided.

95.2.1 If so, would this be considered sufficient as one of the two points of contact required prior to disconnection for non-payment?

Response:

A voicemail is not considered sufficient. A site visit or direct telephone contact with the customer is considered sufficient.

96.0 Reference: Exhibit B-6, BCUC 1.117.1

> FortisBC is not aware of any states or provinces that allow opt-out for no fee.
>
> FortisBC understands that the following states and provinces permit electric utility customers to opt-out of a "smart meter" program for a fee:

96.1 Does FortisBC have a definition of opt out for each state or province on the list? If so, please provide.

Response:

FortisBC has found the following information:

Hydro Quebec

Individual customers will be able to opt out on request, but will have to pay an initial charge of $98 (before taxes) for installation of a non-RF meter and monthly charges of $17 (before taxes) for manual meter reading. These charges ensure that, as is usual in such cases, the costs of opting out are not passed on to other customers. The Régie de l'énergie has already recognized the principle that options exercised by individuals are paid for by those who request them.

http://media.hydroquebec.com/en/communiques/communique/hydro-quebec-terms-installation-meters-without-radio-frequency-emissions

Naperville, IL

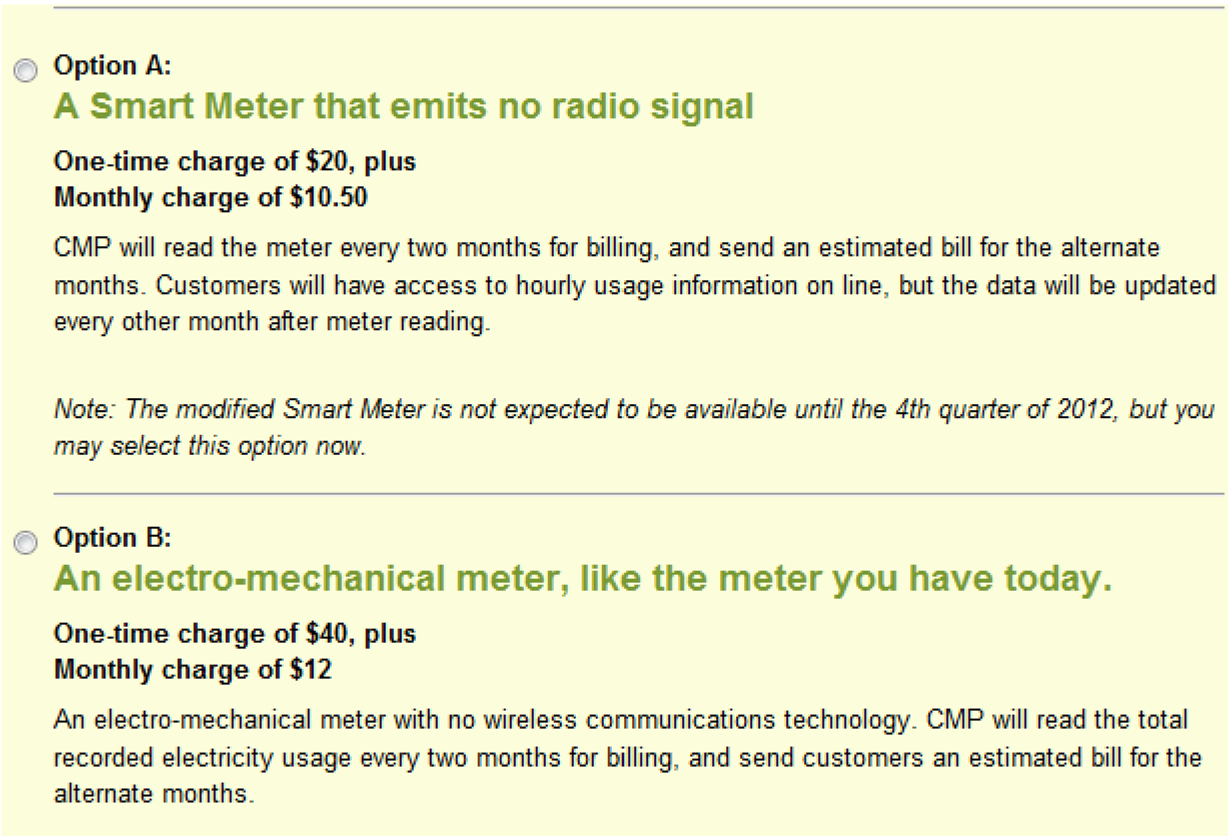
City Council has voted to permit residents to have a non-wireless option instead of a smart meter. It is not clear at this point if a non-RF digital meter will be acceptable or if an analog meter must be used. It appears that the per-read charge is $25 and the one-time fee is $68.

Vermont Utilities

Three Vermont utilities have filed opt-out programs with the Vermont Public Service Board, and some legislation is being considered to prevent opt-out fees until the utility reaches full deployment. The Vermont utilities have all delayed the implementation of their opt-out fees until at least April 2013.

Central Maine Power

The screenshot provided below is taken directly from the website for Central Maine Power.



Option A:

A Smart Meter that emits no radio signal

One-time charge of $20, plus
Monthly charge of $10.50

CMP will read the meter every two months for billing, and send an estimated bill for the alternate months. Customers will have access to hourly usage information on line, but the data will be updated every other month after meter reading.

Note: The modified Smart Meter is not expected to be available until the 4th quarter of 2012, but you may select this option now.

Option B:

An electro-mechanical meter, like the meter you have today.

One-time charge of $40, plus
Monthly charge of $12

An electro-mechanical meter with no wireless communications technology. CMP will read the total recorded electricity usage every two months for billing, and send customers an estimated bill for the alternate months.

Source: http://www.cmpco.com/smartmeter/smartmeteroptions.html

Nevada Energy

NV Energy asked the Public Utilities Commission of Nevada to let it charge a $98.75 one-time opt-out fee, plus a monthly charge of $7.61, in Southern Nevada. In Northern Nevada the one-time fee would be $107.66 and the monthly fee would be $11.01.

PG&E

The screen shot provided below is taken directly from the website for PG&E.

SmartMeter™ Opt-Out Program

At Pacific Gas and Electric (PG&E), we support offering our customers a choice when it comes to the meters at their home. We're happy to announce that the California Public Utilities Commission (CPUC) has approved analog mechanical meters as an alternative to the SmartMeter™ for our residential customers.

Please note, if you choose to opt-out, the following charges set by the CPUC will be added to your energy statement:

- An initial $75 setup charge, as well as a $10 ongoing monthly charge.
- Income-qualified customers pay an initial $10 setup charge, as well as a $5 ongoing monthly charge.

Please complete all fields in the form below to submit your SmartMeter™ Opt-Out preference. Fill out this form once per residence that you wish to opt-out of the SmartMeter™ Program.

Terms & Conditions

☐ * I agree that I am a named, authorized person on the customer account number entered above. Further, I am indicating that I want to opt-out of the SmartMeter™ program, am opting for the analog mechanical meter alternative, and am aware of the initial setup and ongoing monthly charges, which will be added to my energy statement. By opting out, I understand that all SmartMeter™-enabled services, including Energy Alerts and special rate program SmartRate™, among others, will no longer be available to me, and I thus agree to forfeit these services and benefits.

http://www.pge.com/myhome/customerservice/smartmeter/optout/

96.2 Please identify the fees that are being charged for individuals to opt-out of the smart meter programs identified in the list.

Response:

Please refer to the response to CEC IR No. 1 Q96.1.

96.3 Does FortisBC believe that the fees being charged to opt-out would be likely be sufficient to cover the expenses incurred and/or the foregone benefits caused by the opt-out? Please explain.

Response:

FortisBC cannot speculate whether the fees being charged to opt-out for the various jurisdictions identified are sufficient to cover the expenses incurred and/or the foregone benefits that result (with the exception of Quebec, where the Régie de l'énergie has recognized the principle that options exercised by individuals are paid for by those who request them).

Please also see the response to CEC IR No. 1 Q50.3.

97.0 Reference: Exhibit B-6, Appendix and BCUC IR 1.22.1 and Exhibit B-6, BCUC 1.22.2

11 FortisBC does not propose to charge customers to change their billing date.

A customer-selected due date was the clear favorite among these options, with 47 percent of respondents saying they were "somewhat interested" or "very interested" in participating (**Figure 1**). The popularity of this program indicates that it may be another weapon in the utility arsenal against low customer satisfaction scores.

97.1 Is FortisBC intending to implement customer-selected due dates, and if so, when?

Response:

Yes, FortisBC intends to allow customers the option of choosing a flexible billing date. This option will be provided for no additional cost upon full implementation of the AMI system in 2015.

1. Does FortisBC believe that the traditional utility business model (selling more electricity to generate more profit) provides enough incentive to discourage wasteful electricity use?

Response:

FortisBC notes that the question posed is based on a fundamental misunderstanding of the current regulatory construct in British Columbia. For clarity, FortisBC's earned return (or profit) is not a function of the sale of electricity to customers, but rather a function of the Company's investment in the utility.

As approved by Order G-58-06, the Company has a deemed capital structure of 60 percent debt and 40 percent equity, with an allowed Return on Equity of 9.9 percent approved pursuant to Order G-162-09. FortisBC is required to ensure a reasonable standard of service to customers, as determined by the Commission, and is permitted to earn an approved return on the equity it invests in the utility. These investments include expenditures incurred as part of FortisBC's PowerSense programs which ultimately serve to reduce customers' electricity use. In this way, demand-side management programs provide the same return on equity as supply-side investments.

Therefore, in the current regulatory construct, increases and decreases in electricity sales affect customer rates, but do not affect Company profit.

The implementation of AMI will allow the Company to provide customers with more detailed information about their electrical consumption (through the customer information portal, or optional in-home displays), as well as support the development of additional time-based conservation rate structures. These enhanced benefits are expected to allow the utility to create conservation rates that incent conservation, while at the same time providing customers with better information to manage their electric usage and the associated costs.

2. How does FortisBC reconcile the financial objective to provide shareholder dividends with the objective of saving energy through customer energy efficiency programs?

Response:

Please refer to the response to the NCGP IR No. 1 Q1.

3. What percentage of its annual electricity needs has FortisBC had to purchase from other utilities for the years 2007 to 2011?

Response:

FortisBC buys electricity from a variety of sources including other utilities. The percentage of annual energy load supplied by purchased energy is shown in the table below:

Table NCGP IR1 Q3

Year	**2007**	**2008**	**2009**	**2010**	**2011**
Percent Purchased	56%	53%	54%	54%	56%

4. What is the annual cost of electricity FortisBC purchased from other utilities for the years 2007 to 2011?

Response:

FortisBC buys electricity from a variety of sources including other utilities. The cost of purchased energy is shown in the table below:

Table NCGP IR1 Q4

	2007	**2008**	**2009**	**2010**	**2011**
Cost of purchased electricity ($000s)	66,629	66,010	70,776	71,964	71,519

5. Please list the residential customer information and behaviour energy efficiency programs initiated by FortisBC during the years 2007 to 2011.

Response:

FortisBC provides energy efficiency information through a variety of channels to reach its customers, including website and on-bill tips, periodic PowerLines newsletters and program specific billing inserts, booths at regional home shows, conservation ambassadors at community events, providing speakers at local events and conferences, and media purchases (primarily radio and print).

Behavioural measures include product giveaways (retractable clotheslines, CFLs, low-flow showerheads) including energy-saving kits for low-income customers. The clotheslines were tied to the EnergyStar appliance program, which won the Natural Resources Canada Regional Utility award.

Such measures frequently include “prompts” such as dryer magnets (to suggest using the clothesline, if weather is appropriate) and shower timers.

Community-based social marketing (CBSM) is a key stone of education/behaviour-change programming, as was demonstrated in the Rossland Energy Diet pilot. CBSM was also the basis for the Earth Hour promotion, which offered an energy retrofit for a community building for the community with the most per capita pledges.

6. Please list the business and industrial customer information and behaviour energy efficiency programs initiated by FortisBC during the years 2007 to 2011.

Response:

In addition to the information channels referred to in NCGP IR No. 1 Q5, PowerSense provides sponsorships (and expert subject matter speakers) to industry conferences, which often include a trade booth and networking opportunities. PowerSense has also funded Natural Resources Canada information and training workshops like “Spot the Savings” and “Dollar to Sense Energy Management” and hosted energy efficiency, solar hot water and other workshops and provided grants for trades training courses.

To assist institutional and larger commercial customers create internal “green teams” and employee education, PowerSense has provided funding and collateral materials.

Over the past 15-plus years PowerSense has hosted its annual Conservation Awards to publicly recognize and honour community leaders, consisting of both trade allies and customers undertaking larger (>100 MWh) energy conservation projects. The Conservation Awards events are augmented by significant public relations and advertising campaigns, including case studies on the FortisBC website and in the PowerLines newsletter, to pay tribute to the recipients and promote the energy efficiency measures undertaken.

In 2012 the Awards function was expanded into a full day energy efficiency and conservation forum to help propagate program information and promote energy efficiency.

7. What were the annual expenditures made by FortisBC to encourage residential customer energy efficiency and conservation measures for the years 2007 to 2011? Please provide as overall total spending and as an amount per residential customer.

Response:

Please refer to the table below.

Year	Customer Count*	Program costs ($000's)	Unit Costs ($/cust)
2007	134,804	$1,303	$9.67
2008	137,875	$1,236	$8.96
2009	139,830	$1,624	$11.61
2010	141,471	$1,838	$12.99
2011	142,780	$1,700	$11.91

* includes indirect custs served by wholesalers

8. What were the annual expenditures made by FortisBC to encourage business and industrial customer energy efficiency and conservation measures for the years 2007 to 2011? Please provide as overall total spending and as an amount per business and industrial customer.

Response:

Please refer to the table below.

Table NCGP IR1 Q8

Year	Customer Count*	Program cost ($000's)	Unit Costs ($/cust)
2007	19,254	$739	38.38
2008	19,653	$881	44.85
2009	19,467	$1,060	54.47
2010	19,541	$1,123	57.48
2011	19,694	$2,832	143.82

* includes indirect custs served by wholesalers

9. If smart meters are being rolled out to allow households to gain full control over their electricity consumption, why does FortisBC want to charge customers for an in-home monitoring device?

Response:

FortisBC does not intend to charge customers for an in-home display (IHD). The Company does intend to provide an incentive for customers to purchase an IHD.

If customers do not wish to make an investment in an IHD, they will be able to use the AMI customer information portal functionality at no cost to customers with internet access, whether at home or through a public library etc.

Please refer to the response to CEC IR No. 1 Q33.1 in regards to IHDs.

10. Is FortisBC aware that pilot programs indicate that real-time feedback combined with useful details on energy use tends to generate the highest level of customer savings?

Response:

Yes, please refer to the response to BCSEA IR No. 1 Q43.3 for the Company's AMI/IHD engagement programs.

11. Please provide a list of references that FortisBC has consulted to learn about the public health and cancer impacts of wireless technologies with regard to smart meters.

Response:

Please see the list of references regarding EMF and health on the project website at http://www.fortisbc.com/About/ProjectsPlanning/ElecUtility/ProjectsInYourCommunity/AdvancedMeteringInfrastructure/Pages/FAQs-and-other-information.aspx .

The references used in the Exponent report on Status of Research on Radiofrequency Exposure and Health in Relation to Advanced Metering Infrastructure are detailed starting on page 31 of Exhibit B-1, Appendix C-5.

12. Do any of the references consulted in question 11 include research by Cindy Sage and David O. Carpenter?

Response:

FortisBC believes that neither Ms. Sage nor Dr. Carpenter have published any original, peer-reviewed, health research studies of radiofrequency fields. Both have offered opinions on published health research studies of radiofrequency fields in documents posted to the internet and some published reviews of research. Exponent scientists have reviewed and considered these opinions.

13. Is FortisBC aware that hard-wired smart meters are being used in Idaho, Vermont, and Italy?

Response:

FortisBC is aware that hard-wired advanced meters are being used in Idaho and Italy. In Vermont, the Washington Electric Cooperative, which services 10,500 members in 41 towns in north-central Vermont, uses wired technology. The state's two largest utilities, Central Vermont Public Service and Green Mountain Power, have both opted for wireless smart meters.

14. Is FortisBC aware that the state of Idaho chose hard-wired smart meters because they were cheaper?

Response:

The state of Idaho did not choose hard-wired meters. There is no mandate from the Idaho Public Utilities Commission with respect to technology choice. The Idaho Power Company has installed a wired solution, whereas Idaho Falls Power has implemented a wireless test system.

FortisBC assumes that the wired system used by Idaho Power Corporation and the wireless system used by Idaho Falls Power represent the best functional and economic fit for each utility's circumstances.

15. Please clarify the FortisBC policy with regard to time-of-use rates for customers. Is the utility in favour of them, or not? Does FortisBC intend to utilize such a rate structure after the installation of smart meters?

Response:

FortisBC has not yet decided whether to apply for time-based rates. If it did, it would likely recommend that they be a voluntary alternative to the default rate structures.

Fortis Document Titled B-1

1.1 Overview of the Project

Line 6 & 7 on Page 6 say the AMI system is primarily driven by the opportunity to efficiently manage electrical usage and costs for the benefit of the customer as well as the company.

Although buildings and their energy use are designed with Regional Climatic Data supplied through BC Building Code, buildings as well as their energy use are signed off as compliant with BC Building Code without verification. The AMI system is not catching the heat loss and associated energy consumption with heat loss from buildings. Here are residential, commercial buildings, schools, etc in the infrared spectrum in Fortis's area wasting energy and producing more GHG. http://www.thermoguy.com/blog/index.php?itemid=105

Solar radiation is causing buildings to grossly exceed BC Building Code in the summer and thousands of watts per hour per building is wasted reacting to the symptoms of solar radiation. Air conditioning is in fact refrigeration requiring a big electrical load responding to the exterior being radiated. Here is the rule and not the exception of building performance in Fortis's area as well as others. http://www.thermoguy.com/blog/index.php?itemid=88. The AMI system is not addressing this massive energy waste. Shade or low e finishes would.

1.3 Proposed Regulatory Process

Compliance with Safety Code 6 is a requirement of the AMI technology and the technology does not comply with Safety Code 6.

Safety Code 6 is the same science standards as the FCC and other international organizations but admits mechanisms were missing linking the frequancies to adverse health effects. Stimulation of tissue is to be avoided as is the heat effect. Stimulation of tissue is limited to medical imaging in controlled environments with an intended position of use and protective clothing to attenuate(eliminate) the frequencies from hitting other parts of the body.

The missing mechanisms were reported to Health Canada and by expert witness through Canadian Parliament's Standing Committee October 26th of 2010. Health Canada uses the Specific Absorption Rate which admits energy is being absorbed, the meters were only considered as an end use device. The rest of the wireless infrastructure wasn't considered in a radiation equation as the frequencies hit people from head to toe. Humans were considered to be tissue heating and not vulnerable intricate electrical systems with their own electricity. As a result millions or billions of frequencies of biological systems were left out of a frequency equation.

January, 2011 the dangers of the frequencies were lectured in medical academia for education credits required for medical licensing and applicable in North America.

Fortis has a 60 Hz electrical grid to communicate with 60 Hz appliances or the appliances wouldn't run safely or efficiently. 900 Mhz of the AMI system isn't compatible with an 8 Hz brain wave.

1. What is the geographical area coverage of each AMI wireless component in the AMI system including cell tower antennas and satellites?

Response:

The RF coverage area of each technology used in the proposed AMI project is a function of the terrain and foliage. The following rough numbers are used as general guidelines for the typical maximum coverage radius around the device:

- RF LAN meters, repeaters and collectors - ~ 1 km;
- WiMAX Base Stations – 10-15 kms;
- Cellular – Please see third party cellular service provider coverage maps;
- Satellite – Very little geographic coverage, antenna is narrow beam width and pointed into the sky.

The information requests provided by WKCC contain a number of statements and inaccuracies with which FortisBC does not agree. In particular, FortisBC notes a statement at the end of the WKCC information request set that asserts *"The frequencies associated with AMI are illegal as applied."* The Company does not agree with this statement and believes that the AMI project will be compliant with the applicable legal framework.

2. What are the attenuation co-efficients and frequencies of biology hit by the AMI equipment in the coverage areas?

Response:

Attenuation coefficients depend greatly on the tissue and its thickness. A good approximation is that the majority of the signal incident on a human body is either reflected away from the body or attenuated inside it, with only a minor fraction passing through it.

3. What are the attenuation co-efficients of building materials and are the frequencies going inside buildings?

Response:

The attenuation of signal depends on the building material type and material thicknesses (which vary considerably). There are several sources available: e.g., Holloway et al. (2008) http://www.eeel.nist.gov/kate_papers/R12_TN1545.pdf

4. The frequencies going through structures and fire separations are causing the building materials at molecular levels to vibrate 180 degrees at twice the speed of the frequencies. How is the AMI program addressing high speed vibrations of structural components and fire separations at billions of times per second?

Response:

BC Building Code 4.1.3.6 deals with physical vibrations, not photon oscillations of electromagnetic nature. Smart meters use RF radios and generally communicate for less than one minute per day. This type of radio is the same kind of radio that a number of everyday devices use, including cordless phones and baby monitors. Radio frequency will not cause any physical vibrations that would cause structural system issues.

5. Doesn't that compromise Part 4 of BC Building Code under Vibration?

Response:

No. Please refer to the response to WKCC IR No. 1 Q4.

6. How have the biological considerations of bees, birds and pollinators been considered in the AMI program? Bees and birds use a magnetic field, not a high speed electromagnetic field.

Response:

Birds and bees are widely reported to 'sense' the earth's static geomagnetic field or man-made sources of static magnetic fields. Exponent is not aware of a body of scientific evidence that confirms any adverse effect of RF fields on bees or birds at the frequencies and intensities of RF fields produced by the FortisBC advanced meters.

7. BC Medical Plan puts in pacemakers and tells the recipients to stay out of electromagnetic fields. The AMI program is taking the EMF to the recipients where the pacemaker will be electromagnetically induced.

Response:

FortisBC was able to locate a document entitled *Care of Your Child with a Pacemaker* from the BC Children's Hospital, which is an agency of the Provincial Health Services Authority (http://www.cw.bc.ca/library/pdf/pamphlets/Pacemaker_392_mar06.pdf). That document states, with respect to Environmental/Hospital Hazards:

> *Your child can be safely exposed to most household appliances and tools that are in good repair and are properly grounded, including:*
>
> - *Microwave ovens*
> - *TVs, AM/FM radios, VCRs, remote controls*
> - *Personal computers, printers, fax machines*
> - *Hand-held appliances: hair dryers, shavers (avoid holding against implant site)*
> - *Electric blankets, heating pads*
> - *Cellular phones if kept at least 6 inches away from the pacemaker site*

Since AMI meters emit less EMF than TV and radio (please refer to Exhibit B-1, Appendix C-5, p45) and emit far less EMF than permitted by the relevant standard, Health Canada Safety Code 6 (Exhibit B-1, Appendix C-5, Appendix A, Table 1 and Table 2), FortisBC concludes the proposed AMI system is safe generally and safe with respect to pacemakers.

8. How many frequencies are there with all human biological systems.

Response:

The number of individual frequencies emitted from the human body or other biological organisms is not readily available but the range of frequencies would extend from 0 Hz to several THz (10^{12} Hz).

9. Were the AMI meters and associated equipment tested for accuracy in a full load electromagnetic field?

Response:

AMI meters are approved for accuracy per Measurement Canada testing requirements. These testing requirements do not require or prohibit the presence of an electromagnetic field. Electromagnetic fields are present everywhere at all times, so all equipment is tested in an environment with electromagnetic fields. FortisBC can confirm that the proposed AMI meters are tested by the vendor with consideration for electromagnetic exposure as per ANSI C12.1, section 4.7.3.12.1.

10. With all the energy waste not being caught or addressed, how is this meeting GHG reduction targets?

Response:

FortisBC has made no claims with respect to energy waste, although the Company agrees that the energy conservation capabilities introduced by AMI could reduce GHG emission related to electricity generation (but notes that very little FortisBC electricity is purchased from GHG-emitting generation sources).

FortisBC has identified the GHG emissions associated with the current meter reading methodology in Exhibit B-1, Executive Summary, p2, and provided an estimate of the annual amount of GHGs to be concretely eliminated in the responses to CEC IR No. 1 Q25.1 and BCSEA IR No. 1 Q48.1.

11. Blasting frequencies over large areas will induce charges in volatile areas, how can Fortis ensure there won't be a static charge setting off explosions or starting fires?

<u>Response:</u>

The proposed AMI system will not "blast frequencies over large areas" or "induce charges in volatile areas". There are millions of devices throughout the world transmitting at the same frequencies and power levels as the AMI system, and the related EMF emissions do not set off explosions and start fires.