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July 26, 2012

Via Email
Original via Courier

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. Application for a Certificate of Public Convenience and Necessity for the Advanced Metering Infrastructure Project

FortisBC Inc. attaches its application for a Certificate of Public Convenience and Necessity for the Advanced Metering Infrastructure Project. Twelve hard copies will be couriered to the BC Utilities Commission.

If further information is required, please contact the undersigned at (250) 717- 0890.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

cc: Registered Intervenors - 2012-13 Revenue Requirements Application

FORTISBC INC.

An Application for a Certificate of Public Convenience and Necessity

Advanced Metering Infrastructure (AMI) Project

July 26, 2012

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Glossary of Terms

1) **Advanced meter:** means a meter that contains a device that receives, records, displays and transmits data and provides other advanced utility functions
2) **AMI:** means Advanced Metering Infrastructure
3) **AMI system:** means a collection of hardware, software and communications systems that enable remote two-way communications and control with meters and allow for data storage and retrieval
4) **Backhaul:** means the transmission of data over an alternative route to prevent disruptions in data delivery when the normal route is unavailable or overtaxed
5) **BCUC:** means the British Columbia Utilities Commission and is also referred to as the "Commission"
6) **Bi-directional meters:** means meters that record the flow of energy in two directions. Used to meter generated and delivered power
7) **BPL:** means Broadband Over Powerline, a higher-bandwidth version of PLC
8) **Collector**: means the field device which aggregates data from multiple meters and other endpoint devices, and interfaces them, via the WAN to the HES
9) **Commission:** means the British Columbia Utilities Commission and is also referred to as the "BCUC"
10) **CPCN:** means a Certificate of Public Convenience and Necessity
11) **CPP:** means Critical Peak Pricing
12) **CVR**: means Conservation Voltage Reduction
13) **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
14) **Data Collector**: means a communications device that acts as a relay between the Local Area Network (LAN) and the Wide Area Network (WAN) backhaul
15) **DSM:** means Demand Side Management and refers to the PowerSense program in place at FortisBC which helps customers manage their electricity consumption through energy efficiency improvements
16) **Feeder Meters:** means an end device that registers bi-directional, energy flow, at a point on the distribution system feeder
17) **FortisBC Service Territory:** means the geographical area in which FortisBC has active customers
18) **GIS:** means FortisBC's Geographic Information System
19) **HAN:** means Home Area Network
20) **HES:** means Head End System and is the AMI System component that manages the customer meters and other endpoint devices
21) **IHD:** means In-Home Display or In-Home Device
22) **IT:** means Information Technology
23) **LAN:** means Local Area Network communication of the AMI system and is the secure two way communication of the Meter Modules with other Meter Modules or directly with the Collectors
24) **Line Loss:** means electric energy lost because of the transmission and distribution of electricity
25) **MDMS:** means Meter Data Management system and is the component with the AMI System that manages data transmitted from the meter
26) **Mesh Network:** means an AMI system in which each endpoint also may serve as a repeater, forwarding signals from other

endpoints to a collector**.** This capability of an AMI System enables reliable transmission of data even when the prime path is temporary unavailable

27) **MV-90:** Is a meter data collection, management and analysis application used to gather interval data from commercial and industrial (C&I) metering devices
28) **MV-RS:** is a PC-based meter reading software system for data collection and route management
29) **Off-Peak:** means periods of relatively low electrical system demand
30) **Outage:** The period during which a generating unit, transmission line, or other electrical system facility is out of service
31) **Peak:** means the period of highest system demand
32) **PLC:** means power line carrier. PLC is a fixed network communication system that provides similar, though less, data communication capabilities to that of a RF System
33) **PHEV:** means Plug-In Hybrid Electric Vehicle which is a hybrid vehicle with rechargeable batteries that can be restored to full charge by connecting a plug to an external electric power source
34) **RFP:** means Request for Proposal
35) **RF System:** means Radio Frequency System. This type of AMI communications system utilizes radio waves to transmit data to/from meters and the utility
36) **SCADA:** means Supervisory Control and Data Acquisition system
37) **Self-Healing:** refers to RF AMI System's capability to automatically discover alternate communications paths between the meters and utility in order to ensure reliable data transfer. (see Mesh Network, above)
38) **Use Cases:** are documents developed to identify, clarify and organize system and business requirements for an MDMS and AMI Technology
39) **VEE:** means Validation, Editing and Estimation
40) **VVO:** means Volt/VAR Optimization
41) **WAN:** means Wide Area Network and is a secure two-way telecommunications network between the collectors and the HES

EXECUTIVE SUMMARY

Developments in technology enable utilities to deliver electricity more efficiently and reliably to customers. These technologies are providing both utilities and their customers with better tools to more efficiently manage electricity usage and the associated costs. FortisBC's proposed AMI Project (the Project) is a key element in facilitating an improved ability to manage the cost of electricity, and will provide immediate benefits as described below, as well as support for the future development and implementation of conservation rates.

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.

Based on both the financial and non-financial benefits, FortisBC believes the transition to advanced meters, as the standard form of metering technology, to be in the public interest. Accordingly, and pursuant to sections 45 and 46 of the *Utilities Commission Act* (the Act or the UCA), FortisBC Inc. (FortisBC or the Company) applies (the Application) to the British Columbia Utilities Commission (BCUC or the Commission) for a Certificate of Public Convenience and Necessity (CPCN) to develop and deploy its Advanced Metering Infrastructure (AMI) Project at an estimated capital cost of $47.7 million.

MORE RATE OPTIONS AND INFORMATION BECOME AVAILABLE TO CUSTOMERS

Although no rate structure changes are proposed as part of this Application, the AMI Project will allow FortisBC to begin development of optional time-based rate structures to offer to customers, , subject to future Commission approval, as an alternative to consumption-based rate structures such as the default Residential Inclining Block (RIB) rate.

More detailed electricity use information will be made available to customers through the FortisBC website as well as through optional in-home displays (IHDs), helping customers to better understand their bills and manage their consumption.

AMI REDUCES METER READING RISKS AND GREEN HOUSE GAS EMISSIONS

The manual meter reading process carries several inherent safety risks due to exposure to vehicle incidents, animals, and hazardous weather conditions. The AMI Project will virtually eliminate the requirement for manual meter reading, decreasing the exposure to these risks while contributing to improvements in public and employee safety.

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.

AMI HELPS PREVENT ELECTRICITY THEFT

FortisBC estimates that electricity theft is costing customers approximately $3.7 million annually in lost revenues (based on the 2012 residential rate). FortisBC currently employs a revenue protection program that relies primarily on tips provided to the Company about suspected theft. However, the current lack of system visibility between distribution stations and the point of delivery to the customer presents a challenge in comprehensively identifying and addressing all instances of theft. It is expected that the implementation of AMI will help to both deter theft, as well as provide an improved ability to identify and recover lost revenues where theft is occurring. This will help to mitigate rates for all customers. In addition to the economic concerns associated with electricity theft, there are often safety risks created for FortisBC employees, first responders, and the public from improper electric wiring and other hazards that will be lessened as the occurrence of theft is reduced.

AMI PROVIDES IMMEDIATE NOTIFICATION OF POWER OUTAGES

The AMI Project will provide FortisBC with faster and more geographically precise power outage information that will allow FortisBC to more effectively respond to unplanned power outages and help ensure that all customers have their power restored in a timely manner.

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.

CUSTOMER CONSUMPTION DATA WILL REMAIN SECURE AND PRIVATE

FortisBC respects customer privacy and seeks to protect their personal information. The requirement for security of information within all elements of the AMI system is a key consideration throughout design, procurement and implementation of the Project. FortisBC's AMI system will follow the security specifications set out by AMI-SEC, which is a North American AMI task force responsible for developing security guidelines, recommendations, and best practices for AMI system elements. As well, FortisBC intends to conduct security audits during both the AMI implementation and routinely thereafter to confirm that the AMI system continuously meets or exceeds the security standards set forth by AMI-SEC.

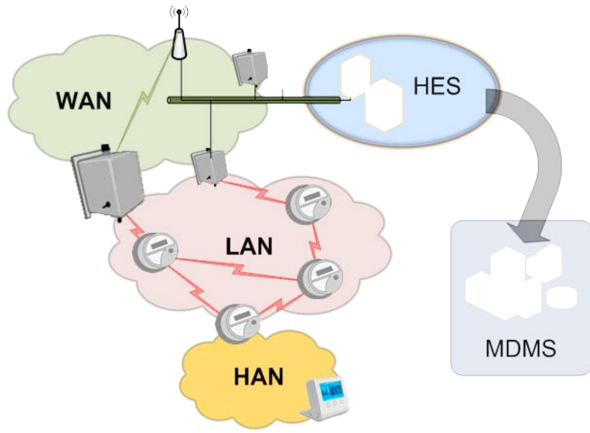
The collection and use of metering data obtained via the AMI system will comply with the *Personal Information Protection Act* and the federal *Personal Information Protection and Electronic Documents Act*, as applicable. FortisBC's privacy policy is further discussed in Section 8.4.4.

CUSTOMER HEALTH CONCERNS

FortisBC is aware that some customers have concerns regarding potential health issues associated with the proposed Project. The Company acknowledges these concerns, however it is important to note that FortisBC's proposed AMI solution is safe and secure, and complies with Health Canada's Safety Code 6 limit of 0.6 mW/cm^2. Further discussion of this customer concern is provided in Section 8.4.

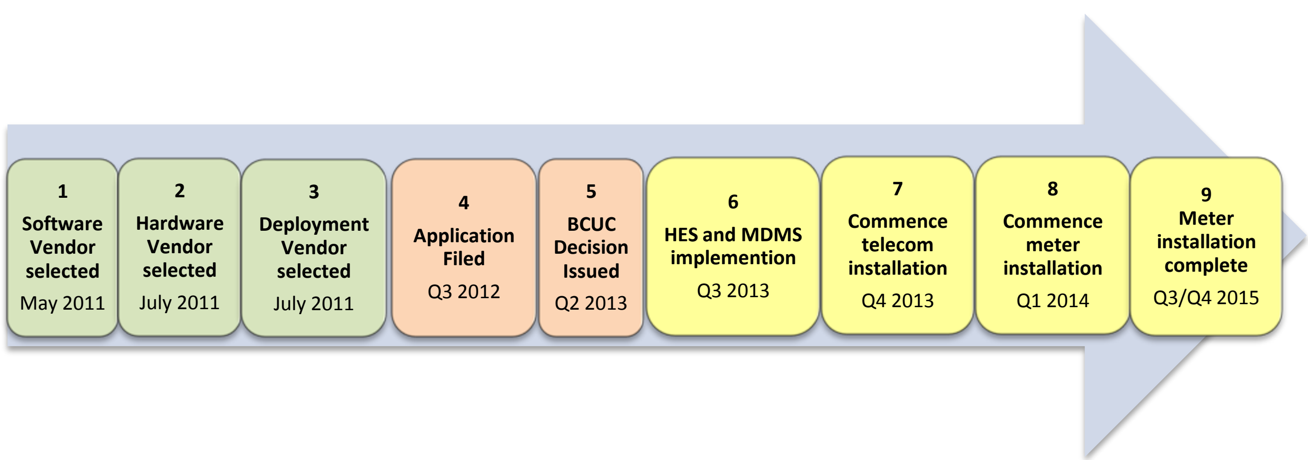
Description of the FortisBC Advanced Metering Infrastructure Project

The AMI technology chosen consists of several inter-related networks and systems starting at the customer premises and extending to the utility. The meters record consumption hourly and communicate with each other and to a collector using radio frequency (RF) technology. Together, the meters and the collectors form the local area network (LAN). The collector aggregates the meter data traffic and forwards it to the utility, constituting the wide area network (WAN). At the utility, the meter data is collected by the Head End System (HES) and sent to the Meter Data Management System (MDMS) where it is made available to FortisBC computer systems as required. Customers can also choose to enable a home-area network (HAN), which allows additional optional features such as the use of an IHD for viewing near real-time information on electricity usage and rates.



The AMI Project began in 2006, with the Company filing an AMI CPCN application in December 2007. The application was rejected in November 2008 with the Commission directing the Company to conduct additional work on developing a proposal for the implementation of AMI. This topic is further discussed in Section 1.4 below.

Based on the *Clean Energy Act* and the direction received from the Commission to conduct additional work on developing an AMI proposal, as well as the transition by numerous utilities across North America to advanced metering as the standard metering technology, FortisBC believes it has been prudent in incurring the development costs associated with the AMI Project. Upon completion in 2015, the Project, inclusive of planning, procurement, design, deployment and acceptance, will have encompassed nine years. The following graphic illustrates the high level milestones for the proposed AMI implementation.



Following an RFP process involving multiple vendors, FortisBC selected Itron Canada as the vendor for the MDMS, meters, and communications devices, and to manage both the communications network and meter deployment (Items 1, 2 and 3). BC Hydro has also selected Itron Canada as the vendor for its AMI system. Further discussion of the RFP process is provided in Section 4.2.

The Project milestones described within this Application presume a BCUC decision regarding the CPCN application by the second quarter of 2013 (Item 5).

During 2013 the Company plans to focus on building and testing the software components of the AMI Project, inclusive of integration with existing FortisBC systems. This work is anticipated to proceed into 2014 (Item 6).

Deployment of the communications network is expected to commence in late 2013 and meters in early 2014 (Items 7 and 8). Field and acceptance testing, and final Project completion will take two years (Item 9), with an expected completion date in 2015.

In addition to the various non-financial benefits discussed above, financial analysis of the Project, as evaluated over a 20 year period, shows that rates will be lower than they would be without the AMI Project, due primarily to cost savings from reduced electricity theft and a reduction in manual meter reading costs. It is expected that advanced metering will provide a rate decrease of approximately 1 percent over the life of the Project, saving customers approximately $19 million on a net present value basis using an 8 percent discount rate. In summary, FortisBC believes that the Application demonstrates that the AMI Project is in the public interest and asks that a CPCN be granted to the Company for the Project.

1.0 THE APPLICATION

FortisBC hereby applies to the BCUC, pursuant to sections 45 and 46 of the UCA, for a CPCN for the AMI Project at an estimated cost of $47.7 million, including the cost of salvage.

1.1 Overview of the Project

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. As discussed below, the existing manual metering infrastructure system provides limited one-way information that is costly to collect. This limitation inhibits customers from making more informed decisions about electricity consumption. The near real time two-way communication capability afforded by AMI will remove this limitation, allowing FortisBC to read meters more frequently and efficiently on a cost effective basis.

The Project enables FortisBC to continue to deliver safe and reliable electricity while improving the quality and timeliness of information gathered from, and provided to, customers. This improved availability of consumption information will allow customers to make better informed decisions, and will help to increase their ability to manage the cost of electricity through conservation and more efficient use of energy.

The Project will also improve the Company's ability to manage the cost of electricity, including recovery and deterrence of a portion of the estimated $3.7 million in annual lost revenue due to electricity theft as further discussed in Section 5.3.2 below. As well, the operational data provided by the AMI system will assist FortisBC in making future system operation and enhancement decisions that will increase the efficiency of service provided to customers, including an improved ability to address outages experienced by customers.

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 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.

1.2 Order Requested

Pursuant to sections 45 and 46 of the UCA, FortisBC applies to the BCUC for an Order issuing a CPCN to develop and deploy the AMI Project as more fully described in this Application. Additionally, pursuant to Section 56 of the UCA, the Company requests approval for a revised depreciation rate for the proposed meters to be installed as part of the AMI Project. FortisBC proposes that the revised depreciation rate of 5 percent would apply to the AMI meters until the next depreciation study is completed. A draft Order is included as Appendix A to this Application.

1.3 Proposed Regulatory Process

FortisBC proposes that the Application be reviewed by way of a hybrid written/oral hearing process as further detailed below. As discussed in the Application, the need for the Project is driven by the improved ability it affords both customers and the Company to manage the cost of electricity. This ability is primarily enabled by a reduction in operating costs for collecting metered consumption information, the provision of improved consumption information (timing and amount) to customers, as well as the detection and deterrence of electricity theft. FortisBC believes that a written hearing component offers the most effective means of examining the technical and financial details of the justifications for the proposed implementation of AMI as presented in the Application.

With respect to proposed oral hearing phase, extensive public consultation conducted by FortisBC regarding the Project has revealed the following primary concerns that the Company believes should be addressed through an oral hearing process:

- Health – some stakeholders have expressed concerns regarding the health effects associated with a wireless RF AMI network. FortisBC submits that the proposed AMI technology complies with Health Canada’s Safety Code 6 as further detailed in Section 8.4.2. As such, FortisBC submits that its proposed AMI Project does not present any risk to customers’ health or safety.

- Security - some stakeholders have expressed concerns regarding the security of the AMI system, with a particular concern expressed that their personal information could be intercepted as a result of the Company's decision to implement a wireless AMI system. FortisBC considers the security of customer information a fundamental priority, and has ensured that the requirement for security of information collected by the AMI system is a key consideration throughout the design, procurement and implementation phases of the Project. As further detailed in Section 8.4.3, the AMI system is designed to maintain the security of customer data. FortisBC submits that its proposed AMI Project does not present a risk to the security of customer data.
- Privacy – some stakeholders have expressed concerns regarding privacy in relation to AMI, and have specifically identified a concern that AMI would allow the utility to know when customers were home, or when certain appliances were being used. The AMI system cannot collect personal information about the source of electricity consumption within a premises; it can only collect aggregate electricity consumption data for the entire premises at any given time. FortisBC respects customer privacy and seeks to ensure the protection of any personal information collected by the Company. As detailed further in Section 8.4.4, FortisBC has revised its Privacy Policy such that it will apply to all personal information collected by FortisBC, some of which will be collected using the advanced metering system. FortisBC submits that its proposed AMI Project does not present any risk to customer privacy.

FortisBC believes that an oral hearing component would provide an opportunity for a full discussion surrounding these issues. FortisBC proposes that the discussion of these issues be further augmented by the inclusion of three Commission-led public input sessions as part of the oral phase. It is anticipated that these sessions will allow Registered Interveners and/or Interested Parties an opportunity to informally express their opinions regarding the Project before the Commission. As noted below, FortisBC has proposed three public input sessions, scheduled in Trail, Osoyoos, and Kelowna, B.C.

FortisBC requires a BCUC decision on the proposed Project by July 20, 2013 in order to maintain firm contract pricing on the proposed AMI system as has been negotiated with the AMI vendor. With this consideration, the Company proposes the following regulatory timetable for review of the Application:

Application Filed	July 26, 2012
Registration of Interveners	August 29, 2012
BCUC and Intervener Information Request (IR) No. 1	September 14, 2012
FortisBC Response to BCUC and Intervener IR No. 1	October 12, 2012
BCUC and Intervener IR No. 2	October 19, 2012
FortisBC Response to BCUC and Intervener IR No. 2	November 16, 2012
Intervener Filed Evidence	November 23, 2012
Procedural Conference	November 29, 2012
Information Requests on Intervener Filed Evidence	November 30, 2012
Intervener Responses to IRs on Submitted Evidence	December 21, 2012
Public Input Session No. 1 – Trail (evening)	January 18, 2013
Oral Hearing Commences in Kelowna	January 21, 2013
Public Input Session No. 2 – Osoyoos (evening)	January 21, 2013
Public Input Session No. 3 – Kelowna (evening)	January 22, 2013
FortisBC Final Written Submission	February 8, 2013
Intervener Final Written Submission	February 15, 2013
FortisBC Written Reply Submission	February 22, 2013

With regard to participant interest in the regulatory review of the Application, FortisBC is aware of the significant interest in advanced metering not only within FortisBC's service territory, but also in other utilities' service territories for which AMI implementation is either being contemplated, or already underway. 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. In the absence of this consideration, it is likely that significant additional costs (related to participants without a direct interest in the Application) will be incurred to complete the regulatory review of the Application, which will ultimately have to be recovered from FortisBC customers. The Company submits that the granting of interested party status for participants unable to sufficiently demonstrate a direct interest in the Project is appropriate in order to ensure an efficient and thorough review of the Application.

1.4 Regulatory History

1.4.1 ISSUES FROM THE 2007 APPLICATION

On December 19, 2007 FortisBC applied to the BCUC for a CPCN for a proposed AMI project (the 2007 Application). Subsequent to a written public hearing process completed on June 27, 2008 the Commission issued Order G-168-08 dated November 12, 2008 denying a CPCN for the Application.

In its Decision, the Commission noted a number of issues with respect to the 2007 Application. These issues, and a brief discussion of FortisBC's response to the Commission's findings, are set out below.

- the Commission Panel is of the view that it would be prudent to consider the regulations before FortisBC proceeds with its AMI Project (G-168-08, page 6).

The Smart Meters and Smart Grid Regulation (B.C. Reg. 368 /2010) came into force on December 15, 2010. Sections 2 and 3 of the Regulation prescribe the requirements of the smart meters that BC Hydro must install under subsection 17(2) of the *Clean Energy Act.* FortisBC has completed a comparison between the proposed AMI Project and the requirements detailed in the Regulation, and determined that the FortisBC AMI Project is aligned with them. Further discussion of the Smart Meters and Smart Grid Regulation and the prescribed requirements as compared to FortisBC's proposed AMI Project is provided in Section 3.2.2.

- The Commission Panel considers that the application of the AMI technologies/protocol, and the opportunities for co-ordination to achieve optimal cost effectiveness have not been developed in these Applications to the point where the Commission Panel has sufficient evidence before it to assess the merits of the AMI Project (G-168-08, page 12).

and:

- The Commission Panel is also of the view that, since both BC Hydro and FortisBC plan to implement hybrid technologies, there may, in fact, be economies of scale available through collaboration (G-168-08, page 19).

Subsequent to the Commission's 2008 Decision, FortisBC continued work on the development of an AMI proposal, as described in this Application. Collaborative discussions occurred between FortisBC, FortisBC Energy, and BC Hydro to review the opportunities and benefits of collaboration on Smart Meter (AMI) projects. Please refer to Section 8.2 below for further discussion of FortisBC's collaboration efforts undertaken with other stakeholder utilities as part of this AMI Application.

Further, FortisBC has conducted consultations with the municipal electric utilities within its service territory (Cities of Kelowna, Penticton, and Grand Forks, District of Summerland, and Nelson Hydro) to discuss the Company's AMI proposal. As of the date of this Application the municipal electric utilities have indicated their preference for observing the progress of the Company's AMI Application prior to making further decisions on the subject. Nonetheless, FortisBC has developed some basic principles to guide the potential participation of the municipal utilities, including the sharing of costs. This subject is further discussed in Section 8.3.

- The Commission Panel is of the view that there could be significant potential cost and other advantages if FortisBC were able to coordinate its AMI project with BC Hydro's SMI project, particularly with respect to timing and technology selection (G-168-08, page 10).

and:

- The Commission Panel encourages FortisBC to explore coordinating its meter technology selection with that of BC Hydro with the objective of achieving a cost advantage based on the combined purchasing power of the two utilities (G-168-08, page 10).

Due to the timing of the legislation mandating BC Hydro to implement its SMI project, FortisBC and BC Hydro conducted independent RFP processes for the procurement of their AMI (SMI) projects. However, both processes, including consideration of functional requirements of their systems, were informed by the collaborative discussions mentioned above. Further discussion of FortisBC's RFP process for the AMI is provided in Section 4.2.1.

- 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 applications (G-168-08, page 22).

FortisBC has selected Itron Canada as the vendor for the major components of the AMI Project – meters, communications network and deployment of both. Substantial cost certainty has been achieved on these major cost components, and the remaining cost risks have been addressed with the inclusion of a 6.4 percent contingency in the Project budget.

FortisBC, based on the best information available now, has provided a reasonable estimate of the capital costs for the AMI Project as proposed, the scope for which will provide concrete benefits for customers immediately upon implementation. It is important to note that the potential financial benefits attributable to future programs enabled by AMI have not been factored into the rate impact analysis of the AMI Project. Further discussion of these benefits is provided in Section 6.0.

- Uncertainty exists around the useful lives of AMI components (G-168-08, page 26).

Assumptions regarding depreciation rates for the AMI components have been determined based on the observed useful lives of AMI components as established through industry experience, as well as through the component manufacturers' recommendations. These inputs have been used to calculate the assumed composite depreciation rate (and therefore useful life of the components) as determined by the various asset classes. Further discussion on this topic is provided in Section 5.2.

1.4.2 APPROACH TAKEN

As a result of the scope and cost issues identified by the Commission in Order G-168-08, and the encouragement provided by the Commission for 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 AMI), the Company determined it was prudent to conduct an RFP to address the concerns identified by the Commission prior to submitting the current Application. FortisBC engaged the services of an experienced consultant to facilitate the AMI system procurement process. The RFP process for the AMI system closely followed the BC Hydro smart meter procurement process, which also allowed FortisBC and BC Hydro to informally share information regarding operational requirements, helping to ensure an efficient RFP process for FortisBC.

Additionally, FortisBC has undertaken the following activities as part of the Project and Application development, including:

- Development of the details of specific functional, operational and technical requirements of the proposed AMI system, captured in a set of Use Cases described in further detail in Section 4.2 below;
- Commissioning a future use study of programs relying on AMI technologies with the results of the study (provided as Appendix C-1) incorporated into the potential benefit analysis;
- Active participation in technology and industry groups[1] focused on advanced metering and smart grid strategies;
- Monitoring the progress and results from utilities who have implemented or are in the process of implementing advanced metering projects, including Fortis Alberta, Fortis Ontario, BC Hydro, and Southern California Edison; and
- Engaging AMI industry experts to help track advances in metering technologies and software products to ensure FortisBC's choices are based on relevant, affordable and secure technologies.

1.5 Structure of the Application

Section 2 provides the Company's financial and technical capacity and contact information for the AMI Project. Section 3 describes the need for the AMI Project, the existing metering system used by FortisBC today, and includes detail on FortisBC's long term vision for the implementation and use of AMI, including a discussion of AMI as a necessary enabling component of the "Smart Grid". Section 4 provides a detailed description of the AMI Project, including the project scope, as well as information related to the procurement process undertaken as part of this Application, the metering technology selected as a result of the procurement process, and detail on the implementation of the various elements of the AMI Project including the communication networks, the MDMS, and the HES. Section 5 provides a discussion of the costs and benefits attributed to the AMI Project, as well as the assumptions upon which the financial analysis is based. Section 6 discusses the future benefits and opportunities afforded by AMI. Section 7 provides an examination of the alternatives considered to the proposed AMI Project. Section 8 details the Project environment, and includes information on the status of other utility AMI deployments, as well

[1] FortisBC has participated in various industry events such as Autovation, Distributech and other AMI conferences both in Canada, and the US.

as information on customer-identified concerns (EMF, privacy, security) to FortisBC's AMI Project. Section 9 discusses FortisBC's public consultation and communication efforts regarding the Project.

A draft Order is included as Appendix A to this Application. Appendix B provides a copy of the 2007 BC Energy Plan, the BC Climate Action Charter, as well as copies of relevant legislation as referenced throughout the Application. Appendix C provides copies of various reports as referenced throughout this Application. Appendix D provides copies of the financial analyses spreadsheets for the proposed Project and the considered alternatives. Appendix E provides copies of customer correspondence received related to the Project. Appendix F provides a copy of the AMI-SEC System Security Requirements and a copy of the Itron OpenWay Security Overview.

2.0 THE APPLICANT

2.1 Name, Address, and Nature of Business

FortisBC Inc.
Suite 100, 1975 Springfield Road
Kelowna, BC V1Y 7V7

FortisBC is an investor-owned, regulated utility engaged in the business of generation, transmission, distribution and bulk sale of electricity in the southern interior of British Columbia.

2.2 Financial and Technical Capacity

FortisBC is an integrated utility serving over 162,000 customers directly and indirectly. FortisBC was incorporated in 1897 and is regulated under the UCA. The Company owns assets of approximately $1.3 billion, including four hydroelectric generating plants with a combined capacity of 223 megawatts and approximately 7,000 kilometres of transmission and distribution power lines for the delivery of electricity to major load centers and customers in its service area. FortisBC employs approximately 550 full time and part time people.

2.3 Contact Persons

Communications with respect to this Application should be directed to:

Regulatory Contact:

Dennis Swanson
Director, Regulatory Affairs
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3.0 PROJECT NEED

In this Application, FortisBC is proposing the implementation of an advanced metering system that provides both customers and the Company improved information about electrical consumption. In this section, the Company provides a description of the existing metering system and explains the reasons for proposing the AMI Project, including consideration of British Columbia's energy objectives, the Company's long-term vision, as well as both the financial and non-financial benefits provided by the Project.

3.1 Description of Existing System

FortisBC currently has two types of metering systems:

- For residential, commercial, and some industrial customers:
    - Electro-mechanical meters, (approximately 80,000);
    - Solid-state (or digital) meters (non-AMI) for the remaining meter population in the Company's service territory. This includes several hundred interval Time-of-Use meters, as well as wireless Encoder/Receiver/Transmitter (ERT) meters used for hard-to-access meter locations; and
- MV-90, a cellular modem based system, used to collect reads for approximately 60 industrial customers who require interval metering data (typically collected by hour).

Electro-mechanical and digital meters have identical functionality with the sole distinction being that digital meters have digital (versus mechanical) operation. For commercial customers, FortisBC has installed digital meters for approximately the last nine years as the standard metering technology. For residential customers, FortisBC has installed digital meters for approximately the last six years as the standard metering technology.

Although electro-mechanical metering technology has remained largely unchanged since the mid-twentieth century electro-mechanical meters have been replaced by digital meters as the standard form of metering technology for the past number of years as the manufacturing and support for electro-mechanical meters has been gradually eliminated.

Non-AMI digital and electro-mechanical meters, although reliable, have limitations which stem from the labour-intensive meter reading methodologies and infrequent, one-way flow of information between meters, customers and the utility. The existing meters are limited to recording energy consumed at a customer's premises in a manner similar to the function of a car odometer. The information recorded must be collected manually by meter readers and transmitted to the Company's Customer Information System in order to bill customers (typically every two months) for their energy consumption. Thus, the consumption information collected is primarily used for billing purposes, and provides limited useful data to either customers or the utility because of its infrequency and one-way flow of information.

Moreover, new regulations (S-S-06) from Measurement Canada increase the accuracy requirements for calibrating and testing meters. The approximately 80,000 electro-mechanical meters in the Company's metering fleet are expected to fail compliance sampling at an increased rate, and the expected lifespan of the meter population will be significantly reduced. Furthermore, due to the larger minimum sampling size mandated by S-S-06, the maintenance of small meter lots (less than 250) will become uneconomic. This represents approximately 8,000 digital meters.

For clarity, the accelerated replacement of meters to comply with Measurement Canada's new sampling requirements will have to take place either via the proposed AMI Project, or, absent approval of the AMI project, via a separate project as contemplated under the status quo and contracted meter reading alternative options discussed in Section 7.0. Further discussion of the impact of Measurement Canada's new sampling requirements is provided in Section 5.3.4.

3.2 Advanced Metering Infrastructure

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 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.

3.2.1 BETTER INFORMATION AND BETTER COST MANAGEMENT ABILITY

As discussed above, AMI has the ability to provide more and better information regarding energy consumption. This, in turn, will provide an improved ability to manage the cost of electricity from both customers' and the Company's perspective.

From the customers' perspective, FortisBC expects that the capability afforded by the AMI system for customers to access their usage history and statistics through an online customer information portal or through an optional IHD will result in greater customer satisfaction since they will be able to get detailed information about the quantity and timing of their energy consumption. FortisBC plans to provide an overlay of ambient temperatures coinciding with the hourly meter readings in the proposed customer information portal, helping customers better understand the relationship between temperature and electricity consumption for their particular premises. This information will help customers make decisions regarding their energy consumption relative to their personal needs. Additionally, for customers who require FortisBC's assistance in resolving unexplained high consumption, the capability of an AMI system to provide readings at regular intervals will allow customers (through the online customer information portal), as well as FortisBC customer service representatives, to examine electric usage in a timely and unobtrusive manner. In particular, for customers requesting the assistance of the FortisBC PowerSense department, this capability will improve the timeliness with which the Company can provide energy efficiency recommendations to a customer.

From the Company's perspective, the existing manual meter reading process inherently makes it expensive to obtain customer consumption data beyond the single readings typically obtained every two months. AMI will reduce the incremental cost of additional meter readings to nearly zero by virtually eliminating the need for a manual meter reading process. The automated flow and increased granularity of information related to customers' energy consumption will enable the Company to more efficiently direct operational budgets, more accurately assess system infrastructure requirements, and reduce electricity theft – all of which equate to even more effectively managing the cost of electricity.

3.2.2 CONSISTENCY WITH BRITISH COLUMBIA'S ENERGY OBJECTIVES

The framework for the provincial energy policy is the 2007 BC Energy Plan[2] (the Plan). The Plan commits British Columbia to address climate change by reducing overall GHG emissions, and by providing a renewed focus on the efficient use of energy sources. The Plan also includes support for the use of innovative rate structures that encourage energy efficiency and conservation. Implementation of rate structures that achieve these goals is an opportunity afforded by AMI as further discussed in Section 3.2.5 below.

The Provincial Government has given effect to the 2007 BC Energy Plan in several pieces of legislation, as further discussed below.

GREENHOUSE GAS REDUCTION TARGETS ACT

Enacted in 2007, the *Greenhouse Gas Reduction Targets Act* (GGRTA)[3] mandates the reduction of provincial GHG emissions of thirty-three percent by 2020 and eighty percent by 2050 using 2007 as the baseline. The GGRTA also required all departments of the provincial government to become GHG neutral for 2010. According to a Live Smart BC news release, dated June 30, 2011, this target was achieved for 2010.

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.

BRITISH COLUMBIA CLIMATE ACTION CHARTER[4] AND THE CARBON TAX ACT

As of June 21, 2010, the Province of BC, along with the Island Trust and 179 municipalities across BC, signed the British Columbia Climate Action Charter. This Charter describes how

[2] See Appendix B-1 for the 2007 BC Energy Plan
[3] See Appendix B-2 for the *Greenhouse Gas Reduction Targets Act*
[4] See Appendix B-3 for the BC Climate Action Charter

these parties both endorse and actively support the goal of GHG emissions reduction. This objective of no-net-emission of GHGs by 2012 will be achieved through a combination of capturing and containing GHG emissions, reducing GHG emissions, and investing in projects that eliminate GHGs where ever possible.

The Carbon Tax Act[5]*,* passed in 2008 and amended in May 2012, further signalled the provincial government's commitment to the reduction of GHG emissions. As stated on the British Columbia Ministry of Finance website, the purpose of the carbon tax "is to ensure that a consistent long term price signal is provided to consumers so that they continue to make the choices required to reduce their fossil fuel use and emissions." The implementation of AMI, and the consequent decrease in vehicle usage, will support these provincial goals of GHG reduction.

UTILITIES COMMISSION ACT

In 2008, the provincial government amended the UCA to require the Commission to ensure that utilities undertake efficiency and conservation measures in their operations, and to consider British Columbia's energy objectives in specified approval processes. Section 46 (3.1)(a) and (b) of the UCA states that in considering whether to issue a CPCN, the Commission must consider the British Columbia's energy objectives as provided in the *Clean Energy Act*[6] (CEA), as well as the most recent long-term resource plan filed by the public utility under section 44.1. Further discussion of the CEA and the British Columbia energy objectives applicable to FortisBC's AMI Project is provided below. A discussion of the AMI Project in relation to FortisBC's 2012 Long Term Resource Plan is provided in Sections 3.2.5.

CLEAN ENERGY ACT

The CEA aims to ensure electricity self-sufficiency by 2016, to harness B.C.'s clean power potential to create jobs, and to strengthen environmental stewardship and reduce GHG emissions. The CEA received Royal Assent on June 3, 2010, with further amendments made effective July 1, 2011 and May 31, 2012.

The CEA further promotes energy efficiency objectives as a consideration in evaluating the activities, programs and rate-setting undertaken by utilities within the province of British Columbia.

[5] See Appendix B-4 for the *Carbon Tax Act*
[6] See Appendix B-5 for *Clean Energy Act*

The CEA defines the British Columbia energy objectives, which include:

> (b) to take demand-side measures and to conserve energy;
>
> (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;
>
> (g) to reduce BC greenhouse gas emissions.

These energy objectives provided in the CEA place a new focus on demand-side management measures and smart metering (AMI/SMI technologies). The Provincial Government has explicitly stated its support for smart metering solutions, mandating BC Hydro to install smart meters by the end of 2012, and establish a program to install and put into operation a smart grid by the end of 2015 as provided in the CEA and the Smart Meters and Smart Grid Regulation.

The Provincial Government has demonstrated its support for advanced metering for utilities other than BC Hydro. Section 17 (6) of the CEA provides:

> (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.

FortisBC submits that the implementation of AMI supports British Columbia’s energy objectives as cited above, and meets the government’s goal of having smart meters and a smart grid (as defined in the CEA and in the related regulation) in use for FortisBC customers.

AMI will also enable demand-side measures (such as IHDs) which will provide energy conservation benefits. Under the existing manual meter reading system, measures such as these cannot be cost effectively deployed to FortisBC’s customers. Further, AMI, as an innovative technology, provides a foundation to support and enable energy conservation and efficiency primarily through the provision of increased energy consumption information for customers. 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.

SMART METERS AND SMART GRID REGULATION

As part of the CEA, the Smart Meters and Smart Grid Regulation (2010) details the prescribed requirements of “Smart Grid” and “Smart Meter”. FortisBC has examined the regulation, and has determined that its proposed AMI Project is aligned with the requirements. A summary table of the regulation requirements is provided below.

Table 3.2.2.a – Summary of SMI Requirements

Category	Requirements of Smart Grid Regulation	FortisBC Complies
Meter	Measures electricity to eligible premises	✓
	Transmits and receives information in digital form	✓
	Enables remote disconnect and reconnect for residential premises	✓
	Records and timestamps measurements of electricity	✓
	Records intervals at a frequency of at least 60 minutes	✓
	Can be configured remotely or onsite	✓
	Can measure and record electricity generated at a premises and supplied to the electric distribution system	✓
	Can transmit information to and from an IHD	✓
Installation	An advanced meter will be installed for each eligible premises	✓
	Secure hardware and software systems will be installed to: • Monitor, control and configure advanced meters and communications infrastructure • Store, validate, analyze and use the data measured by and received from advanced meters • Provide secure internet access for data about a customer's electricity consumption and generation, measured by the advanced meter • Establish a secure telecommunications link between IHDs and advanced meters • Bill customers in accordance with rates that encourage the shift of the use of electricity from periods of higher demand to periods of lower demand • Integrate with FortisBC's systems	✓
	Communications infrastructure includes a telecommunications network that is capable of delivering two-way, digital and secure communications	✓
	Communications infrastructure must integrate to FortisBC systems	✓
Smart Grid Enablement	To enable FortisBC to perform electricity balance analyses for the electric distribution system	✓
	To enable FortisBC to perform analyses to estimate the unmetered load	✓
	To enable FortisBC to use investigative device and / or software to identify the location of unmetered loads	✓
	Establish a telecommunications network with sufficient speed and bandwidth to facilitate distributed generation	✓
	Establish a telecommunications network with sufficient speed and bandwidth to facilitate the use of electric vehicles	✓
	Integrate the operation of the smart grid with FortisBC's systems	✓

3.2.3 FORTISBC SMART GRID VISION

The "Smart Grid" concept has become common with electric utilities worldwide. However, a single, encompassing definition for the "Smart Grid" remains elusive, and subject to the sometimes differing perspectives guiding different organizations. In many cases, subsets of smart grid technology – such as advancing metering or distribution automation – have become synonymous with the larger "Smart Grid".

At FortisBC, the following definition has been used to characterize the Company's smart grid concept. Fundamentally, the "Smart Grid" is:

> *"The application of digital technology to improve the efficiency, safety, reliability and cost-effectiveness of the electric power system."*

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.

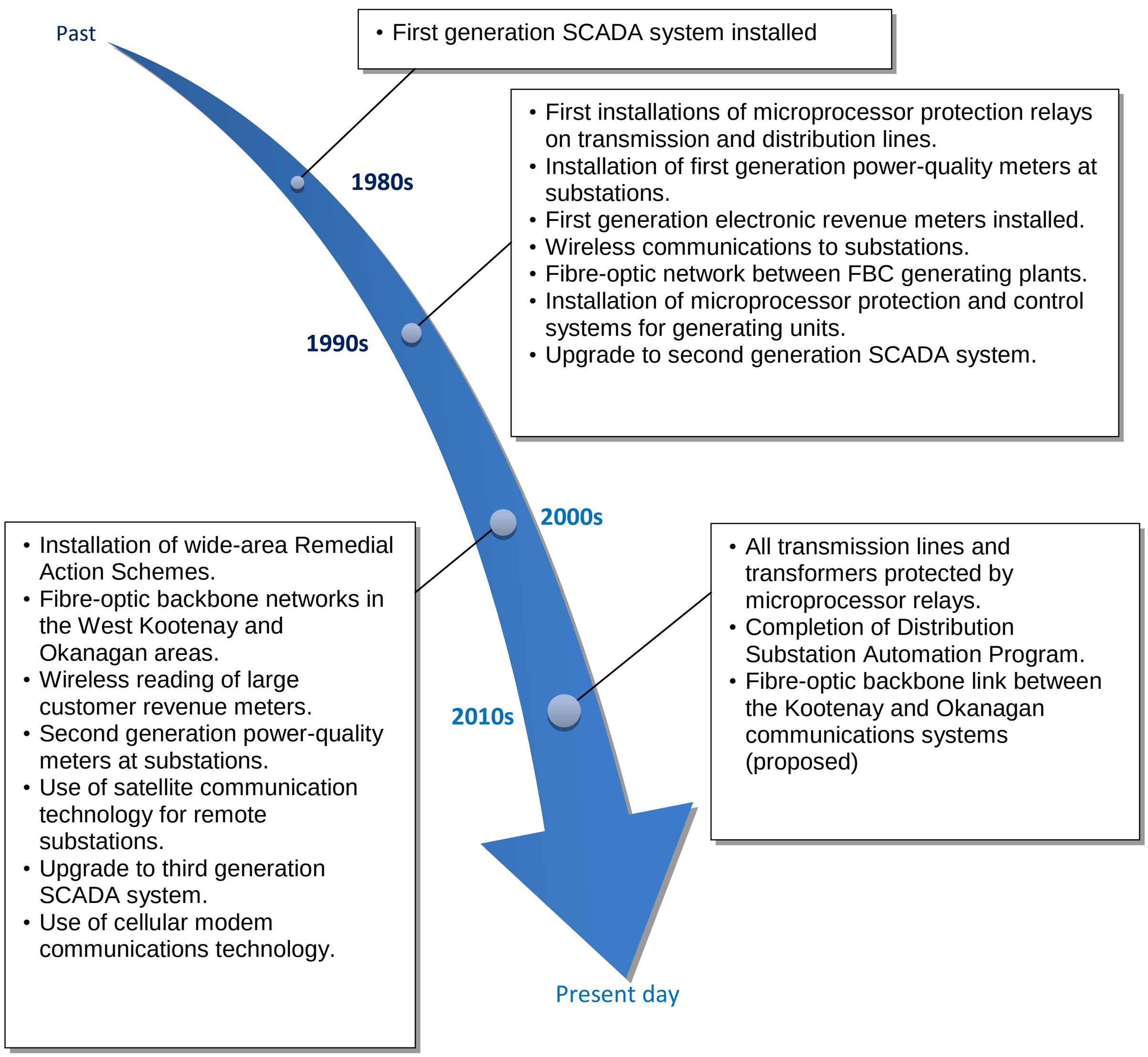
HISTORICAL PERSPECTIVE

While the term "Smart Grid" is a relatively modern development (popularized by the electric industry in the 2000s), the principles that it embodies have been embraced by electric utilities for many years. It is important to note that the implementation of smart grid technology at FortisBC does not represent any fundamental shift in the way of doing business. FortisBC has a demonstrated record of looking to emerging – but proven – technologies to improve the Company's ability to provide safe and reliable service. In each case the specific implementation was evaluated to confirm that it was a cost-effective solution which would improve efficiency and/or reduce costs.

FortisBC currently has remote visibility of its generation facilities, transmission assets and substations using its Supervisory Control and Data Acquisition (SCADA) systems. 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. The Commission ultimately concluded that replacement of this legacy technology with new electronic technology to be appropriate and of benefit to ratepayers.[7]

Some examples of other key technology deployments at FortisBC which would now be captured under the smart grid umbrella are shown in Figure 3.2.3.a below.

Figure 3.2.3.a - Timeline of Historical Technology Deployments at FortisBC

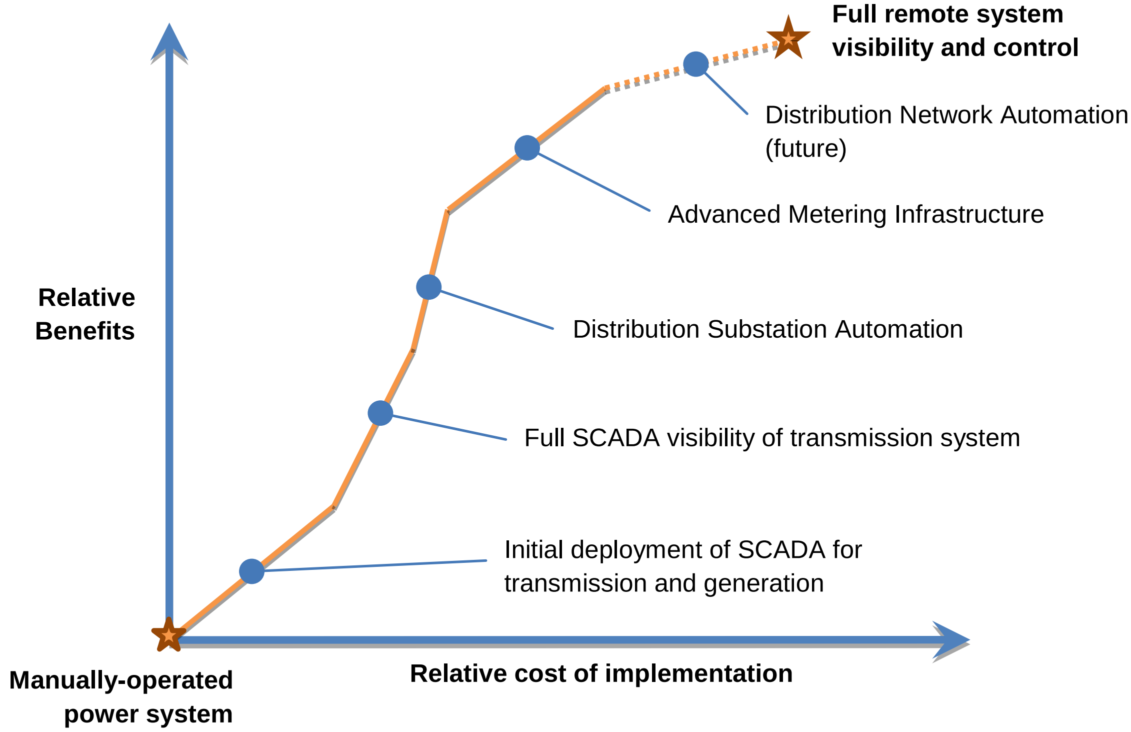


[7] Appendix A to Order C-11-07, page 13

SMART GRID BUILDING BLOCKS

As represented by the timeline in Figure 3.2.3.a, the deployment of smart grid technology at FortisBC has been evolutionary. Another way to view to the benefits of this evolution is represented by the following graph.

Figure 3.2.3.b – Progression of Smart Grid Technology at FortisBC



The origin of the graph represents a point where the electric system is operated completely manually with no remote monitoring or control of any infrastructure. As smart grid components are added, the ability to remotely operate and monitor the power system improves.

Utility operations and customers benefit from these system improvements, primarily through increased reliability, improved power quality, and reduced costs. FortisBC system operators are able to remotely view system parameters, predict potential problems and be proactive with respect to operating and maintaining the electric grid. When failures occur, historical data provided by DSAP assists in the Company in determining the cause and in designing a solution.

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.

As discussed in the introduction, FortisBC intends to build upon existing systems and infrastructure where there are further benefits that can be achieved. A list is provided below of many accepted smart grid technologies. While the list is not intended to be exhaustive, it does represent the key components which go towards building a fully realized smart grid.

- Advanced Metering Infrastructure (AMI)
- Automated Vehicle Location (AVL) - *
- Computerized Maintenance Management System (CMMS) - *
- Conservation Voltage Reduction (CVR)
- Customer information portals
- Cyber-security infrastructure - *
- Dispatch system - *
- Distributed generation (DG) integration
- Distribution Automation (DA)
- Demand response (DR) control
- Distribution Management System (DMS)
- Electric (EV) or plug-in hybrid (PHEV) vehicle integration
- Energy Management System (EMS)
- Fibre-optic communications networks - *
- In-Home Displays (IHD)
- Meter Data Management System (MDMS)
- Outage Management System (OMS)
- Phasor Measurement Units (PMU) - *
- Real-time transformer monitoring - *
- Real-time transmission line rating
- Supervisory Control and Data Acquisition (SCADA) - *
- Substation Automation - *
- Wide-area (wireless) communications networks

- Work Management system

** - indicates a technology either fully or partially deployed at FortisBC*

For clarity, FortisBC is not proposing to implement all of the technologies listed above at this time. In fact, some solutions may have limited application at FortisBC and would not be proposed. This could occur for a number of reasons: the primarily rural nature of much of the service territory, the load versus available resources balance, the relatively small size of the service territory, or the lack of customer uptake. Each technology deployment will be evaluated to determine if it is cost-effective and in the best interests of customers.

As technologies are identified, evaluated and deployed the progression to a smart grid will allow the Company to increase safety, increase reliability, decrease operational costs, target capital expenditures more effectively, and enhance customer service by gathering real-time data on all aspects of the power system. For example, real-time information on the distribution system could be made available from devices such as reclosers, switches, capacitor banks, transformers and meters. The information could be used to monitor and change system parameters to maintain operating efficiency, to identify poorly functioning assets for maintenance or replacement and to delineate size and causes of power events and outages to ensure a safe, timely and accurate response.

THE KEY ROLE OF AMI IN THE SMART GRID

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, 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. This information will allow a full analysis of system losses, and will assist the Company in assessing if specific system upgrade projects are warranted to reduce these losses. System improvements such as these as enabled by AMI will help to make the grid more reliable and more efficient and will help the Company manage the cost of electricity.

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.

3.2.4 FINANCIAL BENEFITS TO CUSTOMERS

The installation of AMI will save customers approximately $19 million on a net present value basis over the 20 year evaluation of the Project. The financial benefits provided by AMI will mitigate future rate increases. In absence of the Project rates will be higher than they would be with implementation of the Project. Section 5.3 below provides details on the financial benefits, including costs savings and reduction of revenue loss, associated with the AMI Project. 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; and
5. Reduction in costs related to disconnection/reconnection of meters for non-payment.

Financial analysis of the Project shows that rates will be approximately 1 percent lower than they would without the AMI Project over the 20 year study period.

Although not included in the financial model, there is also an inherent opportunity cost if AMI is not pursued at this time due to the non-financial customer service and operational benefits associated with the Project that will not be realized should the Project not proceed. Further discussion of these non-financial benefits is provided below.

3.2.5 NON-FINANCIAL CUSTOMER SERVICE AND OPERATIONAL BENEFITS

The proposed AMI system provides a number of non-financial benefits that are of importance to customers. These benefits include improvements in billing, additional conveniences to the customer, increased operational efficiencies and a reduced environmental impact.

CONSERVATION RATE STRUCTURES

On March 31, 2011, FortisBC submitted an application for the implementation of a Residential Inclining Block (RIB) rate in compliance with Commission Order G-156-10 which directed the Company "...to develop a plan for introducing residential inclining block rates..." On January 13, 2012, the Commission issued Order G-3-12 approving the RIB rate for implementation as the mandatory default rate for all FortisBC residential customers effective July 1, 2012. All residential customers have been transitioned to the new RIB rate (also referred to as the Residential Conservation Rate in customer communications) on July 1, 2012, with FortisBC's residential Time-of-Use (TOU) rate closed at that time to new participants. 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.

It is, however, recognized that service under the default RIB rate will not allow customers to benefit from choices about the timing of electric consumption (rather than total consumption 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).

Although no rate structure changes are proposed as part of this Application, an AMI system will provide information and capability to enable other time-based conservation rate structures, such as an expanded and enhanced TOU or Critical Peak Pricing (CPP).

AMI is a necessary foundation to enable the development and implementation of additional rate options such as these for FortisBC customers. The AMI solution provides interval metering data for use in the billing system. Changes in rate periods or time buckets used for billing purposes can be administered through the billing system as opposed to the meter.

Without AMI, these meters must be physically removed, returned to an accredited meter repair facility, re-programmed and re-sealed through the certification program. Although difficult to predict and quantify, this is an expensive process for the Company and is inconvenient for the customer. 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. This flexibility, provided by AMI, will permit FortisBC to consider widely offering time-based rates as a voluntary alternative to other forms of conservation rates (such as RIB). Further discussion about TOU and other potential rate structures can be found in Section 8.0 below. Any such alternate rate structures, if proposed by FortisBC, would be submitted to the BCUC for approval.

The transition to advanced meters as the standard form of metering will permit more detailed electricity usage information to be made available to customers through a FortisBC online web portal as well as through optional IHDs. These tools can be used by customers to obtain detailed information about their overall usage and consumption habits, helping them 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.

ENHANCED BILLING INFORMATION

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.

IMPROVED BILLING ACCURACY

Under the current manual metering reading system, it is often necessary to estimate customer bills for a variety of reasons (such as staffing shortages due to unexpected illness or injury, property access issues, and severe weather conditions). Despite reading over 98 percent of meters when scheduled in 2011, approximately 16,000 scheduled meter reads could not be obtained and were therefore estimated. The necessary practice of estimating bills, in the absence of AMI, is a frequent source of customer dissatisfaction and confusion, particularly with regard to FortisBC's residential monthly billing options (monthly billing and Equal Payment Plan) which require the use of a meter estimate between the bimonthly verified meter reads.

In the FortisBC fourth quarter 2011 Customer Satisfaction Survey, the percentage of customers indicating their satisfaction with the accuracy of metering reading as 9 out of 10 or higher (10 being most satisfied) was 55 percent. Meter readings must also be estimated when a rate change occurs (except when a bimonthly read happens to coincide with the date of a rate change). AMI will improve bill accuracy by eliminating the current practice of bill estimation and the occurrence of manual meter reading misreads.

Approximately 14 percent of all residential customers, and 4 percent of small commercial customers, receive billing on a monthly basis, with actual meter reads only captured every two months and an estimated bill provided for the months in between. The majority of residential customers who receive monthly billings are enrolled in the Company's Equal Payment Plan which allows for fixed monthly budget billing. It is estimated that there are approximately 78,500 estimates required annually by the equal payment plan option. In 2011 the Contact Centre handled more than 3,500 calls relating to monthly budget billing, with the majority of the calls regarding the estimated usage appearing on the customer's bill. AMI will allow customers to receive an actual reading each month which would provide a more accurate status of the equal payment plan balance and actual consumption.

CONSOLIDATED BILLING FOR MULTIPLE CUSTOMER LOCATIONS

FortisBC has received requests from customers with multiple electricity accounts to receive a single bill that includes all of their accounts. If the electric services are in different geographic locations, or are billed under different tariffs, they are frequently read on different dates. This makes the provision of a consolidated bill impractical and FortisBC has been unable to accommodate the majority of these requests. AMI technology allows the

Company to obtain meter readings at different locations simultaneously. This will allow FortisBC to provide a single bill for these customers, addressing customer concerns and lowering the bill printing and payment processing costs of the Company.

FLEXIBLE BILLING DATE

Since AMI provides more frequent meter readings, FortisBC intends to allow customers the opportunity to choose a billing date that meets their needs rather than be restricted to the date dictated by the scheduled meter reading route, which for monthly billed residential customers includes a meter read estimate every other month. The ability to select a preferred billing date could be of particular importance for FortisBC's fixed-income customers. The option to select a flexible billing date is expected to help reduce late payment charges for those customers that currently struggle to make prompt payments tied to the current manual meter reading schedule. As well, FortisBC will be able to consistently provide actual opening and closing reads for customers moving in/out of premises. Current practices dictate that FortisBC must estimate some off-cycle opening or closing reads. It is expected that the ability to provide actual reads for customers moving in/out of premises will result in an improvement in customer satisfaction.

REDUCED NEED TO ACCESS CUSTOMER PREMISES

Meter readers must access customer property in order to obtain manual meter readings. Although the anticipated meter reading date is currently included on a customer's bill, meter readers frequently encounter customers who do not understand or comply with the tariff requirement to provide safe and ready access to the electric meter. Premises with an access issue generally receive estimates until the access problem can be resolved, which typically requires additional time and effort on the part of the meter reader to coordinate a resolution to the access issue. There were over 20 customer complaints received by FortisBC in 2011 alone regarding private property access issues. Aside from reducing customer complaints, the reduced need to access private property will reduce the amount of administrative work associated with securing and managing keys to access inaccessible meters on customer premises. It will also reduce the risk to meter readers from customers who may be engaged in the theft of electricity, as well as other safety issues associated with access as discussed further below regarding improved safety.

ENHANCED SYSTEM MODELLING

AMI provides system load data with much greater granularity and timeliness than currently available; this allows simulation and analysis of the electrical system to a higher degree of accuracy. System Planning currently relies on both system measurements and modelling to predict performance of the electrical network. As with any modelling exercise, the results obtained are only as good as the inputs into the model. The System Planning simulation model is comprised of:

1. The electrical network model;
2. Information on the power supplied into the network; and
3. Information on the power consumed by that network.

The electrical network model is defined by the electrical quantities and impedance characteristics derived from the physical configuration of the various generators, substations, transformers and conductors (wires). FortisBC relies on the information contained within the Company's AM/FM GIS system to develop accurate electrical models of both its transmission and distribution system. GIS Information related to transmission system elements is known to a high degree of accuracy. However, knowledge of the distribution system is more limited. For example, FortisBC has tens of thousands of single-phase distribution transformers which are used to supply residential customers. These transformers can be connected to any one of the three distribution phase conductors. Currently, information regarding which phase is used to supply these transformers is very limited. This impacts the accuracy of the model as it is not possible to correctly allocate the actual amount of connected load to the appropriate phases of a given distribution feeder. AMI would support the cost-effective collection of load data by phase for each distribution transformer.

FortisBC already has detailed and accurate information on power supplied into the electrical network. For example, instantaneous values regarding generator production and transmission interconnection flows are available. FortisBC's SCADA system has near-real-time visibility of all transmission lines and substations. Additionally, through systems installed as part of the DSAP, the load supplied by substations into the distribution network is well known (both instantaneously and historically). In general, AMI will not directly benefit the monitoring or visibility of the generation or transmission portion of the electrical system. However, once power leaves the distribution substations currently there is virtually no visibility or monitoring of the distribution system beyond that point.

AMI has the potential to improve system modelling by providing planners with precise average and interval loads at each metering point. In conjunction with the metering installed through the DSAP, these improvements would allow thermal loading, voltage and loss performance to be calculated to a higher degree of accuracy.

IMPROVED FINANCIAL REPORTING, LOAD FORECASTING, AND COST OF SERVICE ANALYSES

AMI technologies allow for a more accurate calculation of unbilled usage and overall system losses for use in financial reporting, load forecasting and cost of service analyses. This information can then be used to help plan power purchases, optimize the system to minimize losses, more accurately estimate unbilled power, better assign costs to customers (as indicated through a cost of service analysis), and potentially conduct innovative rate design.

Aside from larger customers which are provided with interval metering, most customer metering reports only consumption (in kWh) and in some cases peak demand (in kVA) billing data. There is no timestamp associated with the peak demand reading and thus there is no way of knowing when the customer consumption peaked. Combined with the limited information provided by energy-only consumption data, FortisBC has no information on the load profile or real-time consumption information for the vast majority of 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.

IMPROVED SAFETY

FortisBC's proposed AMI Project will contribute to an improvement in safety for Company employees and customers. The Company strives to maintain an effective safety management system, in compliance with relevant legislative requirements and in accordance with leading industry practices and standards. FortisBC continually strives to ensure the safety of employees and the safe delivery of electrical service to all customers. AMI improves safety by reducing the number of exposure hours related to driving, walking, animal and property access hazards. FortisBC customers and the general public benefit from having fewer vehicles on the road.

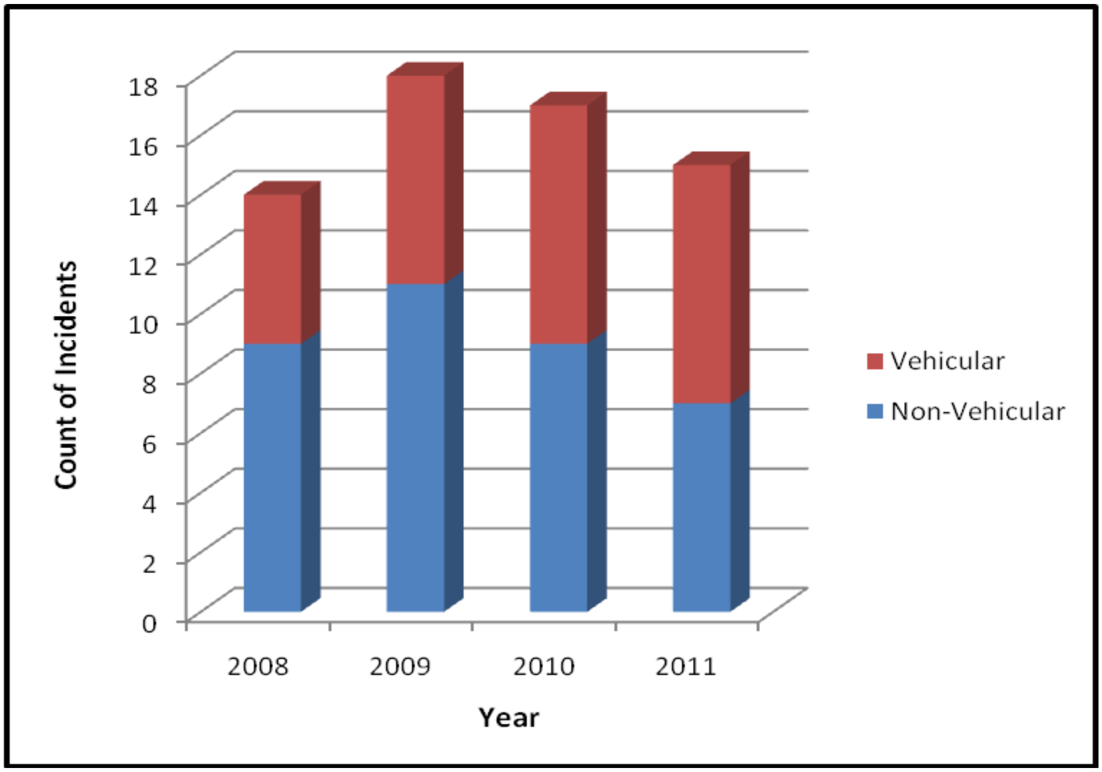
The manual meter reading process exposes employees to a variety of potential dangers. Between 2006 and 2011, there were 93 safety incidents within the meter reading department, including, but not limited to:

- Vehicle incidents;
- Falls while walking;
- Property access issues;
- Animal attacks (primarily dogs);
- Hazardous weather conditions for both driving and walking.

These meter reading incidents would be avoided with the implementation of an AMI system.

Figure 3.2.5.a below graphically illustrates recorded safety incidents for the period 2008 – 2011 for FortisBC's meter reading department.

Figure 3.2.5.a - Meter Reader Safety Incidents 2008 - 2011



Driving is the most significant risk faced by FortisBC meter reading employees. An AMI system will assist in minimizing driving-related risks in other parts of the Company as well. For example, the additional information available from an AMI system will help to reduce 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.

Revenue protection activities also expose FortisBC employees and contractors to hazards. Although the number of driving exposure hours from revenue protection work is lower than from meter reading, the property access hazards are greater. The workers involved in revenue protection activities may have to access customer properties several times in order to verify theft by reading the meter. The theft of electricity is accompanied by many unsafe practices, including the use of electrical diversions to bypass the meter, creating safety risks for the Company's customers at properties adjacent to locations where theft is occurring. Furthermore, as these properties are generally being used for the illegal production of marijuana, there are obvious hazards associated with the required access. The capabilities built into AMI technology will assist the Company in identifying and addressing theft, and will considerably reduce if not eliminate the need to access customer meters for the purpose of verifying electricity theft, thereby reducing the associated safety concerns.

REDUCED GHG EMISSIONS

The FortisBC service territory's physical geography is predominantly rural with a relatively low customer density and a largely radial road network resulting in a significant amount of vehicle use. Although walking is employed where possible, a meter reader's primary means of traveling between metered service points is by vehicle.

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.

IMMEDIATE NOTIFICATION OF POWER OUTAGES AND RESTORATION

Power outages are inconvenient and may be expensive for the Company's customers. 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 an outage. As FortisBC's System Control Centre currently has very limited visibility of the distribution system beyond the substation fence, it is anticipated that the outage information provided by AMI will be particularly helpful for smaller outages that occur downstream of distribution substations. In comparison to the current process of manually patrolling distribution feeders to identify the cause of an outage, the information made available by

AMI will allow FortisBC to more quickly and effectively respond to power outages and help ensure that all customers have had their power restored in a timely manner.

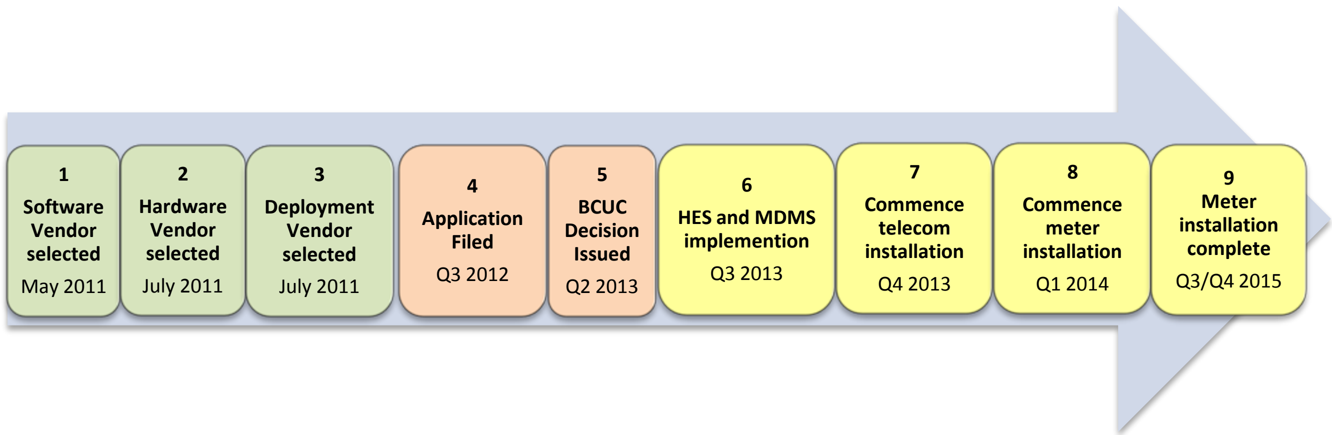
FortisBC expects that AMI will reduce restoration time for customers, but any improvement will be difficult to measure. The difficulty in measuring improvements arises from the fact that AMI will provide more accurate and complete outage statistics than are available today making the cause of changes in outage statistics difficult to determine. It is anticipated, however, that the more accurate and complete data available with AMI will allow FortisBC to conduct an improved post outage analysis of time off/ time on, duration (SAIDI), and frequency (SAIFI), which may prove useful in addressing and resolving customer complaints.

IMPROVED POWER QUALITY MONITORING

Alarms in the AMI meters will alert the Company to a variety of operating conditions that may impact customer power quality. In addition to the detection and reporting of exceptions related to meter inversion, meter removal, reverse power flow and power outages, AMI meters will also report electric service and wiring errors detected by the meter, including reverse polarity, cross-phase and energy flow, phase voltage deviation, inactive phase current, phase angle displacement and current waveform distortion. AMI will allow the Company to proactively address these events and ensure that these installations are corrected, resulting in improved power quality and safety for affected customers.

4.0 PROJECT DESCRIPTION

The development of the AMI Project began in 2006 with development of the initial application. Subsequent to the Commission's decision contained in Order G-168-08, pre-planning and Use Case development for the current application commenced in 2009. Upon completion in 2015, the Project, inclusive of planning, procurement, design, deployment and acceptance will have encompassed nine years. The following graphic illustrates the proposed AMI Project's high level milestones. The activities involved at each level are discussed in this section of the Application.



The Advanced Metering Infrastructure Project will:

- Implement software infrastructure (specifically the MDMS and HES) to manage the AMI network and to store data securely, including integration with existing FortisBC systems;
- Deploy communications network infrastructure components required to transmit metering data to and from FortisBC customer meters using RF mesh technology;
- Install approximately 115,000 residential and commercial AMI meters capable of remote connection and disconnection of electric service;
- Provide customers with an internet-based secure customer information portal where they may access and view their consumption information, and the AMI meters will support customer-purchased IHDs capable of providing current electric consumption and pricing information; and
- Enhance the ability of FortisBC to detect and deter electricity theft.

Implementation of AMI will take place over three years, beginning with the installation of the HES and MDMS and integration with existing FortisBC systems, and following with the installation of the communications network and meter equipment. The implementation start date will be set after receipt of regulatory approval, anticipated by mid-2013, with a system in-service date of 2015.

4.1 AMI Project Components

The proposed AMI Project will result in the replacement of existing customer meters with AMI enabled meters (excluding approximately 60 industrial customers currently served by the MV-90 metering system) and the associated infrastructure to support transmission of metering information from the AMI meters at customers' premises back to the Company.

AMI includes meters, collectors, range extenders, wide area network communication devices, the HES and the MDMS. Through a communication module inside each sealed meter, meter readings and operational data (such as voltage and outage information) are sent to and aggregated by collectors. The collectors then relay the information to the HES and MDMS to be used by other internal FortisBC systems.

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.

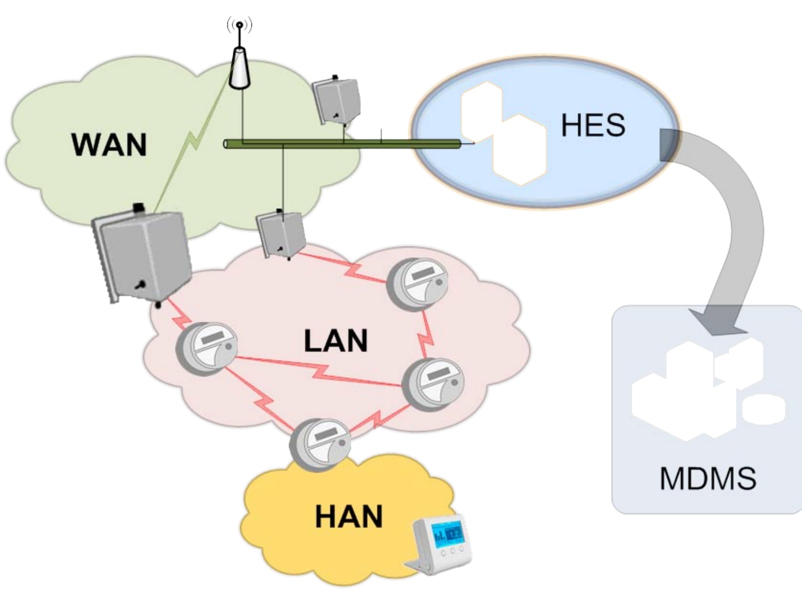
The components of the proposed AMI system are summarized below and subsequently expanded upon.

- Home Area Network – This optional network connects the AMI meters with customer-purchased IHDs. This will allow a customer to view power usage within their home and enable them to make informed decisions affecting the level or timing of their electric consumption.
- Local Area Network – The LAN is a network of meters, range extenders, and collectors that communicate with each other. The LAN provides each meter with a network path to at least one collector for data aggregation and forwarding. Range

extenders are added in key locations to aid in boosting the signal for meters in harder to reach areas of the service territory. In the RF mesh system proposed, the LAN is considered “self healing”. This means that if, for whatever reason, the primary (or “normal”) path for data communications is blocked, then the LAN will automatically reconfigure to an alternate communication path so as to preserve the connection between the customer AMI meter and the collector.

- Wide Area Network – The role of the WAN is to aggregate and forward data from the collectors, back to the HES. The collector provides a single point of access that is used to perform this aggregation function.
- Head End System – The HES is comprised of three important applications; the collection engine, the reporting system and the network management system. These applications monitor, optimize, and report on the AMI network. The HES also manages the secure transfer of data between the LAN and the MDMS.
- Meter Data Management System – The MDMS captures and acts as a repository for data delivered from the AMI system’s HES and distributes the data after processing by Validation, Editing and Estimation (VEE) algorithms to the FortisBC internal systems.
- Customer Information Portal – a customer information portal will allow FortisBC customers access to their consumption information over the internet through a secure website.

Figure 4.1.a - AMI System Overview



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.

4.1.1 HOME-AREA NETWORK

One of the benefits of an AMI solution is the capability to allow customers to take a more active role in monitoring, controlling and moderating personal electric use. Customers can easily view the amount and timing of their electric use through the HAN and/or customer information portal. One of the requirements of the procurement process was that vendors be able to meet emerging industry standards for IHDs using the Zigbee[8] 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. The ZigBee Alliance is a group of companies that maintain and publish the ZigBee standard. The Alliance publishes application profiles that allow multiple original equipment manufacturers (OEM) to create interoperable products. It is an enhancement of ZigBee Smart Energy v1.1, adding services for plug-in electric vehicle (PEV) charging, installation, configuration and firmware download, prepay services, user information and messaging, load control, demand response and common information and application profile interfaces for wired and wireless networks.

[8] ZigBee is a specification for a suite of high-level communication protocols using small, low-power digital radios based on an IEEE 802 standard for personal area networks.

Figure 4.1.1.a – Sample In-Home Display

FortisBC intends, through its PowerSense group, to offer incentives to customers enabling them to purchase compatible IHDs. The IHD communicates directly with the customer's AMI meter, and will display real-time consumption and rate data. When 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. This communications path is secured by encryption keys specific to the AMI meter at the customer's premises, and their IHD.

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 or change when they consume electricity. The FortisBC Navigant Future Program Study, provided as Appendix C-1, indicates a 5.4 percent reduction in energy use associated with the use of 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 as a result of the energy use data they accessed on their IHDs. A survey done mid-point during this pilot[10] indicated that 81 percent of respondents agreed or strongly agreed with the statement "The information displayed on your in-home energy monitor will influence you to take steps to lower your electricity consumption within the future." Notwithstanding the fact that these savings have not been reflected in the Application, this is compelling evidence that the capability of an AMI system to provide comprehensive energy consumption information to customers can result in positive changes in energy consumption

[9] http://energy.gov/oe/articles/centerpoint-energy-and-us-deputy-secretary-energy-daniel-poneman-announce-results-pilot

[10] http://www.puc.state.tx.us/industry/projects/electric/34610/AMITMtg032911/500-Unit_In_Home_Display_Program.pdf

habits. These savings will be included in future PowerSense DSM applications to the extent that the Company provides a related incentive.

The widespread deployment of ZigBee-based HANs by utilities throughout North America is expected to result in a variety of new products and applications that will help customers 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.

4.1.2 LOCAL AREA NETWORK

The purpose of the AMI LAN is to provide a medium for meter data (such as aggregate consumption information) to reach a collector, and for utility data (such as electricity pricing) to reach the AMI meter. The LAN consists of meters, collectors, and range extenders.

- 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. Pole mounted range extenders will be used when physical distance or obstructions limit meter to meter communication.
- A wireless LAN connection is created between meters and collectors that have an RF path between them. This creates multiple optional paths for data to take in most environments. A preliminary network design has been completed which indicates that 136 collectors are required to aggregate the meters in the RF mesh.
- 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.
- 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.
- 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. Integrated functionality such as Quality of Service (QoS) and Virtual

LANs (VLAN) permits these different applications to be logically separated for ease of management and security, and will ensure that required bandwidth is allocated to the highest priority applications such as Distribution Automation (DA). This also reduces technology risk as the IP technology is well understood, standardized and under active development.

The selected AMI residential meters have two-way connectivity, four channel bi-directional energy measurement, remote firmware upgradability, remote configurability, remote load limiting, integrated remote disconnect switches and ZigBee-based HAN capabilities.

Advanced meters are the same as the standard digital meters currently used in the electric industry (and the current standard metering at FortisBC), with the addition of the ZigBee and LAN communications radios sealed inside the meter. FortisBC has been installing digital meters for nine years, with approximately 35,000 digital meters in service. The radios in the AMI meters enable two-way communication of metering data and operational information between the utility and the customer AMI meter.

Advanced meters will transmit consumption data back to FortisBC through the LAN and WAN. 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.

4.1.3 WIDE AREA NETWORK

The WAN is used to carry meter data from the collectors to the HES, and from the utility to the collectors. It will be built using a variety of technologies, depending on the location of each collector. Generally, the transmission will occur over networks running standard IP/Ethernet protocols. This makes the technology choice low risk as there are providers throughout the FortisBC service area that offer services with low capital and operating costs. FortisBC will deploy a cost-effective WAN solution that will use the optimal combination of the following technologies:

- **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 long term certainty with respect to the technology.

- **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. Capital costs are higher to install a base station, but since the base station is shared with all the endpoints in an area there is an economy of scale when multiple endpoints can be serviced. In addition, there is a small yearly licensing fee, typically less than $100 per site. The technology can be expected to be available for approximately 7-10 years but FortisBC can mitigate this risk by purchasing spares since it has control over the long term operation of the network.
- **Cellular** – Using third party cellular providers is the simplest solution, and benefits include low capital costs and ease of installation. On the other hand, there are ongoing monthly fees for connection/data and FortisBC has no control over the technology or network. Technology generally needs to be replaced in 7-10 years as the carriers continue migrating their networks to new technologies, and this will add additional costs to the system in the future when the cellular modems need to be replaced. However, due to the low capital costs and ease of deployment the financial risks are low.
- **Satellite** – In remote areas where cellular coverage is not available, third-party backhaul over satellite is also a possibility. Although this solution is generally more expensive than the other options noted above from both a capital and monthly perspective, it can be the most cost-effective in certain locations.

Table 4.1.3.a - WAN Option Analysis

	Costs		Technology		
Solution	**Incremental Capital**	**Ongoing**	**Performance**	**Risk****	**Lifespan**
Direct Network Connected	Medium	-	Excellent	Very Low	15+ years
WiMAX	Medium	Very Low	Good	Low	15+ years*
Cellular	Medium	Medium	Satisfactory	Medium	7-10 years
Satellite	Medium	High	Satisfactory	Medium	10+ years

* With suitable sparing program

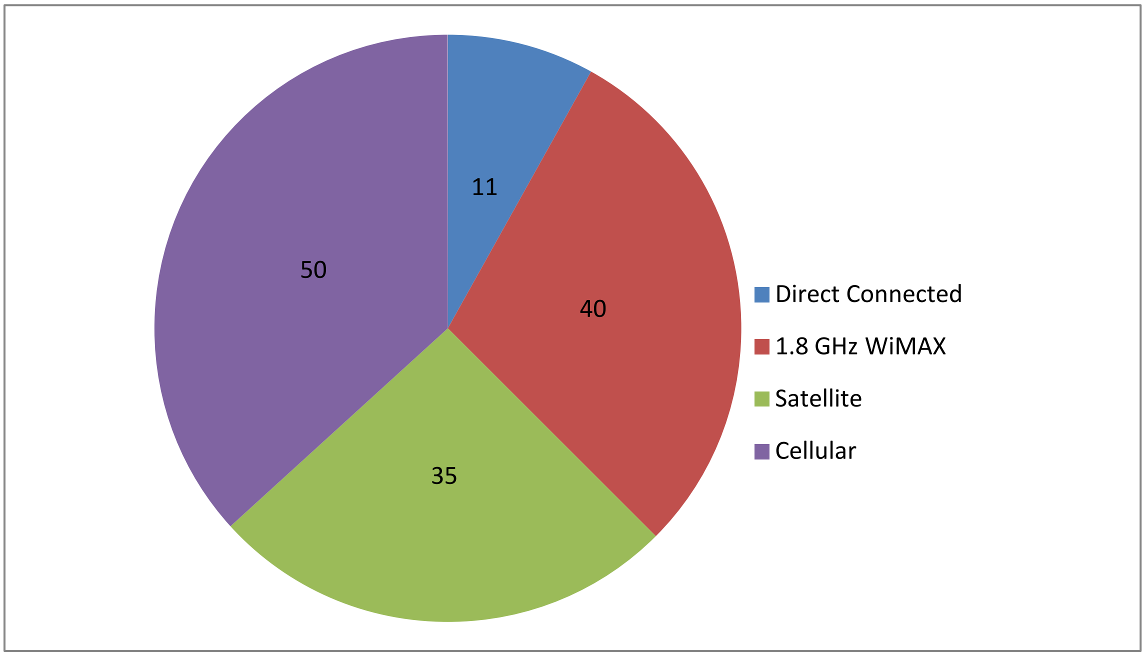
**Technology risks include obsolescence, amount of control over timing of migration, ease of replacement upon failure etc.

These costs combined with the technological considerations described above were used to determine the best WAN technology choice for each of the 136 collector locations in the preliminary network design based on the following guidelines:

1. Direct Network Connected – Chosen first if suitable infrastructure (fibre optic cable) is available for backhaul. This option has a low total cost of ownership, low risk and the greatest ability to be leveraged for other applications in the future.
2. 1.8 GHz WiMAX was chosen next as long as a suitable Base Station location existed (access to backhaul, FortisBC occupied transmitter site, grid power) and that base station location had the ability to service a minimum of 6 collector sites.
3. Cellular chosen next where coverage is available.
4. Satellite chosen as technology of last resort.

At the time of system deployment, the selection of the optimal available WAN solution will be based on the specific circumstances for the area to be served. Based on a preliminary analysis, however, the Company has forecast the following distribution of WAN technologies for the AMI Project as shown in Figure 4.1.3.a below.

Figure 4.1.3.a – Distribution of WAN Technologies



It is also anticipated that a small number of AMI meters (less than 1 percent) will not have an economic WAN option available (based on the technologies described above) at the time of AMI deployment. FortisBC plans to manually download data from the meters at billing period intervals. The Company expects to obtain the same information made available through the WAN technologies discussed above, but at less frequent intervals. The costs of the manual meter download have been included in the overall Project cost. FortisBC will continue to evaluate the economics of WAN options with the intent of eventually providing WAN connections for all meters.

4.1.4 HEAD END SYSTEM

An important characteristic of the advanced metering platform is the ability to report on all aspects of the system. This includes collection and aggregation of meter usage data, outage and event information, network health, security events, and trending statistics. The intelligence of the platform is in the HES which is an automated data collection system that contains three main applications.

1. The collection engine system is designed to optimize and coordinate all data collection. It is integral in managing secure data transfer and message processing between the meters and other utility systems.

2. The reporting system enables operators to understand the overall health of the AMI system including past and current performance. It is used to visualize and troubleshoot data interruptions across the AMI network.
3. The network management system provides a monitoring and control interface to all devices on the network including meters and collectors. This system supports real-time monitoring of connectivity status, event logging for diagnostics as well as alarming on key network parameters.

These systems are designed to seamlessly integrate with numerous upstream and downstream systems. Meter and usage data will be transferred to the MDMS for further processing and with the future possibility of outage data transferred to a downstream Outage Management system as further discussed in section 6.3.

4.1.5 METER DATA MANAGEMENT SYSTEM

The MDMS is a software application that maintains storage of the high volumes of data being sent from the meters in the AMI system. This data includes register, interval, voltage and meter event data such as tamper, high/low voltage and outage events. The MDMS can import data from a variety of sources including the HES, and other meter data collection systems such as MV-RS and MV-90 – both used by FortisBC today. As data is received, it is subjected to VEE processes that ensure the data stored is consistent and does not have any missing intervals.

VEE is a collection of algorithms that identify problematic information in the granular meter data received and uses tools to address quality issues before the data is made available for use by other utility systems. Problematic data may include anomalies in the information such as gaps, overlaps and redundancies, as well as tolerance issues between consumption reads and interval data. The MDMS provides the ability to select and adjust validation logic, rules and algorithms through an integrated calculation engine. When validation fails, the MDMS can be configured to execute contingencies, such as automatically estimating the read or passing a “no read”, which will be reported to staff on a “failed validation” report. The MDMS allows manual user interaction with the data, and all modifications are fully supported by auditable change tracking.

In addition to extensive VEE abilities, functionality of the MDMS includes aggregation and calculation of usage data for complex rate structures such as tier rates, TOU, CPP, and other conservation rates. After data is subjected to VEE processes it is ready for billing and analysis. The MDMS features sophisticated export management capabilities as well as full interoperability with other business systems used for billing, outage management, and load forecasting. Additionally, the MDMS can support gas and water meter data streams.

4.1.6 CUSTOMER INFORMATION PORTAL

As part of the Project, FortisBC plans to implement an internet-based portal that will enable customers to view usage information from their home computer. Once the customer has authenticated their identity by logging in to the secure portal, they will have access to their personal usage information, including their current and past trends, payment and financial interactions and other billing data.

Detailed reporting will give customers the opportunity to view recent energy usage to see when and how much energy they use at certain times of the month or day. Customers will also be able to compare their usage historically and make informed decisions on how they use their electricity and consider options for power saving changes at their premise. With a web portal, customers will be able to see a greater depth of detail of their hourly, daily or monthly usage with charts and graphs which is not currently possible with the existing metering system.

4.2 Project Scope

The AMI Project team worked with a broad cross-section of representatives throughout the Company to define detailed requirements of the proposed AMI Project. As a result, FortisBC developed twenty-four business Use Cases to identify, clarify and organize functional, process, and business requirements for the AMI system. They include a description of events that must take place in order for the system to be useful and achieve the desired results. These Use Cases, displayed in Table 4.2.a below, were applied throughout the procurement processes and will be used to assist final design, planning, system testing, and training to ensure the systems function as required.

Table 4.2.a - Business Use Cases for Advanced Metering System

Billing	Customer Service	Field Operations Services	AMI Installation & Maintenance	Finance and Reporting	Future Uses
B1	C1	O1	I1	R1	F1
CIS billing system uses AMI data to bill customers	Customer has access to readings, recent energy usage and cost Information	Distribution operator locates outage using AMI data and restores service	Utility installs, provisions and configures AMI system	Utility uses AMI data for Reporting	Customer requests to pair their meter with in-home devices such as a display
B2	C2	O2	I2		F2
CIS billing system uses AMI data to bill actual readings on move-in and move-outs	Customer billed on net metering tariff	AMI system recovers after power outage, communications or equipment failure	Utility manages overall health of the AMI system		Contract meter reading for other utilities (including gas and water)
B3	C3	O3			F3
CIS uses MV-90 system for industrial billing	Contact Centre uses AMI data to provide support to customers for common questions and concerns	Utility uses AMI to replace physical disconnection with virtual disconnection			Utility upgrades AMI system to address future requirements
	C4	O4			F4
	Customer has access to consolidated billing options and flexible billing dates	Distribution operators optimize network based on data collected by the AMI system			Customer billed on Pre-Pay tariff
	C5	O5			F5
	CSR uses AMI system to gain an on-demand reading	Operations completes meter related service requests post AMI			Development of TOU and/or CPP rates
	C6	O6			
	Utility detects possible tampering or theft at customer site	Security Requirements			
		O7			
		Utility remotely limits or connects / disconnects customer			

4.2.1 PROCUREMENT PROCESS

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. A third RFP for the meter deployment sub-contract will be competitively tendered by Itron prior to meter deployment. The content of the RFP documents were approved by an AMI Project Steering Team comprised of departmental leaders from across the Company, who also were responsible for evaluation of the proposals received.

Requirements included in the RFPs ensured that the selected system would be able to provide 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.

After the scoring of each proposal was completed, the top three vendors were selected based on their combined operational and financial scores. Once the short list was determined, selected proponents were invited to provide product demonstrations with reference checks of the proponents subsequently conducted.

4.2.2 PROCUREMENT RESULTS

MDMS

As described above, the MDMS is the repository of meter data. FortisBC considered the following as key requirements from its MDMS vendor:

- Financial/business stability;
- Experience providing same or similar products and services;
- Synchronization with all FortisBC systems;
- Project management, system design, commissioning and training;
- Value added service options such as Remote Disconnect/Reconnect, Event Management Tools, Outage Management information, and Customer Service Support Tools;
- System costs;
- VEE;

- Data analysis and rules management;
- MDMS system reporting;
- MDMS patch / major release process;
- MDMS system security;
- MDMS scalability; and
- Support.

Nine bids were received and seven compliant responses to the MDMS RFP were evaluated. After completing the systematic evaluation of the above bids, Itron's Enterprise Edition MDMS proposal was selected.

ADVANCED METERING INFRASTRUCTURE

The AMI system is inclusive of both advanced meters and the communication network required to transmit the meter (and other) data back to the Company and to allow the Company to transmit data to the AMI meter. FortisBC considered the following as key requirements from its AMI vendor:

- Financial/business stability;
- Experience providing same or similar products & services;
- LAN specifications;
- WAN specifications;
- AMI communication standards/protocols supported;
- Collector specifications;
- Meters and communication modules functionality;
- HES functionality;
- HAN functionality;
- Distribution automation functionality;
- Remote disconnect capabilities;
- Ability to integrate gas/water meters on system;

- Compliance with Health Canada regulations;
- System warranty;
- Quality assurance and change management processes;
- System implementation and design processes;
- Training and support services; and
- AMI system security.

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, however it is important to note that all proposals received by FortisBC use RF communications technology. No proposals were received for AMI systems using other forms of communication technology. After completing the evaluation of bids received, Itron was selected as the vendor for the AMI meters and network infrastructure.

The AMI solution proposed by Itron will provide the following:

- A communication network via a combination of RF mesh and other technologies;
- A solution that delivers:
  - Billing and hourly interval data;
  - Data processing and storage;
  - On demand read capability;
  - Remote disconnect / reconnect; and
  - Remote configuration.
- A reporting system to track and monitor performance of the AMI solution;
- A data repository for all AMI data using an MDMS;
- Integration of new applications to FortisBC systems;
- Deployment of network devices; and
- Deployment of customer meters including removal and disposal of existing meters in an environmentally safe and efficient way.

ADVANCED METERING INFRASTRUCTURE DEPLOYMENT

Itron is responsible for infrastructure deployment, and will competitively tender the deployment sub-contract for the meters, according to the requirements specified by FortisBC, following receipt of a Commission decision on the Project. Itron will manage all logistics associated with the infrastructure deployment while FortisBC will maintain overall project management of the end-to-end solution including deployment. A single control source accountable for product design, build, delivery and installation reduces logistical complexity, minimizes risk for the Company, and will bring FortisBC's AMI solution to production more quickly by avoiding potentially time consuming and costly interfaces between multiple vendors.

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.

4.3 Project Management

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.

The management of the AMI Project is supported by a cross-functional dedicated team. Project planning was formulated with input from all impacted departments and stakeholders. The following sections provide greater details on how the AMI Project will be implemented and managed.

4.3.1 PROJECT EXECUTION

Pre-planning and Use Case development for AMI implementation began in 2009. This was the first step to define in detail the Company's requirements for an AMI system and provide a basis for the subsequent RFPs that were created in order to select the best vendor for the Company's needs.

The AMI Project will be executed using a phased approach as summarized in Table 4.3.1.a. The final meter installations are expected to happen in 2015.

Table 4.3.1.a - Project Phases

Phase	Key Activities	Date
Project Planning and Kick Off		Q3 2013
Define	Solution requirements workshops. Use case refinement. Process development. Includes initial training of the FortisBC project team on the back office components – the "back office" describes the new AMI software (HES, MDMS) and how they integrate into existing FortisBC systems. Itron will gain further, detailed technical understanding of FortisBC's specific needs in order to successfully perform the work. Business and technical requirements will be defined in this phase which will form the basis of the project and allow everyone to move forward to the next phase.	Q3/Q4 2013
Design	Business solutions requirements document and technical architectural document completed and accepted. Finalize WAN, communications network and customer meter deployment plans. Create test plans. Create training plans. Develops the plans and designs to install, build, configure, test and operate the back office. Final communications system plan and the deployment plan for WAN, network devices, and customer meters will be completed.	Q4 2013
Build	Procure and install IT hardware. Build, configure and integrate software applications. Function, integration, end to end and solutions testing. HES and MDMS implemented and available for production. Executes the plans and designs to install, build, configure, integrate, test and operate the back office.	Q4 2013 Q2 2014
Deploy/ Operate	Commence communications network deployment. Commence customer meter deployment. Regional acceptance testing. Initiates the deployment of network devices and customer meters throughout the FortisBC territory and the activities associated with these major tasks including all acceptance testing. During this timeframe, the customer portal will be designed, integrated, and built.	Q1 2014 Q2 2014 – Q4 2015
Transfer	Meter installation complete. This phase transitions the responsibility of the operation of the HES and MDMS to FortisBC, and includes final system acceptance testing.	Q4 2015

Immediately following commencement of the Project, the define, design, and build phases of the Project will begin. The primary goal driving these first three phases of the Project is the requirement to get the back-office software systems operational (HES and MDMS are fully tested, integrated and implemented). This component is important as it will ensure that the Company will have visibility of the AMI system when the network devices and customer meters are installed. Central to the define, design, and build phases of the Project will be the creation of two documents, the business solution requirements and technical architectural document. These are intended to address FortisBC's requirements by laying out the design of the technical architecture, detailing how the HES and MDMS software applications will be configured, and how they will be integrated to each other as well as to FortisBC systems. Additionally, a number of planning documents designed to guide project activities such as communications, risk and issues tracking, reporting, testing and training will be created at that time.

Concurrent with the back-office work, Itron and FortisBC will finalize the plans for the communications network and meter deployment activities, including:

- Communications network site selection and make-ready work;
- Regional meter deployment schedule;
    - The Company's service territory will be divided into sub regions – largely matching existing meter reading routes – for meter deployment.
- Network device deployment; and
- WAN final design and deployment.

The network communication devices and AMI meters will be deployed in predefined sub-regions. Site surveys will be completed to ensure that each location initially chosen for the collectors and range extenders is suitable. The communications system deployment is designed to be accomplished in two steps:

1. The minimum number of collectors and range extenders required to initialize the AMI system is deployed first.

2. The communications system is optimized to achieve required stable performance by the addition of range extenders and/or collectors as necessary.

Each region will undergo complete end-to-end system testing to ensure that the performance standards and functionality of the AMI system are met before the region is accepted into service.

Concurrent with the last three quarters of the deployment phase, the customer information portal will be designed, integrated, and built.

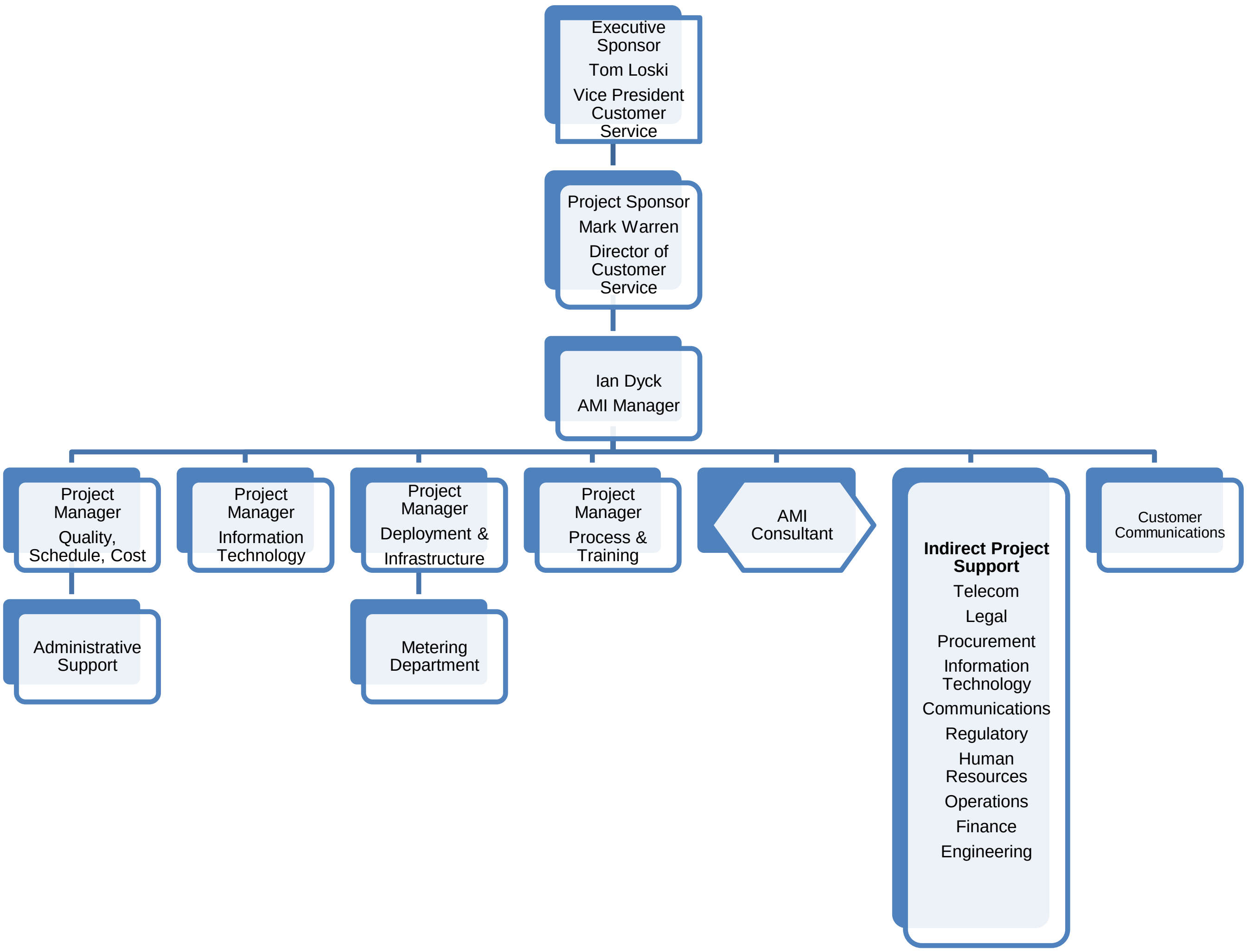
4.3.2 PROJECT SCHEDULE

FortisBC has created a detailed schedule of activities from commencement of the Project to completion. Project milestones represent significant times within the Project schedule. These milestones are associated with clearly delineated activities that need approval from FortisBC before moving onto the next task or phase of the Project. After receipt of the Commission's approval, no more than 60 days will be required to prepare resources for the commencement of the Project. Post-decision milestones are detailed in Table 4.3.1.a above and are subject to review and finalization during the design phase of the Project.

4.3.3 ROLES AND RESPONSIBILITIES

Figure 4.3.3.a below details the organizational structure for the AMI Project. Further description of each of the roles depicted in the organizational chart is provided below.

Figure 4.3.3.a - Project Functional Organizational Chart



EXECUTIVE SPONSOR

The Executive Sponsor is responsible for:

- Establishing the overall strategy for the Project;
- Ensuring that the AMI Project is aligned with overall organizational direction; and
- Championing the Project within the organization.

PROJECT SPONSOR

The Project Sponsor is accountable to ensure that the Project deliverables meet the objectives of the Project. The Project Sponsor is responsible for:

- With the Executive Sponsor, developing the AMI implementation strategy and relationships with external stakeholders;
- Marshalling support for the Project within the organization, and ensuring that sufficient and appropriate resources are assigned throughout the Project schedule;
- Ensuring the business objectives of the Project are met; and
- Coordinating the activities of and acting as part of the AMI Steering Committee.

STEERING COMMITTEE

The Steering Committee includes representatives from all major aspects of FortisBC operations. They act as the primary internal stakeholders for the AMI Project, and perform the following functions:

- Providing on-going strategic guidance and support for the Project;
- Providing business knowledge to the Project team;
- Reviewing Project status;
- Reviewing escalated issues (strategic, regulatory and organizational) for resolution;
- Reviewing and approving budget, project milestones and scope changes;
- Reviewing and approving Project communication plan;
- Committing resources to Project;
- Authorizing all changes to the initial scope, objectives, resources, plan and budget for the Project; and
- Formally accepting the completed Project.

The Steering Committee is comprised of:

- Director of Customer Services;
- Director of Network Operations;
- Director of Engineering Services;

- Senior Director, Legal Services;
- Manager of Network Services;
- Director of Information Systems; and
- Director of Financial Operations.

AMI MANAGER

The AMI Manager is responsible for delivering the Project on time and within the budget and scope constraints approved by the Project Sponsor. The AMI Manager is responsible for the following:

- Developing and maintaining Project plans and budget;
- Staffing the Project with support from the Project Sponsor, Steering Team and functional managers;
- Liaising with and guiding the vendor Project manager to ensure that the delivered solution meets FortisBC requirements as well as contractual obligations;
- Leading and co-ordinating activities of the Project Team;
- Preparing and providing status reports;
- Escalating issues as appropriate;
- Managing all aspects of the Project schedule;
- Managing Project issues; and
- Managing change requests.

PROJECT MANAGER, QUALITY, SCHEDULE AND COST (QSC)

The Project Manager, QSC, is accountable for managing schedule and cost change processes, and reporting throughout the entire Project. Project administrative support will report to this person.

This person is also accountable for quality control (including scope) through the design, build, implement and acceptance testing. This includes all testing related to implementing the back-office software systems (HES and MDMS) prior to field deployment of the communications network and meters, as well as the operations of the network management system. Finally, this person is accountable for acceptance testing related to regional deployments and the final system acceptance testing. All system testing resources will report to the Project Manager, QSC.

More specifically, the responsibilities of this project manager within the AMI Project are:

- Developing and managing cost and time schedules for the Project, including system testing;
- Tracking vendor service level agreements and report any variance to the FortisBC AMI Manager;
- Managing the infrastructure prioritization by regional meter roll out including all testing and required approvals in order to meet QSC expectations; and
- Supervising testing staff (both internal and external), including recruitment, coaching, discipline and training.

PROJECT MANAGER, INFORMATION TECHNOLOGY

The Project Manager, Information Technology is accountable for managing the definition, design, building and implementation of the software applications, including integration into new and existing FortisBC systems. This person is also accountable for the design, build, integration and implementation of the customer information portal. More specifically, the responsibilities of this project manager within the AMI Project are:

- Supervising internal development staff, including recruitment, coaching, discipline and training, Developing and managing cost and time schedules for AMI related systems, specifically:
    - MDMS;
    - HES;
    - Ad hoc and standard reporting related to AMI data;
    - Network management system;
    - Integration of all new AMI-specific software with existing FortisBC systems, as applicable;
    - Field deployment manager software integration; and
    - Customer information portal.

- Gathering, reviewing and communicating functional and business requirements for each of the integration points within the Project;
- Supervising vendor software development to ensure performance guarantees and quality requirements are met; and
- Managing change control processes for software implementations and ensuring IT change management processes and corporate controls are adhered to.

PROJECT MANAGER, DEPLOYMENT AND INFRASTRUCTURE

The Project Manager for Deployment and Infrastructure is accountable for the following portions of the AMI Project:

- Communications Infrastructure
  - Managing, with the vendor, the design, planning and scheduling of required communication infrastructure and supporting hardware (network devices);
  - Managing the site selection and verification, and, as applicable, managing site make-ready work;
  - Supervision of network device deployment staff, including vendor contractor staff;
  - Managing the vendor's adherence to the pre-defined network device roll-out schedule; and
  - Managing costs and issues relating to network device deployment, including the timing of network device purchases and tracking installation issues.
- Meter Deployment
  - Defining the implementation plan for AMI meter roll-out;
  - Development of the AMI meter deployment plan;
  - Supervision of AMI meter deployment Project staff, including deployment contractor staff;
  - Managing the vendor's adherence to the predefined roll-out schedule;
  - Managing costs and issues relating to AMI meter deployment, including the timing of meter purchases and keeping track of installation issues;

  - Identifying and resolving any AMI metering issues related to the installation of customer meters; and
  - Managing the hand-off of infrastructure to operational groups.
- Wide Area Network (WAN)
  - Developing and managing cost and time schedules for WAN;
  - Designing, building and implementing WAN infrastructure; and
  - Supervising internal staff, including recruitment, coaching, discipline and training, necessary for WAN development.

PROJECT MANAGER, PROCESS AND TRAINING

The Project Manager, Process and Training is accountable for identifying, updating and developing processes within each operational group that will be affected by the implementation of AMI. This person will work closely with individuals and groups throughout the Company in order to deliver the training necessary to achieve the benefits of the AMI Project. The following are the responsibilities of this project manager for the AMI Project:

- Identifying and updating all business processes that will be impacted by AMI through the continued evolution of the AMI Use Cases or identify and develop new business processes that will result from the implementation of an AMI solution;
- Identifying AMI related training requirements, developing and providing training to internal staff on AMI processes, the Project, and key messages related to the Project;
- Developing a graduated implementation plan to ensure these items are implemented on time and in the correct order to support the full AMI roll-out; and
- Communicating and receiving sign-off from stakeholders and functional managers on defining the requirements for configuring and building the AMI solution.

AMI CONSULTANT

The AMI Consultant will assist with the following portions of the implementation of AMI:

- Assisting with design and testing of all aspects of the back office;
- Assisting with the Regional and System Acceptance Testing; and
- Assisting with new and redesigned process development.

INDIRECT PROJECT SUPPORT

The AMI Project will impact many functional areas within the Company, and will change how the Company interacts with its customers. To be successful, the entire Company must be supportive of the changes required to processes, communications, and operations that will occur. FortisBC departments, as represented by functional managers, will provide their expertise as well as departmental resources when required to ensure a successful Project.

CUSTOMER COMMUNICATIONS

Customer communications will be responsible for managing direct customer communications during implementation to ensure a successful Project.

4.3.4 CHANGE MANAGEMENT POLICIES

Any changes to project deliverables will be clearly documented. Changes within predefined schedule, scope or costs will be managed by the Project Manager, QSC and are subject to the approval of the AMI Manager. Changes outside of predefined schedule, scope or cost will require the approval of the Project Sponsor and AMI Steering Team.

4.3.5 PROJECT RISK AND MITIGATION STRATEGIES

AMI technologies have proven to be very reliable as evidenced by the growing number of installations across Canada and throughout the United States and Europe. However, any complex project carries potential risk. FortisBC has identified risks and created an appropriate response to each.

The structure of the contract that FortisBC negotiated with Itron Canada has ensured costs certainty on major Project elements, and eliminated risk to the Company in many cases. An overview of risks and mitigation plans is provided in Table 4.3.5.a below.

1 **Table 4.3.5.a - Overview of Risks and Solutions**

Risk Category	Risk Trigger	Mitigation / Response Strategy	Contingency
Schedule	The Project does not meet set milestones in the project schedule.	FortisBC has selected Itron Canada as its vendor for MDMS, communications network devices and deployment, and meters and their deployment. Elimination of the need to manage multiple vendors reduces project schedule risk. Internally, the steering team ensures continued internal support and resources throughout the AMI Project thereby mitigating schedule risk from internal sources.	Financial penalties are incorporated within the contract to incent the vendor to stay on schedule.
Cost	Project costs increase over the planned budget.	FortisBC has selected a single vendor for MDMS, communications network devices and deployment, and meters and their deployment. All major cost elements (meters, communications devices, software applications) are provided on a fixed-price or fixed-unit-price basis. 64% of the contracted price was fixed at contract signing, with the remaining 36% to be fixed during the define/design stage of project implementation. Where estimates have been used, an appropriate contingency has been added to the project cost.	Cost contingencies provided for: - MDMS - Meter and communication network devices - Professional services - Meter deployment Overall Project contingency is 6.4%
Scope	Change requests are received.	A detailed change control process has been implemented as an integral part of the project management process. Significant changes must be signed off by AMI steering team.	Change requests may be denied.
Performance / Quality	Failures in integration work OR AMI system components not performing as required during the design phase of the Project.	FortisBC has set out a testing schedule at all major milestones and has also ensured that there are proper testing phases in place for the vendor such as functional testing during integration activities and factory acceptance testing of the AMI equipment.	Warranties related to equipment, software and all aspects of system performance are included in the contract.

2

4.4 AMI Talent Transition Plan

FortisBC has consulted with impacted employees and Union Representatives throughout the development of the AMI Project. FortisBC first notified the International Brotherhood of Electrical Workers (IBEW) Local 213 of plans to examine the possibility of an AMI deployment several years ago. A detailed plan, as per the IBEW collective agreement, will be executed as necessary project approvals are obtained.

Ongoing communication with employees in regard to the proposed AMI Project is critical in reducing any unnecessary impact to the individuals directly affected. Discussions have been underway with affected staff, and will continue as updates are available. The meter reading supervisor will facilitate communications with the meter reading group to confirm the filing with the BCUC and to provide an opportunity to address any questions that arise. FortisBC recognizes that the Project will result in a net reduction of 9.5 full-time and part-time (temporary) staff, however, where practical staff will be trained and transitioned to other areas of the organization as appropriate.

5.0 PROJECT COSTS AND BENEFITS

This section of the Application describes in detail the costs and benefits expected from implementation of the FortisBC AMI Project.

The capital cost of the Project is $47.7 million and will provide customers with $18.6 million in net benefits over the economic life of the Project, in addition to a number of operational and customer service benefits. Financial analysis of the Project shows that rates will be lower than they would be without the AMI Project as evaluated over the 20 year study period, due primarily to cost savings from reduced electricity theft and a reduction in manual meter reading. In the analysis of net benefits, FortisBC has accounted for all known and foreseeable capital and operating costs and savings related to the Project.

The summary table below displays the total savings to FortisBC customers between 2015 and 2030 and calculates the net present value of these savings in 2012 dollars.

Table 5.0 - AMI Cost and Benefit Summary

Benefits		**2012 NPV ($000s)**
	Meter Reading	(23,785)
	Theft Reduction	(38,386)
	Remote Disconnect/Reconnect	(5,466)
	Meter Exchanges	(797)
	Contact Centre	(441)
Costs		
	Operating Costs	14,320
	Depreciation Costs	14,686
	Carrying Costs	17,239
	Income Tax	4,043
Total		**(18,589)**

This section of the Application describes in detail the estimated capital expenditures and cost savings expected from implementation of the AMI Project. Section 5.1 provides information regarding the costs of implementing AMI. Section 5.2 summarizes the revenue requirement and rate impact related to the AMI Project. Section 5.3 details the quantifiable financial benefits that will be realized from the Project.

5.1 Project Costs

The AMI Project cost is estimated at $47.7 million. The cost and timing of major Project elements is summarized in Table 5.1.a below. Software, network communication devices, AMI meters are contracted and have firm total prices or unit prices. The remaining cost estimates are based on the most recent information currently available to FortisBC and are based on an in-service date of fourth quarter 2015. The Company prepared the Project cost estimate based on AACE Class 3 specifications in accordance with the CPCN Guidelines (Commission Order G-50-10). The cost certainty afforded by the terms of the contract with Itron Canada has resulted in an overall Project contingency of 6.4 percent.

Table 5.1.a – AMI Project Capital Cost Summary

	Item	**2013**	**2014**	**2015**	**Total 2013-2015**
		($000s)			
1	Third Party Software and Services	4,746	723	361	5,830
2	Meters (Including Deployment)	384	10,089	9,850	20,323
3	Network Infrastructure	-	1,677	2,772	4,449
4	System Integration	1,519	511	319	2,349
5	Theft Detection	-	-	1,100	1,100
6	Project Management	936	1,274	920	3,130
7	CPCN Development/Approval Costs	4,915	-	-	4,915
8	Capitalized Overhead, AFUDC, PST	1,230	2,519	1,842	5,592
9	**Total**	**13,730**	**16,793**	**17,166**	**47,689**

Further details on the capital expenditures are provided below.

Third Party Software and Services – These costs are comprised of the MDMS software, supporting modules, the HES and network management system, security appliances and software installation, integration, and configuration.

Meters - These costs include the meters and modules, and all installations, management and deployment costs for the meters including the implementation of Field Deployment Management software.

Network Infrastructure - These costs are comprised of all network infrastructure, network applications, WAN costs and test lab. This equipment will be required to collect data from each meter and communicate that data back to FortisBC systems. The costs also include related network installation and configuration costs.

System Integration - These costs are comprised of internal IT costs required to integrate the new AMI software with existing FortisBC systems and for the creation of the Customer Information Portal.

Theft Detection - These costs are for additional metering required to detect losses on the distribution system.

Project Management - Project Management costs include resources, design, testing and training.

CPCN Development/Approval - These costs include the CPCN application development cost, including procurement, and the forecast costs associated with the regulatory process.

Capitalized Overhead, Allowance for Funds Used During Construction, Provincial Sales Tax – These are ancillary costs related to the Project.

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.

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	-	(183)	(169)	(243)	3,854	3,259
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)**	**(1,050)**	**(504)**	**(1,143)**	**(836)**	**(3,678)**
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)	915	(174)
Contact Centre	-	20	7	(20)	(1,163)	(1,157)
Total Operating Expenses	**-**	413	(208)	(1,961)	(38,762)	(40,518)
Theft Reduction	(383)	(987)	(1,711)	(2,835)	(87,789)	(93,705)

The financial analysis of the proposed AMI Project includes the impact of the net sustaining capital and operating costs as shown in the table above. A copy of the financial NPV analysis of the AMI Project is provided in Appendix D, and has also been included as an embedded electronic Excel file with this filing.

5.1.1 CPCN DEVELOPMENT/APPROVAL COSTS

FortisBC has been developing this CPCN Application over the past several years, capturing the costs in a non-rate base deferral account, and reporting the details to the Commission in relevant revenue requirements filings. These deferred expenditures have been included in this Application as part of the Project and for Commission approval as part of the CPCN Application, and, following Project approval, will be amortized over the life of the Project. The following are the costs incurred by the Project at the date of filing.

Table 5.1.1.a - AMI Project Development and Regulatory Costs

	Activity	Cost
	($000s)	
1	2007 AMI Application	291
2	2012 AMI Application	1,687
3	Consultants	275
4	Regulatory Process (forecast)	2,660
5	**Total**	**4,913**

As detailed above, the Company expects to incur costs of approximately $4.9 million, inclusive of the CPCN development cost, the proposed 2012 hybrid written/oral regulatory process, and additional public communications.

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 prudency 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.

5.1.2 ONGOING SUSTAINING CAPITAL AND OPERATING COSTS

With the implementation of the AMI Project, there will be new costs involved to ensure that the AMI system is maintained and that all benefits are realized. Additionally, as a result of the AMI implementation, there will be changes to some existing operating costs.

The New Operating and Maintenance Costs (as shown above in Table 5.1.b) are anticipated to fall into the following 5 major categories:

- Staffing;
- Software Licensing / Support;
- Wide Area Network (WAN);
- Hardware; and
- Operations

Existing operations that will be significantly impacted by the AMI system include:

- Meter Reading;
- Disconnect/Reconnect;
- Meter Exchanges, and
- Contact Centre

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 required to troubleshoot, fix, replace and/or install AMI-related network devices;
- Telecom Engineer – 0.5 additional office resources required to monitor and maintain the health of the AMI system. Work will include optimization activities, planning and coordinating all the work that has to be done on the network; and
- Revenue Protection Analysis Team – 2 resources required to analyze data coming from the AMI system, investigate specific alerts and alarms and strategically deploy energy balancing meters in high risk areas.

The changes in existing operating expenses are elaborated upon in Section 5.3.

The implementation of AMI will also result in new sustaining capital costs required to support the system, as well as an increase in sustaining costs related to customer growth and the incremental cost of AMI meters relative to the cost of existing meters. The incremental increase in sustaining costs related to meter growth is shown as *Meter Growth and Replacement* in Table 5.1.b above. For the period 2013 – 2021, this category shows a net savings as a result of the avoided meter compliance costs resulting from the deployment of AMI meters.

The incremental increase in sustaining costs required to support the AMI system are shown as *IT Hardware, Licensing, and Support Costs* in Table 5.1.b. These sustaining capital costs result from the addition of new software such as the MDMS, HES and network management system, and include ongoing software licensing and support costs.

5.2 Revenue Requirement and Rate Impact

The following assumptions have been made in the cost analysis provided below:

5.2.1 DISCOUNT RATE

The NPV of Revenue Requirements has been calculated over a 20 year period using an 8 percent nominal discount rate based on FortisBC's Weighted Average Cost of Capital.

5.2.2 GENERAL INFLATION RATE

Inflation is estimated to be 1.8 percent over the 20 year analysis period. This is based on a Conference Board of Canada Provincial forecast dated April 19, 2012 of BC CPI for the period 2012 – 2016 inclusive.

5.2.3 COMPOSITE DEPRECIATION RATE

The composite depreciation rate of 5.22 percent for the Project was calculated based on the following estimated depreciation rate of each asset class as below:

- Meters - Assumptions regarding depreciation rates for the AMI meters have been determined based on the observed useful lives as established through industry experience, as well as through the manufacturer's recommendations. This has resulted in a 5 percent depreciation rate based on an estimated economic life of 20 years;
- Computer Equipment and Software – 5.01 percent depreciation rate based on the 2011 Depreciation Study; and
- Communication Structures and Equipment – 8.05 percent depreciation rate based on the 2011 Depreciation Study.

5.2.4 COMPOSITE CCA RATE

The Project composite CCA rate of 15.72 percent was calculated based on the following CCA 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.

5.2.5 COMBINED INCOME TAX RATE

The combined income tax rate is the combined Canadian federal and BC provincial rates. The 2012 combined rate is 25 percent and is assumed to remain at that level over the analysis period.

5.2.6 CARRYING COSTS

The Project carrying costs were calculated assuming FortisBC's deemed capital structure of 60 percent debt and 40 percent equity. Interest expense was calculated assuming a weighted average cost of approximately 6 percent. The cost of equity was calculated assuming a return on equity of 9.9 percent.

All expenditures in this analysis are presented on an incremental basis to the base case, which is the status quo alternative identified in Section 7.1.

The implementation of AMI has a net present value impact on rates of -1 percent and an associated net benefit of $18.6 million as evaluated over a 20 year period. The maximum incremental annual rate impact is 1.7 percent in 2014.

5.2.7 ACCOUNTING TREATMENT OF EXISTING METERS

FortisBC has considered three options for the accounting treatment of the existing meters to be removed from service as part of the proposed AMI Project. They are:

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.

FortisBC recommends option 1 which does not require an accounting variance.

5.3 Financial Benefits

The AMI Project has various benefits. Many of those benefits will result in cost savings to customers. The benefits that can be quantified are detailed below and have been included as part of the financial analysis of the AMI Project.

5.3.1 METER READING

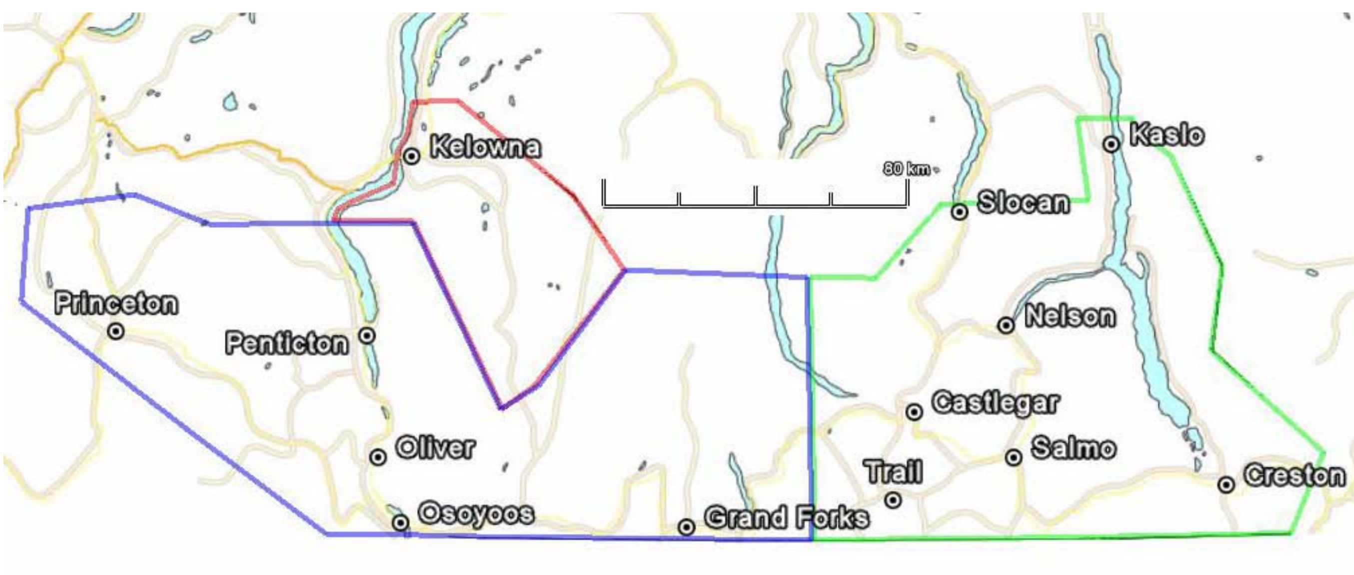
The existing meter reading system is a labour intensive manual process. Because of this, it is inherently expensive to obtain additional consumption data beyond the bimonthly readings obtained for the majority of customers today. AMI will reduce the cost of meter readings by virtually eliminating the need for a manual meter reading process. As well, the inevitable, inadvertent errors resulting from the manual keying of meter reads will be eliminated.

The meter reading workforce is comprised of 20 employees including 3 lead-hands, 14 regular full time meter readers, 1 regular part time meter reader, a meter data management analyst and a supervisor. Meter readers are members of the IBEW, Local 213, and the meter data management analyst is a member of the Canadian Office and Professional Employees (COPE) Union, Local 378. The supervisor is a non-union position. The meter data management analyst is responsible for the upload of meter reads to the billing system and for administrative support for the meter reading function. The meter reading supervisor is responsible for the day-to-day supervision of the meter reading staff including scheduling, resource management, and the safety of the meter readers.

FortisBC's service territory covers more than 17,000 square kilometres, from the mountainous West Kootenay region of British Columbia, to the urban area of Kelowna, to the semi-arid South Okanagan and Similkameen regions. The meter reading function is organized geographically into three areas: Kelowna, South Okanagan and the Kootenay regions. Each area is responsible for a set of meter reading routes which are scheduled daily over an average of 20 business days per month, with a bimonthly frequency.

The figure below shows the FortisBC service territory and indicates each of the current meter reading regions: South Okanagan (blue), Kelowna (red) and Kootenay (green).

Figure 5.3.1.a - Meter Reading Zones in FortisBC Service Territory



Currently, over 99 percent of FortisBC meters are read by a meter reader, requiring an on-site visit to each meter location. 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.

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).

Although the majority of customer meters are read on a bimonthly basis, some customers (approximately 14 percent of residential customers and 4 percent of small commercial customers) elect to be billed on a monthly basis (primarily to take advantage of the equal payment plan program). As a result, meter readings for bills issued between the bimonthly meter reads are estimates based on historical consumption. Meter readings must also be estimated when a rate change occurs to provide an approximation of a customer's consumption before and after a rate change.

Commercial customers subject to a demand billing determinant are subject to monthly meter readings and are billed on a monthly cycle (approximately 30 days) in order to capture and reset the peak demand registered during the billing period.

Additionally, FortisBC obtains manual readings each time a customer requests to move in or out of a premise, or to address a customer's request to verify a previous reading. These additional reads, termed "soft reads", account for approximately 10 percent of total meter reading costs.

The collection of meter data requires that all but one employee (the meter data analyst) drive a Company vehicle. Technical support for the meter reading handheld units is provided via a yearly maintenance contract with the manufacturer as well as support from an internal IT resource. Table 5.3.1.a below provides a summary of meter reading costs for the past four years.

Table 5.3.1.a – Historical Meter Reading Costs

	Actual Costs			
	2008	**2009**	**2010**	**2011**
Total Operating Labour (incl. Benefits)	$1,709,755	$1,639,648	$1,761,794	$1,923,792
Total Non-Labour Operating	$115,942	$137,034	$110,583	$140,381
Vehicle Expenses	$306,168	$316,152	$340,200	$340,262
Handheld Support	$12,864	$14,653	$16,627	$16,628
Total Meter Reading Expenses	**$2,144,730**	**$2,107,488**	**$2,229,204**	**$2,421,063**

The implementation of an AMI system will allow the Company to reduce meter reading costs, reduce the need to access customer properties, and eliminate bill estimates associated with customer moves and rate changes.

Table 5.3.1.b below details the meter reading savings (labour costs and non-labour costs) resulting from the proposed AMI Project. Labour cost savings include salaries and benefits. Non-labour cost savings include vehicle expenses, general administrative expenses (meals, travel, phones etc.), handheld unit support and the cost required for replacement of these handheld reader units every seven years. As a result of the elimination of the current manual meter reading process, a savings of approximately $24 million is realized on a net present value basis over the life of the Project. Please refer to Table 5.3.1.b below for further detail on the yearly forecast savings resulting from the elimination of manual meter reading.

Table 5.3.1.b - Net Meter Reading Savings

Savings ($000s)							
Meter Reading	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	-	-	(998)	(2,544)	(2,713)	(2,757)	(2,803)
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	(2,983)	(3,032)	(3,082)	(3,274)	(3,329)	(3,384)	(3,589)
	2027	**2028**	**2029**	**2030**	**2031**	**2032**	
	(3,649)	(3,710)	(3,929)	(3,991)	(4,058)	(4,292)	

5.3.2 THEFT REDUCTION

Energy theft is a serious concern for FortisBC and its customers for safety and financial reasons. Premises where theft is occurring have been altered without the certification required under the *Safety Standards Act*. Many of these service alterations impose fire hazards and other risks on unknowing neighbours, first responders and electric utility workers.

Energy theft is unmetered electricity that is provided by FortisBC through increased power purchases but is not paid for directly by the customers consuming the energy. This increased power purchase cost places a burden on all other customers as theses costs must be recovered through electricity rates. FortisBC is therefore motivated to reduce energy theft in support of the Company's mandate to deliver energy safely at the most reasonable cost to customers. Reduction in electricity theft will result in the following benefits:

- Reduction of safety hazards;
- Increased revenues; and
- Decreased power purchase costs.

CAUSE OF ENERGY THEFT AND ASSOCIATED LOST REVENUES

The majority of energy theft at FortisBC is attributed to indoor marijuana grow operations. Customers engaged in indoor marijuana grow operations are motivated to steal electricity in an effort to avoid detection for two main reasons:

- Customer billing records can be subject to production orders by law enforcement officials and used as evidence to secure search warrants; and
- 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.

As a result, marijuana grow operators often rely on energy theft to avoid scrutiny by authorities. Table 5.3.2.a below provides detail on the derivation of the AMI theft benefit calculation. The table inputs are drawn from FortisBC internal data compiled from 2007 to 2011 as well as published academic research on the subject.

Table 5.3.2.a – Key Assumptions

	Item	Source	Data
A	Total marijuana sites in BC	Plecas Report	13,740
B	FortisBC proportionate share of residential customers	Operating statistics	6%
C	Marijuana sites in FortisBC service territory	A x B	824
D	Average number of 1000W lights per site	FortisBC	30
E	Days in grow cycle	Plecas Report	90
F	Daily kWh per light		14
G	Number of grow cycles per year		4
H	Annual energy per light (kWh)	E x F x G	5,040
I	Annual energy per site (kWh)	H x D	151,200
J	Annual marijuana energy use (MWh)	(C x I)/1000	124,589

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 in 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.

Dr. Plecas reports an average of 36 lights per site; however, FortisBC historical data indicates 30 lights per site. Although FortisBC data indicates the number is trending upward, the more conservative 30 has been used in the theft benefit calculation. Each light consumes an average 14 kWhs per day based on a combination of 18 and 12 hours cycles which translates into 151,200 kWhs annually per site. Therefore these 824 sites will consume approximately 125,000 MWhs in 2012.

In addition to the basic assumptions outlined above, the more critical assumptions relate to the deterrence impact of the current FortisBC revenue protection program as compared to the deterrence impact resulting from the proposed AMI-enabled revenue protection program.

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.

PROBABLE STATUS QUO FORECAST

In determining the increased theft detection and deterrence benefit to FortisBC customers of an AMI program, it is necessary to forecast the changes in the status quo if deployment does not proceed. FortisBC projects that the number of marijuana sites will continue to increase at 2 percent annually and that the theft detection rate of 8 percent will remain constant using current methods and resources. However, it is anticipated that after it becomes clear that FortisBC will not have an AMI-enabled theft detection program (as would be the case with the status quo), the current deterrence benefit will drop from 75 percent in 2012 to 70 percent by 2017. FortisBC makes this assumption in consideration of BC Hydro's comprehensive theft detection program and the resulting perception that energy theft will be a more viable option in FortisBC's service territory. The Company believes this to be an appropriately conservative approach to modeling the impact of not having an AMI-enabled theft detection program.

PROBABLE AMI FORECAST

There is considerable uncertainty in predicting long term customer behaviour related to marijuana production in an environment of political debate on the topic and evolving legislative response. This uncertainty dictates that the Company take a conservative approach in assigning theft benefits to AMI deployment while at the same time present the additional risk and cost imposed on FortisBC customers of not deploying AMI technology. 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. This reduction in gross load is accounted for by assuming a 1 percent growth in grow sites in the probable AMI forecast as opposed to the 2 percent assumed in the status quo model.

The enhanced revenue protection program proposed in this Application is expected to increase the benefit to customers above the current status quo program. For the reasons described below, AMI-enabled revenue protection is expected to increase theft detection from 8 to 25 percent by 2016, and gradually increase deterrence from 75 to 95 percent by 2021. The assumptions of the probable AMI forecast for the first five years of the project are detailed in Table 5.3.2.b below.

Table 5.3.2.b – Probable AMI Forecast

Probable AMI Forecast

		2012	2013	2014	2015	2016
Marginal Revenue	per MWh	$ 120.03	$ 125.98	$ 136.78	$ 148.32	$ 160.63
Marginal Cost	per MWh	$ 54.68	$ 57.30	$ 61.18	$ 64.49	$ 68.47
Marginal Revenue Margin	per MWh	$ 65.35	$ 68.68	$ 75.60	$ 83.83	$ 92.16
Status Quo - Probable						
Deterrence (% paying grow-ops)		75%	74%	73%	72%	71%
Investigation success		8.0%	8.0%	8.0%	8.0%	8.0%
Total sites		824	841	858	875	892
Total paying sites		618	622	627	631	635
Total theft sites		206	218	231	244	257
Identified theft sites		16	17	18	20	21
Revenue margin from paying sites		6,109,373	6,463,489	7,162,791	7,996,908	8,852,497
Power purchase cost from theft sites		(1,703,956)	(1,892,737)	(2,137,580)	(2,378,679)	(2,661,337)
Recovered revenue from theft identification		359,080	399,492	458,782	525,188	599,373
Total benefit/(cost) from Status Quo - Probable		**4,764,497**	**4,970,244**	**5,483,994**	**6,143,416**	**6,790,533**
AMI Program - Probable						
Deterrence (% paying grow-ops)		75%	77%	79%	81%	84%
Investigation success		8.0%	8.0%	12.0%	15.0%	25.0%
Total sites		824	833	841	849	858
Total paying sites		618	641	663	691	721
Total theft sites		206	191	177	158	137
Identified theft sites		16	15	21	24	34
Revenue margin from paying sites		6,109,373	6,660,390	7,584,059	8,759,240	10,045,812
Power purchase cost from theft sites		(1,703,956)	(1,657,038)	(1,641,857)	(1,543,771)	(1,417,774)
Recovered revenue from theft identification		359,080	349,744	528,580	639,091	997,826
Total benefit/(cost) from AMI - Probable		**4,764,497**	**5,353,097**	**6,470,782**	**7,854,560**	**9,625,864**
Total probable net benefit/(cost) from AMI		**-**	**382,852**	**986,789**	**1,711,144**	**2,835,330**
		NPV of Net Benefit				
		$ 38,386,403				

A key assumption included in the above analysis is the ongoing deterrence effect of FortisBC's AMI-enabled revenue protection program. The enhanced program will provide a customer benefit with a net present value of approximately $38 million over the life of the Project. FortisBC's financial analysis of the AMI Project as presented in this Application incorporates the projected benefit as determined under the probable AMI forecast scenario described above.

Potential AMI Forecast

As an alternative to the conservative probable analysis presented above, FortisBC also prepared an analysis of the potential benefit that may be achieved by implementing an AMI-enabled theft detection program. This analysis has been prepared using the following assumptions:

- An increase in the annual growth rate of marijuana production sites from 2 percent to 3 percent in the status quo model for five years (2013 – 2017);
- 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.

These revised assumptions can be supported by the following considerations.

- The theft ratio in the status quo may increase more quickly if the municipalities in FortisBC service area decide to engage in "safety focus" initiatives or if growers from other jurisdictions move to FortisBC's electric grid and decide to steal versus pay;
- 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 these sites begin to steal electricity, the 36 light average reported by Plecas can be readily supported; and
- The improved quality of tips and increased theft detection anticipated as a result of AMI deployment may increase the perception of risk and allow the deterrence to increase above 95 percent.

The potential AMI benefit calculation increases the NPV benefit to customers to approximately $52 million over the 20 year analysis period. The assumptions of the potential AMI forecast for the first five years of the Project are detailed in Table 5.3.2.c below.

Table 5.3.2.c – AMI Potential Forecast

Potential AMI Forecast

		2012	2013	2014	2015	2016
Marginal Revenue	per MWh	$ 120.03	$ 125.98	$ 136.78	$ 148.32	$ 160.63
Marginal Cost	per MWh	$ 54.68	$ 57.30	$ 61.18	$ 64.49	$ 68.47
Marginal Revenue Margin	per MWh	$ 65.35	$ 68.68	$ 75.60	$ 83.83	$ 92.16
Status Quo - Potential						
Deterrence (% paying grow-ops)		75%	74%	72%	71%	69%
Investigation success		8.0%	8.0%	8.0%	8.0%	8.0%
Total sites		824	849	875	901	928
Total paying sites		618	624	631	637	644
Total theft sites		206	225	244	263	284
Identified theft sites		16	18	19	20	22
Revenue margin from paying sites		7,331,247	7,781,870	8,653,304	9,695,095	10,771,451
Power purchase cost from theft sites		(2,044,747)	(2,335,566)	(2,705,796)	(3,082,448)	(3,524,487)
Recovered revenue from theft identification		430,896	488,173	569,515	660,942	763,388
Total benefit/(cost) from Status Quo - Potential		**5,717,396**	**5,934,476**	**6,517,023**	**7,273,589**	**8,010,352**
AMI Program - Potential						
Deterrence (% paying grow-ops)		75%	77%	79%	81%	84%
Investigation success		8.0%	8.0%	12.0%	15.0%	25.0%
Total sites		824	833	841	849	858
Total paying sites		618	641	663	691	721
Total theft sites		206	191	177	158	137
Identified theft sites		16	15	21	24	34
Revenue margin from paying sites		7,331,247	7,992,468	9,100,871	10,511,088	12,054,975
Power purchase cost from theft sites		(2,044,747)	(1,988,445)	(1,970,228)	(1,852,526)	(1,701,329)
Recovered revenue from theft identification		430,896	419,693	634,296	766,909	1,197,391
Total benefit/(cost) from AMI - Potential		**5,717,396**	**6,423,716**	**7,764,939**	**9,425,471**	**11,551,037**
Total potential net benefit/(cost) from AMI		**-**	**489,240**	**1,247,916**	**2,151,883**	**3,540,684**
		NPV of Net Benefit				
		$ 52,041,696				

The potential AMI theft reduction benefit detailed above would improve the net present value of the AMI Project to approximately $32 million, with a cumulative rate impact of -1.8 percent.

Based on academic research published by Dr. Darryl Plecas, RCMP University Research Chair at the University of the Fraser Valley and information from Professor Neil Boyd, professor of criminology at Simon Fraser University, FortisBC has prepared two additional calculations based on its interpretation of their data: a low range ("Low Range") and a high range ("High Range") estimate.

As compared to the probable AMI forecast discussed above, the key difference reflected in the Low Range analysis is the assumption that marijuana production sites produce 3 grow cycles per year as opposed to 4 grow cycles per year. Although this assumption forms part of the Low Range analysis, FortisBC's internal data supports the assumption used in the probable AMI forecast that marijuana grow sites operate on a continuous basis (4 cycles annually). The Low Range analysis indicates a net benefit of approximately $29 million resulting from an AMI-enabled theft detection program.

As compared to the AMI potential forecast discussed above, the key difference reflected in the High Range analysis is the assumption that theft deterrence begins at 48 percent and does not improve in the status quo model, but does gradually improve in the AMI model. This analysis indicates a net benefit of approximately $93 million resulting from the deployment of AMI.

Table 5.3.2.d – Comparison of Theft Reduction Analyses

Forecast	Result
Low	$29M
Probable	$38M
Potential	$52M
High	$93M

AMI-ENABLED REVENUE PROTECTION PROGRAM

FortisBC intends to implement new AMI-enabled processes that will help identify potential theft sites. These new processes reduce reliance on external leads and increase theft recoveries to the benefit of FortisBC customers. The improved theft detection processes will be implemented in two phases.

Phase I -Theft Detection Improvements

The following features enabled by the AMI system that will improve theft detection.

Tamper Detection

Advanced meters have a tamper detection feature that will automatically notify FortisBC if they have been removed from the meter socket, inverted or otherwise manipulated. The tamper flags from the AMI system will begin to provide additional leads for FortisBC investigators as soon as deployment begins in 2014.

Improved Data Quality

Advanced meters are capable of recording energy consumption, instantaneous load, and voltage at frequent intervals whereas electro-mechanical meters collect only peak load and the total energy used every 60 days. A review of these consumption files using existing data analysis tools will increase both the quality and the number of leads on potential theft sites.

On-Demand Meter Readings

On-demand meter reading enhances field investigator productivity by eliminating the need to physically read meters to verify theft. This feature eliminates return trips to premises under investigation and improves the safety of the investigator by reducing the need to access premises potentially engaged in illegal activities.

The combination of these three improvements, which will increase both the number of leads and the efficiency of field verification of theft, is expected to increase detection from the current 8 percent to 12 percent beginning with meter deployment in 2014.

Phase II -Theft Detection Improvements

Energy Balancing

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-connected transformer meters can be strategically deployed downstream to effectively balance the energy inventory in targeted areas of the feeder.

This energy balancing methodology is specifically prescribed in section 4.1 of the Smart Meters and Smart Grid Regulation 368/2010 as provided under the *Clean Energy Act*. While FortisBC is not legislated to install advance meters or employ energy inventory balancing, the Company is cognizant of the government's goal of having advanced meters and a smart gird deployed in utilities other than BC Hydro and has included this technology as part of the Application.

Energy balancing will require the purchase of feeder, transformer and portable wireless meters plus the associated annual operational expense. The Company proposes a capital investment of $1.1 million for a selection of energy balancing meters. This capital cost is based on preliminary unit costs quoted from vendors who are active in product development, and has been included in the capital expenditure request for the AMI Project. The AMI Project includes a strategic deployment of these meters beginning in 2015. The accompanying operational expense is forecast at $0.24 million in 2015.

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.

SAVINGS FROM ENERGY THEFT REDUCTION

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.

Table 5.3.2.e - Forecast Savings from Energy Theft Reduction

<table>
<tr><th colspan="8">Forecast Savings ($000s)</th></tr>
<tr><td rowspan="8">Theft Reduction</td><td rowspan="2">Phase 1</td><td>2013</td><td>2014</td><td colspan="4" rowspan="2"></td></tr>
<tr><td>(383)</td><td>(987)</td></tr>
<tr><td rowspan="6">Phase 2</td><td>2015</td><td>2016</td><td>2017</td><td>2018</td><td>2019</td><td>2020</td></tr>
<tr><td>(1,711)</td><td>(2,835)</td><td>(3,611)</td><td>(4,114)</td><td>(4,540)</td><td>(4,901)</td></tr>
<tr><td>2021</td><td>2022</td><td>2023</td><td>2024</td><td>2025</td><td>2026</td></tr>
<tr><td>(5,131)</td><td>(5,248)</td><td>(5,346)</td><td>(5,455)</td><td>(5,596)</td><td>(5,739)</td></tr>
<tr><td>2027</td><td>2028</td><td>2029</td><td>2030</td><td>2031</td><td>2032</td></tr>
<tr><td>(5,885)</td><td>(6,046)</td><td>(6,249)</td><td>(6,440)</td><td>(6,675)</td><td>(6,815)</td></tr>
</table>

5.3.3 REMOTE DISCONNECT/RECONNECT

Customer meters will include an integrated service switch that can be opened or closed remotely by FortisBC. This functionality will allow FortisBC to remotely connect or disconnect a service as required, without physically accessing a customer's premises. Connects and disconnects are required for several reasons. Vacant premises are disconnected after a period without an associated customer account. Reconnections must be performed when a disconnected vacant premises becomes occupied. Services are disconnected for non-payment as a last resort as per the FortisBC collections processes, and must be promptly reconnected after payment is received.

Currently, FortisBC follows the process described below when a customer moves out of a premises and a new customer does not activate service at the address in a timely manner:

- The service is designated inactive in the billing system, power is left connected at the address;
- A report is run periodically that lists all premises that have an inactive (still connected) service with no associated account;
- If enough time has elapsed since the move out date of the previous customer, and no new account has been linked to the service, a Customer Service Person (CSP) is dispatched to "sock" (disconnect) the meter;
- Upon arrival at the premises, the CSP will attempt to determine if the premises is occupied and make contact with the occupants.
  - If the premises appears occupied and contact is not made, the CSP will "tag" the door with a disconnect notice with an option to call FortisBC to activate the service;
  - If contact is made with the new occupants, the CSP will advise them of the need to activate the service;
  - If the premises do not appear occupied at the initial visit, or if the new occupants fail to activate the service after being notified to do so, the meter is disconnected and a tag left advising occupants on how to reconnect.

Customers that pay for a reconnection for any reason expect and deserve prompt service. Although FortisBC endeavours to perform reconnections promptly, factors such as field crew availability, weather, and traffic can affect the timeliness of reconnecting service at a given premises.

The management of vacant premises can involve multiple vehicle trips to each identified vacant site. An initial trip is required to confirm vacant site status or to leave notification for the occupants of the requirement to contact the Company to establish an account. A second trip is often required to either disconnect the premises, or to leave another tag advising the occupant to contact the Company to avoid any interruption in service. The process is time consuming, labour intensive, and thus expensive, particularly as multiple vehicle trips are required before resolution occurs (1 - 2 for disconnect and 1 for reconnect).

In 2011, FortisBC dispatched nearly 7,700 service calls to disconnect or reconnect services at customer premises.

The AMI system provides remote disconnect/reconnect functionality, resulting in the required number of vehicle trips to disconnect or reconnect premises being greatly reduced. As a result, an AMI system will provide O&M cost savings by streamlining this process as outlined below:

1. Services at premises will not be disconnected for 10 business days after premises becomes vacant unless the electricity consumption exceeds a minimal electricity usage threshold (initially set at 250 kWh) The usage threshold is intended to represent a level of consumption below which it is unlikely that the premises is occupied or that any significant use of electricity is occurring.
2. If the 10 business day limit or usage threshold is exceeded, the premises will be remotely disconnected.

Table 5.3.3.a below details the projected savings associated with remote disconnect/reconnect functionality.

The reported savings are based on 2011 data with future years escalated at 1.8 percent. FortisBC assumed that a CSP will still require one visit to 50 percent of vacant premises and 100 percent of premises scheduled for disconnection due to non-payment. Additionally, since a CSP will be dispatched more quickly to vacant sites, the consumption that would previously have been unbilled has been calculated at FortisBC's current residential tariff rate and included in the analysis.

Table 5.3.3.a - Forecast Savings from Remote Disconnects/Reconnects

Forecast Savings ($000s)							
Remote Disconnect / Reconnect	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	-	(133)	(414)	(544)	(564)	(584)	(605)
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	(627)	(648)	(671)	(694)	(717)	(741)	(766)
	2027	**2028**	**2029**	**2030**	**2031**	**2032**	
	(791)	(817)	(843)	(870)	(898)	(1,339)	

5.3.4 MEASUREMENT CANADA COMPLIANCE

In Canada, meters that measure electricity usage are governed by the federal *Weights and Measures Act*, which is enforced by Measurement Canada, an agency of Industry Canada. Electric meter construction standards dictate that access to the working parts and adjustments should be effectively prevented by application of a seal. This is typically a metal wire threaded between the glass and metal sections of the meter, and clamped together with a soft, impressionable metal tab. The delicate nature of the seal is purposeful to show evidence of any attempt to break or manipulate the seal.

Meters installed for the purpose of billing electrical consumption have an initial seal period between 8 and 12 years as provided for under the *Weights and Measures Act*. The seal period determines the initial date and duration that measurement from these devices is legally valid. In order to ensure standards and calibrations are maintained, meters are subjected to verification, re-verification, acceptance and compliance sampling at prescheduled intervals determined by Measurement Canada. Measurement Canada has defined meter seal extension periods ranging from 1 year to 10 years.

Meters are received and installed in 'compliance groups' or 'batches'. Meters that make up a compliance group are from the same vendor, and are of similar type and factory specification in addition to conforming to homogeneity rules set out by Measurement Canada. Prior to the initial seal period of a compliance group lapsing, Measurement Canada issues the testing requirements for the meters in the expiring group. This includes the count of meters to be tested, the testing criteria, and the unique identifiers of the meters being sampled. In this process the sample meters are randomly chosen to be removed for testing and the results of this sample are deemed to be representative of the larger compliance group of meters. The sampling process allows the larger groups of meters to stay installed at customers' premises and a small sample of meters to be removed for testing, saving FortisBC customers the cost of removing large groups of meters every year.

Meters selected for compliance testing or for re-test of the compliance group, must be removed, tested and the results reported back to Measurement Canada by a predetermined date. Failure to comply will result in the imposition of fines against the utility by Measurement Canada. Using a formula, the meters in the compliance group are assigned a new seal period if the randomly sampled meters pass the tests. Alternatively, in the event of failure of the sampled meters, the entire batch of meters is considered non-compliant and must be removed from service.

Effective January 1, 2014, Measurement Canada has stated that it will require all registered electric contractors (including utilities such as FortisBC) to adhere to a new sampling plan (S-S-06) for electro-mechanical meters installed in Canada. A copy of the new sampling plan is provided as Appendix B-7. The new sampling plan narrows the allowed tolerances for compliance testing. FortisBC experience shows that the new sampling plan will result in an increased failure rate for electro-mechanical meters. As solid state digital meters consistently exhibit better test results than their electro-mechanical counterparts, they are typically granted longer seal extensions for the installed groups of meters. Electro-mechanical meters, which have many moving parts, will have greater difficulty passing the new testing requirements and are expected to have shorter seal extensions and more outright failures yielding no seal extension and requiring immediate replacement of the entire batch. As an example, under the existing EG-04 regulations between 2006 and 2010, only one group out of the 92 tested failed. When these same test results were subjected to the new S-S-06 requirements, 12 groups failed.

Furthermore, the larger sampling size mandated by S-S-06 presents other challenges for FortisBC due to the large number of small compliance groups present in the current population. The new regulations will increase the number of compliance meters that have to be exchanged and tested (in some cases more than half of the group will need to be removed), making the management of these small groups significantly more expensive than under the current regulations.

Based on the new S-S-06 regulations, FortisBC anticipates increased failures, shorter seal extensions, and an increase in compliance sampling costs. As a result, FortisBC expects an accelerated replacement of approximately 80,000 electro-mechanical meters and 8,000 digital meters over a 21 year period. In the financial analysis of the Project, FortisBC has only accounted for the incremental number of meters, outside the ongoing meter exchange process, that are replaced or exchanged on an accelerated basis as a result of S-S-06.

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 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. To illustrate this, under S-S-06 the current compliance groups require more than 18,000 meters to be exchanged and tested per seal extension, but after the population is replaced the number of meters required to be exchanged and tested diminishes to 6,600.

The following table outlines the costs to replace the FortisBC electro-mechanical fleet under the new S-S-06 regulations, assuming the population is managed to the end of its life. Because this expenditure will be required if an AMI Project does not replace these meters, the benefit is an avoided cost that would no longer be required by another project. The costs include the meters, deployment and disposal for the approximately 88,000 electro-mechanical meters that would require replacement.

Table 5.3.4.a - Forecast Meter Replacement Savings

Forecast Savings ($000s)							
Measurement Canada Compliance	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	(146)	(909)	(903)	(1,478)	(976)	(2,310)	(1,072)
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	(1,645)	(1,229)	(1,070)	(1,452)	(820)	(1,324)	(486)
	2027	**2028**	**2029**	**2030**	**2031**	**2032**	
	(501)	(293)	(306)	(302)	(432)	(901)	

The avoidance of capital costs related to the revised Measurement Canada sampling plans represents a benefit to FortisBC customers of $9.8 million as evaluated on a net present value basis.

5.3.5 METER EXCHANGES

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. Table 5.3.5.a below details these forecast savings.

Table 5.3.5.a - Forecast Meter Exchange Savings

Forecast Savings ($000s)							
Meter Exchange	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	-	(349)	(331)	(408)	(310)	(531)	(302)
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	(187)	(212)	511	542	573	626	245
	2027	**2028**	**2029**	**2030**	**2031**	**2032**	
	218	(151)	(155)	(193)	(116)	357	

The avoidance of costs related to ongoing meter exchanges represents a benefit to FortisBC customers of $0.8 million as evaluated on a net present value basis.

5.3.6 CONTACT CENTRE

The majority of FortisBC's meters are read on a bimonthly schedule (approximately every 60 days), with the remaining meters (approximately 1,900 customers subject to a demand billing determinant) read on a monthly schedule (approximately every 30 days). However, there are several reasons that a meter may need to be read between its regular scheduled intervals, including when a customer moves into or out of a premises or to verify assumed inaccuracies in the reading, either as a result of customer request or as part of the standard billing verification process. The office administration related to the off-cycle readings is termed "soft reads". Detailed below is the sequence of events that currently occur for a typical soft read:

- Meter readers print off a report daily with addresses of customers requiring a soft read;
- A meter reader drives to all premises requiring a soft read, reads the meter and records the results;
- The results are faxed to the FortisBC Contact Centre in Trail, B.C.;
- The soft read is entered into the billing system; and
- The account is flagged to ensure steps are taken to verify if/when a new customer hooks up service at the premises, or alternatively the service is disconnected.

In 2011, there were over 19,000 soft reads completed by FortisBC meter reading staff. An AMI system would change this work from its existing manual process to one that could be accomplished from the Company's offices using AMI technology. The cost savings for the meter readers has already been accounted for in the reduction of manual meter reading analysis, but there are additional savings resulting from the manual entry of soft reads that would no longer need to be completed at the FortisBC Contact Centre.

The cost savings associated with the elimination of soft reads realized as a result of an AMI deployment are summarized in the Table 5.3.6.a below. The claimed savings are simply the labour costs of a contact centre representative that would be required to input the soft reads into the billing system for the estimated number of soft reads that would be needed if an AMI system was not deployed.

There will be an increase in call volume during Project implementation, expected to be no more than 15 percent above normal operations. The claimed contact centre benefits factors in this increased call volume cost in each of 2013, 2014, and 2015.

As discussed above in Section 3.2.5, 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 in the Table 5.3.6.a below.

Table 5.3.6.a - Forecast Savings from Contact Centre

	Forecast Savings ($000s)						
Contact Centre	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	-	20	7	(20)	(56)	(58)	(6)
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	(62)	(64)	(66)	(69)	(71)	(73)	(76)
	2027	**2028**	**2029**	**2030**	**2031**	**2032**	
	(78)	(81)	(83)	(86)	(89)	(91)	

The forecast savings in Contact Centre operating costs represents a benefit to FortisBC customers of $0.4 million as evaluated on a net present value basis.

6.0 FUTURE BENEFITS

The AMI Project enables other possible benefits, subject to potential additional capital expenditure. Any future capital expenditures required to realize the potential future benefits described below would be the subject of a future application to the BCUC.

The trigger for each of the future benefits listed below is shown in the following table.

Table 6.0 – Future Benefit Implementation

Future Benefit	Trigger Type	Trigger
Distribution Loss Reduction	Event	After AMI Project is implemented and distribution losses are accurately established.
Power Grid Voltage Optimization	Event	Higher power purchase costs or lower implementation costs make the project economic
Outage Management	Date	Possible regulatory application in 2015
Customer Pre-Pay Tariff	Date	Possible regulatory application in 2015
Future Conservation Rate Structures	Date	Possible regulatory application in 2016

6.1 Distribution Loss Reduction

Although loss reduction does not generally drive capital improvements, it is often an ancillary benefit of certain capital projects (reconductoring, voltage conversions, etc.). The loss reduction benefits associated with system improvements such as these are typically realized at the transmission level (as these capital projects are usually implemented on the transmission system), however the majority of system losses are known to occur on the distribution system, with approximately 50-60 percent of overall system losses estimated to be on the distribution network. While system losses can be reasonably measured at the transmission level, the current metering system does not allow accurate measurement of distribution losses as meter readings downstream cannot be accurately synchronized with measurements at the substation.

Currently, FortisBC estimates its annual total energy losses based on comparisons between gross load data and multi-year as-billed loss studies. Peak losses are calculated from simulation models (primarily for the transmission system), actual system data, and generation and billing records. Instantaneous measured losses at any point in time are unknown, and currently cannot be calculated due to the fact that real-time consumption information for all customer endpoints is not available. The implementation of advanced metering would allow the Company to synchronize end-point readings with substation meter reading allowing accurate determination of losses at the individual feeder level. Where economical, specific capital programs could be targeted to address those losses.

Although section 7.4 of FortisBC's Electric Tariff requires customers to regulate their loads 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.

Since FortisBC does not have the additional information on distribution losses until AMI is implemented, it cannot propose an explicit loss reduction program at this time. Once distribution losses are accurately established (following the implementation of AMI), FortisBC will be able to consider specific loss reduction capital projects where a cost/benefit analysis demonstrates a clear benefit to customers. The consideration of the benefit of loss reduction becomes particularly important in an era of continued upward pressure on electricity prices.

6.2 Power Grid Voltage Optimization

Conservation Voltage Regulation (CVR) techniques control field devices such as tap changers, voltage regulators and feeder/transformer/customer meters to achieve specific energy efficiency, voltage regulation and VAR optimization objectives. These objectives can be energy conservation, load peak shaving, voltage regulation and feeder loss reduction due to inefficiency. Unlike simpler methods such as Line Drop Compensation (LDC) and Set Point Reduction (SPR), Volt/VAR Optimization (VVO) uses feedback from all the meters on a feeder, and therefore requires the infrastructure provided by an AMI system. LDC and SPR can be implemented without an AMI system.

A FortisBC study was performed by PCS UtiliData, a consulting group based in Spokane, WA, and is provided as Appendix C-3. FortisBC staff reviewed the methodology and assumptions and provided input data to the study. The study determined the costs and benefits of various methods of CVR, including:

- CVR with Set Point Regulation (SPR) is a method of implementing CVR by setting the On Load Tap Changer (OLTC) set point voltage to a fixed level which maintains customer delivery voltages above CSA minimum acceptable levels at peak load.
- CVR with Line Drop Compensation is a method of implementing CVR by having the OLTC dynamically adjust its internal voltage set point as the load current changes, thereby holding the voltage at a distant point at a relatively constant level. This is accomplished by setting the X and R parameters (which represent the modeled impedance of the feeder or system of feeders) and computing the appropriate internal OLTC set point. This allows the overall average voltage on a feeder or system of feeders to be lowered while at the same time keeping customer delivery voltages above CSA minimum acceptable levels.
- CVR with Smart Grid Volt/VAR Optimization (VVO) is a method of implementing CVR using an advanced application that runs periodically or in response to operator demand. Combined with two-way communication infrastructure and remote control capability for capacitor banks and voltage regulating transformers, VVO makes it possible to optimize energy conservation and reduce demand on distribution systems using real-time information.

The study found that FortisBC could conserve 50,072 MWh or more per year by installing and operating a Smart Grid VVO system on its entire electric distribution system.

Table 6.2.a below presents a summary of potential costs and benefits for the three types of CVR implementation noted above. The table shows estimated annual energy conservation in MWh, and assigns a dollar value to the estimated conservation based upon a 2011 wholesale cost of electricity $51.79 per MWh. The table also shows the estimated cost of each type of implementation.

Table 6.2.a - Conservation Voltage Reduction Costs and Savings

	Annual MWh Saved	Annual Savings	Estimated Cost
		($000s)	
Volt Var Optimization (VVO)	50,072	$2,593	$8,892
Line Drop Compensation (LDC)	19,529	$1,011	$2,667
Set Point Reduction (SPR)	6,975	$361	$1,333

The following assumptions were made in the study, based on information provided to the consultant by FortisBC:

1. The CVR with VVO option assumes the existence of AMI infrastructure. No other infrastructure improvements are assumed for either the energy conservation numbers or the cost estimates;
2. Total system losses including transmission energy losses were assumed at 8.8 percent of total energy produced;
3. Distribution energy losses were assumed at 6.3 percent of total energy on a distribution feeder. Distribution energy losses are all losses downstream of the substation transformer;
4. Non-technical losses are assumed to be included in the distribution losses;
5. Transformers sharing load with municipal energy resellers were not included in the analysis because there is no certainty their customers will have an AMI system;
6. Rural feeders were assumed to have 80 percent residential and 20 percent commercial load;
7. 112 volts is the minimum acceptable service entrance voltage; and
8. For purposes of estimating voltage reductions the assumption was made that during a 24 hour day there were 12 on-peak hours and 12 off-peak hours in the daily load cycle.

Additional scenarios were run in order to determine the percentage of savings that could be allocated to capacity for the CVR with VVO option. The number of peak hours was reduced to 4, which relates to the fact that the peak portion of the typical FortisBC daily load curve has an approximate duration of 4 hours. The results show that 6 percent of the reduction for the CVR with VVO option can be allocated to capacity reduction. This translates to a reduction in peak demand of 4-5 MW. This capacity reduction is not expected to have any future project deferral benefits.

CVR, combined with VVO and AMI infrastructure, has energy reduction benefits that appear to substantially outweigh the costs. The net present value of the power purchase benefit is approximately $3 million annually, however the revenue loss associated with this benefit is approximately $6 million annually. Due to the fact that the marginal savings from power purchases reductions are expected to be less than the associated marginal revenue loss for the foreseeable future, all forms of CVR currently show a negative payback for customers. As such, no form of CVR is proposed at this time, although FortisBC will continue to study the potential to implement CVR and may propose a solution if higher power purchase costs or lower implementation costs make the project economic.

6.3 Outage Management

With the near real-time operational data provided by the AMI system, FortisBC will be able to react to power outages more effectively. There were nearly 1,200 outages in the FortisBC service territory in 2011. Due to the limited visibility currently available to the System Control Center on the status of the distribution network downstream from distribution substations, current processes rely primarily on customers contacting the Company to advise of local outages in their area. This method determines a rough geographic location of the outage but does not provide the exact timing or scale of the outage. Crews must be dispatched to patrol feeders and identify the specific sections affected by the outage (for example blown fuses, damaged infrastructure, etc). The time-consuming nature of this process can be further impacted by the occurrence of multiple outage events due to weather conditions, as well as the time of day as it is difficult to visually verify the status of infrastructure during a night time outage event. When an outage occurs during the night, the Company may not even receive notification from customers until the following day, further delaying the timely restoration of service.

Outage data from the AMI system can be used to map outages and determine location and number of customers without service. Disruptions in power delivery can be detected at specific transformers, down to individual metering endpoints with full visibility provided back to the System Control Center. This information will facilitate improved identification of the scope of the outage and assist with prioritizing the restoration of service.

Armed with this information, field crews' response and repair times will be reduced. Real time power outage notification will help to identify any "nested" outages within larger outages after power has been restored ensuring that all customers will have their power restored before crews leave the area. More accurate and timely outage information and the resultant restoration of those outages will result in an increase in customer satisfaction, comfort, and safety.

By implementing an Outage Management System (OMS), FortisBC expects to reduce the vehicle time spent by power line technicians locating specific outage causes, resulting in a reduction in outage times for customers, and improved safety and reliability for both the Company and customers.

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.

6.4 Customer Pre-Pay Tariff

Pre-pay functionality will allow customers to elect to pre-pay for energy and have their balance reflected on an IHD. New systems such as the MDMS and HES will allow the creation of special reporting, queries and communication to the customer premises through IHDs allowing customers to view remaining balances at their convenience. For customers with poor payment and/or credit history, the requirement to provide a security deposit for service could be waived should the customer elect instead to pre-pay for electric consumption. The option of pre-pay may be particularly beneficial to low and fixed income customers as discussed in the Navigant report provided as Appendix C-1, which details lower customer energy consumption when using pre-pay as opposed to on account billing.

The Navigant report estimates that potentially 3 percent to 8 percent of customers could choose the option of pre-paying. Table 6.5.a below includes the forecast savings that could result from the option of pre-pay, based on the assumption that 8 percent of customers elect to use this option. If AMI is approved, FortisBC intends to fully investigate the potential development costs and potential savings associated with a pre-pay system. If warranted, a proposal for a prepay system will be included in a future application filing for possible submission in 2015 or later.

6.5 Future Conservation Rate Structures

AMI allows FortisBC to remotely and economically apply time-varying rate structures to selected meters dispersed throughout the Company's service territory. These rate structures could be available as an optional rate based on the customer's preference. AMI therefore enables FortisBC to consider conservation rate structures other than the existing default rate – Residential Inclining Block (RIB), and to consider implementing an enhanced Time of Use (TOU) rate. In all cases the objective would remain the same: to improve customers' control over their electricity bills and reduce the load that FortisBC serves.

FortisBC has estimated, using data from its Future Program Study (by Navigant) and the BC Wholesale Market costs for energy and capacity (as presented in the Company's 2012 Long Term Resource Plan – Midgard Consulting 2011 FortisBC Energy & Capacity Market Assessment), the effect of possible conservation rate structures enabled by AMI. TOU, Critical Peak Pricing (CPP) and pre-pay rate structures have been assessed at this high level with potential impacts stated as incremental to those achieved via the Company's default RIB rate. Table 6.5.a below indicates that each of these conservation rate structures has potential to reduce power purchase costs.

The baseline RIB rate includes capacity savings of 0.5 percent (based on the Navigant Future Program Study provided as Appendix C-1) and energy savings of 1.9 percent (based on the FortisBC RIB Application).

Table 6.5.a - Conservation Rate Structures - Indicative Avoided Power Purchase Costs

	Participation Rate	Per Participant Savings (Capacity) Incremental to RIB	Per Participant Savings (Energy) Incremental to RIB	2016 Power Purchase Savings	2020 Power Purchase Savings	2030 Power Purchase Savings
				($000s)		
TOU	20%	10.50%	3.60%	$881	$959	$1,216
CPP	20%	9.50%	0.00%	$117	$158	$308
Pre-pay	8%	5.30%	9.80%	$667	$705	$818

Note: Source for take up and participation rates is Navigant AMI Future Program Study - November 2010, provided as Appendix C-1. Power purchase savings are based upon BC Wholesale Market cost of Energy and Capacity (Midgard Consulting - 2011 FortisBC Energy & Capacity Market Assessment).

The Company recognizes that the information shown in the table above is only the first step. Presuming a set-up cost for each innovative rate structure of approximately $250,000 (and possibly higher for pre-pay), the potential avoided power purchase costs indicate that continued investigation is merited.

FortisBC intends to continue researching AMI-enabled innovative rate structures. As part of any future rate study the Company will further determine and validate expected take up and participation rates for each rate structure. The Company will further define avoided power purchase costs in terms of both energy and capacity, and will consider potential impacts to system load. Finally, the Company will clarify implementation costs associated with each additional rate structure. If, after sufficient further investigation, it is determined that one or more innovative rate structures would enable a cost-effective means of allowing the utility to reduce the load it serves and helping customers exert control over their electricity bill, then the Company will enter into appropriate stakeholder consultation and regulatory processes, with consideration for the submission of a regulatory application in 2016 or later.

7.0 PROJECT ALTERNATIVES CONSIDERED

FortisBC has considered several alternatives to the proposed AMI solution including status quo (manual metering reading), Automated Meter Reading (AMR), and Power Line Carrier (PLC) technology. The proposed AMI Project has the largest positive impact on future FortisBC rates, and provides the most non-financial benefits to customers as compared to the alternatives.

In this section, the gross costs and theft reduction savings related to each of the alternatives is presented, allowing for a direct comparison of gross costs and benefits between alternatives.

The net savings figures presented in Sections 5.3.1 through 5.3.6 are the net of the status quo and AMI alternative costs and savings shown below. To ease comparison analysis between the alternates and the AMI proposal, all costs and benefits are also presented on a net of status quo basis for each alternate.

The *New Operating Costs* are incremental to the status quo alternative and are described in the sections below and in Section 5.1.2 for the AMI alternative.

Unless otherwise noted, all annual costs are inflated by 1.8 percent per year.

7.1 Status Quo

The status quo alternative is the base case against which all benefits and costs of the proposed AMI Project, as well as the considered alternatives, are measured. The status quo does not propose any additional meter functionality, but requires the accelerated replacement of 88,000 meters to remain in compliance with Measurement Canada's S-S-06 regulation. The table provided below details the ongoing operating and capital costs associated with the status quo alternative option.

Table 7.1.a – Status Quo Capital and Operating Costs

Status Quo	**2013**	**2014**	**2015**	**2016**	**2017 – 2032**	**Total**
Capital						
Project Capital	-	-	-	-	-	-
Sustaining Capital						
Meter Growth and Replacement	406	474	453	533	5,942	7,808
Handheld Replacement	-	250	-	-	899	1,149
IT Hardware, Licensing, and Support Costs	-	-	-	-	-	-
Measurement Canada Compliance	146	909	903	1,478	15,119	18,556
Total Capital	**552**	**1,633**	**1,356**	**2,011**	**21,960**	**27,513**
Operating Expenses						
New Operating Costs	-	-	-	-	-	-
Meter Reading	2,518	2,684	2,733	2,782	59,705	72,896
Disconnect/Reconnect	513	532	552	573	12,817	15,481
Meter Exchanges	311	349	331	408	3,729	5,371
Contact Centre	479	497	511	530	11,157	13,639
Total Operating Expenses	**3,822**	**4,062**	**4,127**	**4,294**	**87,408**	**107,387**
Theft Reduction	(4,970)	(5,484)	(6,143)	(6,791)	(99,065)	(127,218)

As evident in the table above, the most significant capital costs associated with the status quo relate to the required *Measurement Canada Compliance* costs as further discussed in Section 5.3.4. These costs are related to the need to replace the approximately 88,000 meters in response to new Measurement Canada regulations.

Sustaining Capital expenditures consist of the forecast annual costs related to the ongoing replacement of meters and the addition of new meters required throughout the service territory. *Handheld Replacement* costs are related to the routine replacement of the meter reading handheld devices that are used to manually collect meter readings.

Meter Reading, Disconnect/Reconnect, Meter Exchanges, Contact Centre, and Theft Reduction cost categories are described in Sections 5.3.1 through 5.3.6. In those sections, the net difference between the proposed AMI Project and status quo alternatives are presented. In the table above, only the gross costs related to these categories in the status quo option are shown.

Meter Reading costs include all labour, expenses and vehicle costs related to the manual meter reading function using internal staff, with annual costs escalated with customer growth and inflation.

Disconnect/Reconnect costs are all expenses related to the current disconnect/reconnect process outlined in Section 5.3.3. The services are provided by internal staff in the status quo alternative.

Meter Exchanges are the costs required to maintain compliance with Measurement Canada regulations assuming the continued use of non-AMI meters and compliance with the new S-S-06 regulations described in Section 5.3.5.

Contact Centre costs represent the proportion of the overall contact centre budget that is dedicated to the current status quo processes described in Section 5.3.6.

Theft Reduction estimates revenue recoveries associated with continuing the existing revenue protection program and not implementing AMI, as further described in Section 5.3.2.

As explained in Section 3.1, the existing status quo metering system is limited in its application and the amount of information it is capable of providing. More specifically, the status quo option was rejected as a non-feasible alternative because:

1. It does not provide any of the quantified benefits of an AMI system listed in Section 5.3.
2. It does not provide any of the non-quantified benefits of an AMI system discussed in Section 3.2.5.
3. It does not allow the future benefits listed in Section 6.0, including the ability to implement future innovative rate structures that support energy efficiency and conservation.
4. It is not consistent with British Columbia's energy objectives outlined in Section 3.2.2.
5. It is not consistent with the metering system and services deployed to 1.8 million BC Hydro electricity customers.

6. It requires the accelerated replacement of approximately 88,000 meters as a result of the new Measurement Canada regulations (see Section 5.3.4).
7. The status quo alternative does not provide any cost savings for customers as compared to the proposed AMI Project.

7.2 Automated Meter Reading (AMR)

Automated meter reading requires replacement of existing meters with wireless meters that communicate with vehicle-based collection systems. The implementation of this technology would allow for a reduction in meter reading costs by increasing the number of meters read by an individual in a day while eliminating the need for a reader to physically access every individual meter to collect a read. This technology uses a meter equipped with an Itron Encoder Receiver Transmitter (ERT) module that transmits a reading via an RF signal to a handheld or vehicle-mounted radio transceiver.

Drive-by meter reading technology has the potential to improve productivity and lower operating costs. The number of employees required to obtain meter readings could be reduced to approximately 8 from the current staff of 20, resulting in a reduction of *Meter Reading* costs as compared to the status quo alternative. The reduced number of staff and vehicles also lessens the exposure hours to potentially hazardous conditions. Bill errors resulting from manual entry errors could also be reduced. *Contact Centre* costs are expected to be slightly higher than status quo during meter deployment as customer queries are being handled. *Meter Exchange* costs will be lower than the status quo since the AMR meter deployment will result in the replacement of those meters that would require replacement under status quo in order to comply with Measurement Canada's S-S-06 regulation. The table provided below details the gross ongoing operating and capital costs associated with the AMR alternative option.

Table 7.2.a - – Gross AMR Capital and Operating Costs

Automated Meter Reading	2013	2014	2015	2016	2017 – 2032	Total
Capital						
Project Capital	6,923	11,191	10,188	-	-	28,302
Sustaining Capital						
Meter Growth and Replacement	406	227	223	227	8,672	9,349
Handheld Replacement	-	-	-	-	-	-
IT Hardware, Licensing, and Support Costs		30	35	36	1,157	1,258
Measurement Canada Compliance	-	-	-	-	-	-
Total Capital	**7,297**	**11,448**	**10,446**	**263**	**9,830**	**39,283**
Operating Expenses						
New Operating Costs	-	89	162	165	3,093	3,509
Meter Reading	2,518	2,684	1,242	1,265	23,629	33,813
Disconnect/Reconnect	513	532	552	573	12,817	15,481
Meter Exchanges	312	-	-	-	4,644	5,198
Contact Centre	479	529	544	564	11,157	13,738
Total Operating Expenses	**3,822**	**3,834**	**2,501**	**2,567**	**55,340**	**71,738**
Theft Reduction	(4,970)	(5,485)	(6,143)	(6,791)	(99,065)	(127,218)

The table provided below details the ongoing operating and capital costs associated with the AMR alternative option net of status quo. These costs have been calculated based on the difference between the status quo costs shown in Table 7.1.a and the gross costs shown above in Table 7.2.a.

Table 7.2.b – Net AMR Capital and Operating Costs

Automated Meter Reading	**2013**	**2014**	**2015**	**2016**	**2017 – 2032**	**Total**
Capital						
Project Capital	6,891	11,191	10,188	-	-	28,270
Sustaining Capital						
Meter Growth and Replacement	-	(427)	(231)	(306)	2,731	1,947
Handheld Replacement	-	(250)	-	-	(899)	(1,149)
IT Hardware, Licensing, and Support Costs		30	35	36	1,157	1,258
Measurement Canada Compliance	(146)	(909)	(903)	(1,478)	(15,119)	(18,556)
Total Capital	**6,777**	**9,815**	**9,090**	**(1,748)**	**(12,131)**	**11,770**
Operating Expenses						
New Operating Costs	-	89	162	165	3,093	3,509
Meter Reading	-	-	(1,490)	(1,517)	(36,075)	(39,083)
Disconnect/Reconnect	-	-	-	-	-	-
Meter Exchanges	-	(349)	(331)	(408)	915	(174)
Contact Centre	-	32	33	34	-	98
Total Operating Expenses	**-**	**(229)**	**(1,627)**	**(1,727)**	**(32,067)**	**(35,649)**
Theft Reduction	-	-	-	-	-	-

In addition to the cost categories identified in Section 7.1, the AMR alternative includes costs in the category *New Operating Costs*. These costs are for a technical analyst and additional AMR-related software and hardware costs.

The *Project Capital* costs are related to the replacement of nearly all existing meters with wireless AMR meters that allow drive-by reading, as well as the related vehicle-mounted reading equipment. The replacement of the meters as part of *Project Capital* also means no *Measurement Canada Compliance* capital is required.

When considered in comparison to the proposed AMI Project, AMR does not provide a similarly complete solution. The current process for collecting off-cycle reads (on/off, re-reads) would not see any improvements via AMR as the off-cycle reads would still need to be entered into the billing system manually. Similarly, the disconnect/reconnect process remains a manual procedure. Significantly, AMR does not improve the quality or quantity of information available to either the Company or customers and therefore does not provide the same opportunity to manage the cost of electricity as considered in the proposed AMI Project.

A copy of the financial NPV analysis of the AMR solution (net of status quo costs) is provided in Appendix D, and has also been included as an embedded electronic Excel file with this filing.

In summary the AMR solution was rejected as it does not address the British Columbia's energy objectives, nor does it have as positive an impact on rates as compared to the proposed AMI Project. Further, it does not provide the level of functionality, nor enable the other benefits, including the capability to offer customers future innovative rate structures that incent energy efficiency and conservation, as afforded by the AMI system as proposed in this Application.

1. It does not provide any of the quantified benefits of an AMI system listed in Section 5.3, aside from a portion of the meter reading benefits listed in Section 5.3.1.
2. It does not provide the same level of non-quantified benefits of an AMI system listed in Section 3.2.5.
3. It does not allow the future benefits listed in Section 6.0.
4. It is not consistent with British Columbia's energy objectives outlined in Section 3.2.2.
5. It is not consistent with the metering system and services deployed to 1.8 million BC Hydro electricity customers.
6. The resulting rate impact and NPV of the revenue requirement impact is not as favourable as compared to the proposed AMI Project.

7.3 Power Line Carrier AMI Systems

PLC AMI systems can communicate with meters and other distribution devices using a fixed hard-wired network. Two-way communicating AMI systems have the added ability to remotely transmit data back to meters and distribution devices. Among other things, this allows meters to be read on demand and permits remote meter configuration.

In a PLC AMI system, meter data is transmitted over the electrical distribution network as a modulated carrier wave, and received by a collector which is housed in distribution substations. The transmission of data from the collector to the meter data storage servers at the utility is made through a separate WAN solution. A PLC AMI system is dependent upon the existing electrical distribution system. Since the collectors are housed in the substations, the cost of the PLC option is, in part, dependent upon the number of endpoints served per substation. The cost of the infrastructure within the substation is the same no matter how many customers are downstream of that particular substation. However, the distance between the metering endpoint and the substation determines how many line devices need to be installed upon the distribution lines to ensure that the data can travel the required distance.

Depending on the number of endpoints and the frequency of reading intervals, the amount of data travelling between the meters and the collectors can overwhelm the bandwidth of a PLC system. This becomes increasingly challenging once load control or pricing signal data is included for transmission through these same communication channels. The volume of data can impact the speed of transmission and can cause delays in getting the information back to the central computer in a timely fashion.

As mentioned in Section 4.2.2, no PLC proposals were received from any vendors during the RFP process. However, Itron was able to provide an estimate of PLC capital costs of approximately $66 million for a system with nearly equivalent functionality to their RF technology. The table provided below details the gross ongoing operating and capital costs associated with the PLC alternative option.

1 **Table 7.3.a – Gross PLC Capital and Operating Costs**

Power Line Carrier	2013	2014	2015	2016	2017 – 2032	Total
Capital						
Project Capital	16,362	25,692	24,296	-	-	66,351
Sustaining Capital						
Meter Growth and Replacement	406	291	285	290	9,796	11,067
Handheld Replacement	-	-	-	-	-	-
IT Hardware, Licensing, and Support Costs	-	292	567	577	11,285	12,721
Measurement Canada Compliance	-	-	-	-	-	-
Total Capital	**16,768**	**26,275**	**25,148**	**867**	**21,081**	**90,139**
Operating Expenses						
New Operating Costs	-	768	1,362	1,387	25,115	28,631
Meter Reading	2,518	2,684	1,734	238	5,130	14,779
Disconnect/Reconnect	513	399	138	29	641	2,214
Meter Exchanges	312	-	-	-	4,644	5,198
Contact Centre	479	516	518	510	9,994	12,482
Total Operating Expenses	**3,822**	**4,368**	**3,752**	**2,163**	**45,524**	**63,304**
Theft Reduction	(5,353)	(6,471)	(7,855)	(9,626)	(186,854)	(220,923)

2 The table provided below details the ongoing operating and capital costs associated with the
3 PLC alternative option net of status quo. These costs have been calculated based on the
4 difference between the status quo costs shown in Table 7.1.a and the gross costs shown
5 above in Table 7.3.a.

Table 7.3.b – Net PLC Capital and Operating Costs

Power Line Carrier	2013	2014	2015	2016	2017 – 2032	Total
Capital						
Project Capital	16,362	25,692	24,296	-	-	66,351
Sustaining Capital						
Meter Growth and Replacement	-	(183)	(169)	(243)	3,854	3,259
Handheld Replacement	-	(250)	-	-	(899)	(1,149)
IT Hardware, Licensing, and Support Costs	-	292	567	577	11,285	12,721
Measurement Canada Compliance	(146)	(909)	(903)	(1,478)	(15,119)	(18,556)
Total Capital	**16,216**	**24,643**	**23,792**	**(1,144)**	**(879)**	**62,626**
Operating Expenses						
New Operating Costs	-	768	1,362	1,387	25,115	28,631
Meter Reading	-	-	(998)	(2,544)	(54,574)	(58,116)
Disconnect/Reconnect	-	(133)	(414)	(544)	(12,176)	(13,627)
Meter Exchanges	-	(349)	(331)	(408)	915	(174)
Contact Centre	-	19	7	(20)	(1,163)	(1,157)
Total Operating Expenses	**-**	**305**	**(375)**	**(2,130)**	**(41,883)**	**(44,083)**
Theft Reduction	(383)	(987	(1,711)	(2,835)	(87,789)	(93,705)

The cost categories shown above are described in Section 7.1 status quo and Section 7.3 Automated Meter Reading.

New Operating Costs, although higher than the status quo, are lower than the AMI alternative, primarily due to lower WAN data backhaul costs.

The costs of the PLC alternative are similar to AMI as described in Section 7.5, aside from *Project Capital* costs which are higher with PLC. The scope of the PLC project is also similar to the AMI project, with all meters being replaced with meters that communicate over a fixed network to FortisBC. The replacement of the meters as part of *Project Capital* also means no *Measurement Canada Compliance* capital is required.

A copy of the financial NPV analysis of the PLC solution is provided in Appendix D, and has also been included as an embedded electronic Excel file with this filing. On a net present value basis, FortisBC determined that the cost of implementing a 100 percent PLC AMI solution in 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.

1. It does not allow all of the future benefits listed in Section 6.0.
2. It is not consistent with the metering system and services deployed to 1.8 million BC Hydro electricity customers.
3. The resulting rate impact and NPV of the revenue requirement impact is not as favourable as compared to the proposed AMI Project.

7.4 Advanced Metering Infrastructure

The table provided below details the gross ongoing operating and capital costs associated with the proposed AMI Project.

Table 7.4.a – Gross AMI Capital and Operating Costs

AMI	2013	2014	2015	2016	2017 – 2032	Total
Capital						
Project Capital	13,730	16,793	17,166	-	-	47,689
Sustaining Capital						
Meter Growth and Replacement	406	291	285	290	9,796	11,067
Handheld Replacement	-	-	-	-	-	-
IT Hardware, Licensing, and Support Costs	-	292	568	578	11,329	12,767
Measurement Canada Compliance	-	-	-	-	-	-
Total Capital	**14,136**	**17,376**	**18,018**	**868**	**21,125**	**71,523**
Operating Expenses						
New Operating Costs	-	875	1,529	1,556	28,236	32,196
Meter Reading	2,518	2,684	1,734	241	5,130	14,779
Disconnect/Reconnect	513	399	138	29	641	2,214
Meter Exchanges	312	-	-	-	4,644	5,198
Contact Centre	479	516	518	510	9,994	12,462
Total Operating Expenses	**3,822**	**4,475**	**3,919**	**2,333**	**48,646**	**66,869**
Theft Reduction	(5,353)	(6,471)	(7,855)	(9,626)	(186,854)	(220,923)

The table below summarizes AMI capital and operating costs net of status quo. These costs have been calculated based on the difference between the status quo costs shown in Table 7.1.a and the gross costs shown above in Table 7.4.a.

Table 7.4.b – Net AMI Capital and Operating Costs

AMI	2013	2014	2015	2016	2017 – 2032	Total
Capital						
Project Capital	13,730	16,793	17,166	-	-	47,689
Sustaining Capital						
Meter Growth and Replacement	-	(183)	(169)	(243)	3,854	3,259
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	**(13,584)**	**(15,743)**	**(16,682)**	**(1,143)**	**(836)**	**44,011**
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)	915	(174)
Contact Centre	-	20	7	(20)	(1,163)	(1,157)
Total Operating Expenses	**-**	413	(208)	(1,961)	(38,762)	(40,518)
Theft Reduction	(383)	(987	(1,711)	(2,835)	(87,789)	(93,705)

The cost categories shown above are described in Section 7.1 and Section 7.2 and are further discussed in Section 5.3.

The replacement of the meters as part of *Project Capital* also means no *Measurement Canada Compliance* capital is required. *New Operating Costs* are detailed in Section 5.1.2.

Contact Centre costs are expected to be less than the status quo due to reduction in soft read data entry as described in Section 5.3.6. FortisBC expects higher call volume during meter deployment, which is reflected in the costs above.

Meter Reading costs decline as compared to the status quo alternative beginning in 2014 as manual meter reading begins to be phased out. The savings are expected to be fully embedded by 2016, although a small manual meter reading budget will be required to allow manual download of data from AMI meters that cannot be economically connected to the AMI network. The number of meters requiring manual download of data is expected to be less than 1 percent of the total meter population.

As is the case with the AMR and PLC alternatives, *Meter Exchange* costs are reduced as compared with status quo due to lower sampling requirements as further described in Section 5.3.5.

The cost of *Disconnect/Reconnect* is lower than the status quo as detailed in Section 5.3.3.

Theft Reduction benefits increase with the AMI alternative as compared with status quo for the reasons described in Section 5.3.2.

Further discussion of the proposed AMI Project is provided in Section 4.0 and Section 0 above.

7.5 Summary of Alternatives Considered

This section summarizes and compares the various alternate, in terms of:

- Gross capital, operating expense, and theft reduction benefits;
- Capital, operating expense, and theft reduction benefits net of status quo;
- Yearly incremental rate impact;
- Cumulative rate impact; and
- Benefits delivered

Table 7.5.a below summarizes the gross capital, operating and theft reduction costs/benefits of the alternate options.

1 **Table 7.5.a – Meter Reading Options – Gross Capital, Operating and Theft Reduction**
2 **Costs/Benefits**

	Dec-13	Dec-14	Dec-15	Dec-16	Total 2017 - 2032	Total
STATUS QUO			**($000s)**			
Total Capital	552	1,633	1,356	2,011	21,960	27,513
Total Operating Expenses	3,822	4,062	4,127	4,294	87,408	107,387
Theft Reduction	(4,970)	(5,484)	(6,143)	(6,791)	(99,065)	(127,218)
Automated Meter Reading (AMR)						
Total Capital	7,329	11,448	10,446	263	9,830	39,315
Total Operating Expenses	3,822	3,834	2,501	2,567	55,340	71,738
Theft Reduction	(4,970)	(5,484)	(6,143)	(6,791)	(99,065)	(127,218)
PLC AMI						
Total Capital	16,768	26,275	25,148	867	21,081	90,139
Total Operating Expenses	3,822	4,368	3,752	2,163	45,524	63,304
Theft Reduction	(5,353)	(6,471)	(7,855)	(9,626)	(186,854)	(220,923)
AMI						
Total Capital	14,136	17,376	18,018	868	21,125	71,523
Total Operating Expenses	3,822	4,475	3,919	2,333	48,646	66,869
Theft Reduction	(5,353)	(6,471)	(7,855)	(9,626)	(186,854)	(220,923)

3 Table 7.6.b, following, summarizes the capital, operating and theft reduction costs/benefits
4 of the alternate options net of the status quo.

Table 7.5.b – Meter Reading Options – Net Capital, Operating and Theft Reduction Costs/Benefits

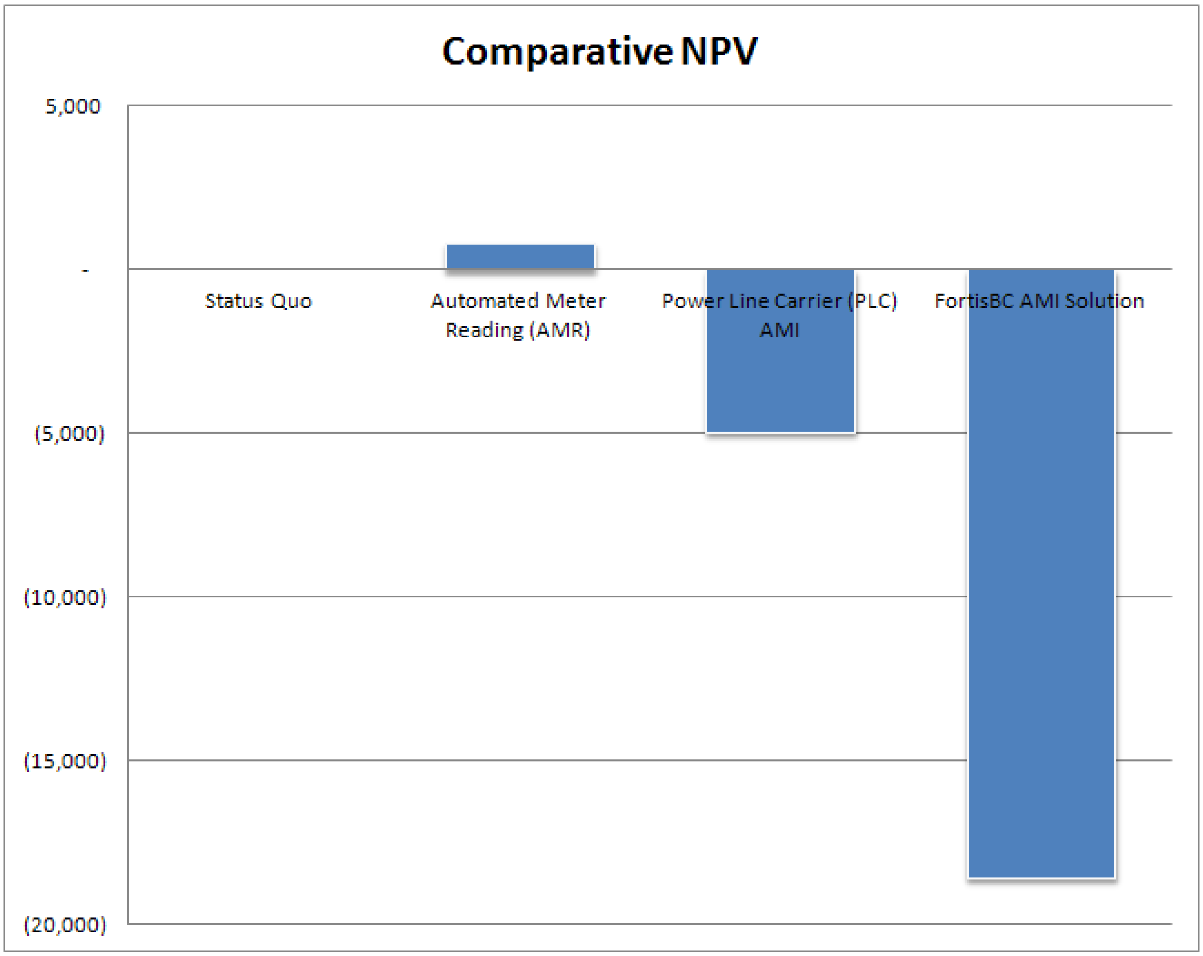
	Dec-13	Dec-14	Dec-15	Dec-16	Total 2017 - 2032	Total
STATUS QUO			($000s)			
Total Capital	-	-	-	-	-	-
Total Operating Expenses	-	-	-	-	-	-
Theft Reduction	-	-	-	-	-	-
Automated Meter Reading (AMR)						
Total Capital	6,744	9,815	9,090	(1,748)	(12,131)	11,770
Total Operating Expenses	-	(229)	(1,627)	(1,727)	(32,067)	(35,649)
Theft Reduction	-	-	-	-	-	-
PLC AMI						
Total Capital	16,216	24,643	23,792	(1,144)	(879)	62,626
Total Operating Expenses	-	305	(375)	(2,130)	(41,883)	(44,083)
Theft Reduction	(383)	(987	(1,711)	(2,835)	(87,789)	(93,705)
AMI						
Total Capital	(13,584)	(15,743)	(16,682)	(1,143)	(836)	44,011
Total Operating Expenses	-	413	(208)	(1,961)	(38,762)	(40,518)
Theft Reduction	(383)	(987	(1,711)	(2,835)	(87,789)	(93,705)

FortisBC has considered the NPV revenue requirements impact of the alternative options discussed above. Table 7.5.c below compares this impact, while Figure 7.5.a graphically illustrates the NPV of the revenue requirements impact for the various Project alternatives as compared to the proposed AMI solution.

Table 7.5.c – Meter Reading Options – NPV of Revenue Requirements Impact

Meter Reading Option	Revenue Requirements 2012 NPV ($000s)
Status Quo	-
Automated Meter Reading	815
Power Line Carrier AMI	(4,969)
FortisBC AMI Solution	(18,589)

Figure 7.5.a - Comparative NPV of Alternate Options



The Company has also examined both the yearly incremental rate and cumulative rate impacts of the Project alternatives. Figure 7.6.b, following, presents the yearly incremental rate impact of the alternates. Figure 7.6.c, and Table 7.6.d, demonstrate the cumulative rate impacts of the alternates.

Figure 7.5.b – Comparative Yearly Rate Impact

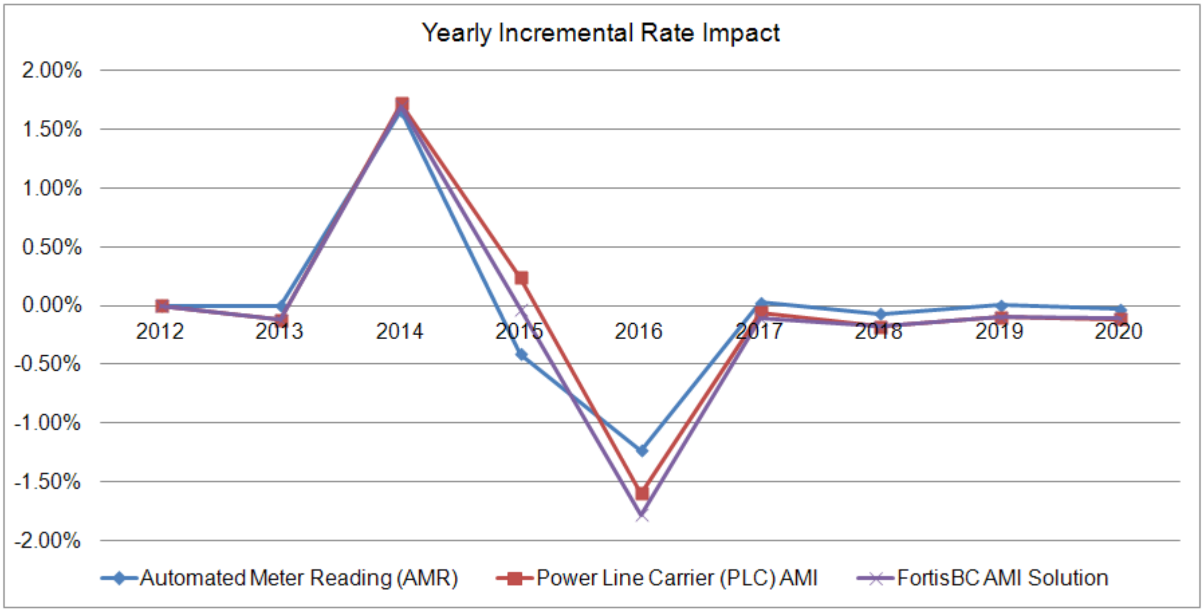
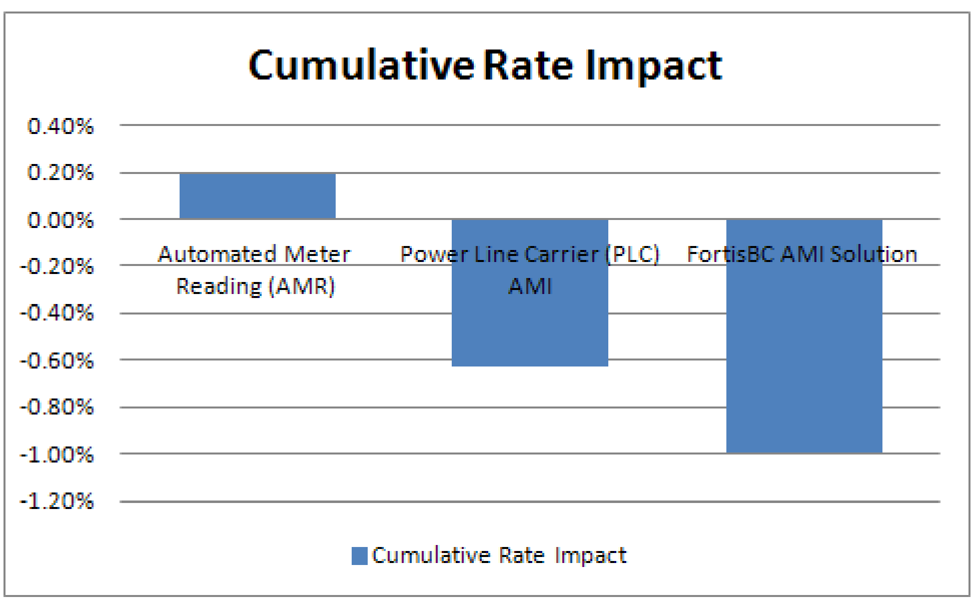


Table 7.6.d – Comparative Cumulative Rate Impact

Alternate	Cumulative Rate Impact
Automated Meter Reading	0.19%
Power Line Carrier	-0.63%
FortisBC AMI Solution	-0.99%

Figure 7.5.c – Comparative Cumulative Rate Impact



The following table illustrates functional capabilities available via the PLC and AMR alternative options as compared to the proposed AMI solution.

Table 7.5.d - AMI Alternative Option Functionality Matrix

Features Available	AMI RF	AMI PLC	AMR
Bi-Monthly Meter Readings	●	●	●
Monthly Meter Readings for All Customers	●	●	●
Daily Meter Readings for All Customers	●	●	
Hourly Meter Readings for All Customers	●	◒	
Reduction in Meter Reading Costs	●	●	◒
Outage Notification	●	●	
Restoration Verification	●	●	
Flexible Billing Dates	●	●	
Bill Consolidation for Customers	●	●	
Home Area Network	●	◒	
Meter Tamper Detection	●	●	●
System Modelling Enhancements	●	●	
Time Based Rates	●	●	●
Virtual Disconnects	●	●	
Remote Disconnect	●	●	●
Load Control	●	◒	
Conservation Voltage Reduction (VVO)	●		
Reduction in Energy Theft	●	●	
Distribution Automation Device Support	●	◒	
Supports Provincial Energy Objectives	●	◒	◒

◒ designates limited functionality available from solution

In summary, as discussed and illustrated above, the AMI Project proposed in this application provides the most financial, non-financial, and future benefits of the alternates examined.

8.0 PROJECT ENVIRONMENT

Nationally and internationally, utilities have been implementing advanced metering technologies. The technology is available for water, gas and electric, as well as multi-commodity utilities. Some utilities have been mandated by government to implement the technology, which is known by a host of names including "Smart", "Next Generation", and "Automated" as well as "Advanced" metering. Reasons for installing the Smart Meters, as cited by BC Hydro[11], include the "modernization of B.C.'s electricity system, improved safety and reliability, reduced electricity theft, and the ability to provide customers with new tools to manage their energy use and ultimately save money."

FortisBC was the first utility in BC to apply to the BCUC for an Advanced Metering Infrastructure project on December 19, 2007. Following an extensive regulatory process, the Application was denied by Order G-168-08. As discussed above in section 1.4, the Commission identified, among other things, a need for FortisBC to coordinate and collaborate with other stakeholder utilities in British Columbia in exploring an AMI implementation. As a result, FortisBC and BC Hydro have reviewed the opportunities and benefits of collaboration and coordination on Smart Meter (AMI) projects in British Columbia as both utilities move forward with a smart meter plans. As well, FortisBC has explored the possibility of cost-sharing with other utilities contracting to use the Company's proposed AMI.

Advanced metering technology is in the media spotlight. Reports, either extolling the virtues of AMI or lobbying against implementations, are seen daily. An often noted concern is the subject of electro-magnetic frequency (EMF) emissions. While EMF is not exclusive to advanced metering or smart grid implementations, the high-profile nature of these projects has focused attention on the subject. Additional concerns related to privacy and the security of consumption information, as well as concerns regarding billing accuracy (high bills), have also received much attention in the province, particularly as BC Hydro proceeds with its SMI implementation.

A discussion regarding the various smart meter initiatives currently underway in North America is provided in Section 8.1 below. Section 8.2 reviews the opportunities and benefits of utility collaboration and coordination on Smart Meter (AMI) projects in British Columbia while Section 8.3 considers the possibility of cost-sharing of AMI with other

[11] See Appendix C-3 for the BC Hydro Smart Meter Press Release from Jan 18 2011

utilities, including with the wholesale municipal customers within the Company's service territory. Lastly, a discussion of the challenges associated with FortisBC's AMI Project is provided in Section 8.4 below.

8.1 North American Smart Grid Initiatives

Across North America, smart grid activity has seen significant growth over the past several years. There are more than 25 million [12] advanced meters installed in North America, with 3.65 million[13] advanced meters shipped to North American utilities in the first quarter of 2011 alone. This growth in installations is expected to continue over the next few years as several large utilities begin system wide deployments.

8.1.1 AMI PROJECTS IN CANADA

BC HYDRO

BC Hydro is moving forward to install over 1.8 million smart meters in BC, with deployment having commenced on July 4, 2011. BC Hydro selected Itron's OpenWay® smart meter solution and Itron's associated head-end software and meter data management system. BC Hydro claims that "the [Smart Metering] program will avoid $222 million in meter reading costs, save $208 million through more efficient grid management, and protect $732 million in revenue through better detection of power theft.[14]"

ALBERTA

In 2007, Fortis Alberta conducted a pilot project deploying 28,000 Power Line Carrier (PLC) advanced meters. At the successful conclusion of the pilot Fortis Alberta launched the full project covering more than 470,000 customers with full deployment completed in 2011. Fortis Alberta implemented the Landis & Gyr's Gridstream TS2 Power Line Carrier AMI system.

MANITOBA

From 2006 to 2009, Manitoba Hydro ran an AMI pilot project which included approximately 4,500 wireless electric meters in Winnipeg and approximately 200 PLC electric meters near Landmark. The intent of the pilot project was to help gain an understanding of the issues

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[12] http://analysis.smartgridupdate.com/end-use/north-american-smart-grid-technology-it-getting-closer-optimum-consumer-endgame

[13] http://analysis.smartgridupdate.com/end-use/north-american-smart-grid-technology-it-getting-closer-optimum-consumer-endgame

[14] See Appendix C-4 for BC Hydro Smart Metering and Infrastructure Program Business Case

with installing, operating, and maintaining an AMI system. Currently, Manitoba Hydro is in the process of preparing a business case for the deployment of electric smart meters.

QUEBEC

Hydro- Québec has plans to deploy approximately 3.8 million smart meters by the year 2017[15]. The utility has chosen Landis & Gyr to supply the advanced metering infrastructure, including a meter data management system and meters with deployment anticipated to be completed by 2017.

ONTARIO

The Government of Ontario[16] committed to install a smart electricity meter in all Ontario homes and small businesses by the end of 2010 with a mandate to implement TOU rates by June 2011. Meters that provide consumers with the ability to understand their detailed consumption pattern combined with TOU rates are expected to encourage a shift in consumption habits to assist in the Province's conservation efforts.

As of April 30, 2011 there were 4.7 million installed electric smart meters in Ontario and 2.2 million customers on TOU billing.

SASKATCHEWAN

SaskEnergy and SaskPower announced June 5, 2012 that their advanced metering infrastructure project for electrical and gas meters will be tested in the town of Hanley, between Regina and Saskatoon. They propose that this will be followed by further testing in another larger community. They expect to be installing smart electric meters and gas modules throughout the province, beginning in 2013, at a cost of approximately $225 million (for both gas and electric).

[15] http://www.hydroquebec.com/residential/nouveau-compteur/index.html

[16] The Ontario Energy Board received a directive from the Minister of Energy under Section 27.1 of the Ontario Energy Board Act, 1998 (the Act) on July 16, 2004 (the Directive). In it, the Minister directed the Board to consult with stakeholders to identify options and address issues with regard to the targets. The Board was to provide an implementation plan for the achievement of the Government of Ontario's smart meter targets to the Minister by February 15, 2005.

On January 26, 2005, the Board submitted its implementation plan on smart meters to the Minister of Energy. The proposed plan suggested the mandatory technical requirements for smart meters and the support systems distributors would require; set priorities for implementation in order to meet the government's targets; identified regulatory mechanisms for the recovery of costs; and identified how barriers could be mitigated. In addition, the report addressed competitiveness in the provision and support of smart meters and the need for and effectiveness of non-commodity TOU rates.

8.2 Utility Collaboration

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.

8.2.1 THE PROCESS

An initial meeting between the three utilities was held in early 2009 to set the framework for primary collaborative discussions. At this meeting, representatives from each company provided the group with a review of their projects and the group discussed, at a high level, the potential benefits of collaboration and the areas where collaborating might make sense. The group developed guiding principles, described further in Section 8.2.3 below, to help define the extent to which any possible collaboration and/or coordination of AMI technologies could take place. Over the next several months a working group with members from each utility was established to explore the opportunities and benefits of collaboration. Specifically, they were asked to identify areas of opportunity and any potential issues that could arise from collaboration.

In mid-2009, a Smart Metering technology workshop was held with representatives from all major areas of the three utilities. At this workshop, Smart Metering technology options were discussed with a focus on possibilities for leveraging common infrastructure. The companies not only gained a better understanding of the technology options available, but also identified a number of issues that would need further investigation and resolution.

The following outlines the objectives, options and recommendations of the working group.

8.2.2 COLLABORATION OBJECTIVES

The following were identified as the most important objectives of collaboration for the utilities, their customers, the BCUC and the provincial government.

- Consistent advanced metering benefits available to customers throughout the province;
- Lowest possible cost;
- Minimized duplicate assets;
- Meet individual utility needs and objectives; and

- Consistent provincial reporting available from utilities.

In summary, collaborations should provide consistent “smart metering” access and services.

8.2.3 CONSISTENT PROVINCIAL ADVANCED METERING BENEFITS

Both BC Hydro and FortisBC hope to exploit similar opportunities as a result of the implementation of AMI. In particular, customers of the two utilities will have a similar ability to access more detailed information about their electricity consumption. The support for in-home display devices will be consistent for both utilities. As well, FEI will also be able to leverage the devices if they choose to do so in the future. BC Hydro, FEI and FortisBC will continue to work together to ensure that in-home display devices purchased will work for any of the three utilities. BC Hydro and FortisBC customers will also receive similar types of quantifiable benefits, as outlined in Section 5.3 above.

FortisBC and BC Hydro agreed that their AMI solutions would include the ability to read gas and water meters. Therefore, should FEI or municipal water utilities choose to leverage the electric AMI systems (and appropriate terms of use are agreed), a consistent level of service will be available to customers throughout the province. As well, both electric utilities have indicated their willingness to allow municipal electric utilities to share their AMI systems, provided that mutually agreeable contractual arrangement can be made.

The electric AMI systems provide similar levels of data security as part of their network and IT infrastructure. Customers throughout the province can be assured that their data is protected.

LOWEST POSSIBLE COST

All three utilities recognized that there were potential cost benefits attributable to collaboration. Potential cost benefits can be generally categorized in two ways:

Shared Infrastructure: Cost savings and reduced infrastructure requirements may be achieved when two or more utilities share all or part of the advanced metering infrastructure. Any shared infrastructure may also result in some increased cost related to the need to separate the customer data required by each utility and to customize the shared infrastructure to each utility’s requirements.

Purchasing Power: When two or more utilities purchase the same products from the same vendor, it may be possible to realize savings from the higher sales volumes.

However, BC Hydro and FortisBC agreed that no cost savings could reasonably be achieved through collaboration. 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.

Software systems, particularly the MDMS, could potentially be shared. However, an initial cost analysis showed that any savings that might be achieved with a joint software license would be offset by complexities related to 1) integrating the MDMS with two different HESs and two different Customer Information Systems (which is where the bulk of software costs will be spent) and 2) segregating customer data in a manner that would ensure customer privacy.

Shared infrastructure savings are expected between FortisBC and FEI in the event that FEI decides to deploy an AMI system, but not if FEI decides to pursue AMR or continue with the status quo. Please refer to Section 8.3 for a discussion of the potential financial benefits of sharing infrastructure with FEI.

Purchasing power benefits were not available unless the utilities were willing to be in the market at the same time with the same terms and conditions and functional requirements. This was not possible simply from a timing perspective – the BC Hydro schedule was driven by legislative requirements while FortisBC's and FEI's schedules were not.

MINIMIZED DUPLICATE ASSETS

Due to the necessary geographical dispersion of network infrastructure within the BC Hydro and FortisBC service territories, no duplicate physical assets have been identified by FortisBC. In the event that FEI chooses to share the FortisBC AMI system, field network infrastructure will be shared wherever possible and appropriate.

MEET INDIVIDUAL UTILITY NEEDS AND OBJECTIVES

As a result of the decision for BC Hydro and FortisBC to pursue separate procurement processes, each utility used its own functional requirements and contractual terms and conditions in evaluating vendor proposals. Therefore, the needs of each utility were directly addressed in their respective procurement processes.

CONSISTENT REPORTING FROM UTILITIES

Since the AMI systems proposed by FortisBC and BC Hydro have similar capabilities in terms of the ability to read metering data, to read gas and water meters, to support theft reduction and to store and validate data, a consistent level of reporting will be available on a provincial basis. This will provide the provincial government and the BCUC assurance that similar information can be provided from the provincial electric utilities.

8.3 Additional Utilities and Cost Sharing of AMI

FortisBC's proposed AMI system will be capable of scaling to accommodate other utilities within the Company's service territory. Other utilities could include any combination of FortisBC Energy, Nelson Hydro, Grand Forks, Kelowna, District of Summerland or Penticton. FortisBC expects that any other utility desiring to contract usage of the Company's AMI would need to pay fees sufficient to recover a proportionate share of the initial capital cost, future sustaining capital and operating expenses necessary to maintain the infrastructure.

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.

The Company expects that participating utilities would purchase meters and pay a contribution toward the communications network devices and any necessary IT work to connect their meters to the AMI system. It is the intent of FortisBC to collect monthly or annual fees to recover the shared costs.

8.4 Project Challenges

As noted above, the technology associated with smart metering (or AMI) is currently a high profile topic in the media. Concerns have been expressed regarding the accuracy of AMI meters, EMF emissions from the meters and collectors, as well as the privacy and security of consumption information recorded and transmitted by the meters. These topics have gained considerable attention in the media, particularly in British Columbia as BC Hydro proceeds with its smart meter implementation. Indeed, similar concerns were also frequently cited by customers during FortisBC's public consultation efforts for the AMI Project. The discussion provided below examines these concerns in the context of FortisBC's proposed AMI Project.

8.4.1 HIGH BILLS AND METER ACCURACY

FortisBC is aware of potential customer concerns regarding the accuracy of AMI meters, particularly as evidenced by the numerous media articles detailing customer concerns in other areas that have implemented, or are implementing, an AMI system. However, despite these concerns, it is important to note that the use and accuracy of electric meters for revenue purposes is governed by the federal *Weights and Measures Act*, which is enforced by Measurement Canada, an agency of Industry Canada. Meters installed for the purpose of collecting revenue related to electrical consumption are tested for accuracy and certified as accurate with a seal period defined under the *Weights and Measures Act*. The seal period determines the initial date and duration that measurement from these devices is considered legally valid. In order to ensure standards and calibrations are maintained, meters are subjected to verification, re-verification, acceptance and compliance sampling at prescheduled intervals determined by Measurement Canada. In this regard, FortisBC AMI meters will be subject to the same stringent accuracy requirements as existing meters, both non-AMI digital as well as electro-mechanical meters.

As part of the AMI implementation, FortisBC intends to tighten the tolerances used by the Company's billing software in order to catch and proactively review any bills that could be considered potentially in error prior to being sent to customers. There is potential for manual meter reading errors of AMI meters (similar to the potential for manual meter reading errors today) during deployment of the AMI system. The tightening of bill tolerances is expected to ensure that any potential manual misreads during AMI implementation are caught and corrected prior to issuing the bill to the customer, helping to maintain customer satisfaction. Despite this, FortisBC is still forecasting a 15 percent increase in FortisBC Contact Centre costs related to billing/metering inquiries for the for the period 2014 – 2016.

When a customer contacts FortisBC regarding a high bill inquiry, customer concerns can typically be generalized into two categories: concern for a high bill, or a concern that the electric meter is not accurately recording consumption. In the event of a high bill inquiry (customer does not dispute the meter accuracy), the following considerations are examined in an effort to assist the customer:

- Verify whether the bill in question was based on an estimate (due to an off cycle move in/move out, access issue, etc);
- Verify whether the customer is on monthly billing (off cycle monthly estimate could potentially be too low resulting in a “catch-up” bill once a verified read is received);
- Evaluate how the bill compares to the previous year (if significantly different, could indicate a misread);
- Evaluate the number of days billed (certain billing periods could include an additional weekend as compared to the typical bimonthly billing cycle of approximately 60 days);
- Verify whether any other charges have been included on the bill (fees for meter installation or disconnection/reconnection, security deposit, or a balance transfer from a previously closed address); and
- Verify whether the billing period was cooler/hotter as compared to the previous year.

In the event that any of the above items are considered as a possible factor in understanding the cause of the customer’s high bill, an attempt is made to either explain to the customer the reason for the high bill, or possibly obtain a re-read of the meter, either by the customer or by a meter reader dispatched specifically for this task. If none of the above items are considered to adequately address the customer’s concern regarding their high bill, Contact Centre agents review a number of potential items that could help explain the apparent increased consumption. These items include:

- A review of seasonal appliances (baseboard heaters, holiday lighting, car block heaters, hot tubs, air conditioning, fans, pool pumps, etc.); and
- Consideration for whether any renovations have been performed, or whether any new appliances have been added/changed in the household.

Where a customer’s inquiry regarding a high bill does not result in a resolution to the customer’s satisfaction (based on the considerations discussed above), customers are asked if they would like to be contacted by FortisBC’s PowerSense department who may be able to offer additional insight into explaining a high bill, and potentially offer suggestions for improving energy efficiency which could prove beneficial in reducing future consumption.

FortisBC believes its existing high bill inquiry process to be satisfactory in helping to resolve customer high bill concerns, as evidenced by the fact that the majority of customer high bill inquiries are resolved through this process.

For those customers with whom FortisBC is unable to satisfactorily resolve a high bill inquiry, a concern regarding the accuracy of the electric meter is typically expressed by the customer. In this event, FortisBC offers customers the option of a parallel meter test which involves the installation of a "check" meter alongside the customer's existing meter to verify the consumption being recorded. Alternatively, or in addition to the parallel meter test, customers may elect to formally dispute the accuracy of their meter and request that their meter be sent to Measurement Canada for testing and validation. In this instance, customers are responsible for a deposit of $25 for removing and replacing the meter as detailed in Schedule 80 of FortisBC's Electric Tariff. In the event that Measurement Canada determines the customer's meter to be inaccurate, FortisBC refunds this deposit to the customer.

The Company proposes to retain its existing parallel meter process, with an additional modification to include the use of a Measurement Canada certified electro-mechanical meter for use as the parallel "check" meter. It is expected that this modification will help to allay customer concerns regarding the accuracy of digital AMI meters as compared to electro-mechanical meters. Customers will still retain the option of formally disputing the accuracy of their AMI meter by requesting testing by Measurement Canada as discussed above, however FortisBC believes the processes discussed for high bill/meter accuracy resolution are sufficiently robust to address the majority of customers that contact the Company expressing these concerns.

8.4.2 ELECTRO MAGNETIC FIELDS

As has been stated previously, the vast majority of meters that make up the LAN for FortisBC's proposed AMI Project are members of an RF mesh network. There is considerable discussion occurring worldwide with respect to the effects on human health resulting from exposure to electro-magnetic fields (EMF). FortisBC understands these concerns, and has commissioned an independent study that reviews the latest scientific research on the health effects of EMF (also known as radiofrequency fields or RF). The study, provided as Appendix C-5, concludes that the proposed meters are well below the safe exposure limits set out by Health Canada's Limits of Human Exposure to

Radiofrequency Electromagnetic Fields in the Frequency Range from 3 kHz to 300 GHz – Safety Code 6 (2009)[17]", and further states that:

> *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 smart meters will cause or contribute to adverse health effects or physical symptoms in the population.*[18]

The following specifics of the chosen technology are important to consider when evaluating the EMF risks posed by the proposed meters:

- Power – The proposed meters are low power at a maximum of 1 Watt. The low power minimizes the EMF.
- Distance - The strength of an EMF is inversely proportional to the square of the distance, meaning that the level drops off very quickly as the distance to the meter increases. 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. However, there are a number of meters located inside customer residences, typically a result of home renovations after the meter install, or older installations. Enclosed meters are difficult to access for repair, replacement and reading. FortisBC intends to work with customers before and during the AMI implementation to relocate these meters as necessary. This will benefit both the Company and the customer.
- Frequency – The frequency of operation of the meters is relatively low (902-928 MHz) when compared to other ubiquitous technologies such as cellular phones, microwave ovens and Wi-Fi.
- Duty Cycle – The duty cycle is the percentage of time that the transmitter is on and therefore radiating an EMF. The proposed AMI solution only requires a very limited

[17] Health Canada Safety Code 6 included in Appendix B-6
[18] Appendix C-5, page 34

amount of data from each meter, with an average total transmission time of about one minute per day.

The estimate of emission from the proposed AMI metering system and the relevant Health Canada exposure limit are provided in Table 8.4.2.a below. The table indicates that the average (or "mean") exposure from an AMI meter will be approximately 10,000 times below the Health Canada Safety Code 6 limit of 0.6 mW/cm^2.

Table 8.4.2.a - RF Exposure at 902 MHz to 928 MHz

Condition	Exposure at 0.5 meters (mW/cm^2)
Health Canada Safety Code 6 Limit[19]	**0.6**
Mean duty cycle 0.06%	0.000056
Maximum typical duty cycle 0.58%	0.00054
Maximum supported duty cycle 5%	0.0047

8.4.3 SECURITY

FortisBC considers the security of customer information to be of the highest priority. Given the nature of the AMI system, there are several components in relation to which security needs to be considered. These include the meters, LAN, collectors, WAN, HES, and MDMS. Since many components are installed at home or businesses and on Company owned infrastructure, it is critical that the security of the components be comprehensive.

The requirement for security of information within all elements of the AMI system is thus a key consideration throughout design, procurement and implementation. FortisBC's objective is to follow the security specifications set out in the AMI-SEC[20] AMI System Security Requirements, provided as Appendix F-1. In addition, FortisBC will ensure that security audits are carried out by a third-party agency during implementation and on an on-going basis thereafter to verify that the AMI Solution implemented continuously meets or exceeds the security standards as set forth in AMI-SEC.

The security requirements for the AMI system include considerations for, but not limited to the following:

- Confidentiality, integrity, security and privacy of data;

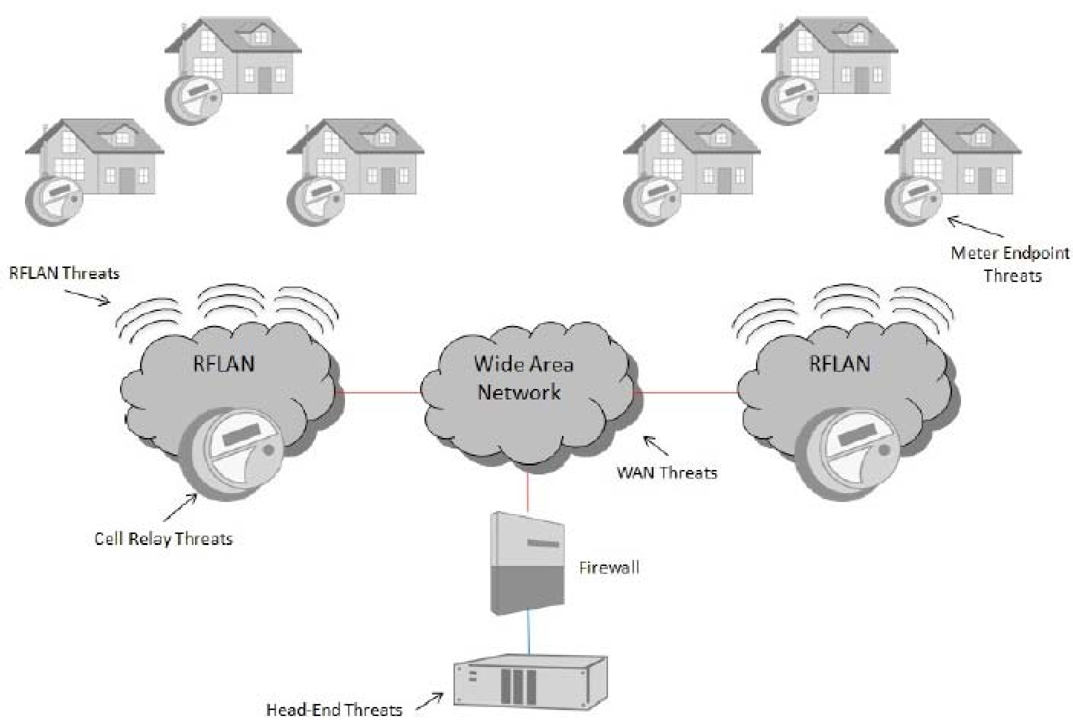
[19] The exposure limit increases with frequency and is equal to 0.62 mW/cm^2 at 928 MHz.
[20] AMI SEC is a North American Advanced Metering Infrastructure task force charged with developing security guidelines, recommendations, and best practices for AMI system elements

- Controls for malicious code detection, spam protection and intrusion detection;
- User authentication and user role controls;
- Audit controls and logging of user actions and events; and
- Immunity from outside electromagnetic interference.

The metering system proposed by Itron includes a security model that meets FortisBC's security requirements and contains the following security features:

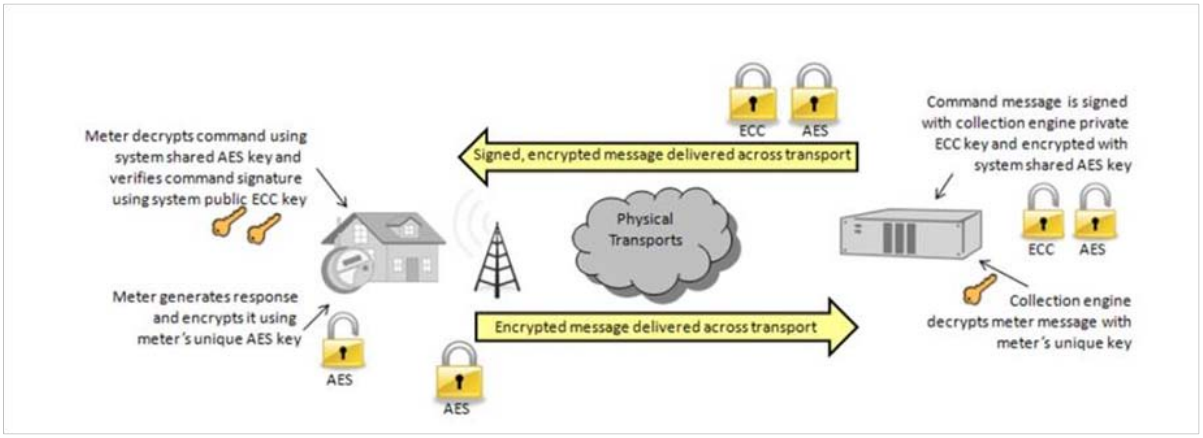
First, the system uses dedicated Signing and Encryption System (SES) and Decryption and Key Update System (DKUS) appliances to handle the volumes of messages expected in an AMI solution. The SES is responsible for securing commands sent from the HES to the meters. To protect the small number of keys used by the SES, the appliance includes an integrated hardware security that is Federal Information Processing Standard (FIPS) 140-2 level 3 compliant. The DKUS provides rapid decryption of messages coming from meters. This appliance is able to decrypt millions of unique AES keyed messages quickly. Figure 8.4.2.a below provides an overview of how messages are secured across the AMI solution.

Figure 8.4.3.a - Security Overview



Second, messages from the HES to the meters are transmitted using an AES-128 bit key and are signed using Elliptical Curve Cryptography (ECC) – 284 bit key. Messages coming from the meter are encrypted using the meter's unique AES-128 bit key providing confidentiality to the customer data.

Figure 8.4.3.b - Message Encryption



Third, the AMI solution from Itron provides a Security Event Manager (SEM) that is able to identify developing or on-going attacks against the system. Even with the significant effort in securing the messages, events on the network need to be monitored for potential security breaches. The SEM is used to collect and analyse audit events in order to detect intrusions and attacks. Attacks or breaches can vary but include threats such as:

- An attacker attempting to shut off a population of meters;
- An attacker trying to obtain consumption information from the AMI system;
- An attacker attempting to execute a denial of service attack against a population of meters;
- An attempt to hijack or spoof on more trusted systems;
- Attempts to recover key material from endpoints; and
- Attempts to modify an endpoint to change metrology or other parameters.

Fourth, the RF LAN technology uses a frequency hopping spread spectrum (FHSS) technique to help ensure the security and integrity of the data as well as to mitigate potential interference. FHSS uses a pseudo-random sequence known only to the transmitters and receivers to hop between frequencies and the signal is spread out over a wide band. These measures make the RF signals resistant to interference and difficult to intercept. The HES and MDMS are protected behind firewalls within the FortisBC corporate network and use role-based security only allowing authenticated users access to the system.

Additional security measures to be implemented by FortisBC include:

- Users are assigned to roles that control the functions they can perform and to security groups that limit access to only the meter data they are authorized to view. These roles eliminate the ability for unauthorized access to any customer data stored in the system; and
- All versions of the data are maintained with the system regardless of how many times it has been modified. Along with each version, the system has a complete audit log that includes which user made the change, when the change was made, how the change was made and why the change was made. These audit logs are designed so that they cannot be modified or deleted.

In summary, the security architecture is designed to secure customer data and ensure no security breaches on the infrastructure. The meter, LAN, WAN and HES are monitored to prevent intrusion and malicious attacks against the AMI solution. Additional details are available in the OpenWay Security Overview provided as Appendix F-2.

8.4.4 PRIVACY

FortisBC respects its customers' privacy and seeks to protect their personal information. The protection of personal information in British Columbia is governed by the provisions of the *Personal Information Protection Act* (PIPA) and the federal *Personal Information Protection and Electronic Documents Act* (PIPEDA), as applicable. FortisBC has revised its privacy policy which will become effective in the second half of 2012 and be applicable to all of the Fortis companies within British Columbia. Each of the Fortis companies within British Columbia will be notifying their customers of the revised policy prior to the effective date. The privacy policy will apply to all personal information collected by FortisBC, some of which will be collected using the advanced metering system.

The following are some important points regarding customer privacy as it applies to AMI meter system:

- The privacy policy applies to the collection, use and disclosure of personal information through the advanced metering system used by FortisBC, including advanced meters, metering equipment systems and technology.

- FortisBC already collects electricity consumption information about its customers. The AMI meter system will allow FortisBC to collect the same data, but more frequently.
- The information collected can be sent automatically from the AMI meter system through wireless encrypted technology.
- The AMI meter system cannot collect personal information about the source of electricity consumption within a premises, it can only collect aggregate electricity consumption data for the entire premises at any given time.
- FortisBC considers the security of consumption information collected via the AMI meter system to be an important and significant priority. The measures enacted to ensure security of information include but are not limited to the following:
    - Controls for malicious code detection, spam protection and intrusion detection;
    - User authentication and user role controls;
    - Audit controls and logging of user actions and events;
    - Immunity from outside electromagnetic interference;
    - Encryption using the advanced meter's unique AES-128 bit key providing confidentiality to the customer data; use of firewalls; and
    - Secure storage of customer data. The security architecture is designed to secure customer data and ensure that there are no security breaches on the AMI meter system.

8.4.5 REMOTE DISCONNECT/RECONNECT CAPABILITY

FortisBC is cognizant of the concerns associated with customers facing disconnection for non-payment. There are legitimate considerations about the safety of occupants of premises facing disconnection for non-payment if an effective communication plan to allow the customer an opportunity to avoid disconnection is not established.

FortisBC notes the following existing policies for the disconnection of customers for non-payment:

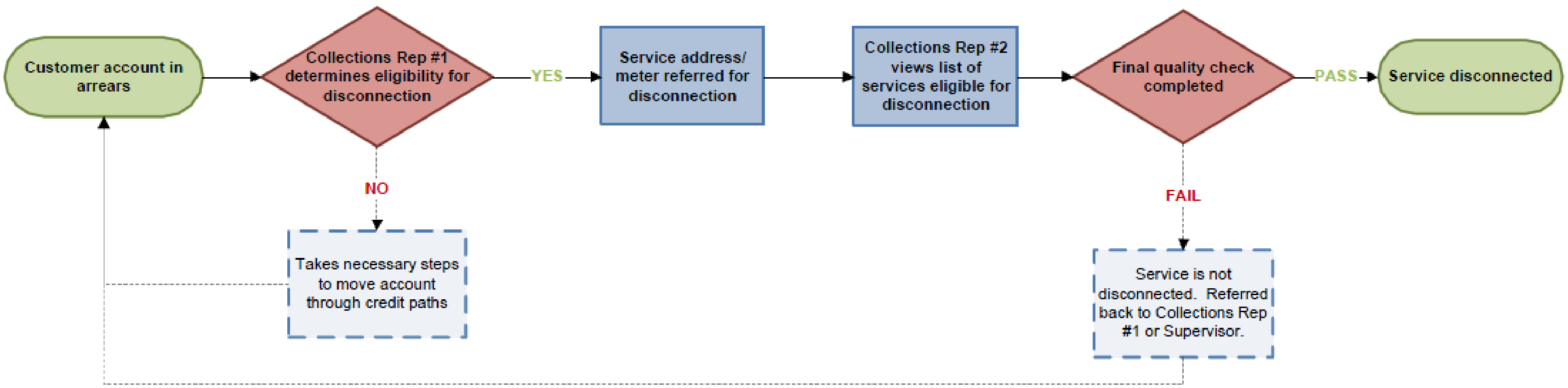
- Customers must receive adequate notice and be aware of the impending disconnection; and
- Disconnection of service cannot affect necessities such as power required for life-support devices.

FortisBC will continue to maintain a stringent process around disconnection for non-payment to ensure that there are at least two notices to the customer prior to that premises being disconnected. As well, the use of special warnings in the Company's Customer Information System related to life support, BCUC complaints in progress, and internal FortisBC considerations or other sensitive issues will continue to be relied upon to ensure the safety of customers and FortisBC employees.

The following diagram details a draft process that addresses concerns around how contact will be made before a disconnection for non-payment is made.

Figure 8.4.5.a

Remote Disconnections for Non-Payment



<u>Non-Pay Disconnection Eligibility Criteria</u>
Prior to referring an account for non-pay disconnection, Collections Rep #1 will look for the following:

1) Has the customer met the current arrears threshold?
2) Has the customer been sent a recent Notice of Disconnection?
3) Has the customer defaulted on their payment arrangements?
4) Have we attempted to contact the customer two or more times?*
5) Is the account free of any other special warnings that would prevent disconnection from occurring?**

If the answer to <u>any</u> of the above is "NO" then Collections Rep #1 follows the alternate pathway above. If the answer is "YES" then the service may be disconnection.

*Contact attempts include: a recent Notice of Disconnection, the customer contacting the company regarding their overdue balance, defaulted payment arrangements, a 48-hour door tag, a phone call from FortisBC.

**Special warnings include: alerts related to life support, BCUC complaints, an internal FortisBC complaints or other sensitive issues.

<u>Non-Pay Disconnection Quality Checks</u>
Prior to completing the non-pay disconnection, Collections Rep #2 will verify the following:

1) The service address & meter being referred for non-pay disconnection matches the information of the customer who is currently in arrears.
2) There are no special warnings that should prevent disconnection from occurring.

If the service address/meter pass the above quality checks then Collections Rep #2 will disconnect the service. If either of the above quality checks fail, the service address/meter will be referred back to Collections Rep #1 for review.

In some cases, the service address/meter may also be referred to the Supervisor. NOTE: All potential service addresses where there is a "life support" warning must have approval by Management before any disconnection can occur.

The welfare of FortisBC's customers is of the Company's utmost concern. Although the underlying benefit of remote disconnection is the reduced need for site visits to customer premises, FortisBC will continue to ensure that there is adequate notice for any disconnection done for non-payment prior to performing the disconnection.

8.5 Customer Refusals and Opt-Out

CUSTOMER REFUSALS

Based on feedback from customers, FortisBC believes there will be some customers that feel strongly that they do not want an advanced meter installed on their home. It is possible that some customers will refuse to allow the installation of an advanced meter at their residence.

FortisBC plans to work with "refusing" customers, communicating the benefits of the Project and addressing any specific concerns they may have. By doing so, FortisBC hopes to avoid and address the majority of customer issues and concerns at the time of advanced meter installation.

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.

OPT-OUT

Several North American jurisdictions have offered an "opt-out" option for customers who oppose having an advanced meter installed. Customers that wish to "opt-out" pay additional fees related to the costs of having to download data from the meters manually, rather than through the wireless network.

FortisBC believes that an opt-out provision is not in the best interest of customers for the following reasons:

- "Opt-out" will not resolve all customer concerns, and customer refusals would still be expected.
- There is no compelling scientific or other evidence to support the need for an "opt-out" provision.
- Advanced metering benefits can be eroded by "opt-out" customers.
- It is not consistent with existing provincial policy.

9.0 CONSULTATION AND COMMUNICATION

FortisBC is committed to meaningful stakeholder engagement on all major projects it undertakes. FortisBC has widely communicated its intent to file an Application for the implementation of AMI. The Company employed multiple channels to communicate Project information and benefits internally and externally, and to respond to public interest and gather information.

9.1 Public Consultation

FortisBC has been engaged in public and First Nation consultation processes related to AMI for some time. In 2008, AMI was introduced in the workshop for the 2009/2010 Capital Expenditure Plan as part of the Demand Side Management Plan. More recently, AMI was featured in the Integrated System Plan public consultation that occurred in February of 2011. The ISP consultation process included four open houses – Castlegar, Kelowna, Osoyoos, and Creston. Each open house began at 6 p.m. with a general presentation followed by customers' questions.

Concurrent with the ISP open houses, FortisBC also hired Illumina Research Partners to conduct two supergroups. The first supergroup was held in Kelowna and included 56 participants; the second was held in Castlegar with 59 participants. The participants completed in-depth surveys and their input was recorded and summarized in a report. The responses to questions pertaining to AMI were generally positive. For example, 46 per cent of participants had positive comments on AMI; 27 per cent had neutral comments; 15 per cent had negative comments. Please refer to Appendix E-1 for a summary of Illumina Research Partners' findings from the supergroup sessions.

FortisBC held another series of public consultation focussed on AMI in June of 2011 with five open houses – Kelowna, Osoyoos, Princeton, Creston, and Trail. Similar to the ISP open houses, each open house began at 6 p.m. with a presentation. The presentation gave customers a comprehensive overview of the project, the benefits, and addressed high-profile concerns such as privacy of information and health concerns related to EMF emissions. FortisBC representatives remained at the open houses until all follow-up questions from customers were addressed.

Ninety-three people participated in the AMI open houses in June 2011. In addition to a feedback form provided online and at the open houses, FortisBC provided an email address

(FBCami@fortisbc.com) for customers to provide feedback. Copies of all customer feedback forms submitted at the open houses are provided as Appendix E-2.

Following the open house consultations, FortisBC continued to receive emails and letters, some sent by registered mail, which included a form letter refusing the installation of an advanced meter.

In general, customers who attended open houses or provided feedback through the Project email address or letters were concerned with:

- **Health Issues**
  - A number of participants attending the AMI open houses were concerned with EMF emissions from advanced meters. A majority of the feedback forms received by FortisBC cited EMF - related health concerns as the main reason for opposition to advanced meters.
- **Rates**
  - Customers are concerned regarding the impact of the Project on customer rates, and some expressed their opinion that the cost of implementing the Project will result in higher rates for all FortisBC customers.
  - Customers expressed concerns about being forced to use electricity at certain times through time-of-use rates.
- **Privacy/Security**
  - Customers were concerned that AMI would allow the utility to tell when customers were home or when certain appliances were being used.
  - Customers were concerned that their personal information could easily be intercepted.

As of June 30, 2012 FortisBC has received 305 email/letters opposing the installation of AMI meters. Of the total correspondence received, 273 opposed the installation of AMI meters without providing a specific reason. The remainder of the correspondence received by the Company cited concerns as discussed above.

Prior to the open houses, FortisBC advertised invitations through newspapers in communities where an open house was to be held with the goal of explaining the Project and to encourage attendance at the open houses. Meetings were held with the Kelowna Daily Courier and the Trail Daily Times.

In addition to the AMI open houses, FortisBC hosted shopping mall information kiosks at two locations – Orchard Park Mall in Kelowna and Waneta Plaza in Trail. FortisBC representatives provided a fact sheet on the AMI Project and gave customers an overview of the Project.

Stakeholder consultation is always to be an important component of the consultation process for FortisBC. FortisBC officials met with two Members of the Legislative Assembly, Katrine Conroy and John Horgan, during the ISP consultation process. FortisBC sent invitations to Mayors and Council and Bands and Nations in the FortisBC service area asking if they would like a presentation on AMI and/or to participate in the public open houses. Following these invitations, FortisBC gave presentations to the Councils of Warfield, Kaslo, Montrose, Castlegar, Keremeos, Midway, and the Regional District of Kootenay Boundary. Additionally, the Company has made AMI presentations to private customer groups such as condominium associations and Rotary Clubs. FortisBC will continue to provide presentations to any interested communities.

FortisBC has also received letters of support for its proposed AMI Project, and the associated benefits stemming from the Project, from the Fire Chiefs' Association of BC, the BC Sustainable Energy Association, GreenStep, and Climate Smart. Copies of these letters are provided as Appendix E-3.

9.2 First Nations Consultation

The AMI Project does not involve any greenfield construction on any Band land or traditional territory. The scope of the Project is limited to the replacement of existing metering infrastructure with the AMI-enabled meters, including the associated communications hardware, limiting the scope of the duty of the Crown to consult as a result of FortisBC's proposed AMI project. FortisBC submits that no Aboriginal or treaty rights are potentially affected, adversely or otherwise, as a result of the proposed Project.

As part of the FortisBC desire for meaningful engagement with its First Nation customers, the Company has endeavoured to inform the various Bands and Nations affected by the AMI Project about the details of the Project. First Nations governments were contacted via telephone in May / June 2011, during which conversations the Company requested input and involvement in the AMI process, including the scheduled AMI open houses. Personal contact continued through telephone calls and face to face meetings with First Nations representatives.

A follow-up letter was sent in July 2011, copies of which are provided as Appendix E-4, which notified First Nations governments that open houses had occurred and that FortisBC is continuing to seek First Nation input on the AMI project. FortisBC is aware that the AMI Project has been discussed during Chief and Council meetings. FortisBC continues to offer in-person presentations to Chief and councils for those interested, and attended a Band Council meeting in early October 2011 to present the AMI Project.

The Company continues to participate in ongoing discussions as and where desired by the First Nations. FortisBC submits that the consultation process carried out to date is reasonable and sufficient to allow the Commission to judge that the scope of any duty to consult has been met. Any issues or concerns identified by First Nations will be addressed by FortisBC should they arise, however no issues or concerns have been raised to date.

9.3 Dominion Radio Astrophysical Observatory

Communication with Dominion Radio Astrophysical Observatory (DRAO) commenced in late 2009. Due to the nature of its operation, which includes the continuous observation of the radio frequency spectrum in the study of distant stars and other astronomical phenomena, the areas adjacent to the DRAO facilities are protected from RF interference by regional by-laws, land use covenants, and contracts specifically intended to protect this research.

In recent discussions and meetings, DRAO has indicated that the amount of interference from the AMI system may be sufficiently limited and therefore acceptable. FortisBC and DRAO intend to work together to perform actual measurements in the field (if the Project is approved) to validate the interference from the system. FortisBC will continue to work with DRAO to mitigate any issues that occur during testing and deployment of the AMI network.

9.4 Other BC Utilities

Phone calls and follow up meetings have been organized with FortisBC's municipal wholesale customers to provide opportunities for discussions on FortisBC's AMI Project and to identify any opportunities that exist as part of this Project for these municipalities.

FortisBC has received communications from a representative of the BCMEU, stating that the BCMEU does not have a strong opinion as to whether FortisBC should or should not implement the proposed AMI Project. The BCMEU did note the following:

- There is an expectation from the BCMEU that there should be no cost impact to the wholesale customers of FortisBC (which are the members of the BCMEU receiving wholesale service from FortisBC);
- Concern that residential rates may become excessively complex as a result of any future rate design offerings made possible by AMI; and
- A majority of the BCMEU members at this time are not interested in having FortisBC implement AMI on their behalf in their respective service areas. However, the City of Kelowna has expressed interest in an AMI system through some type of partnership/procurement advantage for the City if a business case supports such implementation.

9.5 Consultation Summary

FortisBC is sensitive to the concerns expressed during consultation, however believes that many of the comments are based on misinformation that customers have received through various media. As a result, the Communications Plan detailed in Section 9.6 below will focus in part on delivering information to customers that addresses those concerns.

FortisBC believes that the Company's proposed RF-based AMI solution is a safe and cost-effective way to deliver maximum benefits to customers. Nevertheless, based on concerns expressed during public open houses, FortisBC immediately commenced work to quantify the costs and benefits related the implementation of a PLC-based alternative AMI solution. Those results can be found in the discussion of Project alternatives in Section 7.0 above.

9.6 AMI Project Communications

Objectives

The objectives of FortisBC's communication plan during the deployment phase would include the following:

- Communicate the merits of AMI to FortisBC customers, stakeholders and employees;
- Dispel any misunderstandings regarding advanced meters;
- Create a positive environment for all customers and stakeholders for the two years required for the deployment of advanced meters; and

- Engage customers by explaining the exchange and installation process of advanced meters.

General Messages

FortisBC recognizes that communication with customers during deployment of AMI will need to be extensive and comprehensive. Throughout the Project, FortisBC will communicate with customers regarding the benefits of AMI, what customers can expect during the deployment process and how customers can take advantage of the new information provided by AMI. The table below outlines FortisBC's communication plan regarding AMI once BCUC approval is received.

Table 9.6.a - FortisBC AMI Project Deployment Communications Plan

External	Description	Timeline
News Release	Release for earned media regarding deployment of advanced meters and what customers can expect with installs	2 Weeks prior to deployment
Advertising Radio ads Print ads	Telling customers FortisBC will be in the area soon installing new meters	2 weeks prior to deployment to complement earned media
Web Site Page	Updated to include deployment schedule; what customers can expect, video of install process; video of how to use FBC secure web site; form to report trouble with new meter	1 month prior to deployment
Direct mail out to FBC customers	Letter sent to all customers	1 month prior to deployment
Bill Insert or Powerlines[21]	To establish contact with all customers prior to installation of advanced meters	Bill prior to deployment – 2 months
Door Hangers "*Exchange Successful*"	Notification of work to be performed in affected customers areas	Printed one month prior
Door Hangers "*Need to reschedule*"	Provide contact numbers to reschedule meter exchange	Printed one month prior
Follow up communications package	FortisBC will leave a communications package once meter is exchanged at the customers premise	Hand delivered during installation

[21] PowerLines is FortisBC's customer newsletter, published approximately three times annually and included with mailed bills

Appendix A – Draft Order

Appendix B – Legislation and Stimulus

Appendix B-1 – 2007 BC Energy Plan

Appendix B-2 – Greenhouse Gas Reduction Targets Act

Appendix B-3 – Climate Action Charter

Appendix B-4 – Carbon Tax Act

Appendix B-5 – Clean Energy Act

Appendix B-6 – Health Canada Safety Code 6

Appendix B-7 – Measurement Canada Statistical Method S-S-06

Appendix C – Reports and Other Resources

Appendix C-1 – Navigant Future AMI Program Study

Appendix C-2 – PCS Utilidata Conservation Voltage Regulation Optimization Report

Appendix C-3 – BC Hydro Smart Meter Press Release

Appendix C-4 – BC Hydro Smart Meter Business Case

Appendix C-5 – Exponent Status of Research on RF Exposure and Health

Appendix D – Financial and NPV Analyses

Appendix E – Consultation, Communication and Correspondence

Appendix E-1 – Illumina Supergroup Findings

Appendix E-2 – AMI Open House Feedback

Appendix E-3 – AMI Support Letters

Appendix E-4 – AMI First Nations Letters

Appendix F – Technology Section

Appendix F-1 – AMI-SEC System Security Requirements

Appendix F-2 – Itron OpenWay Security Overview

Appendix A

Draft Order

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web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-XX-13

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
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DRAFT ORDER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Inc.
for Approval of the Advanced Metering Infrastructure (AMI) Project

BEFORE:

XXXX XX, 2013

O R D E R

WHEREAS:

A. On July 26, 2012, FortisBC Inc. (FortisBC) applied (the Application) to the Commission pursuant to sections 45, 46, and 56 of the *Utilities Commission Act* (the Act), for the review and approval of the Advanced Metering Infrastructure (AMI) Project Application including approval of a revised depreciation rate for the meters proposed to be installed as part of the Project;

B. FortisBC stated that the AMI Project is estimated to cost $47.7 million and is driven by the opportunity it affords both customers and the Company to have a greater ability to manage the cost of electricity. This opportunity is made possible by the numerous benefits resulting from the Project, including the significant financial savings resulting primarily from a reduction in costs related to the existing manual meter reading process, as well as the deterrence of electricity theft and the recovery of the associated lost revenues.

C. The Application proposed to procure and install hardware and software to enable AMI, integrate these components to existing FortisBC systems and to deploy communications network infrastructure and advanced meters throughout FortisBC's service territory;

D. By Commission Order G-XX-12 dated XX, the Commission established a Regulatory Timetable for a written submissions on procedural matters;

E. By Order G-XX-12, the Commission established an initial Regulatory Timetable for the proceeding to review the application including two rounds of Commission and Intervenor Information Requests to FortisBC, the filing of Intervenor Evidence and the submission of Information Requests to Intervenors who have filed evidence,

.../2

F. On November 29, 2012 a Procedural Conference was held in Kelowna, B.C.;

G. By Order G-XX-12, the Commission established a timetable for an Oral Public Hearing for January 21, 2013 in Kelowna, B.C., as well as a timetable for the filing of Company and Intervenor Written Final Submissions, and FortisBC's Written Reply Submission;

H. The oral public hearing was held in Kelowna, B.C., commencing Monday, January 21, 2013,

I. The Commission has considered the AMI Project and submissions and has determined that an Advanced Metering Infrastructure should be implemented.

NOW THEREFORE the Commission orders as follows:

1. Pursuant to sections 45 and 46 of the Act, a CPCN is granted to FortisBC to implement an Advanced Metering Infrastructure.

2. Pursuant to section 56 of the Act, the Commission approves the depreciation rate of 5 percent to be applied to the AMI meters to be installed as part of the Project.

DATED at the City of Vancouver, in the Province of British Columbia, this XX day of <month> 2013.

BY ORDER

Original signed by:

XXXXXXX
Chair

Appendix B-1

2007 BC Energy Plan

The BC Energy Plan

A Vision for Clean Energy Leadership

BRITISH COLUMBIA
The Best Place on Earth

TABLE OF CONTENTS

MESSAGE FROM THE PREMIER

The BC Energy Plan: A Vision for Clean Energy Leadership is British Columbia's plan to make our province energy self-sufficient while taking responsibility for our natural environment and climate. The world has turned its attention to the critical issue of global warming. This plan sets ambitious targets. We will pursue them relentlessly as we build a brighter future for B.C.

The BC Energy Plan sets out a strategy for reducing our greenhouse gas emissions and commits to unprecedented investments in alternative technology based on the work that was undertaken by the Alternative Energy Task Force. Most importantly, this plan outlines the steps that all of us – including industry, environmental agencies, communities and citizens – must take to reach these goals for conservation, energy efficiency and clean energy so we can arrest the growth of greenhouse gases and reduce human impacts on the climate.

As stewards of this province, we have a responsibility to manage our natural resources in a way that ensures they both meet our needs today and the needs of our children and grandchildren. We will all have to think and act differently as we develop innovative and sustainable solutions to secure a clean and reliable energy supply for all British Columbians.

Our plan will make B.C. energy self-sufficient by 2016. To do this, we must maximize our conservation efforts. Conservation will reduce pressure on our energy supply and result in real savings for those who use less energy. Individual actions that reduce our own everyday energy consumption will make the difference between success and failure. For industry, conservation can lead to an effective, productive and significant competitive advantage. For communities, it can lead to healthier neighbourhoods and lifestyles for all of us.

We are looking at how we can use clean alternative energy sources, including bioenergy, geothermal, fuel cells, water-powered electricity, solar and wind to meet our province's energy needs. With each of these new options comes the opportunity for new job creation in areas such as research, development, and production of innovative energy and conservation solutions. The combination of renewable alternative energy sources and conservation will allow us to pursue our potential to become a net exporter of clean, renewable energy to our Pacific neighbours.

Just as the government's energy vision of 40 years ago led to massive benefits for our province, so will our decisions today. **The BC Energy Plan** will ensure a secure, reliable, and affordable energy supply for all British Columbians for years to come.

Premier Gordon Campbell

MESSAGE FROM THE MINISTER

The BC Energy Plan: A Vision for Clean Energy Leadership is a made-in-B.C. solution to the common global challenge of ensuring a secure, reliable supply of affordable energy in an environmentally responsible way. In the next decade government will balance the opportunities and increased prosperity available from our natural resources while leading the world in sustainable environmental management.

This energy plan puts us in a leadership role that will see the province move to eliminating or offsetting greenhouse gas emissions for all new projects in the growing electricity sector, end flaring from oil and gas producing wells, and put in place a plan to make B.C. electricity self-sufficient by 2016.

In developing this plan, the government met with key stakeholders, environmental non-government organizations, First Nations, industry representatives and others. In all, more than 100 meetings were held with a wide range of parties to gather ideas and feedback on new policy actions and strategies now contained in **The BC Energy Plan**.

By building on the strong successes of Energy Plan 2002, this energy plan will provide secure, affordable energy for British Columbia. Today, we reaffirm our commitment to public ownership of our BC Hydro assets while broadening our supply of available energy.

We look towards British Columbia's leading edge industries to help develop new, greener generation technologies with the support of the new **Innovative Clean Energy Fund**. We're planning for tomorrow, today. Our energy industry creates jobs for British Columbians, supports important services for our families, and will play an important role in the decade of economic growth and environmental sustainability that lies ahead.

The Ministry of Energy, Mines and Petroleum Resources is responding to challenges and opportunities by delivering innovative, sustainable ways to develop British Columbia's energy resources.

Honourable Richard Neufeld
Minister of Energy, Mines and Petroleum Resources

THE BC ENERGY PLAN HIGHLIGHTS

In 2002, the Government of British Columbia launched an ambitious plan to invigorate the province's energy sector. Energy for Our Future: A Plan for BC was built around four cornerstones: low electricity rates and public ownership of BC Hydro; secure, reliable supply; more private sector opportunities; and environmental responsibility with no nuclear power sources. Today, our challenges include a growing energy demand, higher prices, climate change and the need for environmental sustainability. The BC Energy Plan: A Vision for Clean Energy Leadership builds on the successes of the government's 2002 plan and moves forward with new policies to meet the challenges and opportunities ahead.

Environmental Leadership

The BC Energy Plan puts British Columbia at the forefront of environmental and economic leadership by focusing on our key natural strengths and our competitive advantages of clean and renewable sources of energy. The plan further strengthens our environmental leadership through the following key policy actions:

- **Zero greenhouse gas emissions from coal fired electricity generation.**
- **All new electricity generation projects will have zero net greenhouse gas emissions.**
- **Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.**
- **Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.**
- **No nuclear power.**
- **Best coalbed gas practices in North America.**
- **Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.**

British Columbia's current electricity supply resources are 90 per cent clean and new electricity generation plants will have zero net greenhouse gas emissions.

A Strong Commitment to Energy Conservation and Efficiency

Conservation is integral to meeting British Columbia's future energy needs. The BC Energy Plan sets ambitious conservation targets to reduce the growth in electricity used within the province. British Columbia will:

- **Set an ambitious target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.**
- **Implement energy efficient building standards by 2010.**

Current per household electricity consumption for BC Hydro customers is about 10,000 Kwh per year. Achieving this conservation target will see electricity use per household decline to approximately 9,000 Kwh per year by 2020.

Energy Security

The Government of British Columbia is taking action to ensure that the energy needs of British Columbians continue to be met now and into the future. As part of ensuring our energy security, The BC Energy Plan sets the following key policy actions:

- **Maintain public ownership of BC Hydro and the BC Transmission Corporation.**
- **Maintain our competitive electricity rate advantage.**
- **Achieve electricity self-sufficiency by 2016.**
- **Make small power part of the solution through a set purchase price for electricity generated from projects up to 10 megawatts.**
- **Explore value-added opportunities in the oil and gas industry by examining the viability of a new petroleum refinery and petrochemical industry.**
- **Be among the most competitive oil and gas jurisdictions in North America.**
- **BC Hydro and the Province will enter into initial discussions with First Nations, the Province of Alberta and communities to discuss Site C to ensure that communications regarding the potential project and the processes being followed are well known.**

Investing in Innovation

British Columbia has a proven track record in bringing ideas and innovation to the energy sector. From our leadership and experience in harnessing our hydro resources to produce electricity, to our groundbreaking work in hydrogen and fuel cell technology, British Columbia has always met its future energy challenges by developing new, improved and sustainable solutions. To support future innovation and to help bridge the gap experienced in bringing innovations through the pre-commercial stage to market, government will:

- **Establish an Innovative Clean Energy Fund of $25 million.**
- **Implement the BC Bioenergy Strategy to take full advantage of B.C.'s abundant sources of renewable energy.**
- **Generate electricity from mountain pine beetle wood by turning wood waste into energy.**

Ambitious Energy Conservation and Efficiency Targets

The more energy that is conserved, the fewer new sources of supply we will require in the future. That is why British Columbia is setting new conservation targets to reduce growth in electricity demand.

Inefficient use of energy leads to higher costs and many environmental and security of supply problems.

Conservation Target

The BC Energy Plan sets an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020. This will require building on the "culture of conservation" that British Columbians have embraced in recent years.

The plan confirms action on the part of government to complement these conservation targets by working closely with BC Hydro and other utilities to research, develop, and implement best practices in conservation and energy efficiency and to increase public awareness. In addition, the plan supports utilities in British Columbia and the BC Utilities Commission pursuing all cost effective and competitive demand side management programs. Utilities are also encouraged to explore and develop rate designs to encourage efficiency, conservation and the development of renewable energy.

Future energy efficiency and conservation initiatives will include:

- Continuing to remove barriers that prevent customers from reducing their consumption.
- Building upon efforts to educate customers about the choices they can make today with respect to the amount of electricity they consume.
- Exploring new rate structures to identify opportunities to use rates as a mechanism to motivate customers either to use less electricity or use less at specific times.
- Employing new rate structures to help customers implement new energy efficient products and technologies and provide them with useful information about their electricity consumption to allow them to make informed choices.
- Advancing ongoing efforts to develop energy-efficient products and practices through regulations, codes and standards.

POLICY ACTIONS

COMMITMENT TO CONSERVATION

- **Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.**
- **Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.**
- **Encourage utilities to pursue cost effective and competitive demand side management opportunities.**
- **Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.**

The average household uses about 10,000 kilowatt-hours of electricity per year.

Implement Energy Efficiency Standards for Buildings by 2010

British Columbia implemented *Energy Efficient Buildings: A Plan for BC* in 2005 to address specific barriers to energy efficiency in our building stock through a number of voluntary policy and market measures. This plan has seen a variety of successes including smart metering pilot projects, energy performance measurement and labelling, and increased use of Energy Star appliances. In 2005, B.C. received a two year, $11 million federal contribution from the Climate Change Opportunities Envelope to support implementation of this plan.

Working together industry, local governments, other stakeholders and the provincial government will determine and implement cost effective energy efficiency standards for new buildings by 2010. Regulated standards for buildings are a central component of energy efficiency programs in leading jurisdictions throughout the world.

The BC Energy Plan supports reducing consumption by raising awareness and enhancing the efforts of utilities, local governments and building industry partners in British Columbia toward conservation and energy efficiency.

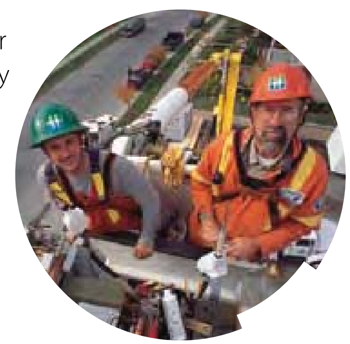
Aggressive Public Sector Building Plan

The design and retrofit of buildings and their surrounding landscapes offer us an important means to achieve our goal of making the government of British Columbia carbon neutral by 2010, and promoting Pacific Green universities, colleges, hospitals, schools, prisons, ferries, ports and airports.

British Columbia communities are already recognized leaders in innovative design practices. We know how to build smarter, faster and smaller. We know how to increase densities, reduce building costs and create new positive benefits for our environment. We know how to improve air quality, reduce energy consumption and make wise use of other resources, and how to make our landscapes and buildings healthy places for living, working and learning. We know how to make it affordable.

Government will set the following ambitious goals for all publicly funded buildings and landscapes and ask the Climate Action Team to determine the most credible, aggressive and economically viable options for achieving them:

- Require integrated environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.
- Supply green, healthy workspaces for all public service employees.
- Capture the productivity benefits for people who live and work in publicly funded buildings such as reduced illnesses, less absenteeism, and a better learning environment.
- Aim not only for the lowest impact, but also for restoration of the ecological features of the surrounding landscapes.



Gigawatt = 1,000,000 kilowatts
Kilowatt = amount of power to light ten 100-watt incandescent light bulbs.

ENERGY CONSERVATION AND EFFICIENCY

Community Action on Energy Efficiency

British Columbia is working in partnership with local governments to encourage energy conservation at the community level through the Community Action on Energy Efficiency Program. The program promotes energy efficiency and community energy planning projects, providing direct policy and technical support to local governments through a partnership with the Fraser Basin Council. A total of 29 communities are participating in the program and this plan calls for an increase in the level of participation and expansion of the program to include transportation actions. The Community Action on Energy Efficiency Program is a collaboration among the provincial ministries of Energy, Mines and Petroleum Resources, Environment, and Community Services, Natural Resources Canada, the Fraser Basin Council, Community Energy Association, BC Hydro, FortisBC, Terasen Gas, and the Union of BC Municipalities.

Leading the Way to a Future with Green Buildings and Green Cities

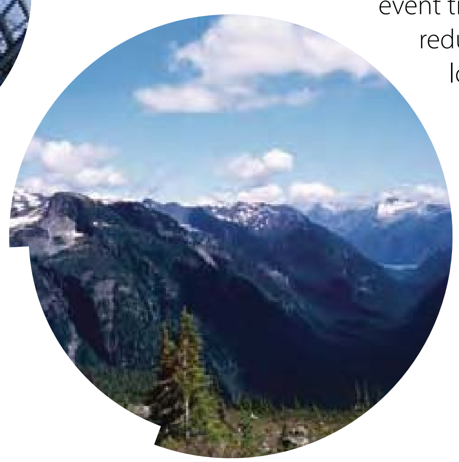
British Columbia has taken a leadership role in the development of green buildings. Through the Green Buildings BC Program, the province is working to reduce the environmental impact of government buildings by increasing energy and water efficiency and reducing greenhouse gas emissions. Through this program, and the Energy Efficient Buildings Strategy that establishes energy efficiency targets for all types of buildings, the province is inviting businesses, local governments and all British Columbians to do their part to increase energy efficiency and reduce greenhouse gas emissions.

The Green Cities Project sets a number of strategies to make our communities greener, healthier and more vibrant places to live. British Columbia communities are already recognized leaders in innovative sustainability practices, and the Green Cities Project will provide them with additional resources to improve air quality, reduce energy consumption and encourage British Columbians to get out and enjoy the outdoors. With the Green Cities Project, the provincial government will:

- Provide $10 million a year over four years for the new LocalMotion Fund, which will cost share capital projects on a 50/50 basis with municipal governments to build bike paths, walkways, greenways and improve accessibility for people with disabilities.
- Establish a new Green City Awards program to encourage the development and exchange of best practices by communities, with the awards presented annually at the Union of British Columbia Municipalities convention.
- Set new financial incentives to help local governments shift to hybrid vehicle fleets and help retrofit diesel vehicles.
- Commit to making new investments in expanded rapid transit, support for fuel cell vehicles and other innovations.

Industrial Energy Efficiency Program

Government will establish an Industrial Energy Efficiency Program for British Columbia to address challenges and issues faced by the B.C. industrial sector and support the Canada wide industrial energy efficiency initiatives. The program will encourage industry driven investments in energy efficient technologies and processes; reduce emissions and greenhouse gases; promote self generation of power; and reduce funding barriers that discourage energy efficiency in the industrial sector. Some specific strategies include developing a results based pilot program with industry to improve energy efficiency and reduce overall power consumption and promote the generation of renewable energy within the industrial sector.



The 2010 Olympic and Paralympics Games: Sustainability in Action

In 2010 Vancouver and Whistler will host the Winter Olympic and Paralympic Games. The 2010 Olympic Games are the first that have been organized based on the principles of sustainability.

All new buildings for the Olympics will be designed and built to conserve both water and materials, minimize waste, maximize air quality, protect surrounding areas and continue to provide environmental and community benefits over their lifetimes. Existing venues will be upgraded to showcase energy conservation and efficiency and demonstrate the use of alternative heating/cooling technologies. Wherever possible, renewable energy sources such as wind, solar, micro hydro, and geothermal energy will be used to power and heat all Games facilities.

Transportation for the 2010 Games will be based on public transit. This system – which will tie event tickets to transit use – will help reduce traffic congestion, minimize local air pollution and limit greenhouse gas emissions.

POLICY ACTIONS

BUILDING STANDARDS, COMMUNITY ACTION AND INDUSTRIAL EFFICIENCY

- **Implement Energy Efficiency Standards for Buildings by 2010.**
- **Undertake a pilot project for energy performance labelling of homes and buildings in coordination with local and federal governments, First Nations and industry associations.**
- **New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.**
- **Develop an Industrial Energy Efficiency Program for British Columbia to address specific challenges faced by British Columbia's industrial sector.**
- **Increase the participation of local governments in the Community Action on Energy Efficiency Program and expand the First Nations and Remote Community Clean Energy Program.**

British Columbia benefits from the public ownership of BC Hydro and the BC Transmission Corporation.

POLICY ACTIONS

SELF-SUFFICIENCY BY 2016

- **Ensure self-sufficiency to meet electricity needs, including "insurance."**
- **Establish a standing offer for clean electricity projects up to 10 megawatts.**
- **The BC Transmission Corporation is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.**
- **Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy.**
- **Ensure that the province remains consistent with North American transmission reliability standards.**

Electricity Security

Electricity, while often taken for granted, is the lifeblood of our modern economy and key to our entire way of life. Fortunately, British Columbia has been blessed with an abundant supply of clean, affordable and renewable electricity. But today, as British Columbia's population has grown, so too has our demand for electricity. We are now dependent on other jurisdictions for up to 10 per cent of our electricity supply. BC Hydro estimates demand for electricity to grow by up to 45 per cent over the next 20 years.

We must address this ever increasing demand to maintain our secure supply of electricity and the competitive advantage in electricity rates that all British Columbians have enjoyed for the last 20 years. There are no simple solutions or answers. We have an obligation to future generations to chart a course that will ensure a secure, environmentally and socially responsible electricity supply.

To close this electricity gap, and for our province to become electricity self-sufficient, will require an innovative electricity industry and the real commitment of all British Columbians to conservation and energy efficiency.

The New Relationship and Electricity

The Government of British Columbia is working with First Nations to restore, revitalize and strengthen First Nations communities. The goal is to build strong and healthy relationships with First Nations people guided by the principles of trust and collaboration. First Nations share many of the concerns of other British Columbians in how the development of energy resources may impact as well as benefit their communities. In addition, First Nations have concerns with regard to the recognition and respect of Aboriginal rights and title.

By focusing on building partnerships between First Nations, industry and government, tangible social and economic benefits will flow to First Nations communities across the province and assist in eliminating the gap between First Nations people and other British Columbians.

Government is working every day to ensure that energy resource management includes First Nations' interests, knowledge and values. By continuing to engage First Nations in energy related issues, we have the opportunity to share information and look for opportunities to facilitate First Nations' employment and participation in the electricity sectors to ensure that First Nations people benefit from the continued growth and development of British Columbia's resources. The BC Energy Plan provides British Columbia with a blueprint for facing the many energy challenges and opportunities that lay ahead. It provides an opportunity to build on First Nations success stories such as:

- First Nations involvement in independent power projects, such as the Squamish First Nation's participation in the Furry Creek and Ashlu hydro projects.

- Almost $4 million will flow to approximately 10 First Nations communities across British Columbia to support the implementation of Community Energy Action Plans as part of the First Nation and Remote Community Clean Energy Program.
- The China Creek independent power project was developed by the Hupacasath First Nation on Vancouver Island.

Achieve Electricity Self-Sufficiency by 2016

Achieving electricity self-sufficiency is fundamental to our future energy security and will allow our province to achieve a reliable, clean and affordable supply of electricity. It also represents a lasting legacy for future generations of British Columbians. That's why government has committed that British Columbia will be electricity self-sufficient within the decade ahead.

Through **The BC Energy Plan**, government will set policies to guide BC Hydro in producing and acquiring enough electricity in advance of future need. However, electricity generation and transmission infrastructure require long lead times. This means that over the next two decades, BC Hydro must acquire an additional supply of "insurance power" beyond the projected increases in demand to minimize the risk and implications of having to rely on electricity imports.

Small Power Standing Offer

Achieving electricity self-sufficiency in British Columbia will require a range of new power sources to be brought on line. To help make this happen, this policy will direct BC Hydro to establish a Standing Offer Program with no quota to encourage small and clean electricity producers. Under the Standing Offer Program, BC Hydro will purchase directly from suppliers at a set price. Eligible projects must be less than 10 megawatts in size and be clean electricity or high efficiency electricity cogeneration. The price offered in the standing offer contract would be based on the prices paid in the most recent BC Hydro energy call. This will provide small electricity suppliers with more certainty, bring small power projects into the system more quickly, and help achieve government's goal of maintaining a secure electricity supply. As well, BC Hydro will offer the same price to those in BC Hydro's Net Metering Program who have a surplus of generation at the end of the year.

Ensuring a Reliable Transmission Network

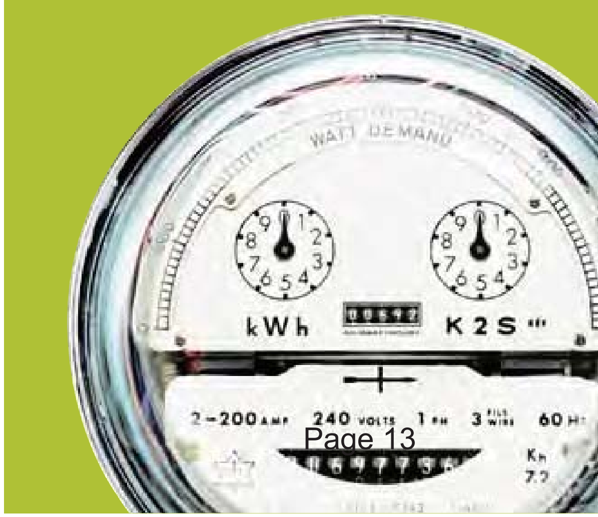
An important part of meeting the goal of self-sufficiency is ensuring a reliable transmission infrastructure is in place as additional power is brought on line. Transmission is a critical part of the solution as often new clean sources of electricity are located away from where the demand is. In addition, transmission investment is required to support economic growth in the province and must be planned and started in anticipation of future electricity needs given the long lead times required for transmission development. New and upgraded transmission infrastructure will be required to avoid congestion and to efficiently move the electricity across the entire power grid. Because our transmission system is part of a much larger, interconnected grid, we need to work with other jurisdictions to maximize the benefit of interconnection, remain consistent with evolving North American reliability standards, and ensure British Columbia's infrastructure remains capable of meeting customer needs.

BC HYDRO'S NET METERING PROGRAM: PEOPLE PRODUCING POWER

BC Hydro's Net Metering Program was established as a result of Energy Plan 2002. It is designed for customers with small generating facilities, who may sometimes generate more electricity than they require for their own use. A net metering customer's electricity meter will run backwards when they produce more electricity than they consume and run forward when they produce less than they consume.

The customer is only billed for their "net consumption"; the total amount of electricity used minus the total produced.

Net metering allows customers to lower their environmental impact and take responsibility for their own power production. It helps to move the province towards electricity self-sufficiency and expands clean electricity generation, making B.C.'s electricity supply more environmentally sustainable.



ELECTRICITY

In order for British Columbia to ensure the development of a secure and reliable supply of electricity, **The BC Energy Plan** provides policy direction to the BC Transmission Corporation to ensure that our transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand. This will include ensuring there is adequate transmission capacity, ongoing investments in technology and infrastructure and remaining consistent with evolving North American reliability standards.

BC Transmission Corporation Innovation and Technology

As the manager of a complex and high-value transmission grid, BC Transmission Corporation is introducing technology innovations that provide improvements to the performance of the system and allow for a greater utilization of existing assets, ensuring B.C. continues to benefit from one of the most advanced energy networks in the world. BC Transmission Corporation's innovation program focuses on increasing the power transfer capability of existing assets, extending the life of assets and improving system reliability and security. Initiatives include:

- System Control Centre Modernization Project: This project is consolidating system operations into a new control center and backup site and upgrading operating technologies with a modern management system that includes enhancements to existing applications to ensure the electric grid is operating reliably and efficiently. The backup site will take over complete operation of the electric grid if the main site is unavailable.
- Real-Time Phasors: British Columbia is among the first North American jurisdictions to incorporate phasor measurement into control centre operations. Phasors are highly accurate voltage, current and phase angle "snapshots" of the real-time state of the transmission system that enable system operators to monitor system conditions and identify any impending problems.
- Real-Time Rating: This is a temperature monitoring system which enables the operation of two 500 kilovolt submarine cable circuits at maximum capacity without overloading. The resulting increase in capacity is estimated to be up to 10 per cent, saving millions of dollars.
- Electronic Temperature Monitor Upgrades for Station Transformers: In this program, existing mechanical temperature monitors will be replaced with newer, more accurate electronic monitors on station transformers that allow transformers to operate to maximum capacity without overheating. In addition to improving performance, BC Transmission Corporation will realize reduced maintenance costs as the monitors are "self-checking."
- Life Extension of Transmission Towers: BC Transmission Corporation maintains over 22,000 steel lattice towers and is applying a special composite corrosion protection coating to some existing steel towers to extend their life by about 25 years.

Public Ownership

Public Ownership of BC Hydro and the BC Transmission Corporation

BC Hydro and the BC Transmission Corporation are publicly-owned crown corporations and will remain that way now and into the future. BC Hydro is responsible for generating, purchasing and distributing electricity. The BC Transmission Corporation operates, maintains, and plans BC Hydro's transmission assets and is responsible for providing fair, open access to the power grid for all customers. Both crowns are subject to the review and approvals of the independent regulator, the BC Utilities Commission.

BC Hydro owns the heritage assets, which include historic electricity facilities such as those on the Peace and Columbia Rivers that provide a secure, reliable supply of low-cost power for British Columbians. These heritage assets require maintenance and upgrades over time to ensure they continue to operate reliably and efficiently. Potential improvements to these assets, such as capacity additions at the Mica and Revelstoke generating stations, can make important contributions for the benefit of British Columbians.

Confirming the Heritage Contract in Perpetuity

Under the 2002 Energy Plan, a legislated heritage contract was established for an initial term of 10 years to ensure BC Hydro customers benefit from its existing low-cost resources. With The BC Energy Plan, government confirms the heritage contract in perpetuity to ensure ratepayers will continue to receive the benefits of this low-cost electricity for generations to come.

British Columbia's Leadership in Clean Energy

The BC Energy Plan will continue to ensure British Columbia has an environmentally and socially responsible electricity supply with a focus on conservation and energy efficiency.

British Columbia is already a world leader in the use of clean and renewable electricity, due in part to the foresight of previous generations who built our province's hydroelectric dams. These dams - now British Columbians' 'heritage assets' - today help us to enjoy 90 per cent clean electricity, one of the highest levels in North America.

All New Electricity Generation Projects Will Have Zero Net Greenhouse Gas Emissions

The B.C. government is a leader in North America when it comes to environmental standards. While British Columbia is a province rich in energy resources such as hydro electricity, natural gas and coal, the use of these resources needs to be balanced through effective use, preserving our environmental standards, while upholding our quality of life for generations to come. The government has made a commitment that all new electricity generation projects developed in British Columbia and connected to the grid will have zero net greenhouse gas emissions. In addition, any new electricity generated from coal must meet the more stringent standard of zero greenhouse gas emissions.

POLICY ACTIONS

PUBLIC OWNERSHIP

- **Continue public ownership of BC Hydro and its heritage assets, and the BC Transmission Corporation.**
- **Establish the existing heritage contract in perpetuity.**
- **Invest in upgrading and maintaining the heritage asset power plants and the transmission lines to retain the ongoing competitive advantage these assets provide to the province.**

ELECTRICITY

POLICY ACTIONS

REDUCING GREENHOUSE GAS EMISSIONS FROM ELECTRICITY

- **All new electricity generation projects will have zero net greenhouse gas emissions.**
- **Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.**
- **Require zero greenhouse gas emissions from any coal thermal electricity facilities.**
- **Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.**
- **Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.**
- **No nuclear power.**

Zero Net Greenhouse Gas Emissions from Existing Thermal Generation Power Plants by 2016

Setting a requirement for zero net emissions over this time period encourages power producers to invest in new or upgraded technology. For existing plants the government will set policy around reaching zero net emissions through carbon offsets from other activities in British Columbia. It clearly signals the government's intention to continue to have one of the lowest greenhouse gas emission electricity sectors in the world.

Ensure Clean or Renewable Electricity Generation Continues to Account For at Least 90 per cent of Total Generation

Currently in B.C., 90 per cent of electricity is from clean or renewable resources. The BC Energy Plan commits to maintaining this high standard which places us among the top jurisdictions in the world. Clean or renewable resources include sources of energy that are constantly renewed by natural processes, such as water power, solar energy, wind energy, tidal energy, geothermal energy, wood residue energy, and energy from organic municipal waste.

Zero Greenhouse Gas Emissions from Coal

The government is committed to ensuring that British Columbia's electricity sector remains one of the cleanest in the world and will allow coal as a resource for electricity generation when it can reach zero greenhouse gas emissions. Clean-coal technology with carbon sequestration is expected to become commercially available in the next decade. Therefore, the province will require zero greenhouse gas emissions from any coal thermal electricity facilities which can be met through capture and sequestration technology. British Columbia is the first Canadian jurisdiction to commit to using only clean coal technology for any electricity generated from coal.

Burrard Thermal Generating Station

A decision regarding the Burrard Thermal Natural Gas Generating Station is another action that is related to environmentally responsible electricity generation in British Columbia.

Even though it could generate electricity from Burrard Thermal, BC Hydro imports power primarily because the plant is outdated, inefficient and costly to run. However, Burrard Thermal still provides significant benefits to BC Hydro as it acts as a "battery" close to the Lower Mainland, and provides extra capacity or "reliability insurance" for the province's electricity supply. It also provides transmission system benefits that would otherwise have to be supplied through the addition of new equipment at Lower Mainland sub-stations.

By 2014, BC Hydro plans to have firm electricity to replace what would have been produced at the plant. Government supports BC Hydro's proposal to replace the firm energy supply from Burrard Thermal with other resources by 2014. However, BC Hydro may choose to retain the plant for "reliability insurance" should the need arise.

No Nuclear Power

As first outlined in Energy Plan 2002, government will not allow production of nuclear power in British Columbia.

Benefits to British Columbians

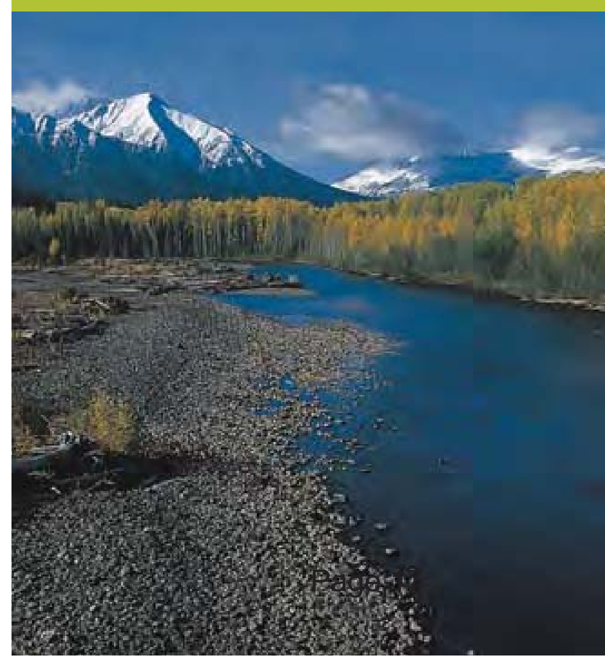
Clean or renewable electricity comes from sources that replenish over a reasonable time or have minimal environmental impacts. Today, demand for economically viable, clean, renewable and alternative energy is growing along with the world's population and economies. Consumers are looking for power that is not only affordable but creates minimal environmental impacts. Fortunately, British Columbia has abundant hydroelectric resources, and plenty of other potential energy sources.

Maintain our Electricity Competitive Advantage

British Columbians require a secure, reliable supply of competitively priced electricity now and in the future. Competitively priced power is also an incentive for investors to locate in British Columbia. It provides an advantage over other jurisdictions and helps sustain economic growth. We are fortunate that historic investments in hydroelectric assets provide electricity that is readily available, reliable, clean and inexpensive. By ensuring public ownership of BC Hydro, the heritage assets and the BC Transmission Corporation and confirming the heritage contract in perpetuity, we will ensure that ratepayers continue to receive the benefits of this low cost generation. Due to load growth and aging infrastructure, new investments will be required. Investments in maintenance and in some cases expansions can be a cost effective way to meet growth and reduce future rate increases.

CARBON OFFSETS AND HOW THEY REDUCE EMISSIONS

A carbon offset is an action taken directly, outside of normal operations, which results in reduced greenhouse gas emissions or removal of greenhouse gases from the atmosphere. Here's how it works: if a project adds greenhouse gases to the atmosphere, it can effectively subtract them by purchasing carbon offsets which are reductions from another activity. Government regulations to reduce greenhouse gases, including offsets, demonstrate leadership on climate change and support a move to clean and renewable energy.



ELECTRICITY

Government will establish a $25 million ***Innovative Clean Energy Fund.***

POLICY ACTIONS

BENEFITS TO BRITISH COLUMBIANS

- **Review BC Utilities Commissions' role in considering social and environmental costs and benefits.**
- **Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources.**
- **Work with BC Hydro and parties involved to continue to improve the procurement process for electricity.**
- **Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.**
- **Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.**

British Columbia must look for new, innovative ways to stay competitive. New technologies must be identified and nurtured, from both new and existing industries. By diversifying and strengthening our energy sector through the development of new and alternative energy sources, we can help ensure the province's economy remains vibrant for years to come.

Ensure Electricity is Secured at Competitive Prices

One practical way to keep rates down is to ensure utilities have effective processes for securing competitively priced power. As part of The BC Energy Plan, government will work with BC Hydro and parties involved to continue to improve the Call for Tender process for acquiring new generation. Fair treatment of both buyers and sellers of electricity will facilitate a robust and competitive procurement process. Government and BC Hydro will also look for ways to further recognize the value of intermittent resources, such as run-of- river and wind, in the acquisition process – which means that BC Hydro will examine ways to value separate projects together to increase the amount of firm energy calculated from the resources.

Rates Kept Low Through Powerex Trading of Electricity

Profits from electricity trade also contribute to keeping our electricity rates competitive. BC Hydro, through its subsidiary, Powerex, buys and sells electricity when it is advantageous to British Columbia's ratepayers. Government will continue to support capitalizing on electricity trading opportunities and will continue to allocate trade revenue to BC Hydro ratepayers to keep electricity rates low for all British Columbians.

BC Utilities Commissions' Role in Social and Environmental Costs and Benefits

The BC Energy Plan clarifies that social, economic and environmental costs are important for ensuring a suitable electricity supply in British Columbia. Government will review the BC Utilities Commissions' role in considering social, environmental and economic costs and benefits, and will determine how best to ensure these are appropriately considered within the regulatory framework.

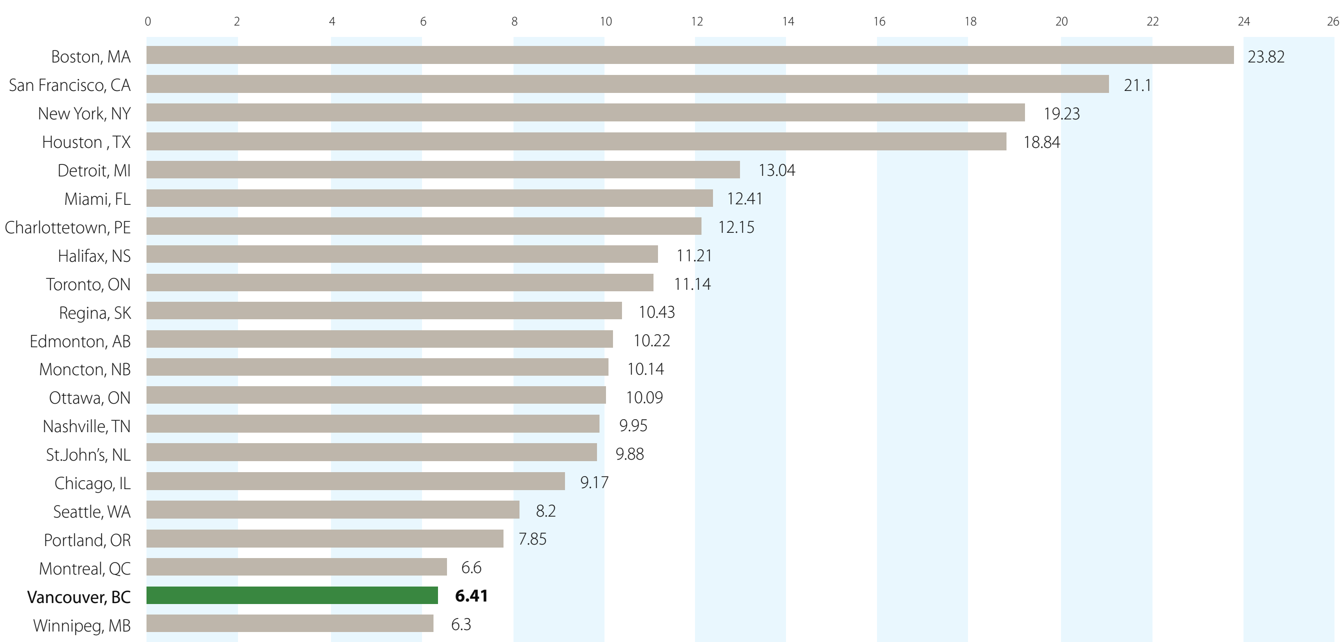
Bring Clean Power to Communities

British Columbia's electricity industry supports thousands of well-paying jobs, helps drive the economy and provides revenues to sustain public services. British Columbia's electricity industry already fosters economic development by implementing cost effective and reliable energy solutions in communities around the province. However, British Columbia covers almost one million square kilometres and electrification does not extend to all parts of our vast province.

Government and BC Hydro have established First Nation and remote community energy programs to implement alternative energy, energy efficiency, conservation and skills training solutions in a number of communities. The program focuses on expanding electrification services to as many as 50 remote and First Nations communities in British Columbia, enabling them to share in the benefits of a stable and secure supply of electricity. Government will put the policy framework in place and BC Hydro will implement the program over the next 10 years. The **Innovative Clean Energy Fund** can also support technological advancements to address the issue of providing a clean and secure supply of electricity to remote communities.

2006 Average Residential Electricity Price

Price (Canadian cents per kilowatt hour)



Source: Hydro Quebec comparison of Electricity Prices in Major North American Cities, April 2006

BRINGING CLEAN POWER TO ATLIN

Electricity in the remote community of Atlin in northwestern British Columbia is currently supplied by diesel generators. The First Nations and Remote Community Clean Energy Program is bringing clean power to Atlin.

The Taku Land Corporation, solely owned by the Taku River Tlingit First Nation will construct a two megawatt run-of-river hydroelectric project on Pine Creek, generating local economic benefits and providing clean power for Atlin. The Taku Land Corporation has entered into a 25 year Electricity Purchase Agreement with BC Hydro to supply electricity from the project to Atlin's grid. Over the course of the agreement, this will reduce greenhouse gas emissions by up to 150,000 tonnes as the town's diesel generators stand by.

The province is contributing $1.4 million to this $10 million project. This is the first payment from a $3.9 million federal contribution to British Columbia's First Nations and Remote Community Clean Energy Program. Criteria for federal funding included demonstrating greenhouse gas emissions reductions, cost-effectiveness, and partnerships with communities and industry.

ALTERNATIVE ENERGY

Government will work with other agencies to maximize opportunities to develop, deploy and export British Columbia clean and alternative energy technologies.

POLICY ACTIONS

INVESTING IN INNOVATION

- **Establish the Innovative Clean Energy Fund to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.**
- **Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.**
- **Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.**

Innovative Clean Energy Fund

British Columbia's increasing energy requirements and our ambitious greenhouse gas emission reduction and clean energy targets require greater investment and innovation in the area of alternative energy by both the public and private sector.

To lead this effort, the government will establish an **Innovative Clean Energy Fund** of $25 million to help promising clean power technology projects succeed. The fund will be established through a small charge on energy utilities. The Minister of Energy, Mines and Petroleum Resources will consult with the energy utilities on the implementation of this charge.

Proponents of projects that will be supported through the fund will be encouraged to seek additional contributions from other sources. Government's new **Innovative Clean Energy Fund** will help make British Columbia a world leader in alternative energy and power technology. It will solve some of B.C.'s pressing energy challenges, protect our environment, help grow the economy, position the province as the place international customers turn to for key energy and environmental solutions, and assist B.C. based companies to showcase their products to world wide markets.

Following the advice of the Premier's Technology Council and the Alternative Energy and Power Technology Task Force, the fund will focus strictly on projects that:

- Address specific British Columbia energy and environmental problems that have been identified by government.
- Showcase B.C. technologies that have a strong potential for international market demand in other jurisdictions because they solve problems that exist both in B.C. and other jurisdictions.
- Support pre-commercial energy technology that is new, or commercial technologies not currently used in British Columbia.
- Demonstrate commercial success for new energy technologies.

Some problems that the fund could focus on include:

- Developing reliable power solutions for remote communities-particularly helping First Nations communities reduce their reliance on diesel generation for electricity.
- Advance conservation technologies to commercial application.
- Finding ways to convert vehicles to cleaner alternative fuels.
- Increasing the efficiency of power transmission through future grid technologies.
- Expanding the opportunities to generate power using alternative fuels (e.g.mountain pine beetle wood).

The British Columbia Bioenergy Strategy: Growing Our Natural Energy Advantage

Currently, British Columbia is leading Canada in the use of biomass for energy. The province has 50 per cent of Canada's biomass electricity generating capacity. In 2005, British Columbia's forest industry self-generated the equivalent of $150 million in electricity and roughly $1.5 billion in the form of heat energy. The use of biomass has displaced some natural gas consumption in the pulp and paper sector. The British Columbia wood pellet industry also enjoys a one-sixth share of the growing European Union market for bioenergy feedstock. The province will shortly release a bioenergy strategy that will build upon British Columbia's natural bioenergy resource advantages, industry capabilities and academic strength to establish British Columbia as a world leader in bioenergy development.

British Columbia's plan is to lead the bioeconomy in Western Canada with a strong and sustainable bioenergy sector. This vision is built on two guiding principles:

- Competitive, diversified forest and agriculture sectors.
- Strengthening regions and communities.

The provincial Bioenergy Strategy is aimed at:

- Enhancing British Columbia's ability to become electricity self-sufficient.
- Fostering the development of a sustainable bioenergy sector.
- Creating new jobs.
- Supporting improvements in air quality.
- Promoting opportunities to create power from mountain pine beetle-impacted timber.
- Positioning British Columbia for world leadership in the development and commercial adoption of wood energy technology.
- Advancing innovative solutions to agricultural and other waste management challenges.
- Encouraging diversification in the forestry and agriculture industries.
- Producing liquid biofuels to meet Renewable Fuel Standards and displace conventional fossil fuels.

Generating Electricity from Mountain Pine Beetle Wood: Turning Wood Waste into Energy

British Columbia is experiencing an unprecedented mountain pine beetle infestation that has affected several million hectares of trees throughout the province. This infestation is having a significant impact on forestry-based communities and industries, and heightens forest fire risk. There is a great opportunity to convert the affected timber to bioenergy, such as wood pellets and wood-fired electricity generation and cogeneration.

Through The BC Energy Plan, BC Hydro will issue a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.

MOUNTAIN PINE BEETLE INFESTATION: TURNING WOOD WASTE INTO ENERGY

British Columbia is experiencing an unprecedented mountain pine beetle infestation that has affected several million hectares of trees throughout the province. This infestation is having a significant economic impact on B.C.'s forestry industry and the many communities it helps to support and sustain. The forest fire risk to these communities has also risen as a result of their proximity to large stands of "beetle-killed" wood.

B.C. has developed a bioenergy strategy to promote new sources of sustainable and renewable energy in order to take advantage of the vast amounts of pine beetle-infested timber and other biomass resources. In the future, bioenergy will help meet our electricity needs, supplement conventional natural gas and petroleum supplies, maximize job and economic opportunities, and protect our health and environment.

The production of wood pellets is already a mature industry in British Columbia. Industry has produced over 500,000 tonnes of pellets and exported about 90 per cent of this product overseas in 2005, primarily to the European thermal power industry. Through The BC Energy Plan, BC Hydro will issue a call for proposals for further electricity generation from wood residue and mountain pine beetle-infested timber.

GOVERNMENT TO USE HYBRID VEHICLES ONLY

The provincial government is continuing the effort to reduce greenhouse gas emissions and overall energy consumption.

As part of this effort, government has more than tripled the size of its hybrid fleet since 2005 to become one of the leaders in public sector use of hybrid cars.

Hybrids emit much less pollution than conventional gas and diesel powered vehicles and thus help to reduce greenhouse gases in our environment. They can also be more cost-effective as fuel savings offset the higher initial cost.

As of 2007, all new cars purchased or leased by the B.C. government are to be hybrid vehicles. The province also has new financial incentives to help local governments shift to hybrid vehicle fleets and help retrofit diesel vehicles.

Addressing Greenhouse Gas Emissions from Transportation

The BC Energy Plan: A Vision for Clean Energy Leadership takes a first step to incorporate transportation issues into provincial energy policy. Transportation is a major contributor to climate change and air quality problems. It presents other issues such as traffic congestion that slows the movement of goods and people. The fuel we use to travel around the province accounts for about 40 per cent of British Columbia's greenhouse gas emissions. Every time we drive or take a vehicle that runs on fossil fuels, we add to the problem, whether it's a train, boat, plane or automobile. Cars and trucks are the biggest source of greenhouse gas emissions and contribute to reduced air quality in urban areas.

The government is committed to reducing greenhouse gas emissions from the transportation sector and has committed to adopting California's tailpipe emission standards from greenhouse gas emissions and champion the national adoption of these standards.

British Columbians want a range of energy options for use at home, on the road and in day-to-day life. Most people use gasoline or diesel to keep their vehicles moving, but there are other options that improve our air quality and reduce greenhouse gas emissions.

Natural gas burns cleaner than either gasoline or propane, resulting in less air pollution. Fuel cell vehicles are propelled by electric motors powered by fuel cells, devices that produce electricity from hydrogen without combustion.

Cars that run on blends of renewable biofuels like ethanol and biodiesel emit lower levels of greenhouse gases and air pollutants. Electricity can provide an alternative to gasoline vehicles when used in hybrids and electric cars.

By working with businesses, educational institutions, non-profit organizations and governments, new and emerging transportation technologies can be deployed more rapidly at home and around the world. British Columbia will focus on research and development, demonstration projects, and marketing strategies to promote British Columbia's technologies to the world.

Implementing a Five Per Cent Renewable Fuel Standard for Diesel and Gasoline

The BC Energy Plan demonstrates British Columbia's commitment to environmental sustainability and economic growth by taking a lead role in promoting innovation in the transportation sector to reduce greenhouse gas emissions, improve air quality and help improve British Columbians' health and quality of life in the future. The plan will implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry. It will further support the federal action of increasing the ethanol content of gasoline to five per cent by 2010. The plan will also see the adoption of quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions. These renewable fuel standards are a major component and first step towards government's goal of reducing the carbon intensity of all passenger vehicles by 10 per cent by 2020.

GO GREEN

Government will implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.

A Commitment to Extend British Columbia's Ground-breaking Hydrogen Highway

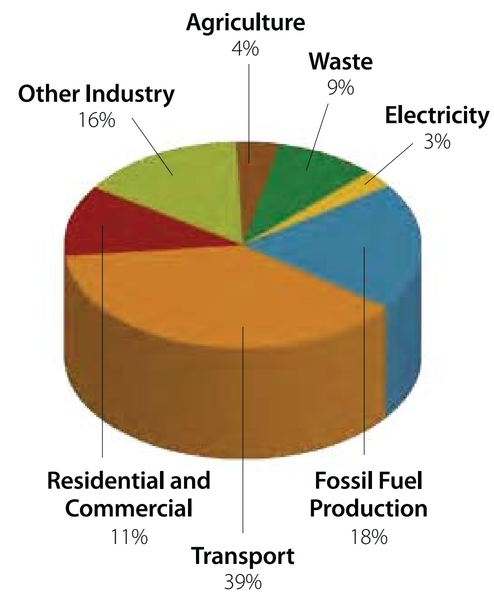
British Columbia is a world leader in transportation applications of the Hydrogen Highway, including the design, construction and safe operation of advanced hydrogen vehicle fuelling station technology. The Hydrogen Highway is a large scale, coordinated demonstration and deployment program for hydrogen and fuel cell technologies.

Vancouver's Powertech Labs established the world's first fast-fill, high pressure hydrogen fuelling station. The station anchors the Hydrogen Highway, which runs from Victoria through Surrey to Vancouver, North Vancouver, Squamish, and Whistler. Additional hydrogen fuelling stations are now in operation in Victoria and at the University of British Columbia.

The goal is to demonstrate and deploy various technologies and to one day see hydrogen filling stations around the province, serving drivers of consumer and commercial cars, trucks, and buses.

The unifying vision of the province's hydrogen and fuel cell strategy is to promote fuel cells and hydrogen technologies as a means of moving towards a sustainable energy future, increasing energy efficiency and reducing air pollutants and greenhouse gases. The Hydrogen Highway is targeted for full implementation by 2010. Canadian hydrogen and fuel cell companies have invested over $1 billion over the last five years, most of that in B.C. A federal-provincial partnership will be investing $89 million for fuelling stations and the world's first fleet of 20 fuel cell buses.

British Columbia will continue to be a leader in the new hydrogen economy by taking actions such as a fuel cell bus fleet deployment, developing a regulatory framework for micro-hydrogen applications, collaborating with neighbouring jurisdictions on hydrogen, and, in the long term, establishing a regulatory framework for hydrogen production, vehicles and fuelling stations.



B.C. Greenhouse Gas Emissions by Sector

(Based on 2004 data)
Source: Ministry of Environment

Cars and trucks are the biggest source of greenhouse gas emissions and reduce the quality of air in urban areas.

POLICY ACTIONS

ADDRESSING GREENHOUSE GAS EMISSIONS FROM TRANSPORTATION AND INCREASING INNOVATION

- **Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.**
- **Support the federal action of increasing the ethanol content of gasoline to five per cent by 2010 and adopt quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions.**
- **Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.**
- **Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.**

Vehicles that run on electricity, hydrogen and blends of renewable biofuels like ethanol and biodiesel emit lower levels of greenhouse gases and air pollutants.

LOCALMOTION FUND: REDUCING AIR POLLUTION IN YOUR COMMUNITY

The province has committed $40 million over four years to help build cycling and pedestrian pathways, improve safety and accessibility, and support children's activity programs in playgrounds.

This fund will help local government shift to hybrid vehicle fleets and help retrofit diesel vehicles which will help reduce air pollution and ensure vibrant and environmentally sustainable communities. This investment will also include expansion of rapid transit and support fuel cell vehicles.

Promote Energy Efficiency and Alternative Energy

It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar thermal and geothermal. Working with municipalities, utilities and other stakeholders the provincial government will promote energy efficiency and alternative energy systems, such as solar thermal and geothermal throughout the province.

Environmental Leadership in Action

The BC Energy Plan: A Vision for Clean Energy Leadership complements other related cross-government initiatives that include supporting transportation demand management, reducing traffic congestion and better integrating land use and transportation planning. These plans include actions across a broad range of activities. Some key initiatives and recent announcements include:

- Extending the tax break on hybrid vehicle purchases beyond the current March 2008 deadline.
- Government to purchase hybrid vehicles exclusively.
- Reducing diesel emissions through new financial incentives to help municipalities shift to hybrid vehicle fleets and retrofit diesel vehicles with cleaner technologies.
- Green Ports:
  - Working with ports and the shipping sector to reduce emissions from their activities and marine vessels.
  - The Port of Vancouver has established idle reduction zones and has reduced truck emissions with its container reservation system which has reduced average wait times from two hours to approximately 20 minutes.
  - The port is also evaluating port-side electrification which would see vessels using shore-side electrical power while berthed rather than diesel power.
- Improving upon the monitoring and reporting of air quality information.
- Highway Infrastructure and Rapid Transit Infrastructure funding including the Gateway Program, the Border Infrastructure Program, high occupancy vehicle lanes, construction of the Rapid Transit Canada Line linking Richmond, the Vancouver International Airport and Vancouver, and the Rapid Transit Evergreen Line linking Burnaby to Coquitlam.
- Expanding the AirCare on the Road Program to the Lower Fraser Valley and other communities.
- Implementing the LocalMotion Program for capital projects to improve physical fitness and safety, reduce air pollution and meet the diverse needs of British Columbians.

A Choice of Electricity Options

The range of supply options, both large and small, for British Columbia include:

Bioenergy: Bioenergy is derived from organic biomass sources such as wood residue, agricultural waste, municipal solid waste and other biomass and may be considered a carbon-neutral form of energy, because the carbon dioxide released by the biomass when converted to energy is equivalent to the amount absorbed during its lifetime.

A number of bioenergy facilities operate in British Columbia today. Many of these are "cogeneration" plants that create both electricity and heat for on-site use and in some cases, sell surplus electricity to BC Hydro.

Reliability[1]: FIRM
Estimated Cost[5]: $75 – $91

Coal Thermal Power: The BC Energy Plan establishes a zero emission standard for greenhouse gas emissions from coal-fired plants. This will require proponents of new coal facilities to employ clean coal technology with carbon capture and sequestration to ensure there are no greenhouse gas emissions.

Reliability[1]: FIRM
Estimated Cost[5,6]: $67– $82

Geothermal: Geothermal power is electricity generated from the earth. Geothermal power production involves tapping into pockets of superheated water and steam deep underground, bringing them to the surface and using the heat to produce steam to drive a turbine and produce electricity. British Columbia has potential high temperature (the water is heated to more than 200 degrees Celsius) geothermal resources in the coastal mountains and lower temperature resources in the interior, in northeast British Columbia and in a belt down the Rocky Mountains. Geothermal energy's two main advantages are its consistent supply, and the fact that it is a clean, renewable source of energy.

Reliability[1]: FIRM
Estimated Cost[2]: $44 - $60

Hydrogen and Fuel Cell Technology:
British Columbia companies are recognized globally for being leaders in hydrogen and fuel cell technology for mobile, stationary and micro applications. For example, BC Transit's fuel cell buses are planned for deployment in Whistler in 2009.

Reliability[1]: FIRM
Estimated Cost[2]: n/a

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1 Reliability refers to energy that can be depended on to be available whenever required

2 Source: BC Hydro's 2006 IEP Volume 1 of 2 page 5-6

3 Based on a 500 MW super ciritcal pulverized coal combustion unit. The BC Energy Plan requires coal power to meet zero GHG emissions

4 Based on a 250 MW combined cycle gas turbine plant. The BC Energy Plan requires coal power to meet zero GHG emissions

5 Source: BC Hydro's F2006 Open Call for Power Report

6 These costs do not reflect the costs of zero GHG emissions for coal thermal power

GOVERNMENT'S COMMITMENT TO THE ENVIRONMENT – THE ENVIRONMENTAL ASSESSMENT PROCESS

The environmental assessment process in British Columbia is an integrated review process for major projects that looks at potential environmental, community and First Nation, health and safety, and socioeconomic impacts. Through the environmental assessment process, the potential effects of a project are identified and evaluated early, resulting in improved project design and helping to avoid costly mistakes for proponents, governments, local communities and the environment.

An assessment is begun when a proposed project that meets certain criteria under the *Environmental Assessment Act* makes an application for an environmental assessment certificate. Each assessment will usually include an opportunity for all interested parties to identify issues and provide input; technical studies of the relevant environmental, social, economic, heritage and/or health effects of the proposed project; identification of ways to prevent or minimize undesirable effects and enhance desirable effects; and consideration of the input of all interested parties in compiling the assessment findings and making decisions about project acceptability. The review is concluded when a decision is made to issue or not issue an environmental assessment certificate. Industrial, mining, energy, water management, waste disposal, food processing, transportation and tourist destination resort projects are generally subject to an environmental assessment.

ELECTRICITY CHOICES

WHAT IS THE DIFFERENCE BETWEEN FIRM AND INTERMITTENT ELECTRICITY?

Firm electricity refers to electricity that is available at all times even in adverse conditions. The main sources of reliable electricity in British Columbia include large hydroelectric dams, and natural gas. This differs from intermittent electricity, which is limited or is not available at all times. An example of intermittent electricity would be wind which only produces power when the wind is blowing.

Large Hydroelectric Dams: The chief advantage of a hydro system is that it provides a reliable supply with both dependable capacity and energy, and a renewable and clean source of energy. Hydropower produces essentially no carbon dioxide.

Site C is one of many resource options that can help meet BC Hydro's customers' electricity needs. No preferred option has been selected at this time; however; it is recognized that the Province will need to examine opportunities for some large projects to meet growing demand.

As part of **The BC Energy Plan**, BC Hydro and the Province will enter into initial discussions with First Nations, the Province of Alberta and communities to discuss Site C to ensure that communications regarding the potential project and the processes being followed are well known. The purpose of this step is to engage the various parties up front to obtain input for the proposed engagement process. The decision-making process on Site C includes public consultation, environmental impact assessments, obtaining a Certificate of Public Convenience and Necessity, obtaining an Environmental Assessment Certificate and necessary environmental approvals, and approval by Cabinet.

Reliability[1]: FIRM
Estimated Cost[2]: $43 - $62

Natural Gas: Natural gas is converted into electricity through the use of gas fired turbines in medium to large generating stations; particularly high efficiencies can be achieved through combining gas turbines with steam turbines in the combined cycle and through reciprocating engines and mini and macro turbines. Combined cycle power generation using natural gas is the cleanest source of power available using fossil fuels. Natural gas provides a reliable supply with both dependable capacity and firm energy.

Reliability[1]: FIRM
Estimated Cost[2,6]: $48 - $100

Small Hydro: This includes run-of-river and micro Hydro. These generate electricity without altering seasonal flow characteristics. Water is diverted from a natural watercourse through an intake channel and pipeline to a powerhouse where a turbine and generator convert the kinetic energy in the moving water to electrical energy.

Twenty-nine electricity purchase agreements were awarded to small waterpower producers by BC Hydro in 2006. These projects will generate approximately 2,851 gigawatt hours of electricity annually (equivalent to electricity consumed by 285,000 homes in British Columbia). There are also 32 existing small hydro projects in British Columbia that generate 3,500 gigawatt hours (equivalent to electricity consumed by 350,000 homes in British Columbia).

Reliability[1]: INTERMITTENT
Estimated Cost[3]: $60 – $95

Solar: With financial support from the Ministry of Energy, Mines and Petroleum Resources, the "Solar for Schools" program has brought clean solar photovoltaic electricity to schools in Vernon, Fort Nelson, and Greater Victoria.

The BC Sustainable Energy Association is leading a project which targets installing solar water heaters on 100,000 rooftops across British Columbia.

Reliability[1]: INTERMITTENT
Estimated Cost[2]: $700 - $1700

Tidal Energy: A small demonstration project has been installed at Race Rocks located west-southwest of Victoria. The Lester B. Pearson College of the Pacific, the provincial and federal government, and industry have partnered to install and test a tidal energy demonstration turbine at Race Rocks. The project will generate about 77,000 kilowatt hours on an annual basis (equivalent to electricity consumed by approximately eight homes).

Reliability[1]: INTERMITTENT
Estimated Cost[2]: $100 - $360

Wind: British Columbia has abundant, widely distributed wind energy resources in three areas: the Peace region in the Northeast; Northern Vancouver Island; and the North Coast. Wind is a clean and renewable source that does not produce air or water pollution, greenhouse gases, solid or toxic wastes.

Three wind generation projects have been offered power purchase contracts in BC Hydro's 2006 Open Call for Power. These three projects will have a combined annual output of 979 gigawatt hours of electricity (equivalent to electricity consumed by 97,900 homes).

Reliability[1]: INTERMITTENT
Estimated Cost[5]: $71 – $74

[1] Reliability refers to energy that can be depended on to be available whenever required
[2] Source: BC Hydro's 2006 IEP Volume 1 of 2 page 5-6
[3] Based on a 500 MW super ciritcal pulverized coal combustion unit. The BC Energy Plan requires coal power to meet zero GHG emissions
[4] Based on a 250 MW combined cycle gas turbine plant.
[5] Source: BC Hydro's F2006 Open Call for Power Report
[6] These costs do not reflect the costs of zero net GHG emissions for natural gas

RACE ROCKS TIDAL ENERGY PROJECT

Announced in early 2005, this demonstration project between the provincial and federal governments, industry, and Pearson College is producing zero emission tidal power at the Race Rocks Marine Reserve on southern Vancouver Island. Using a current-driven turbine submerged below the ocean surface, the project is producing about 77,000 kilowatt hours of electricity per year, enough to meet the needs of approximately eight households. The knowledge gained about tidal energy will help our province remain at the forefront of clean energy generation technology.

Table 1: Summary of Resource Options

Description	Estimated Cost [1] $ /megawatt hour	Reliable[2]	Greenhouse gas emissions[3] tonnes per gigawatt hour
Energy conservation/ efficiency	32 – 76	Yes	0
Large hydroelectric	43 – 62	Yes	0
Natural gas	48 – 100[8]	Yes	0 – 350[4,8]
Coal	67 – 82[9,10]	Yes	0 – 855[5,9]
Biomass	75 – 91[10]	Yes	0 – 500[6]
Geothermal	44 – 60	Yes	0 – 10
Wind	71 – 74[10]	Depends on the availability and speed of wind	0
Run-of-river small hydro	60 – 95[10]	Depends on the flow of water, which varies throughout the year	0
Ocean (wave and tidal)	100 – 360[7]	Future supply option which has great potential for British Columbia	0
Solar	700 – 1700[7]	Depends on location, cloud cover, season, and time of day	0

1 Source: BC Hydro's 2006 Integrated Electricity Plan Volume 1 of 2, page 5-6
2 Reliability refers to energy that can be depended on to be available whenever required
3 Source: BC Hydro's 2006 Integrated Electricity Plan, Volume 2 of 2, Appendix F page 5-14 and Table 10-2
4 Based on a 250 MW combined cycle gas turbine plant
5 Based on a 500 MW supercritical pulverized coal combustion unit
6 GHG are 0 for wood residue and landfill gas. GHG is 500 tonnes per gigawatt hour for municipal solid waste
7 Source: BC Hydro's 2004 Integrated Electricity Plan, page 69
8 The BC Energy Plan requires natural gas plants to offset to zero net greenhouse gas emissions. These costs do not reflect the costs of zero net GHG emissions
9 The BC Energy Plan requires zero greenhouse gas emissions from any coal thermal electricity facilities
The costs do not include the costs of requiring zero emissions from coal thermal power
10 Source: BC Hydro's F2006 Open Call for Power Report

The majority of B.C.'s electricity requirements over the next 10 years can be achieved through increased conservation by all British Columbians and new electricity from independent power producers.

British Columbia's Strength in Electricity Diversity

British Columbia is truly fortunate to have a wide variety of future supply options available to meet our growing demand for energy. A cost effective way to meet that demand is to conserve energy and be more energy efficient. However, British Columbia will still need to bring new power on line to meet demand growth in the years ahead. In order to ensure we have this critical resource available to British Columbians when they need it, government will be looking to secure a range of made-in-B.C. power to serve British Columbians in the years ahead.

Government's goal is to encourage a diverse mix of resources that represent a variety of technologies. Some resource technologies, such as large and small hydro, thermal power, wind and geothermal provide well-established, commercially available sources of electricity. Other emerging technologies that are not yet widely used include large ocean wave and tidal power, solar, hydrogen and advanced coal technologies.

2004 Total Electricity Production by Source (% of total)

	Other Renewables	Hydro Electric	Nuclear	Waste and Biomass	Natural Gas	Diesel Oil	Coal	TOTAL
British Columbia	**0.0**	**92.8**	**0.0**	**1.0**	**6.0**	**0.2**	**0.0**	**100**
Alberta	2.3	4.4	0.0	0.0	12.0	2.6	78.7	100
Australia	0.3	6.9	0.0	0.6	12.3	0.70	79.2	100
California	10.7	17.0	14.5	0.0	37.7	0.0	20.1	100
Denmark	16.3	0.1	0.0	8.8	24.7	4.0	46.1	100
Finland	0.4	17.6	26.5	12.4	14.9	0.7	27.5	100
France	0.2	11.3	78.3	1.0	3.2	1.0	5.0	100
Germany	4.2	4.5	27.1	2.6	10.0	1.6	50.0	100
Japan	0.4	9.5	26.1	1.9	22.6	12.3	27.2	100
Norway	0.3	98.8	0.0	0.5	0.3	0.0	0.1	100
Ontario	1.8	24.8	49.7	0.0	5.2	0.5	18.0	100
Oregon	2.3	64.4	0.0	0.0	26.3	0.1	6.9	100
Quebec	0.7	94.5	3.2	0.0	0.1	1.5	0.0	100
United Kingdom	0.5	1.9	20.2	2.1	40.3	1.2	33.8	100
Washington	2.3	70.0	8.8	0.0	8.6	0.1	10.2	100

SHARING SOLUTIONS ON ELECTRICITY

The BC Energy Plan has a goal that most of B.C.'s electricity requirements over the next 10 years can be achieved through increased conservation and energy efficiency by all British Columbians, coupled with generation by independent power producers. However, these new projects take time to plan and implement. In addition, many of these sources provide limited amounts of firm supply. The province will also need to consider options for new, large scale sources to meet forecasted demand growth in the next 10 to 20 years. Large scale options could include Site C, large biomass facilities, clean coal or natural gas plants. As with all large scale undertakings, these kinds of projects will require years of lead time to allow for careful planning, analysis, consultation and construction.

Perhaps the biggest challenge facing British Columbians is simply to begin choosing our electricity future together. Demand for electricity is projected to grow by up to 45 per cent over the next 20 years. To meet this projected growth we will need to conserve more, and obtain more electricity from small power producers and large projects. Given the critical importance of public participation and stakeholder involvement in addressing the challenges and choices of meeting our future electricity needs, government and BC Hydro will seek and share solutions.

Rapid expansion of our energy sector means a growing number of permanent, well-paying employment opportunities are available.

Taking Action to Meet the Demand for Workers

The energy sector has been a major contributor to British Columbia's record economic performance since 2001. The BC Energy Plan focuses on four under-represented groups that offer excellent employment potential: Aboriginal people, immigrants, women and youth.

At the same time, the energy sector must overcome a variety of skills training and labour challenges to ensure future growth.

These challenges include:

- An aging workforce that upon retirement will leave a gap in experience and expertise.
- Competition for talent from other jurisdictions.
- Skills shortages among present and future workers.
- Labour market information gaps due to a lack of in-depth study.
- The need to coordinate immigration efforts with the federal government.
- The need for greater involvement of under-represented energy sector workers such as Aboriginal people, immigrants, women, and youth.
- A highly mobile workforce that moves with the opportunities.
- The need to improve productivity and enhance competitiveness.

Innovative, practical and timely skills training, and labour management is required to ensure the energy sector continues to thrive. As part of The BC Energy Plan, government will work collaboratively with industry, communities, Aboriginal people, education facilities, the federal government and others to define the projected demand for workers and take active measures to meet those demands.

Attract Highly Skilled Workers

Demographics show that those born at the height of the baby boom are retired or nearing retirement, leaving behind a growing gap in skills and expertise. Since this phenomenon is taking place in most western nations, attracting and retaining skilled staff is highly competitive.

To ensure continued energy sector growth, we need to attract workers from outside the province, particularly for the electricity, oil and gas, and heavy construction industries where the shortage is most keenly felt. At this time, a significant increase in annual net migration of workers from other provinces and from outside Canada is needed to complement the existing workforce.

Government and its partners are developing targeted plans to attract the necessary workers. These plans will include marketing and promoting energy sector jobs as a career choice.

Develop a Robust Talent Pool of Workers

It is vital to provide the initial training to build a job-ready talent pool in British Columbia, as well as the ongoing training employees need to adapt to changing energy sector technologies, products and requirements. We can ensure a thriving pool of talent in British Columbia by retraining skilled employees who are without work due to downturns in other industries. Displaced workers from other sectors and jurisdictions may require some retraining and new employees may need considerable skills development.

Another way to help ensure there are enough skilled energy sector workers in the years ahead is to educate and inform young people today. By letting high school students know about the opportunities, they can consider their options and make the appropriate training and career choices. Government will work to enhance information relating to energy sector activities in British Columbia's school curriculum in the years ahead.

Retain Skilled Workers

Around the world, energy facility construction and operations are booming, creating fierce, global competition for skilled workers. While British Columbia has much to offer, it is critical that our jurisdiction presents a superior opportunity to these highly skilled and mobile workers. That is why we need to ensure our workplaces are safe, fair and healthy and our communities continue to offer an unparalleled lifestyle with high quality health care and education, affordable housing, and readily available recreation opportunities in outstanding natural settings.

Inform British Columbians

To be effective in filling energy sector jobs with skilled workers, British Columbians need to be informed and educated about the outstanding opportunities available. As part of The BC Energy Plan, a comprehensive public awareness and education campaign based on sound labour market analysis will reach out to potential energy sector workers. This process will recognize and address both the potential challenges such as shift work and remote locations as well as the opportunities, such as obtaining highly marketable skills and earning excellent compensation.

OIL AND GAS

POLICY ACTIONS

ENVIRONMENTALLY RESPONSIBLE OIL AND GAS DEVELOPMENT

- **Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.**
- **Establish policies and measures to reduce air emissions in coordination with the Ministry of Environment.**
- **Best coalbed gas practices in North America. Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.**
- **Enhance the Oil and Gas Environmental Stewardship Program, ensuring sound environmental, land and resource management.**

Be Among the Most Competitive Oil and Gas Jurisdictions in North America

Since 2001, British Columbia's oil and gas sector has grown to become a major force in our provincial economy, employing tens of thousands of British Columbians and helping to fuel the province's strong economic performance. In fact, investment in the oil and gas sector was $4.6 billion in 2005. The oil and gas industry contributes approximately $1.95 billion annually or seven per cent of the province's annual revenues.

The BC Energy Plan is designed to take B.C.'s oil and gas sector to the next level to enhance a sustainable, thriving and vibrant oil and gas sector in British Columbia. With a healthy, competitive oil and gas sector comes the opportunity to create jobs and build vibrant communities with increased infrastructure and services, such as schools and hospitals. Of particular importance is an expanding British Columbia-based service sector.

There is a lively debate about the peak of the world's oil and gas production and the impacts on economies, businesses and consumers. A number of countries, such as the UK, Norway and the USA, are experiencing declining fossil fuel production from conventional sources. Energy prices, especially oil prices have increased and are more volatile than in the past. As a result, the way energy is produced and consumed will change, particularly in developed countries.

The plan is aimed at enhancing the development of conventional resources and stimulating activity in relatively undeveloped areas such as the interior basins – particularly the Nechako Basin. It will also foster the development of unconventional resources such as as tight gas, shale gas, and coalbed gas. The plan will further efforts to work with the federal government, communities and First Nations to advance offshore opportunities.

The challenge for British Columbia in the future will be to continue to find the right balance of economic, environmental and social priorities to allow the oil and gas sector to succeed, while protecting our environment and improving our quality of life.

The New Relationship and Oil and Gas

Working together with local communities and First Nations, the provincial government will continue to share in the many benefits and opportunities created through the development of British Columbia's oil and gas resources.

Government is working to ensure that oil and gas resource management includes First Nations' interests, knowledge and values. Government has recently concluded consultation agreements for oil and gas resource development with First Nations in Northeast British Columbia. These agreements increase clarity in the process and will go a long way to enhancing our engagement with these First Nations.

Government will continue to pursue opportunities to share information and look for opportunities to facilitate First Nations' employment and participation in the oil and gas industry to ensure that Aboriginal people benefit from the continued growth and development of British Columbia's resources.

The BC Energy Plan adopts a triple bottom line approach to competitiveness, with an attractive investment climate, environmentally sustainable development of B.C.'s abundant resources, and by benefiting communities and First Nations.

While striving to be among the most competitive oil and gas jurisdictions in North America, the province will focus on maintaining and enhancing its strong competitive environment for the oil and gas industry. This encompasses the following components:

- A competitive investment climate.
- An abundant resource endowment.
- Environmental responsibility.
- Social responsibility.

Leading in Environmentally and Socially Responsible Oil and Gas Development

The BC Energy Plan emphasizes conservation, energy efficiency, and the environmental and socially responsible management of the province's energy resources. It outlines government's efforts to meet this objective by working collaboratively with involved and interested parties, including affected communities, landowners, environmental groups, First Nations, the regulator (the Oil and Gas Commission), industry groups and others. Policy actions will support ways to address air emissions, impacts on land and wildlife habitat, and water quality.

The oil and gas sector in British Columbia accounts for approximately 18 per cent of greenhouse gas air emissions in the province. The main sources of air emissions from the oil and gas sector are flaring, fugitive gases, gas processing and compressor stations. While these air emissions have long been part of the oil and gas sector, they have also been a source of major concern for oil and gas communities.

Eliminate Flaring from Oil and Gas Producing Wells and Production Facilities By 2016

Through The BC Energy Plan, government has committed to eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011. In addition, government will adopt policies to reduce natural gas flaring and venting at test sites and pipelines, and encourage compressor station efficiency to cut back emissions. Government will also explore opportunities and new technologies for safe, underground disposal of carbon dioxide or sequestration from oil and gas facilities. Sequestration is considered a cost effective mitigation strategy in reducing carbon dioxide emissions.

Enhance Carbon Dioxide Sequestration in British Columbia

British Columbia is a member of the Plains CO2 Reduction (PCOR) Partnership composed of nearly 50 private and public sector groups from nine states and three Canadian provinces that is assessing the technical and economic feasibility of capturing and storing carbon dioxide emissions from stationary sources in western sedimentary basins.

B.C. is also a member of the West Coast Regional Carbon Sequestration Partnership, made up of west coast state and provincial government ministries and agencies. This partnership has been formed to pursue carbon sequestration opportunities and technologies.

To facilitate and foster innovation in sequestration, government will develop market oriented requirements with a graduated schedule. In consultation with stakeholders, a timetable will be developed along with increasing requirements for sequestration.

BRITISH COLUMBIA COMPANIES RECOGNIZED AS WORLD ENERGY TECHNOLOGY INNOVATORS

The leadership of British Columbian companies can be seen in all areas of the energy sector through innovative, industry leading technologies.

Production of a new generation of chemical injection pump for use in the oil and gas industry is beginning. The pumps, developed and built in British Columbia, are the first solar powered precision injection pumps available to the industry. They will reduce emissions by replacing traditional gas powered injection systems for pipelines.

Other solar technologies developed in British Columbia provide modular power supplies in remote locations all over the globe for marine signals, aviation lights and road signs.

Roads in B.C. and around the world are hosting demonstrations of fuel cell vehicles built with British Columbia technology. Thanks to the first high pressure hydrogen fuelling station in the world, compatible fuel cell vehicles in B.C. can carry more fuel and travel farther than ever before.

The Innovative Clean Energy Fund will help to build B.C.'s technology cluster and keep us at the forefront of energy technology development.

OIL AND GAS

Government will work to improve oil and gas tenure policies as well as develop new guidelines to determine areas that require special consideration prior to tenure approval.

POLICY ACTIONS

OFFSHORE OIL AND GAS DEVELOPMENT

- **Continue to work to lift the federal moratorium on offshore exploration and development and reiterate the intention to simultaneously lift the provincial moratorium.**
- **Work with the federal government to ensure that offshore oil and gas resources are developed in a scientifically sound and environmentally responsible way.**
- **Participate in marine and environmental planning to effectively manage marine areas and offshore oil and gas basins.**
- **Develop and implement a comprehensive community engagement program to establish a framework for a benefits sharing agreement resulting from offshore oil and gas development for communities, including First Nations.**

Environmental Stewardship Program

In 2004, the Ministry of Energy, Mines and Petroleum Resources initiated the Oil and Gas Environmental Stewardship Program having two components: the Environmental Policy Program and the Environmental Resource Information Project. The Environmental Policy Program identifies and mitigates environmental issues in the petroleum sector focusing on policy development in areas such as environmental waste management, habitat enhancement, planning initiatives, wildlife studies for oil and gas priority areas and government best management practices. Some key program achievements include the completion of guidelines for regulatory dispersion modeling, research leading to the development of soil quality guidelines for soluble barium, a key to northern grasses and their restorative properties for remediated well sites, and moose and caribou inventories in Northeast British Columbia.

The Environmental Resource Information Project is dedicated to increasing opportunities for oil and gas development, through the collection of necessary environmental baseline information. These projects are delivered in partnership with other agencies, industry, communities and First Nations.

The BC Energy Plan enhances the important Oil and Gas Environmental Stewardship Program. This will improve existing efforts to manage waste and preserve habitat, and will establish baseline data as well as development and risk mitigation plans for environmentally sensitive areas. Barriers need to be identified and steps taken for remediation, progressive reclamation, and waste management.

Best Coalbed Gas Practices in North America

Government will continue to encourage coalbed gas development with the intent of demonstrating that British Columbia is a leading socially and environmentally responsible coalbed gas developing jurisdiction. Coalbed gas, also known as coalbed methane, is natural gas found in coal seams. It is one of the cleanest burning of all fossil fuels. Proponents wanting to develop coalbed gas must adopt the following best practices:

- Fully engage local communities and First Nations in all stages of development.
- Use the most advanced technology and practices that are commercially viable to minimize land and aesthetic disturbances.
- Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.
- Meet any other conditions the Oil and Gas Commission may apply.
- Demonstrate the company's previous experience with coalbed gas development, and information must be made publicly available as to how the company plans to meet and be accountable for these best practices.

Ensuring Offshore Oil and Gas Resources are Developed in a Scientifically Sound and Environmentally Responsible Way

The BC Energy Plan includes actions related to the province's offshore oil and gas resources. Since 1972, Canada and British Columbia have each had a moratorium in place on offshore oil and gas exploration and development. With advanced technology and

British Columbia's oil and gas industry supports thousands of well-paying jobs, helps drive the economy and provides revenues to sustain public services.

positive experiences in other jurisdictions, a compelling case exists for assessing British Columbia's offshore resource potential.

Government will work with coastal communities, First Nations, the federal government, environmental organizations, and others to ascertain the benefits and address the concerns associated with offshore oil and gas development.

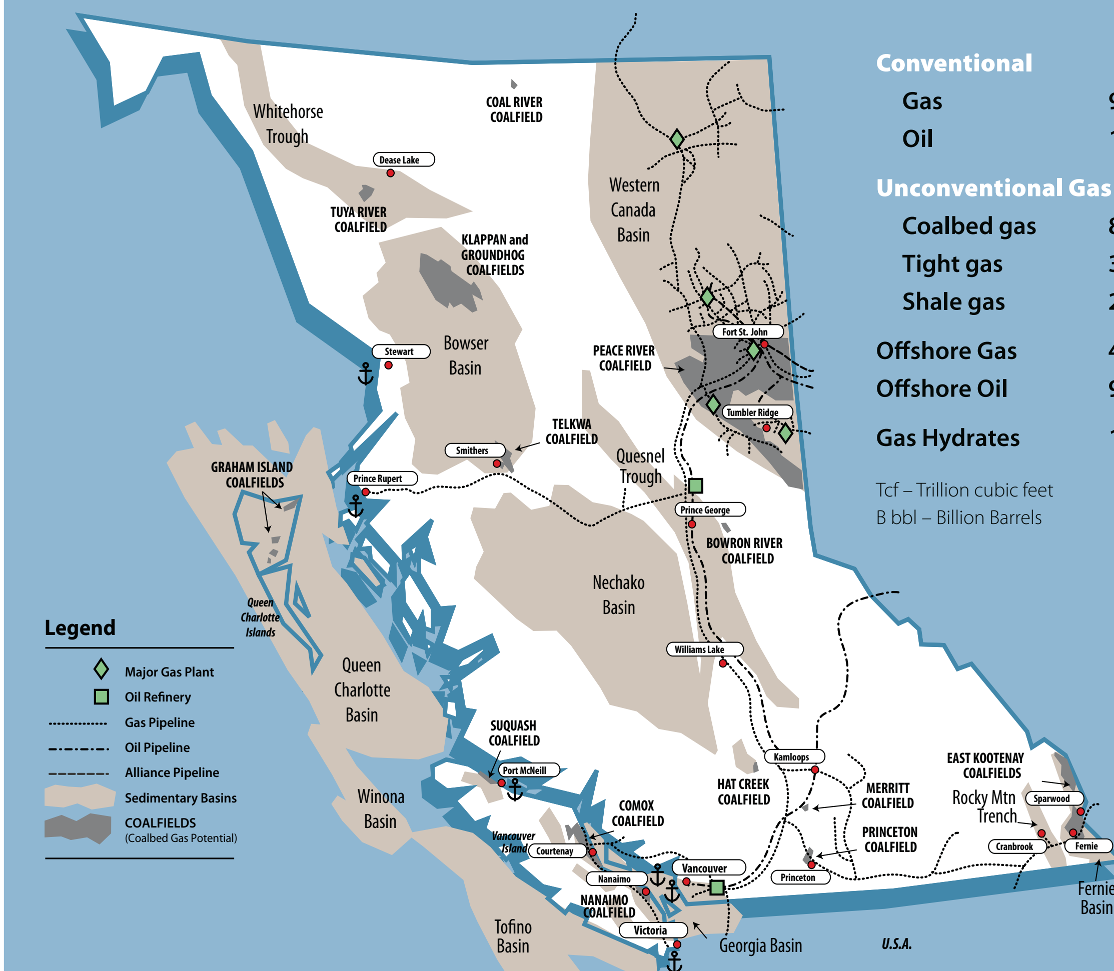
Maintaining B.C.'s Competitive Advantage as an Oil and Gas Jurisdiction

British Columbia's oil and gas industry is thriving thanks to high resource potential, industry and service sector expertise, and a competitive investment climate that includes a streamlined regulatory environment. To attract additional investment in British Columbia's oil and gas industry, we need to compete aggressively with other jurisdictions that may offer lower taxes or other investment incentives.

Another key way to be more competitive is by spurring activity in underdeveloped areas while heightening activity in the northeast, where our natural gas industry thrives. The province will work with industry to develop new policies and technologies for enhanced resource recovery making, it more cost-effective to develop British Columbia's resources.

By increasing our competitiveness, British Columbians can continue to benefit from well-paying jobs, high quality social infrastructure and a thriving economy.

BC OIL AND GAS UNDISCOVERED RESOURCE ESTIMATES



Conventional	
Gas	98.0 Tcf
Oil	17.6 B bbl
Unconventional Gas	
Coalbed gas	84.0 Tcf
Tight gas	300 Tcf
Shale gas	250 Tcf
Offshore Gas	41.8 Tcf
Offshore Oil	9.8 B bbl
Gas Hydrates	113-847 Tcf

Tcf – Trillion cubic feet
B bbl – Billion Barrels

OIL AND GAS

British Columbia's Enormous Natural Gas Potential

The oil and gas sector will continue to play an important role in British Columbia's future energy security. Our province has enormous natural gas resource potential and opportunities for significant growth. The BC Energy Plan facilitates the development of B.C.'s resources.

British Columbia has numerous sedimentary basins, which contain petroleum and natural gas resources. In north-eastern British Columbia, the Western Canada Sedimentary Basin is the focus of our thriving natural gas industry. The potential resources in the central and northern interior of the province, the Nechako and Bowser Basins and Whitehorse Trough, have gone untapped.

The delayed evaluation and potential development of these areas is largely due to geological and physical obstructions that make it difficult to explore in the area. Volcanic rocks that overlay the sedimentary package combined with complex basin structures, have hindered development.

The BC Energy Plan is aimed at enhancing the development of conventional resources and stimulating activity in undeveloped areas such as the interior basins – particularly the Nechako Basin. It will also foster the development of unconventional resources and take a more stringent approach on coalbed gas to meet higher environmental standards.

Attracting Investment and Developing our Oil and Gas Resources

The BC Energy Plan promotes competitiveness by setting out a number of important regulatory and fiscal measures including: monitoring British Columbia's competitive ranking, considering a Net Profit Royalty Program, promoting a B.C. service sector, harmonizing and streamlining regulations, and developing a Petroleum Registry to examine royalty and tenure incentives, and undertaking geoscience programs.

Establishment of a Petroleum Registry

The establishment of a petroleum registry that functions as a central database will improve the quality and management of key volumetric, royalty and infrastructure information associated with British Columbia's oil and gas industry and promote competition while providing transparency around oil and gas activity.

NEEMAC: SUCCESS THROUGH COMMUNICATION

As energy, mining and petroleum resource development increases in northeast B.C., so too does the need for input from local governments, First Nations, community groups, landowners and other key stakeholders. In 2006, the Northeast Energy and Mines Advisory Committee (NEEMAC) was created to provide an inclusive forum for representative organizations to build relationships with each other, industry and government to provide input on Ministry policy, and recommend innovative solutions to stakeholder concerns.

Since its creation, NEEMAC has identified and explored priority concerns, and is beginning to find balanced solutions related to environmental, surface disturbance, access and landowner rights issues. The Ministry is committed to implementing recommendations that represent the broad interests of community, industry and government and expects that the committee will continue to provide advice on energy, mining and petroleum development issues in support of The BC Energy Plan.

An opportunity to increase competitiveness exists in British Columbia's Interior Basins – namely the Nechako, Bowser and Whitehorse Basins – where considerable resource potential is known to exist.

Increasing Access

In addition to regulatory and fiscal mechanisms, the plan addresses the need for improving access to resources. Pipelines and road infrastructure are critical factors in development and competitiveness. The BC Energy Plan calls for new investment in public roads and other infrastructure. It will see government establish a clear, structured infrastructure royalty program, combining road and pipeline initiatives and increasing development in under-explored areas that have little or no existing infrastructure.

Developing Conventional and Unconventional Oil and Gas Resources

To support investment in exploration, The BC Energy Plan calls for partnerships in research and development to establish reliable regional data, as well as royalty and tenure incentives. The goal is to attract investment, create well-paying jobs, boost the regional economy and produce economic benefits for all British Columbians. We can be more competitive by spurring activity in underdeveloped areas while heightening activity in the northeast where our natural gas industry thrives. The plan advocates working with industry to develop new policies and technology to enhance resource recovery, including oil in British Columbia.

Improve Regulations and Research

The province remains committed to continuous improvement in the regulatory regime and environmental management of conventional and unconventional oil and gas resources. The opportunities for enhancing exploration and production of tight gas, shale gas, and coalbed gas will also be assessed and supported by geoscience research and programs. The BC Energy Plan calls for collaboration with other government ministries, agencies, industry, communities and First Nations to develop the oil and gas resources in British Columbia.

Focus on Innovation and Technology Development

The BC Energy Plan also calls for supporting the development of new oil and gas technologies. This plan will lead British Columbia to become an internationally recognized centre for technological advancements and commercialization, particularly in environmental management, flaring, carbon sequestration and hydrogeology. The service sector has noted it can play an important role in developing and commercializing new technologies; however, the issue for companies is accessing the necessary funds.

THE HUB OF B.C.'S OIL AND GAS SECTOR

Oil and gas is benefiting all British Columbians - not just those living in major centres. Nowhere is this more apparent than in booming Fort St. John, which has rapidly become the oil and gas hub of the province. Since 2001, more than 1,400 people have moved to the community, an increase of 6.3 per cent and two per cent faster growth than the provincial average. Construction permits are way up - from $48.7 million in 2004, to $50.6 million in 2005, to over $123 million in 2006. In the past five years, over 1,000 new companies have been incorporated in Fort St. John, as young families, experienced professionals, skilled trades-people and many others move here from across the country.

OIL AND GAS

POLICY ACTIONS

BE AMONG THE MOST COMPETITIVE OIL AND GAS JURISDICTIONS IN NORTH AMERICA

- **Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdictions in North America.**
- **Enhance infrastructure to support the development of oil and gas in British Columbia and address impediments to economic development such as transportation and labour shortages.**
- **Encourage the development of conventional and unconventional resources.**
- **Support the growth of British Columbia's oil and gas service sector.**
- **Promote exploration and development of the Interior basins with a priority focus on the Nechako Basin.**
- **Encourage the development of new technologies.**
- **Add value to British Columbia's oil and gas industry by assessing and promoting the development of additional gas processing facilities in the province.**

Technology Transfer Incentive Program

A new Oil and Gas Technology Transfer Incentive Program will be considered to encourage the research, development and use of innovative technologies to increase recoveries from existing reserves and encourage responsible development of new oil and gas reserves. The program could recover program costs over time through increased royalties generated by expanded development and production of British Columbia's petroleum resources.

Scientific Research and Experimental Development

The BC Energy Plan supports the British Columbia Scientific Research and Experimental Development Program, which provides financial support for research and development leading to new or improved products and processes. Through credits or refunds, the expanded program could cover project costs directly related to commercially applicable research, and development or demonstration of new or improved technologies conducted in British Columbia that facilitate expanded oil and gas production.

Research and Development

The BC Energy Plan calls for using new or existing research and development programs for the oil and gas sector. Government will develop a program targeting areas in which British Columbia has an advantage such as well completion technology and hydrogeology.

A program to encourage oil and gas innovation and research in British Columbia's post-secondary institutions will be explored. These opportunities will be explored in partnership with the Petroleum Technology Alliance Canada and as part of the April 2006 Memorandum of Understanding between British Columbia and Alberta on Energy Research, Technology Development and Innovation.

Together with the Oil and Gas Centre of Excellence in Fort St. John, an oil and gas technology incubator, a site which provides innovators with space to build prototypes and carry out testing as well as providing business infrastructure and assistance accessing additional support will be established, allowing entrepreneurs to develop and test new innovations and commercialize new, innovative technologies and processes.

Nechako Initiative

The BC Energy Plan calls for government to partner with industry, the federal government, and Geoscience BC to undertake comprehensive research in the Nechako Basin and establish new data of the resource potential. It will include active engagement of communities and the development and implementation of a comprehensive pre-tenure engagement initiative for First Nations in the region. Specific tenures and royalties will be explored to encourage investment, as well as a comprehensive Environmental Information Program to identify baseline information needs in the area through consultations with government, industry, communities and First Nations.

By increasing our oil and gas industry's competitiveness, British Columbians can continue to benefit from well-paying jobs, high quality social infrastructure and a thriving economy.

Value-Added Opportunities

To improve competitiveness, The BC Energy Plan calls for a review of value-added opportunities in British Columbia. This will include a thorough assessment of the potential for processing facilities and petroleum refineries as well as petrochemical industry opportunities. The Ministry of Energy, Mines and Petroleum Resources will conduct an analysis to identify and address barriers and explore incentives required to encourage investment in gas processing in British Columbia. A working group of industry and government will develop business cases and report to the Minister by January 2008 with recommendations on the viability of a new petroleum refinery and petrochemical industry and measures, if any, to encourage investment.

Oil and Gas Service Sector

British Columbia's oil and gas service sector can also help establish our province as one of the most competitive jurisdictions in North America. The service sector has grown over the past four years and with increased activity, additional summer drilling, and the security of supply, opportunities for local companies will continue. Government can help maximize the benefits derived from the service sector by:

- Promoting British Columbia's service sector to the oil and gas industry through participation at trade shows and providing information to the business community.
- Identifying areas where British Columbian companies can play a larger role, expand into other provinces, and through procurement strategies.

The government also supports the Oil and Gas Centre of Excellence at the Fort St. John Northern Lights College campus, which will provide oil and gas, related vocational, trades, career and technical programs.

Improving Oil and Gas Tenures

Government will work to improve oil and gas tenure issuance policies as well as develop new guidelines to determine areas that require special consideration prior to tenure approval by the end of 2007. This will provide clear parameters for industry regarding areas where special or enhanced management practices are required. These measures will strike the important balance between providing industry with clarity and access to resources and the desire of local government, communities, landowners, stakeholders and First Nations for input into the oil and gas development process.

Create Opportunities for Communities and First Nations

Benefits for British Columbians from the Oil and Gas Sector

The oil and gas sector offers enormous benefits to all British Columbians through enhanced energy security, tens of thousands of good, well-paying jobs and tax revenues used to help fund our hospitals and schools. However, the day-to-day impact of the sector has largely been felt on communities and First Nations in British Columbia's northeast. Community organizations, First Nations, and landowners have communicated a desire for greater input into the pace and scope of oil and gas development in British Columbia.

OIL AND GAS

Together with the Oil and Gas Centre of Excellence in Fort St. John, an oil and gas technology incubator will be established, allowing entrepreneurs to develop and test new innovations.

POLICY ACTIONS

WORKING WITH COMMUNITIES AND FIRST NATIONS

- **Provide information about local oil and gas activities to local governments, First Nations, education and health service providers to inform and support the development of necessary social infrastructure.**
- **Work with First Nations to identify opportunities to participate in and benefit from oil and gas development.**
- **Support First Nations in providing cross-cultural training to agencies and industry.**
- **Improve working relationships among industry and local communities and landowners by clarifying and simplifying processes, enhancing dispute resolution methods, and offering more support and information.**
- **Examine oil and gas tenure policies and develop guidelines to determine areas that require special consideration prior to tenure approval.**

Through The BC Energy Plan, government intends to develop stronger relationships with those affected by oil and gas development, including communities and First Nations. The aim is to work cooperatively to maximize benefits and minimize impacts. The plan supports improved working relationships among industry, local communities and landowners by increased and improved communication to clarify and simplify processes, enhancing dispute resolution methods, and offering more support and information.

The government will also continue to improve communications with local governments and agencies. Specifically, The BC Energy Plan calls for efforts to provide information about increased local oil and gas activities to local governments, education and health service providers to improve their ability to make timely decisions on infrastructure, such as schools, housing, and health and recreational facilities. By providing local communities and service providers with regular reports of trends and industry activities, they can more effectively plan for growth in required services and infrastructure.

Building Better Relationships with Landowners

The BC Energy Plan: A Vision for Clean Energy Leadership also supports improved working relationships between industry, local communities and landowners and First Nations. Landowners will be notified in a more timely way of sales of oil and gas rights on private land. Plain language information materials, including standardized lease agreements will be made available to help landowners deal with subsurface tenures and activity. There will be a review of the dispute resolution process between landowners and industry by the end of 2007. The existing setback requirements, the allowed distance of a well site from a residence, school or other public place, will also be examined. These measures seek to strike the important balance between providing industry with clarity and access to resources and the desire of local government, communities, landowners, stakeholders and First Nations for input into oil and gas development.

Working in Partnership with First Nations and Communities

Government will work with First Nations communities to identify opportunities to benefit from oil and gas development. By developing a greater ability to participate in and benefit from oil and gas development, First Nations can play a much more active role in the industry. The BC Energy Plan also supports increasing First Nations role in the development of cross-cultural training initiatives for agencies and industry.

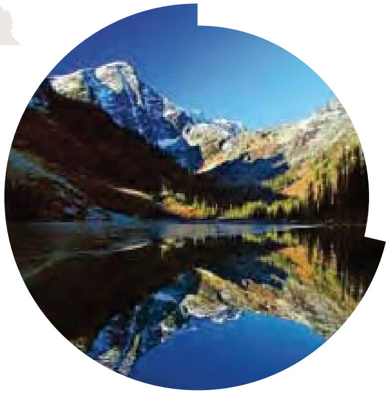
CONCLUSION

Conclusion

The BC Energy Plan: A Vision for Clean Energy Leadership sets the standard for proactively addressing the opportunities and challenges that lie ahead in meeting the energy needs for all the citizens of the province, now and in the future. Appendix A provides a detailed listing of the policy actions of the plan.

The BC Energy Plan will attract new investments, help develop and commercialize new technology, build partnerships with First Nations, and ensures a strong environmental focus.

British Columbia has a proud history of innovation that has resulted in 90 per cent of our power generation coming from clean sources. This plan builds on that foundation and ensures B.C. will be at the forefront of environmental and economic leadership for years to come.



APPENDIX A The BC Energy Plan: Summary of Policy Actions

ENERGY CONSERVATION AND EFFICIENCY

1. Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.
2. Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.
3. Encourage utilities to pursue cost effective and competitive demand side management opportunities.
4. Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.
5. Implement Energy Efficiency Standards for Buildings by 2010.
6. Undertake a pilot project for energy performance labeling of homes and buildings in coordination with local and federal governments, First Nations, and industry associations.
7. New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.
8. Develop an Industrial Energy Efficiency Program for British Columbia to address specific challenges faced by British Columbia's industrial sector.
9. Increase the participation of local governments in the Community Action on Energy Efficiency Program and expand the First Nations and Remote Community Clean Energy Program.

ELECTRICITY

10. Ensure self-sufficiency to meet electricity needs, including "insurance" by 2016.
11. Establish a standing offer for clean electricity projects up to 10 megawatts.
12. The BC Transmission Corporation is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.
13. Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy.
14. Ensure that the province remains consistent with North American transmission reliability standards.
15. Continue public ownership of BC Hydro and its heritage assets, and the BC Transmission Corporation.
16. Establish the existing heritage contract in perpetuity.
17. Invest in upgrading and maintaining the heritage asset power plants and the transmission lines to retain the ongoing competitive advantage these assets provide to the province.
18. All new electricity generation projects will have zero net greenhouse gas emissions.
19. Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.
20. Require zero greenhouse gas emissions from any coal thermal electricity facilities.
21. Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.
22. Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.
23. No nuclear power.
24. Review BC Utilities Commissions' role in considering social and environmental costs and benefits.
25. Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources.
26. Work with BC Hydro and parties involved to continue to improve the procurement process for electricity.
27. Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.
28. Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.

ALTERNATIVE ENERGY

29. Establish the Innovative Clean Energy Fund to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.
30. Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.
31. Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.
32. Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.
33. Support the federal action of increasing the ethanol content of gasoline to five per cent by 2010 and adopt quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions.
34. Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.
35. Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.

OIL AND GAS

36. Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.
37. Establish policies and measures to reduce air emissions in coordination with the Ministry of Environment.
38. Best coalbed gas practices in North America. Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.
39. Enhance the Oil and Gas Environmental Stewardship Program, ensuring sound environmental, land and resource management.
40. Continue to work to lift the federal moratorium on offshore exploration and development and reiterate the intention to simultaneously lift the provincial moratorium.
41. Work with the federal government to ensure that offshore oil and gas resources are developed in a scientifically sound and environmentally responsible way.
42. Participate in marine and environmental planning to effectively manage marine areas and offshore oil and gas basins.
43. Develop and implement a comprehensive community engagement program to establish a framework for a benefits sharing agreement resulting from offshore oil and gas development for communities, including First Nations.
44. Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdictions in North America.
45. Enhance infrastructure to support the development of oil and gas in British Columbia and address impediments to economic development such as transportation and labour shortages.
46. Encourage the development of conventional and unconventional resources.
47. Support the growth of British Columbia's oil and gas service sector.
48. Promote exploration and development of the Interior basins with a priority focus on the Nechako Basin.
49. Encourage the development of new technologies.
50. Add value to British Columbia's oil and gas industry by assessing and promoting the development of additional gas processing facilities in the province.
51. Provide information about local oil and gas activities to local governments, education and health service providers to inform and support the development of necessary social infrastructure.
52. Work with First Nations to identify opportunities to participate in and benefit from oil and gas development.
53. Support First Nations in providing cross-cultural training to agencies and industry.
54. Improve working relationships among industry and local communities and landowners by clarifying and simplifying processes, enhancing dispute resolution methods, and offering more support and information.
55. Examine oil and gas tenure policies and develop guidelines to determine areas that require special consideration prior to tenure approval.

Energy in Action

POWERSMART

BC Hydro offers a variety of incentives to adopt energy saving technologies. Incentives such as rebates on efficient lighting or windows encourages British Columbians to improve the energy efficiency of their homes and businesses.

PROVINCIAL SALES TAX EXEMPTIONS

Tax breaks are offered for a wide variety of energy efficient items, making it easier to conserve energy. Tax concessions are in place for alternative fuel and hybrid vehicles as well as some alternative fuels. Bicycles and some bicycle parts are exempt from provincial sales tax, as are a variety of materials, such as Energy Star® qualified windows, that can make homes more energy efficient.

NET METERING

The Net Metering program offered by BC Hydro for customers with small generating facilities, allows customers to lower their environmental impact and take responsibility for their own power production. The customer is only billed for their "net consumption"; the total amount of electricity used minus the total produced. Net Metering helps to move the province towards electricity self sufficiency and expands clean electricity generation.

POWERING THE ECONOMY

The Oil and Gas sector invested $4.6 billion in B.C. in 2005 and contributed more to the provincial treasury than any other resource in 2005/06. In 2006 1,416 oil and gas wells were drilled in the province and between 2002 and 2005, summer drilling increased 242 per cent.

FRIDGE BUY-BACK PROGRAM

This program offers customers $30 in cash and no-cost pickup and disposal of an old, inefficient second fridge. If all second operating fridges in B.C. were recycled, we would save enough energy to power all the homes in the city of Chilliwack for an entire year.

LIGHTING REBATES

This program offers instant rebate coupons for the retail purchase of Energy Star® light fixtures and Energy Star® CFLs (Compact Fluorescent Lights).

WINDOWS REBATE

The Windows Rebate Program offers rebates for the installation of Energy Star® windows in new, renovated or upgraded single-family homes, duplexes, townhouses or apartments.

PRODUCT INCENTIVE PROGRAM

The Product Incentive Program provides financial incentives to organizations which replace inefficient products with energy efficient technologies or add on products to existing systems to make them more efficient.

HIGH-PERFORMANCE BUILDING PROGRAM FOR LARGE COMMERCIAL BUILDINGS

Financial incentives, resources, and technical assistance are available to help qualified projects identify energy saving strategies early in the design process; evaluate alternative design options and make a business case for the high-performance design; and, offset the incremental costs, if any, of the energy-efficient measures in the high-performance design.

HIGH-PERFORMANCE BUILDING PROGRAM FOR SMALL TO MEDIUM COMMERCIAL BUILDINGS

Incentives and tools are offered to help owners and their design teams create and install more effective and energy-efficient lighting in new commercial development projects.

NEW HOME PROGRAM

Builders and developers are encouraged to build energy efficient homes by offering financial incentives and Power Smart branding for homes that achieve energy efficient ratings.

ANALYZE MY HOME

BC Hydro offers an online tool that provides a free, personalized breakdown of a customer's home energy use and recommendations on where improvements can be made to lower consumption.

CONSERVATION RESEARCH INITIATIVE

A 12-month study in six communities that examines how adjusting the price of electricity at different times of day influences energy use by residential customers, and how individual British Columbians can make a difference in conserving power in their homes and help meet the growing demand for electricity in B.C.

THE GREEN BUILDINGS PROGRAM

Provides tools and resources to support school districts, universities, colleges, and health authorities to improve the energy efficiency of their buildings across the province.

ATTRACTING WORKERS

The Ministry of Energy, Mines and Petroleum Resources hosts job fairs across B.C. to attract workers to the highly lucrative oil and gas sector. Job fairs were held in 14 communities in 2005 and 16 communities in 2006 attracting thousands of people and resulting in hundreds of job offers. Centre of Excellence Government is partnering with industry and the Northern Lights College in Fort St. John to build a centre for oil and gas excellence, more than doubling the number of students training for jobs in the oil and gas industry.

CENTRE OF EXCELLENCE

Government is partnering with industry and the Northern Lights College in Fort St. John to build a centre for oil and gas excellence, more than doubling the number of students training for jobs in the oil and gas industry.

100,000 SOLAR ROOFS FOR B.C.

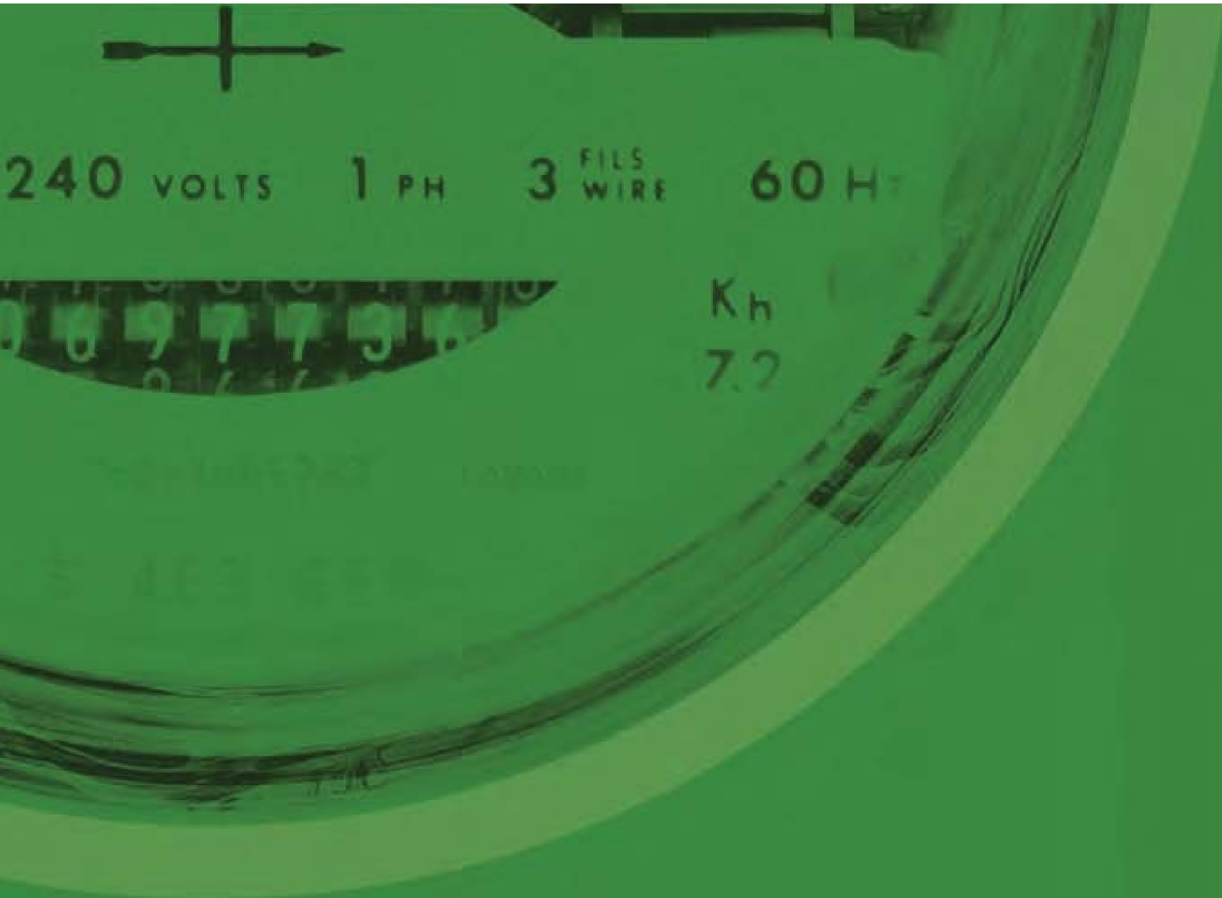
The Ministers of Environment, and Energy, Mines and Petroleum Resources are sponsoring the development of a plan that will see the aggressive adoption of solar technology in B.C. The goal of the project is to see the installation of solar roofs and walls for hot water heating and photovoltaic electricity generation on 100,000 buildings around B.C.

PARTNERING FOR SUCCESS

Since 2003, the Province of B.C. has partnered in the construction of $158 million in new oil and gas road and pipeline infrastructure. The Sierra Yoyo Desan Road public private partnership improved the road allowing year round drilling activity in the Greater Sierra natural gas play. The project was recognized with the Gold Award for Innovation and Excellence from the Canadian Council for Public Private Partnerships in 2004.

ENERGY EFFICIENT BUILDINGS: A PLAN FOR BC

This strategy will lower energy costs for new and existing buildings by $127 million in 2010 and $474 million in 2020, and reduce greenhouse gas emissions by 2.3 million tonnes in 2020. The Province is implementing ten policy and market measures in partnership with the building industry, energy consumer groups, utilities, non-governmental organizations, and the federal government.



For more information on
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A Vision for Clean Energy Leadership, contact:

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BRITISH COLUMBIA
The Best Place on Earth

Ministry of
Energy, Mines and
Petroleum Resources

Appendix B-2

Greenhouse Gas Reduction Targets Act

PDF Version
[Printer-friendly - ideal for printing entire document]

GREENHOUSE GAS REDUCTION TARGETS ACT

Published by Quickscribe Services Ltd.
Updated To:
[effective Jan. 1, 2008 (B.C. Reg. 407/2007)]

GREENHOUSE GAS REDUCTION TARGETS ACT

CHAPTER 42 [SBC 2007]

[effective Jan. 1, 2008 (B.C. Reg. 407/2007)]

Contents

Definitions

1. In this Act:

"carbon neutral" , in relation to a public sector organization for a particular period, means that the public sector organization has complied with the obligations under section 6 *[requirements for achieving carbon neutral status]* to

(a) pursue actions to minimize the relevant greenhouse gas emissions for that period, and

(b) net those greenhouse gas emissions to zero in accordance with that section;

"emission offset" means an emission offset, as established, approved or recognized under the regulations for the purpose of

(a) reducing greenhouse gas emissions, or

(b)

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reducing atmospheric greenhouse gas concentrations through storage, sequestration or other means;

"greenhouse gas" means any or all of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulphur hexafluoride and any other substance prescribed by regulation;

"Provincial government" means that part of the government reporting entity referred to in paragraph (a) *[government as reported through the consolidated revenue fund]* of the definition of "government reporting entity" in section 1 (1) of the *Budget Transparency and Accountability Act*;

"PSO greenhouse gas emissions" , in relation to a public sector organization, means the PSO greenhouse gas emissions for which the organization is responsible under the regulations;

"public sector organization" means any of the following:

(a) the Provincial government;

(b) an organization or corporation that is not part of the Provincial government but is included within the government reporting entity under the *Budget Transparency and Accountability Act*, unless excluded by regulation under this Act;

(c) any other public organization or corporation included by regulation.

2007-42-1 (B.C. Reg. 407/2007).

PART 1 – BC Greenhouse Gas Emissions Targets

BC greenhouse gas emissions – target levels

2. (1) The following targets are established for the purpose of reducing BC greenhouse gas emissions:

(a) by 2020 and for each subsequent calendar year, BC greenhouse gas emissions will be at least 33% less than the level of those emissions in 2007;

(b) by 2050 and for each subsequent calendar year, BC greenhouse gas emissions will be at least 80% less than the level of those emissions in 2007.

(2) By December 31, 2008, the minister must, by order, establish BC greenhouse gas emissions targets for 2012 and 2016.

(3) The minister may, by order, establish BC greenhouse gas emissions targets for other years or periods.

2007-42-2 (B.C. Reg. 407/2007).

Determination of 2007 baseline level

3. As soon as reasonably practicable, the minister must determine and make public the 2007 BC greenhouse gas emissions level for the purpose of section 2.

2007-42-3 (B.C. Reg. 407/2007).

Progress reports on reducing BC greenhouse gas emissions

4. Beginning with a report on 2008 BC greenhouse gas emissions, and continuing with a report for every subsequent even-numbered calendar year, the minister

Page 3 of 7

must, as soon as reasonably practicable for each year, make public a report respecting

(a) a determination of the BC greenhouse gas emissions level for the relevant calendar year,

(b) the progress that has been made toward achieving the targets under section 2,

(c) the actions that have been taken to achieve that progress, and

(d) the plans to continue that progress.

2007-42-4 (B.C. Reg. 407/2007).

PART 2 – Carbon Neutral Public Sector

Targets for carbon neutral public sector

5. (1) Each public sector organization must be carbon neutral for the 2010 calendar year and for each subsequent calendar year.

(2) The Provincial government must be carbon neutral for the 2008 and 2009 calendar years in relation to its PSO greenhouse gas emissions that are directly related to public officials travelling on public business for which the travel expenses are covered by the consolidated revenue fund.

(3) In advance of the obligation under subsection (1), for the 2008 and 2009 calendar years, each public sector organization must pursue actions to minimize its PSO greenhouse gas emissions.

2007-42-5 (B.C. Reg. 407/2007).

Requirements for achieving carbon neutral status

6. (1) In order to be carbon neutral for a calendar year, a public sector organization must

(a) pursue actions to minimize its PSO greenhouse gas emissions for the calendar year,

(b) determine its PSO greenhouse gas emissions for that calendar year in accordance with the regulations, and

(c) no later than the end of June in the following calendar year, apply emission offsets in accordance with the regulations to net those emissions to zero.

(2) In order to be carbon neutral in relation to the PSO greenhouse gas emissions referred to in section 5 (2) *[emissions related to travel]* for a calendar year, the Provincial government must

(a) pursue actions to minimize those PSO greenhouse gas emissions for the calendar year,

(b) determine those PSO greenhouse gas emissions for that calendar year in accordance with the regulations, and

(c) no later than the end of June in the following calendar year, apply emission offsets in accordance with the regulations to net those emissions to zero.

2007-42-6 (B.C. Reg. 407/2007).

Carbon neutral action reports – Provincial government

7. (1) Beginning with a report for the 2008 calendar year, and continuing with a report for every subsequent calendar year, the minister must prepare, and make public no later than the end of June of the following calendar year, a carbon neutral action report in accordance with this section.

(2) The carbon neutral action reports for 2008 and 2009 must include the following:

(a) a description of the actions taken by the Provincial government in the relevant calendar year to minimize its PSO greenhouse gas emissions;

(b) its plans to continue minimizing those emissions;

(c) a determination of the PSO greenhouse gas emissions referred to in section 5 (2) *[emissions related to travel]* for the relevant calendar year;

(d) a statement of the emission offsets applied by the Provincial government in relation to those emissions;

(e) any other information required by regulation.

(3) The carbon neutral action reports for 2010 and subsequent calendar years must include the following:

(a) a description of the actions taken by the Provincial government in the relevant calendar year to minimize its PSO greenhouse gas emissions;

(b) its plans to continue minimizing those emissions;

(c) a determination of its PSO greenhouse gas emissions for the relevant calendar year;

(d) a statement of the emission offsets applied by the Provincial government in relation to those emissions;

(e) any other information required by regulation.

2007-42-7 (B.C. Reg. 407/2007).

Carbon neutral action reports – other public sector organizations

8. (1) Beginning with a report for the 2008 calendar year, and continuing with a report for every subsequent calendar year, each public sector organization, other than the Provincial government, must prepare, and make public no later than the end of June of the following calendar year, a carbon neutral action report in accordance with this section.

(2) The carbon neutral action reports for 2008 and 2009 must include the following:

(a) a description of the actions taken by the public sector organization in the relevant calendar year to minimize its PSO greenhouse gas emissions;

(b) its plans to continue minimizing those emissions;

(c) any other information required by regulation.

(3) The carbon neutral action reports for 2010 and subsequent calendar years must include the following:

(a) a description of the actions taken by the public sector organization in the relevant calendar year to minimize its PSO greenhouse gas emissions;

(b) its plans to continue minimizing those emissions;

(c) a determination of its PSO greenhouse gas emissions for the relevant calendar year;

(d) a statement of the emission offsets applied by the public sector organization in relation to those emissions;

(e) any other information required by regulation.

2007-42-8 (B.C. Reg. 407/2007).

Obligations may be combined

9. If satisfied that it is appropriate to do so, the minister may, by order, permit or require 2 or more public sector organizations to be treated as a single organization for the purposes of this Part.

2007-42-9 (B.C. Reg. 407/2007).

PART 3 – General Provisions

Public sector organization authority in relation to emission offsets

10. Without limiting an authority provided under any other Act, but subject to the regulations,

(a) public sector organizations may, for the purposes of this Act or for other prescribed purposes, acquire, dispose of or otherwise deal with emission offsets, and

(b) the Provincial government may act as agent for other public sector organizations in exercising their authority under paragraph (a).

2007-42-10 (B.C. Reg. 407/2007).

Making documents public

11. If a person or public sector organization is required to make a document public under this Act, the person or public sector organization meets that obligation by making the document available to the general public in a reasonable manner, which may include by electronic means.

2007-42-11 (B.C. Reg. 407/2007).

Regulations

12. (1) The Lieutenant Governor in Council may make regulations referred to in section 41 of the *Interpretation Act*.

(2) Without limiting subsection (1), the Lieutenant Governor in Council may make regulations as follows:

(a) prescribing a substance, whether it is normally gaseous or not, as a greenhouse gas;

(b) prescribing organizations or corporations as being included within, or excluded from, the definition of "public sector organization";

(c) respecting the form of measurement in which greenhouse gas emissions are to be expressed for the purposes of this Act;

(d) respecting what are deemed to be BC greenhouse gas emissions and the basis on which and the methodology by which these greenhouse gas emissions and their levels are to be determined including, without limiting this, respecting accounting for emission offsets in the determination of BC greenhouse gas emissions;

(e) authorizing the minister to revise previously determined BC greenhouse gas emission levels and establishing criteria that must be applied by the minister in doing this;

(f) respecting what are deemed to be PSO greenhouse gas emissions for which a public sector organization is responsible and the methodology by which these greenhouse gas emissions and their levels are to be determined;

(g) respecting emission offsets including, without limiting this,

(i) establishing one or more systems of emission offsets,

(ii) providing authority for projects or actions to be approved as the basis for emission offsets, including authority to establish the parameters of emission offsets related to projects or actions,

(iii) recognizing as emission offsets for the purposes of this Act units of systems established by other jurisdictions or organizations, and

(iv) providing when, how and to what extent emission offsets are to be applied;

(h) providing exceptions from the obligation under section 6 *[requirements for achieving carbon neutral status]* in circumstances where the relevant greenhouse gas emissions are or are deemed to be below a threshold level;

(i) requiring reports under section 7 or 8 *[carbon neutral action reports]* to be verified in accordance with the regulations;

(j) prescribing circumstances in which public sector organizations are exempt from the reporting obligation under section 8 *[carbon neutral action reports]* in relation to a calendar year;

(k) respecting the authority under section 10 *[public sector organization authority in relation to emission offsets]*;

(l) establishing additional reporting requirements in relation to greenhouse gas emissions and related matters;

(m) respecting the preparation of reports required under this Act including, without limiting this, respecting the timing, form and content of those reports, and respecting records that must be maintained in relation to these reports and access that must be provided to those records;

(n) defining words and expressions used but not defined in this Act;

(o) respecting any other matter for which regulations are contemplated by this Act.

(3) A regulation under this Act may do one or more of the following:

(a) delegate a matter to a person;

(b) confer a discretion on a person;

(c) make different regulations in relation to

(i) different matters or circumstances or different classes of matters or circumstances, and

(ii) different public sector organizations or classes of public sector organizations.

(4) A regulation under this Act may adopt by reference, in whole, in part or with any changes considered appropriate, a regulation, code, standard or rule

(a) enacted as or under a law of another jurisdiction, including a foreign jurisdiction, or

(b) set by a provincial, national or international body or any other code, standard or rule making body,

as the regulation, code, standard or rule stands at a specific date, as it stands at the time of adoption or as amended from time to time.

2007-42-12 (B.C. Reg. 407/2007).

Appendix B-3

Climate Action Charter

THE BRITISH COLUMBIA CLIMATE ACTION CHARTER

BETWEEN

THE PROVINCE OF BRITISH COLUMBIA (THE PROVINCE)

AND

THE UNION OF BRITISH COLUMBIA MUNICIPALITIES (UBCM)

AND

SIGNATORY LOCAL GOVERNMENTS

(THE PARTIES)

(1) The Parties share the common understanding that:

(a) Scientific consensus has developed that increasing emissions of human caused greenhouse gases (GHG), including carbon dioxide, methane and other GHG emissions, that are released into the atmosphere are affecting the Earth's climate;

(b) the evidence of global warming is unequivocal and the effects of climate change are evident across British Columbia;

(c) reducing GHG emissions will generate environmental and health benefits for individuals, families, and communities;

(d) climate change and reducing GHG emissions are issues of importance to British Columbians;

(e) governments urgently need to implement effective measures to reduce GHG emissions and anticipate and prepare for climate change impacts;

(f) protecting the environment can be done in ways that promote economic prosperity; and

(g) it is important to take action and to work together to share best practices, to reduce GHG emissions and address the impacts of climate change.

(2) The Parties acknowledge that each has an important role in addressing climate change and that:

(a) The Province has taken action on climate change, including commitments made in the 2007 Speech from the Throne, the BC Energy Plan, and the Western Climate Initiative on climate change;

(b) Local Governments have taken action on climate change, including planning livable, sustainable communities, encouraging green developments and transit oriented developments, and implementing innovative infrastructure technologies including landfill gas recapture and production of clean energy; and

(c) these actions create the foundation for the Parties to be leaders in affecting climate change.

(3) This Charter acknowledges that:

(a) The interrelationship between each Order of Government's respective jurisdictions and accountabilities with respect to communities, and activities related to and within communities, creates both a need and an opportunity to work collaboratively on climate change initiatives;

(b) both Orders of Government have recognized a need for action, both see that the circumstances represent a Climate for Change in British Columbia, and both are responding; and

(c) the actions of each of the Parties towards climate change will be more successful if undertaken jointly with other Parties.

(4) The Parties share the common goals of:

(a) Fostering co-operative inter-governmental relations;

(b) aiming to reduce GHG emissions, including both their own and those created by others;

(c) removing legislative, regulatory, policy, or other barriers to taking action on climate change;

(d) implementing programs, policies, or legislative actions, within their respective jurisdictions, that facilitate reduced GHG emissions, where appropriate;

(e) encouraging communities that are complete and compact and socially responsive; and

(f) encouraging infrastructure and a built environment that supports the economic and social needs of the community while minimizing its environmental impact.

(5) In order to contribute to reducing GHG emissions:

(a) Signatory Local Governments agree to develop strategies and take actions to achieve the following goals:

(i) being carbon neutral in respect of their operations by 2012, recognizing that solid waste facilities regulated under *the Environmental Management Act* are not included in operations for the purposes of this Charter.

(ii) measuring and reporting on their community's GHG emissions profile; and

(iii) creating complete, compact, more energy efficient rural and urban communities (e.g. foster a built environment that supports a reduction in car dependency and energy use, establish policies and processes that support fast tracking of green development projects, adopt zoning practices that encourage land use patterns that increase density and reduce sprawl.)

(b) The Province and the UBCM will support local governments in pursuing these goals, including developing options and actions for local governments to be carbon neutral in respect of their operations by 2012.

(6) **The Parties agree that this commitment to working together towards reducing GHG emissions will be implemented through establishing a Joint Provincial-UBCM Green Communities Committee and Green Communities Working Groups that support that Committee, with the following purposes:**

(a) To develop a range of actions that can affect climate change, including initiatives such as: assessment, taxation, zoning or other regulatory reforms or incentives to encourage land use patterns that promote increased density, smaller lot sizes, encourage mixed uses and reduced GHG emissions; development of GHG reduction targets and strategies, alternative transportation opportunities, policies and processes that support fast-tracking of green development projects, community gardens and urban forestry; and integrated transportation and land use planning;

(b) to build local government capacity to plan and implement climate change initiatives;

(c) to support local government in taking actions on becoming carbon neutral in respect of their operations by 2012, including developing a common approach to determine carbon neutrality for the purposes of this Charter, identifying carbon neutral strategies and actions appropriate for the range of communities in British Columbia and becoming reporting entities under the Climate Registry; and,

(d) to share information and explore additional opportunities to support climate change activities, through enhanced collaboration amongst the Parties, and through encouraging and promoting climate change initiatives of individuals and businesses within communities.

(7) Once a common approach to carbon neutrality is developed under section (6)(c), Signatory Local Governments will implement their commitment in 5 (a) (i).

(8) To recognize and support the GHG emission reduction initiatives and the climate change goals outlined in this Charter, Signatory Local Governments are invited by the other Parties to include a statement of their initiatives and commitments as an appendix to this Charter.

(9) This Charter is not intended to be legally binding or impose legal obligations on any Party and will have no legal effect.

SIGNED on behalf of the **PROVINCE OF BRITISH COLUMBIA** by:

______________________________ Date____________________

The Honourable Bill Bennett
Ministry of Community and Rural Development

______________________________ Date____________________

The Honourable John Yap
Minister of State for Climate Action

SIGNED on behalf of the **UNION OF BRITISH COLUMBIA MUNICIPALITIES** by:

______________________________ Date____________________

Chair Harry Nyce and
President of the Union of British
Columbia Municipalities

SIGNED on behalf of the **SIGNATORY LOCAL GOVERNMENT:**

____

(NAME OF LOCAL GOVERNMENT)

by:

______________________________ Date____________________

Mayor/Chair

Appendix
GHG reduction initiatives or commitments of Signatory Local Government

Note: Local Governments that choose to become Signatories may also choose to provide a statement of their individual commitments in a customized addendum to the main body of the Charter. Below is a sample version of the proposed addendum

SAMPLE

Addendum to
The British Columbia Climate Change Action Charter

For

[Name of Local Government]

is committed to

1. Implementing existing plans

Local Governments could list here plans they have developed and are in the process of implementing; for example:

- Community energy plan
- Greenhouse gas emissions inventory
- Official Community Plan – Smart Growth
- Community Action on Energy Efficiency Initiative (CAEE)
- Partners for Climate Protection, Federation of Canadian Municipalities
- District Energy System
- Eco-Industrial Project
- Transit Oriented Development Plan
- Landfill Gas Utilization

2. Continue to pursue activities

Local Governments could list here recent projects they have implemented; for example:

- Bio-diesel fleet vehicle conversion
- E3 Fleet Program
- Greenhouse Gas Reduction Strategy
- Carbon Neutral Municipal Operations
- Organics Recovery
- Recycling and waste management plan

- Greenhouse gas local action plan
- Energy Efficient Municipal Operations
- Employee car-pooling
- Air quality planning

3. Preparing new plans, bylaws, policies, etc.

Local Governments could list here plans, bylaws, policies they are committed to develop; for example:

- Plan for being carbon neutral in respect of their operations by 2012
- Anti-idling bylaw
- Green Buildings BC for Local Governments
- Smart Growth Development Checklist
- Green Building Program – Built Green and LEED standards
- Micro-generation projects (hydro, wind power, etc)
- Sustainable Community Servicing Plan
- Green Roof Policy
- Greywater recycling policy and standards
- Pedestrian and transit friendly community design
- Local Purchasing Policy
- Streamlined Green Building Application Process

Appendix B-4

Carbon Tax Act

PDF Version
[Printer-friendly - ideal for printing entire document]

CARBON TAX ACT

Published by Quickscribe Services Ltd.
Updated To:
[includes 2012 Bill 21, c. 8 amendments (effective May 14, 2012)]

CARBON TAX ACT

CHAPTER 40 [SBC 2008]

[includes 2012 Bill 21, c. 8 amendments (effective May 14, 2012)]

Contents

PART 1 – Interpretation

Interpretation

(AM) May 14/12

1. (1) In this Act:

"assessment" includes reassessment;

(RET) Feb 16/11

"biomethane" means methane produced from biomass;

(RET) Feb 16/11

"biomethane credit" means a credit provided under section 14.1;

"board member" means a member of a board of directors of a corporation and includes a person who is deemed to be a board member under section 50;

"buy" includes to obtain ownership by barter or exchange;

(AM) Jan 01/10

"collector" means a person who is appointed as a collector under section 16 (1);

"combustible" means an item or material set out in column 2 of the Table in Schedule 2;

"deputy collector" means a person who is deemed appointed as a deputy collector under section 17;

"director" means a person appointed by the minister to administer this Act;

(SUB) Jan 01/10

"fuel" means a substance set out in column 2 of the Table in Schedule 1 but does not include

(a) methanol produced from biomass, and

(RET) Feb 16/11

(b) subject to section 13.1, biomethane;

"IFTA commercial vehicle" has the prescribed meaning;

"litre" means,

(a) with respect to fuel in liquid form, one cubic decimetre, or

(b) with respect to fuel in the form of liquefied petroleum gas, 0.5 kg;

"manufacture" includes the production, refining or compounding of fuel;

"month" means a calendar month;

"motive fuel user permit" means a motive fuel user permit issued under the *Motor Fuel Tax Act*;

"motor vehicle" means a vehicle that is designed to be self propelled on land;

(ADD) Jan 01/10

"natural gas" means natural gas as defined in section 1 (1) of Schedule 1;

"person" includes the government of Canada;

"purchaser" means a person who, within British Columbia, buys or receives delivery of fuel

(a) for the person's own use or for use by another person at the first person's expense, or

(b) on behalf of or as an agent for a principal for use by the principal or by other persons at the expense of the principal;

(ADD) Jan 01/10

"refiner collector" means a person who is appointed as a refiner collector under section 16 (2.1);

"registered air service" means a person who holds a registered air service certificate;

"registered air service certificate" means a registered air service certificate issued under section 21;

"registered consumer" means a person who holds a registered consumer certificate;

(AM) Jan 01/09 **"registered consumer certificate"** means a registered consumer certificate issued under section 20;

"registered marine service" means a person who holds a registered marine service certificate;

"registered marine service certificate" means a registered marine service certificate issued under section 21;

(AM) Jan 01/09 **"registration certificate"** means a registration certificate issued under section 19;

(RET) May 01/12 **"retail dealer"** , subject to section 1.1, means a person who, within British Columbia, sells fuel to a purchaser;

(SUB) Jan 01/10 **"scheduled rate change"** means a modification in a rate of tax set out in the Table in Schedule 1 that comes into effect as of July 1 of a year;

"security" includes all penalties and interest that are or may be added to security under this Act;

"sell" includes to transfer ownership by barter or exchange;

"ship" includes any vessel that is designed to be self propelled in or on water;

"tax" includes all penalties and interest that are or may be added to tax under this Act;

(AM) Jan 01/10 **"use"** includes flaring and incineration of natural gas or refinery gas, and a prescribed type of activity in circumstances, if any, that are prescribed;

(RET) May 01/12 **"vendor"** , subject to section 1.1, means a person who, within British Columbia, sells fuel for the first time after

(a) its manufacture in British Columbia, or

(b) its importation into British Columbia;

(RET) May 01/12 **"wholesale dealer"** , subject to section 1.1, means a person who, within British Columbia, buys fuel for resale to a person other than a purchaser.

(2) "Tax" as defined in subsection (1) does not apply to the definition of "non-carbon tax" in section 2.

2008-40-1; 2008-40-155; 2009-14-20; 2009-14-21 (B.C. Reg. 292/2009); 2011-9-4; 2012-8-6, 7.

(RET) May 01/12 **Fuel imported by ship**

1.1 (1) In this section:

"imported fuel" means fuel, other than natural gas and propane, that, as part or all of a single shipment, has entered British Columbia from outside of Canada in compliance with the *Customs Act* (Canada) and the regulations under that Act;

"release" has the same meaning as in the *Customs Act* (Canada);

"shipment" means fuel that is cargo

(a) in a single ship on a single trip,

(b) on a single barge towed or pushed by one or more ships on a single trip, or

(c) on 2 or more physically connected barges towed or pushed by one or more ships on a single trip, if all the fuel on the barges is owned by the same person.

(2) Subject to subsections (3) and (4) and the regulations, all of the following apply to a sale of imported fuel before it is released:

(a) the seller is not a retail dealer, even if the imported fuel is sold to a purchaser;

(b) the seller is not a vendor;

(c)

the buyer is not a wholesale dealer, even if the buyer buys the imported fuel for resale to a person other than a purchaser.

(3) Subsection (2) (a) to (c) does not apply to a sale of imported fuel

(a) from a single shipment if

(i) the imported fuel is a prescribed type of fuel or a prescribed subcategory of a type of fuel or is in a prescribed class of fuel, and

(ii) the amount of the imported fuel sold in that sale from that shipment is less than the amount prescribed for that prescribed type of fuel, prescribed subcategory of a type of fuel or prescribed class of fuel, or

(b) in prescribed circumstances.

(4) If imported fuel is sold before it is released and subsection (2) (a) to (c) does not, under subsection (3) or the regulations, apply to the sale, subsection (2) does not apply to any subsequent sale of that fuel.

(5) A person who, within British Columbia, sells imported fuel for the first time in a sale to which subsection (2) (a) to (c) does not apply is the vendor of that fuel.

2012-8-8; 2012-8-8 [retro from 14 May 2012].

PART 2 – Plans and Reports Respecting the Carbon Tax

Interpretation

2. (1) In this Part:

"adjustment amount" means the dollar amount by which

(a) the estimated or, if known, actual amount of carbon tax collected in a fiscal year

exceeds

(b) the estimated dollar amount of the reduction in Provincial revenues, as a result of revenue measures, in the same fiscal year;

"adjustment measures" means measures or portions of measures designated by the minister to offset an adjustment amount by reducing Provincial revenues through one or more of the following:

(a) granting a non-carbon tax exemption or reducing or eliminating a non-carbon tax or a fee or charge imposed under an Act other than this Act;

(b) continuing for more than one fiscal year a non-carbon tax exemption granted, or the reduction or elimination of a non-carbon tax or a fee or charge imposed under an Act other than this Act;

(c) granting or increasing a non-carbon tax credit, or continuing for more than one fiscal year a non-carbon tax credit or the increasing of a non-carbon tax credit;

"carbon tax" means the tax imposed under this Act;

"carbon tax plan" means the carbon tax plan referred to in section 3 (1) (a) (i);

"minister" means the Minister of Finance;

"non-carbon tax" means a tax, including penalties and interest, that is collected by or for the government, other than the carbon tax;

"non-carbon tax credit" includes an amount that under an enactment is deemed to be a payment or overpayment of non-carbon taxes;

"Provincial revenues" means revenues collected by or for the government that are derived from the payment of a non-carbon tax or a fee or charge imposed under an Act other than this Act;

"report" means the report referred to in section 3 (1) (a) (ii);

"revenue measures" means measures or portions of measures designated by the minister to reduce Provincial revenues through one or more of the following:

(a) granting a non-carbon tax exemption or reducing or eliminating a non-carbon tax or a fee or charge imposed under an Act other than this Act;

(b) continuing for more than one fiscal year a non-carbon tax exemption granted, or the reduction or elimination of a non-carbon tax or fee or charge imposed, under an Act other than this Act;

(c) granting or increasing a non-carbon tax credit, or continuing for more than one fiscal year a non-carbon tax credit or the increasing of a non-carbon tax credit,

but does not include adjustment measures.

(2)

In this Part, the carbon tax is revenue neutral if the dollar amount of the carbon tax collected in a fiscal year is less than or equal to the estimated dollar amount of the reduction in Provincial revenues in the same fiscal year as a result of revenue measures.

2008-40-2.

Preparation of plans and report

3. (1) The minister

(a) must annually prepare

(i) a carbon tax plan that meets the requirements set out in subsection (2), and

(ii) a report that meets the requirements set out in subsection (3),

(b) must, if a report includes an adjustment amount in the earlier fiscal year of the report, prepare an adjustment amount plan that meets the requirements set out in subsection (4) (a) to (d), and

(c) may, if a report includes an adjustment amount in the more recent fiscal year of a report, prepare an adjustment amount plan that includes the matters referred in subsection (4) (e).

(2) A carbon tax plan must

(a) cover a 3 year period beginning at the start of the fiscal year following the fiscal year in which the carbon tax plan is presented to the Legislative Assembly under section 4,

(b) set out the following for each fiscal year of the plan:

(i) a forecast of the carbon tax revenues to be collected;

(ii) the revenue measures that the minister proposes be implemented;

(iii) a forecast of the reduction in the Provincial revenues as a result of the revenue measures referred to in subparagraph (ii), and

(c) forecast that the carbon tax will be revenue neutral in relation to each fiscal year of the carbon tax plan.

(3) A report must

(a) cover a 2 year period that ends at the beginning of the first fiscal year of the carbon tax plan presented to the Legislative Assembly under section 4 at the same time as the report, and

(b) set out the following for each fiscal year of the report:

(i) the estimated or, if known, actual carbon tax revenues collected;

(ii) the estimated reduction in Provincial revenues as a result of the revenue measures that were implemented;

(iii) the adjustment amount, if any.

(4) An adjustment amount plan

(a) must cover the period beginning on the date that the report that includes an adjustment amount is presented to the Legislative Assembly and ending on the last date of the carbon tax plan that is presented to the Legislative Assembly at the same time as the adjustment amount plan,

(b) must include the following with respect to an adjustment amount in the earlier fiscal year of the report:

(i) adjustment measures that the minister proposes be implemented at any time during the period of the adjustment amount plan to offset the adjustment amount;

(ii) a forecast of the reduction of Provincial revenues as a result of the adjustment measures referred to in subparagraph (i),

(c) must include, if the adjustment amount plan of the prior fiscal year included adjustment measures, a revised forecast of the reduction of Provincial revenues as a result of those adjustment measures,

(d) if there is an adjustment amount in the earlier fiscal year of the report, must forecast that the adjustment amount will be offset by a reduction in Provincial revenues resulting from the sum of

(i) the adjustment measures that are proposed for that same fiscal year in the adjustment amount plan, and

(ii) the adjustment measures that were proposed for that same fiscal year in the adjustment amount plan, if any, of the prior fiscal year, and

(e) may include the following with respect to an adjustment amount in the more recent fiscal year of the report:

(i) adjustment measures that the minister proposes be implemented at any time during the period of the adjustment amount plan to offset the adjustment amount;

(ii) a forecast of the reduction of Provincial revenues as a result of the adjustment measures referred to in subparagraph (i).

2008-40-3.

Plans and report presented to the Legislative Assembly

4. At the same time that the main estimates for a fiscal year are presented to the Legislative Assembly, the minister

(a) must also present the following to the Legislative Assembly:

(i) the carbon tax plan for the fiscal year for which the main estimates are presented and the 2 subsequent fiscal years;

(ii) the report for the 2 fiscal years preceding the first year of the carbon tax plan;

(iii) if the report referred to in subparagraph (ii) includes an adjustment amount in the earlier fiscal year of the report, an adjustment amount plan that includes the information referred to in section 3 (4) (b) to (d);

(iv) a statement of all material assumptions and policy decisions underlying the preparation of the report, the plans referred to in subparagraphs (i) and (iii), and an adjustment amount plan referred to in paragraph (b) if that adjustment amount plan is presented to the Legislative Assembly;

(v) a statement, signed by the secretary to Treasury Board, that the requirements referred to in section 3 and the disclosure requirements referred to in subparagraph (iv) of this paragraph have been met, or explaining how those requirements have not been met, and

(b) if the report referred to in paragraph (a) (ii) includes an adjustment amount in the more recent fiscal year of the report, may present to the Legislative Assembly an adjustment amount plan that includes the information referred to in section 3 (4) (e).

2008-40-4.

Failure to introduce legislation

5. (1) In this section, **"specified period"** means the period starting on the date an adjustment amount plan is presented to the Legislative Assembly under section 4 (a) (iii) and ending on the last day of the following fiscal year.

(2) The salary payable to the minister for the fiscal year in which a carbon tax plan and report are presented to the Legislative Assembly is deemed to be reduced in accordance with subsection (3) (a) or (b), whichever is applicable, if legislation for the purpose of implementing

(a) the revenue measures proposed for the first year of the carbon tax plan, and

(b) the adjustment measures proposed for the specified period of the adjustment amount plan to offset the adjustment amount, if there is an adjustment amount in the earlier year of the report,

is reasonably necessary but is not introduced into the Legislative Assembly within 120 days of the date that the carbon tax plan and report are presented to the Legislative Assembly.

(3) If the minister who presented a carbon tax plan and report to the Legislative Assembly is the minister

(a) for the whole of the fiscal year during which that plan and report are presented to the Legislative Assembly, the salary of the minister that is otherwise payable under section 4 of the *Members' Remuneration and Pensions Act* in that fiscal year is deemed to be reduced by 15%, and

(b) for only part of the fiscal year during which that plan and report are presented to the Legislative Assembly, the salary of the minister that is otherwise payable under section 4 of the *Members' Remuneration and Pensions Act* is deemed to be reduced by the product of the following:

$$\text{minister's salary payable in that fiscal year under section 4 of } \textit{Members' Remuneration and Pensions Act} \times .15 \times \frac{\text{days as minister}}{365}$$

(4) The minister must repay the amount of the deemed salary reduction resulting from the operation of this section on or before the 150th day after the date that the minister is required to present the carbon tax plan and report to the Legislative Assembly. 2008-40-5.

Legal proceedings

6. No action or other proceeding may be brought in respect of an obligation established under this Part, other than an action brought by the government to enforce the obligation of the minister under section 5 (4).

2008-40-6.

Plans and reports for the 2008-09, 2009-10 fiscal years

7. (1) The plan called the "Revenue Neutral Carbon Tax Plan" presented to the Legislative Assembly with the main estimates on February 19, 2008 is deemed to be a carbon tax plan presented to the Legislative Assembly under section 4 for the purposes of the reports presented to the Legislative Assembly in the 2008-2009 and 2009-2010 fiscal years.

(2) Despite sections 3 and 4,

(a) the report that is prepared and presented to the Legislative Assembly under those sections in the 2008-2009 fiscal year, although it relates to a carbon tax plan for only the 2008-2009 fiscal year, is a report under those sections, and

(b) the fiscal year to which the report referred to in paragraph (a) applies is deemed to be the more recent fiscal year of the report for the purposes of section 3.

2008-40-7.

PART 3 – Imposition of Tax and Setting the Rate of Tax

Imposition of tax on purchase of fuel

8. (1) Subject to this section and the regulations, a purchaser of a fuel must pay to the government, at the time of purchase, tax on the fuel at the rate for that type of fuel set out in the column of the Table in Schedule 1 that applies for the period of time in which the fuel is purchased.

(2) If a scheduled rate change for a fuel takes effect between the time a purchaser buys the fuel and the time the purchaser receives delivery of the fuel, the purchaser must pay to the government tax on the fuel at the rate for that type of fuel set out in the column of the Table in Schedule 1 that applies for the period of time in which the purchaser receives delivery.

(REP) May 14/12

(3) *Repealed.* [2012-8-10]

(4) This section does not apply to a purchaser who is a registered consumer with respect to the type or subcategory of a type of fuel specified on that person's registered consumer certificate.

(5) A registered air service or registered marine service who purchases the type or subcategory of a type of fuel specified on that person's registered air or marine service certificate must pay the tax under subsection (1) at the prescribed time and in the prescribed manner.

(RET) May 01/12

(6) A purchaser of a fuel in a sale to which section 1.1 (2) (a) to (c) applies must pay the tax under subsection (1) of this section at the prescribed time and in the prescribed manner.

2008-40-8; 2012-8-9, 10.

Imposition of tax on transfer of fuel

9. (1) Subject to this section, a person who is not a purchaser of a fuel but who, within British Columbia, transfers the fuel into the receptacle that supplies the turbine or other engine of

(a) a ship,

(b) any rolling stock or other vehicle run on rails, or

(c) an aircraft

must pay to the government, at the prescribed time and in the prescribed manner, tax on the fuel at the rate for that type of fuel set out in the column of the Table in Schedule 1 that applies for the period of time in which the fuel is transferred.

(2) Subsection (1) applies to a person only if the person transfers the fuel

(a) for the person's own use or for use by another person at the first person's expense, or

(b) on behalf of or as an agent for a principal for use by the principal or by another person at the expense of the principal.

(3) Subsection (1) does not apply to a person who is a registered consumer with respect to the type or subcategory of a type of fuel specified on that person's registered consumer certificate.

(4) A registered air service or registered marine service who transfers the type or subcategory of a type of fuel specified on that person's registered air or marine

service certificate must pay the tax under subsection (1) at the prescribed time and in the prescribed manner.

2008-40-9.

Imposition of tax on fuel brought into British Columbia

10. (1) Subject to this section, a person who

(a) resides, ordinarily resides or carries on business in British Columbia or enters British Columbia with the intention of residing or carrying on business in British Columbia, and

(b) brings or sends into British Columbia fuel in the supply tank or a supplemental supply tank of a motor vehicle, aircraft or ship

must pay to the government, at the prescribed time and in the prescribed manner, tax on the fuel at the rate for that type of fuel set out in the column of the Table in Schedule 1 that applies for the period of time in which the fuel is brought into British Columbia.

(2) Subsection (1) applies to a person only if the person brings or sends into British Columbia the fuel

(a) for the person's own use or for use by another person at the first person's expense, or

(b) on behalf of or as an agent for a principal for use by the principal or by another person at the expense of the principal.

(3) For the purposes of subsection (1), a person is deemed to be carrying on business in British Columbia if

(a) an employee or other representative of that person carries on activities in British Columbia on that person's behalf for the purpose of promoting or facilitating the carrying on of that person's business, or

(b) the person routinely loads or unloads passengers, cargo or both in British Columbia.

(4) Subsection (1) does not apply to a person who is a registered consumer with respect to the type or subcategory of a type of fuel specified on that person's registered consumer certificate.

(5) In the case of an IFTA commercial vehicle to which this Act applies, this section does not apply to fuel in the supply tank or a supplemental supply tank of the IFTA commercial vehicle if a deposit has been paid in accordance with the regulations in respect of tax payable on that fuel under this Act.

(6) A registered air service or registered marine service who brings or sends into British Columbia the type or subcategory of a type of fuel specified on that person's registered air or marine service certificate must pay the tax under subsection (1) at the prescribed time and in the prescribed manner.

2008-40-10.

Imposition of tax on use of fuel

11. A person who, within British Columbia, uses a fuel on which tax is not otherwise payable under sections 8, 9 and 10 must pay to the government, at the prescribed time and in the prescribed manner, tax on the fuel at the rate for that type of fuel set out in the column of the Table in Schedule 1 that applies for the period of time in which the fuel is used.

2008-40-11.

Imposition of tax on combustible

12. A person who, within British Columbia, burns a combustible to produce energy or heat must pay to the government, at the prescribed time and in the prescribed manner, tax on the combustible at the rate for that type of combustible set out in the column of the Table in Schedule 2 that applies for the period of time in which the combustible is burned.

2008-40-12.

Calculation of tax for blends or mixtures

13. (1) If a mixture or blend is composed of one or both of the following combinations:

(a) one or more fuels, with or without one or more non-taxable substances or items;

(b) one or more combustibles, with or without one or more non-taxable substances or items,

the amount of tax payable for a fuel or combustible in the mixture or blend is to be determined by multiplying the rate of tax determined under the applicable provision of this Act by the amount of that fuel or combustible in the mixture or blend.

(2) Subsection (1) does not apply to a prescribed fuel, combustible, substance or item or in prescribed circumstances.

(3) Subject to subsection (4), if a mixture or blend includes a prescribed fuel, combustible, substance or item referred to in subsection (2), the amount of tax payable on the mixture or blend is the amount determined in accordance with the regulations.

(4) If a substance or item is not taxable under this Act, the regulations may deem the substance or item to be taxable at a prescribed rate if the substance or item is included in a mixture or blend but comprises less than the prescribed percentage of the mixture or blend.

2008-40-13.

(RET) **Calculation of tax for certain biomethane blends or mixtures**
Feb
16/11

13.1 (1) If a mixture or blend contains a combined amount of a fuel and biomethane and the proportions of the fuel and biomethane in the combined amount cannot be determined,

(a) for the purpose of applying this Act and the regulations under this Act, the biomethane is deemed to be fuel of the same type or subcategory of a type of fuel as the fuel, and

(b) the total amount of tax payable for the fuel and the biomethane is to be determined by multiplying the rate of tax for the fuel under this Act by the combined amount of the fuel and the biomethane.

(2) If a mixture or blend contains a combined amount of natural gas, another fuel and biomethane, and the proportions of natural gas, the other fuel and biomethane in the combined amount cannot be determined,

(a) for the purpose of applying this Act and the regulations under this Act, the other fuel and the biomethane are deemed to be natural gas, and

(b) the total amount of tax payable for the natural gas, the other fuel and the biomethane is to be determined by multiplying the rate of tax for natural gas under this Act by the combined amount of the natural gas, the other fuel and the biomethane.

2011-9-5.

PART 4 – Exemptions and Credits

Division 1 – Exemptions

Exemptions from tax

14. (1) In this section:

"common carrier" means a person who is in the business of transporting goods for members of the public;

(RET) Sep 02/09 **"non-commercial aircraft or ship"** means an aircraft or ship used solely for personal use.

for a fee.

(2) In addition to exemptions established by regulation, the following are exempt from tax under this Act:

(a) fuel that is brought into British Columbia in the supply tank or a supplemental supply tank of a non-commercial aircraft or ship, if the fuel in the supply tank or supplemental supply tank is to be used in the operation of the aircraft or ship;

(b) up to and including 182 litres of fuel that is brought into British Columbia in the supply tank or a supplemental supply tank of a motor vehicle, other than an IFTA commercial vehicle or a locomotive, if the fuel in the supply tank or supplemental supply tank is to be used in the operation of the motor vehicle;

(RET) May 01/12 (c) fuel that is purchased in British Columbia for use outside of British Columbia and is to be removed from British Columbia by the following persons:

(i) if section 1.1 (2) (a) to (c) does not apply to the sale,

(A) the collector, deputy collector or retail dealer who sold the fuel, or

(B) a person acting on behalf of the collector, deputy collector or retail dealer who sold the fuel;

(ii) if section 1.1 (2) (a) to (c) applies to the sale,

(A) the seller who sold the fuel, or

(B) a person acting on behalf of the seller who sold the fuel;

(iii) if the purchaser of the fuel or a person acting on behalf of the purchaser has at the time of the purchase entered into a contract with a common carrier for the removal of the fuel from British Columbia,

(A) the purchaser, or

(B) the person acting on behalf of the purchaser;

(d) fuel that is purchased in British Columbia for use outside of British Columbia and is to be removed from British Columbia in prescribed circumstances;

(e) fuel for use in the operation of an IFTA commercial vehicle by a licensed carrier, as defined in the *Motor Fuel Tax Act*;

(f) fuel that is used by a registered consumer for interjurisdictional air or marine travel or transport in the prescribed circumstances and in accordance with the prescribed rules.

2008-40-14; 2009-14-22; 2012-8-11.

Division 2 – Biomethane Credit

(RET)**Biomethane credit**
Feb
16/11

14.1 Subject to the regulations, a retail dealer of natural gas, on behalf of the government, must provide a credit to a purchaser at the prescribed time and in an amount determined in the prescribed manner.

2011-9-8.

(RET)**Refund to retail dealer of natural gas**
Feb
16/11

14.2 If the director is satisfied that

(a) a retail dealer of natural gas has provided a biomethane credit to a purchaser in respect of a sale,

(b) the retail dealer has remitted to the director the amount of tax payable in respect of the sale, without deduction for the biomethane credit, and

(c) the purchaser was entitled to receive the biomethane credit,

the director, subject to the regulations, must pay from the consolidated revenue fund to the retail dealer a refund of a portion of the tax remitted by the retail dealer in respect of the sale in an amount determined in the prescribed manner.

2011-9-8.

(RET)**Recovery of amount by retail dealer of natural gas**
Feb
16/11

14.3 (1) If a retail dealer of natural gas

(a) provides a credit to a person in respect of a sale as if it were a biomethane credit, and

(b) does not receive a refund under section 14.2 because the person was not entitled to receive a biomethane credit in respect of the sale,

the retail dealer may by action in a court recover from the person the amount credited.

2011-9-8.

PART 5 – Collection of Tax and Security

Division 1 – Appointments and Certificates

Vendor selling fuel

15. (1) A vendor must not sell, within British Columbia, a fuel unless the vendor is appointed a collector for that type or subcategory of a type of fuel.

(AM) Jul 01/10 (2) This section does not apply to the sale of natural gas.

2008-40-15; 2009-14-23; 2010-2-61.

(ADD) Jun 01/08 Appointment of vendor as collector

16. (1) Subject to subsection (2), and on receipt of an application in the form specified by the director, the director may, if the director considers that the applicant is suitable,

(a) appoint a vendor to be a collector for a type or subcategory of a type of fuel, and

(b) make the appointment subject to any other conditions and limitations specified by the director.

(2) Before an applicant is appointed as a collector, the applicant must enter into an agreement with the director, on behalf of the government, setting out the duties to be performed by the applicant when acting as a collector and any other matters the director considers necessary or advisable.

(ADD) Jan 01/10 (2.1) On receipt of an application in the form specified by the director, the director may

(a) appoint a collector to be a refiner collector with respect to the same type or subcategory of a type of fuel as the collector is appointed under subsection (1) (a), if

(i) the director considers the applicant suitable, and

(ii) the collector or one or more interrelated entities of the collector, individually or collectively, own and operate a crude oil refinery in Canada, and

(b) make the refiner collector appointment subject to any conditions and limitations specified by the director.

(ADD) Jan 01/10 (2.2) In this section, **"interrelated entity"**, in relation to a collector, means a corporation, partnership, trust, joint venture or other incorporated or unincorporated entity that the director considers to be interrelated with the collector for the purpose of this section.

(REP) Jan 01/09 (3) to (6) *Repealed.* [2008-40-156]

2008-40-16; 2008-40-156; 2009-14-24 (B.C. Reg. 292/2009).

Appointment of deputy collector

17. (1) If a wholesale dealer buys fuel

(a) from a collector, the wholesale dealer is deemed, with respect to that fuel, to have been appointed a deputy collector by the collector, or
(b) from a deputy collector, the wholesale dealer is deemed, with respect to that fuel, to have been appointed a deputy collector by the deputy collector

from whom the wholesale dealer bought that fuel.

(2) Subsection (1) does not apply to a wholesale dealer who is appointed a collector and who buys fuel from another collector in a sale described in section 30 (3).

(3) A person who is a deputy collector must comply with the obligations of a deputy collector imposed by this Act even if the person is also a collector or a registered consumer with respect to other fuel.

2008-40-17.

Sale of natural gas

(AM) Jul 01/10

18. A person must not sell, within British Columbia, natural gas to a purchaser unless the person is a retail dealer who holds a registration certificate.

2008-40-18; 2009-14-23; 2010-2-62.

(ADD) **Issue of registration certificate to retail dealer**

Jun 01/08

19. (1) On receipt of an application in the form specified by the director, the director may, if the director considers that the applicant is suitable,

(AM) Jul 01/10

(a) issue a registration certificate to a retail dealer authorizing the retail dealer to sell natural gas, and
(b) make the registration certificate subject to any other conditions and limitations specified by the director.

(AM) Jul 01/10

(2) The director may require that before a registration certificate is issued under subsection (1), the applicant enter into an agreement with the director, on behalf of the government, setting out the duties to be performed by the applicant when acting as a retail dealer of natural gas and any other matters the director considers necessary or advisable.

(REP) Jan 01/09

(3) to (6) *Repealed.* [2008-40-156]

2008-40-19; 2008-40-156; 2009-14-23; 2010-2-62.

(ADD) **Issue of registered consumer certificate**

Jun 01/08

20. (1) Subject to subsection (2) and on receipt of an application in the form specified by the director, the director may

(a) issue a registered consumer certificate for a type or subcategory of a type of fuel specified by the director, to an applicant who
    (i) the director considers suitable,
    (ii) is included in a prescribed category of persons, and
    (iii) meets the prescribed conditions and requirements, if any, and
(b) make the registered consumer certificate subject to any other conditions and limitations specified by the director.

(2) Before an applicant is issued a registered consumer certificate, the applicant must

enter into an agreement with the director, on behalf of the government, setting out the duties to be performed by the applicant when acting as a registered consumer and any other matters the director considers necessary or advisable.

(REP) Jan 01/09 (3) to (6) *Repealed.* [2008-40-156]

2008-40-20; 2008-40-156.

(ADD) Jun 01/08 Issue of registered air or marine service certificate

21. (1) Subject to subsection (2) and on receipt of an application in the form specified by the director, the director may

(a) issue a registered air service certificate or registered marine service certificate, for a type or subcategory of a type of fuel specified by the director, to an applicant who

(i) the director considers is suitable,

(ii) is included in a prescribed category of persons, and

(iii) meets the prescribed conditions and requirements, if any, and

(b) make the registered air service or marine service certificate subject to any other conditions and limitations specified by the director.

(2) Before an applicant is issued a registered air service certificate or registered marine service certificate, the applicant must enter into an agreement with the director, on behalf of the government, setting out the duties to be performed by the applicant when acting as a registered air service or a registered marine service and any other matters the director considers necessary or advisable.

2008-40-21.

(ADD) Jun 01/08 Limitation respecting type of fuel

22. The director may limit the application of a collector's appointment, a registered consumer certificate or a registered air service or marine service certificate to a subcategory of a type of fuel, if the subcategory is prescribed under this Act.

2008-40-22.

Suspension or cancellation of appointment and certificates

23. (1) In this section:

(AM) Jan 01/10 **"appointment"** means an appointment as a collector or as a refiner collector;

"certificate" means a registration certificate, registered consumer certificate, registered air service certificate or registered marine service certificate;

(AM) Jan 01/10 **"person"** means a collector, refiner collector, registered consumer, registered air service, registered marine service and a person who holds a registration certificate.

(2) The director may, without advance notice to a person, suspend the person's appointment or certificate for a period of up to 60 days

(a) if the director is satisfied that the person knowingly gave false information on an application for the appointment or certificate,

(b) if the person refuses or neglects to comply with

(i) a provision of this Act or the regulations,

(ii) a condition or limitation specified by the director on the appointment or certificate held by the person,

(iii) a provision of the agreement referred to in section 16 (2), 19 (2), 20 (2) or 21 (2), or

(RET) Sep 02/09 (iv) a requirement of the director to deposit a bond under section 59,

(ADD) Jan 01/10 (b.1) with respect to an appointment as a refiner collector, if the director is satisfied that the condition referred to in section 16 (2.1) (a) (ii) is not being met, or

(c) if authorized by the regulations.

(3) If the director suspends an appointment or certificate of a person under subsection (2), the director must, as soon as reasonably possible,

(a) advise the person of the reasons for the suspension, and

(b) provide the person with an opportunity to show the director why the suspension should be lifted.

(4) Subject to subsection (5), the director may, by notice delivered to a person, cancel the person's appointment or certificate

(a) if the director is satisfied that the person knowingly gave false information on an application for the appointment or certificate,

(b) if the person refuses or neglects to comply with

(i) a provision of this Act or the regulations,

(ii) a condition or limitation specified by the director on the appointment or certificate held by the person,

(iii) a provision of the agreement referred to in section 16 (2), 19 (2), 20 (2), or 21 (2), or

(RET) Sep 02/09 (iv) a requirement of the director to deposit a bond under section 59,

(ADD) Jan 01/10 (b.1) with respect to an appointment as a refiner collector, if the director is satisfied that the condition referred to in section 16 (2.1) (a) (ii) is not being met, or

(c) if authorized by the regulations.

(5) Before cancelling an appointment or a certificate under subsection (4), the director must

(a) give the person notice of the reasons for the proposed cancellation, and

(b) provide the person with an opportunity to show the director why the appointment or certificate should not be cancelled.

(6) Cancellation of an appointment or certificate under subsection (4) takes effect on the later of

(a) the date that notice of it is delivered to the person, and

(b) the date stated in the notice.

(7) If required by the regulations, the director must cancel a person's appointment or certificate in accordance with the regulations.

(8) If the director cancels a person's appointment or certificate under subsection (7) the director

(a) is not required to provide advance notice of the cancellation to the person, and

(b) must provide written reasons to the person.

(9) A suspension or cancellation of an appointment or certificate of a person under this section or section 24 does not relieve the person from any liability.

2008-40-23; 2009-14-25; 2009-14-26 (B.C. Reg. 292/2009).

Automatic suspension and cancellation

24. (1)

If the appointment of a person as a collector under the *Motor Fuel Tax Act* is suspended under that Act, the appointment of that person as collector under this Act is automatically suspended without notice for the same period as the suspension under the *Motor Fuel Tax Act*, if both appointments are in relation to the same substance.

(ADD) Jan 01/10 (1.1) If the appointment of a person as a collector under this Act or the *Motor Fuel Tax Act* is suspended under either Act, the appointment of that person as refiner collector under this Act is automatically suspended without notice for the same period as the suspension under this Act or the *Motor Fuel Tax Act*.

(2) If the appointment of a person as a collector under the *Motor Fuel Tax Act* is cancelled under that Act, the appointment of that person as collector under this Act is automatically cancelled without notice if both appointments are in relation to the same substance.

(ADD) Jan 01/10 (2.1) If the appointment of a person as a collector under this Act or the *Motor Fuel Tax Act* is cancelled under either Act, the appointment of that person as refiner collector under this Act is automatically cancelled without notice.

(REP) Jul 01/10 (3) and (4) *Repealed.* [2010-5-172]

(5) If a registered consumer certificate issued to a person under the *Motor Fuel Tax Act* is suspended under that Act, the registered consumer certificate issued to that person under this Act is automatically suspended without notice for the same period as the suspension under the *Motor Fuel Tax Act*, if both certificates are in relation to the same substance.

(6) If a registered consumer certificate issued to a person under the *Motor Fuel Tax Act* is cancelled under that Act, the registered consumer certificate issued to that person under this Act is automatically cancelled without notice, if both certificates are in relation to the same substance.

2008-40-24; 2009-14-27 (B.C. Reg. 292/2009); 2010-5-172.

Division 2 – Duties of Retail Dealers, Deputy Collectors and Collectors

Collection of tax on sale of fuel to a purchaser

25. (1) Subject to subsection (3) and the regulations, a retail dealer must collect the tax imposed by this Act at the time of selling fuel to a purchaser.

(2) A person who is a retail dealer must comply with the obligations of a retail dealer even if the person is also a collector or a registered consumer with respect to other fuel.

(3) If a retail dealer sells to a purchaser who is a registered consumer, registered air service or registered marine service fuel that is the type or subcategory of a type of fuel specified on the purchaser's certificate, the retail dealer is not required to collect tax from the purchaser.

2008-40-25.

Duties of retail dealers, deputy collectors and collectors

26. (1) Subject to sections 30, 31 and 32 and the regulations, a collector or deputy collector who sells fuel to a deputy collector or retail dealer must collect the tax from the deputy collector or retail dealer who bought the fuel.

(2) Subject to section 31 and the regulations, a deputy collector who buys fuel from a collector or other deputy collector must, on demand of the collector or the other deputy collector, remit the tax on the fuel collected from a retail dealer or another deputy collector to the person who made the demand.

(3) Subject to section 32 and the regulations, a retail dealer who buys fuel from a collector or deputy collector must, on demand of the collector or deputy collector, remit the tax on the fuel collected from a purchaser to the person who made the demand.

(4) A retail dealer or deputy collector who does not remit the tax collected in accordance with subsection (2) or (3) must remit the tax collected to the director at the prescribed time and in the prescribed manner.

(5) Despite section 38 and the regulations, any money received by a collector, deputy collector or retail dealer in respect of a sale of fuel, up to the full amount of the taxes owing, is deemed to be payment of the taxes owing by the purchaser under this Act.

2008-40-26.

Agent of the government

27. A person who sells fuel is deemed to be an agent of the government and as agent must levy and collect tax as required by this Act.

2008-40-27.

Division 3 – Collected Taxes

Remittance of tax to director

(RET) May 01/12 **28.** (1) A retail dealer of natural gas must remit the tax collected to the government at the prescribed time and in the prescribed manner.

(RET) May 01/12 (2) Subject to section 30, a collector must remit to the government all taxes collected by the collector under this Act at the prescribed time and in the prescribed manner.

(RET) May 01/12 (3) If a person collects an amount as if it were a tax imposed under this Act, the person must remit the amount collected to the government at the same time and in the same manner as tax collected under this Act.

(RET) May 01/12 (4) A person, other than a collector or deputy collector, who sells fuel to a retail dealer and receives money in respect of the tax payable on the fuel must immediately remit that money to the government.

(RET) May 01/12 (5) If a person collects an amount as if it were security under this Act and has not paid security under section 30, 31 or 32, the person must remit the amount collected to the government at the same time and in the same manner as security payable under section 30.

2008-40-28; 2009-14-23; 2010-2-62; 2012-8-12.

Tax collected deemed to be held in trust

29. If a person collects an amount of tax under this Act or collects an amount as if it were tax under this Act,

(a) the person is deemed to hold the amount in trust for the government and for the payment of the amount to the government in the manner and at the time required under this Act, and

(b) the amount collected is deemed to be held separate from and does not form a part of the person's money, assets or estate, whether or not the amount collected has in fact been kept separate and apart from either the person's own money or the assets of the estate of the person who collected the amount.

2008-40-29.

Division 4 – Security

Security from collector

(RET) May 01/12 **30.** (1) Subject to subsections (1.1), (3) and (4), a collector who, within British Columbia, sells a fuel for the first time after the fuel is manufactured in British Columbia or imported into British Columbia must pay, with respect to that fuel, security to the government in an amount equal to the tax that would be collectable if the fuel were sold to a purchaser at that time.

(RET) May 01/12 (1.1) Subject to subsections (3) and (4), a collector who, within British Columbia, sells fuel for the first time in a sale referred to in section 1.1 (5) is deemed to be making the first sale of the fuel for the purposes of subsection (1) of this section.

(RET) May 01/12 (2) The security referred to in subsection (1) must be paid to the government at the prescribed time and in the prescribed manner.

(RET) May 01/12 (3) For the purposes of subsections (1) and (1.1), a sale of fuel within British Columbia for the first time does not include a sale of a type or subcategory of a type of fuel by one refiner collector to another refiner collector, if both are appointed refiner collectors for the same type or subcategory of a type of fuel.

(RET) May 01/12 (4) A collector who sells fuel that the collector bought in the circumstances described in subsection (3) is deemed to be making the first sale of fuel for the purposes of subsection (1) or (1.1), as applicable, if the collector sells the fuel in circumstances other than those described in subsection (3).

(5) A collector who, as a retail dealer, sells

(a) fuel that is exempt from tax under section 14 (2) (c), (d) or (e),

(b) fuel to a purchaser who is not liable to pay tax on that purchase, or

(c) to a person who is a registered air service or registered marine service, fuel that is the type or subcategory of the type specified on that person's registered air service certificate or registered marine service certificate

is exempt from the requirement to pay security under subsection (1) in respect of that fuel.

(6) On application by a collector, the director may, in writing and on conditions the director considers appropriate, exempt the collector from the requirements of subsection (1) in respect of a fuel if the collector satisfies the director that the fuel

(a) is to be sold to a purchaser who is not liable to pay tax on that purchase,

(b) is not to be sold to a purchaser, or

(c) is to be sold to a person who is a registered air service or registered marine service and the fuel is the type or subcategory of a type of fuel specified on the certificate held by that person.

(7) An amount that is paid by a collector as security under subsection (1) may, unless the amount is refunded under this Act, be retained by the government in

satisfaction of the collector's obligation to collect and remit the tax imposed by this Act on a purchaser of fuel.

2008-40-30; 2009-14-28 (B.C. Reg. 292/2009); 2012-8-13.

Security from deputy collector

31. (1) A deputy collector who buys fuel from a collector or another deputy collector must pay, as security to the collector or the other deputy collector, an amount equal to the tax that would be collectable if that fuel were sold to a purchaser at that time.

(2) On application by a deputy collector, the director may, in writing and on conditions the director considers appropriate, exempt the deputy collector from the requirements of subsection (1) in respect of a fuel if the deputy collector satisfies the director that the fuel

(a) is to be sold to a purchaser who is not liable to pay tax on that purchase,

(b) is not to be sold to a purchaser, or

(c) is to be sold to a person who is a registered air service or registered marine service and the fuel is the type or subcategory of a type of fuel specified on the certificate held by that person.

(3) A collector or deputy collector who, in respect of fuel, has paid an amount as security under section 30 (1) or subsection (1) of this section may retain any amount received under subsection (1) of this section instead of collecting the tax imposed on the purchaser in respect of that fuel.

(4) If, under subsection (1), a deputy collector pays an amount as security in respect of fuel and that amount is retained under subsection (3), the deputy collector is, subject to section 35, deemed to have satisfied the deputy collector's obligation to remit the tax that is imposed by this Act on the purchaser of the fuel.

2008-40-31.

Security from retail dealer

32. (1) If a retail dealer buys fuel from a collector or deputy collector, the retail dealer must pay, as security to the collector or deputy collector, an amount equal to the tax that would be collectable if that fuel were sold to a purchaser at that time.

(2) On application by a retail dealer, the director may, in writing and on conditions the director considers appropriate, exempt the retail dealer from the requirements of subsection (1) in respect of a fuel if the retail dealer satisfies the director that the fuel

(a) is to be sold to a purchaser who is not liable to pay tax on that purchase,

(b) is not to be sold to a purchaser, or

(c) is to be sold to a person who is a registered air service or registered marine service and the fuel is the type or subcategory of a type of fuel specified on the certificate held by that person.

(3) A collector or deputy collector who, in respect of fuel, has paid an amount as security under section 30 (1) or 31 (1) may retain any amount received under subsection (1) of this section instead of collecting the tax imposed on the purchaser in respect of that fuel.

(4) If, under subsection (1), a retail dealer pays an amount as security in respect of fuel and that amount is retained under subsection (3), the retail dealer is, subject

to section 35, deemed to have satisfied the retail dealer's obligation to remit the tax that is imposed by this Act on the purchaser of the fuel.

2008-40-32.

Exemption from security

(AM) Jul 01/10 **33.** (1) A person who buys natural gas for resale must not pay security on that natural gas.

(AM) Jul 01/10 (2) A person who sells natural gas must not collect security on that natural gas.

2008-40-33; 2009-14-23; 2010-2-62.

Division 5 – Change in the Rate of Tax

Change in tax rate and collection of tax

34. (1) If a scheduled rate change for a fuel takes effect between the time a retail dealer sells the fuel to a purchaser and the time the purchaser receives delivery of the fuel, the retail dealer must collect tax on that fuel at the rate that applies at the time the purchaser receives delivery of the fuel.

(REP) May 14/12 (2) *Repealed.* [2012-8-10]

2008-40-34; 2012-8-10.

Change in tax rate and payment of security

35. (1) If a deputy collector or retail dealer who owns fuel at the time the rate of tax for the fuel changes, was required to pay security on the fuel before the tax rate changed, the deputy collector or retail dealer must provide the director with an inventory of that fuel, in accordance with the instructions of the director.

(2) For the purposes of subsection (1), if there is a scheduled rate change for a fuel between the time a retail dealer enters into an agreement to sell that fuel to a purchaser and the time the purchaser receives delivery of the fuel, the retail dealer is deemed to own the fuel on the date of the scheduled rate change.

(REP) May 14/12 (3) *Repealed.* [2012-8-10]

(4) For the purposes of subsection (1), a deputy collector or retail dealer, as the case may be, is deemed to own a fuel on the date the tax rate for the fuel changes, if

(a) the deputy collector or retail dealer has entered into an agreement to buy the fuel and the agreement provides that the deputy collector or retail dealer owns the fuel on the date the tax rate changes,

(b) the deputy collector or the retail dealer has not received delivery of the fuel before the date the tax rate changes, and

(c) the deputy collector or the retail dealer has not entered into an agreement with another person that provides that the other person owns the fuel on the date of the tax rate change.

(5) Subject to the regulations, the director may pay a deputy collector or retail dealer who provided an inventory under subsection (1) an allowance in an amount determined under the regulations.

(6) Subject to the regulations, if the rate of tax increases, a deputy collector or retail dealer who is required to provide an inventory under subsection (1) must pay to

the director the additional amount of security determined under subsection (7), within the time required by the director.

(7) The amount of additional security payable is the difference between

(a) an amount equal to the tax that would be collectable for the fuel that was required to be included in the inventory, if that fuel were sold to a purchaser immediately after the increase in the rate of tax, and

(b) the amount the deputy collector or retail dealer paid as security in respect of the fuel.

(8) An amount that is paid by a deputy collector or retail dealer as security under subsection (6) may, unless the amount is refunded under this Act, be retained by the government in satisfaction of the deputy collector's or retail dealer's obligation to collect and remit the tax imposed by this Act on a purchaser of the fuel.

(9) Subject to subsection (11), if the rate of tax decreases, a deputy collector or retail dealer who was required to provide an inventory under subsection (1) may apply to the director for a refund of the amount of security determined under subsection (10).

(10) The refund payable under subsection (9) equals the portion of the security the deputy collector or retail dealer paid that exceeds the amount of tax that would be collectable for the fuel required to be included in the inventory, if that fuel were sold to a purchaser immediately after the decrease in the rate of tax.

(11) The director must pay to a person a refund under subsection (9), from the consolidated revenue fund, if the director is satisfied that the person has not received and is not to receive a refund of the security from any person with respect to the fuel.

2008-40-35; 2012-8-10.

PART 6 – Refunds

Refund of taxes paid or remitted

36. (1) If the director is satisfied that an amount has been paid as tax in circumstances where there was no legal obligation to pay the amount as tax, the director must refund, from the consolidated revenue fund, that amount to the person entitled to it.

(RET) May 01/12 (2) If the director is satisfied that a collector has remitted to the government an amount as collected taxes that the collector neither collected nor was required to collect under this Act, the government must refund the amount to the collector from the consolidated revenue fund.

(RET) May 01/12 (2.1) Subsection (2) applies to a person who sells fuel in a sale to which section 1.1 (2) (a) to (c) applies as if the person were a collector.

(RET) May 01/12 (3) If the director is satisfied that a retail dealer of natural gas has remitted to the government an amount as collected taxes that the retail dealer neither collected nor was required to collect under this Act, the director must refund the amount to the retail dealer from the consolidated revenue fund.

2008-40-36; 2011-9-9; 2012-8-14.

Refund of security

(RET) May 01/12 **37.** (1) If the director is satisfied that a collector has paid an amount as security to the government in circumstances where there was no legal obligation to pay the amount as security, the director must refund, from the consolidated revenue fund, that amount to the collector.

(RET) May 01/12 (1.1) Subsection (1) applies to a person who sells fuel in a sale to which section 1.1 (2) (a) to (c) applies as if the person were a collector.

(2) If the director is satisfied that a person who is a collector, deputy collector or retail dealer has paid security on fuel that

(a) was sold to a purchaser who was not liable to pay tax on that purchase,

(b) was not sold and is not to be sold to a purchaser, or

(c) was sold to a registered air service or registered marine service, and was the type or subcategory of a type of fuel specified on the registered air service's or registered marine service's certificate,

the director must pay, from the consolidated revenue fund, to the person the difference between the amount of security the person paid on the fuel and the amount of security or tax the person received for the fuel.

(3) A deputy collector or retail dealer who has received an amount under subsection (2) for a fuel is not entitled to, and must not request, a refund of security from the person who sold the fuel to the deputy collector or retail dealer.

(4) If a vendor, wholesale dealer or retail dealer receives an amount under subsection (2) for a fuel and subsequently receives security or collects tax or an amount as if it were tax on the fuel with respect to which the amount was paid, the vendor, wholesale dealer or retail dealer must pay to the government the amount received or collected on the fuel at the prescribed time and in the prescribed manner.

2008-40-37; 2012-8-15.

Refund or deduction for bad debts

38. (1) The director may, in accordance with the regulations, refund from the consolidated revenue fund to a collector, deputy collector or retail dealer who sells fuel, a portion, determined in the prescribed manner, of the amount remitted or paid to the government in respect of taxes or security payable on that fuel under this Act.

(2) The director may pay a refund under subsection (1) if

(a) the collector, deputy collector or retail dealer, in accordance with this Act,

(i) remits the tax required to be levied and collected under this Act, or

(ii) pays the security required to be paid under this Act

on the fuel referred to in subsection (1),

(b) the person buying the fuel subsequently fails to pay to the collector, deputy collector or retail dealer the full amount of

(i) the consideration and tax payable on that sale, or

(ii) the consideration and security required to be paid under this Act, and

(c) the collector, deputy collector or retail dealer writes off as unrealizable or uncollectable the amount owing by the person buying the fuel.

(3) A collector may, in the prescribed manner, deduct the amount of the refund payable to the collector under this section from the amount of taxes or security that the collector is required to remit or pay under this Act.

(4) If a collector who has obtained a refund under subsection (1) or has made a deduction under subsection (3) recovers some or all of the amount referred to in subsection (2) (c) with respect to which the refund was paid or the deduction was made, the collector must add an amount, determined in the prescribed manner, to the tax to be remitted or security to be paid by the collector under this Act with respect to the reporting period in which the recovery was made.

(AM) Jul 01/10

(5) Subsections (3) and (4) apply to a retail dealer of natural gas as if the retail dealer were a collector.

(6) Subject to subsection (7), if a deputy collector or retail dealer who is not a collector and who has obtained a refund under subsection (1) recovers some or all of the amount referred to in subsection (2) (c) with respect to which the refund was paid, the deputy collector or retail dealer must, promptly after that recovery, pay to the government an amount determined in the prescribed manner.

(AM) Jul 01/10

(7) Subsection (6) does not apply to a retail dealer of natural gas.

2008-40-38; 2009-14-23; 2010-2-62.

Refund for interjurisdictional air or marine travel or transport

39. If the director is satisfied that an amount has been paid as tax for fuel that was used for interjurisdictional air or marine travel or transport in the prescribed circumstances and in accordance with the prescribed rules, the director must pay a refund, from the consolidated revenue fund, in accordance with the regulations.

2008-40-39.

Refunds authorized or required under the regulations

40. The director

(a) if authorized by the regulations, may pay from the consolidated revenue fund a refund of all or a portion of tax or security paid by an applicant for a refund, and

(b) if required by the regulations, must pay from the consolidated revenue fund a refund of all or a portion of tax or security paid by an applicant for a refund.

2008-40-40.

Claim for refund

41. (1) To claim a refund under this Act, a person must

(a) submit to the director a written application signed by the person who paid the amount claimed, and

(b) provide sufficient evidence to satisfy the director that the person who paid the amount is entitled to the refund.

(2) For the purposes of subsection (1) (a), if the person who paid the amount claimed is a corporation, the application must be signed by a board member or authorized employee of the corporation.

(3) A person who is required to file a return for tax or security under this Act may

(a) instead of submitting a written application under subsection (1) (a), submit, as part of the return, a claim for a refund for the reporting period to which the return relates, and

(b) deduct the amount of the refund claimed from the amount of tax or security required to be remitted or paid by the person.

2008-40-41.

Refund limits

42. (1) Despite section 16 of the *Financial Administration Act*,

(a) a refund of less than $10 must not be made, and

(b) a refund must not be made on a claim for a refund made more than 4 years after the date on which the amount claimed was paid.

(2) Despite the *Limitation Act*, an action for a refund must not be brought more than 4 years after the date on which the amount claimed was paid.

2008-40-42.

PART 7 – Tax Collection Administration

Inspection and audit powers

43. (1) Except as limited by subsection (4), to determine whether, with respect to a fuel, this Act and the regulations are being or have been complied with, the director may enter at any reasonable time the business premises occupied by a person, the premises where the records of the person are kept or a site at which fuel is manufactured, sold, stored or used, in order to do any of the following:

(a) inspect, audit and examine books of account or other records;

(b) inspect, ascertain the quantities of, and take samples of fuel, including, without limitation, fuel in fuel tanks of motor vehicles, aircraft or ships or fuel tanks mounted on motor vehicles, aircraft or ships.

(2) Except as limited by subsection (4), to determine whether, with respect to combustibles, this Act and the regulations are being or have been complied with, the director may enter at any reasonable time the business premises occupied by a person, the premises where the records of the person are kept or a site at which combustibles are burned for the purpose of producing energy or heat, in order to do any of the following:

(a) inspect, audit and examine books of account or other records;

(b) inspect, ascertain the quantities of, and take samples of combustibles.

(3) A person occupying premises or a site referred to in subsection (1) or (2) must

(a) produce all books of account or other records as may be required by the director, and

(b) answer all questions of the director regarding the matters referred to in that subsection.

(4) The power to enter a place under subsection (1) or (2) must not be used to enter a dwelling occupied as a residence without the consent of the occupier except under the authority of a warrant under subsection (5).

(5) On being satisfied by evidence on oath that there are in a place records or other things for which there are reasonable grounds to believe that they are relevant to the matters referred to in subsection (1) or (2), a justice may issue a warrant authorizing a person named in the warrant to enter the place in accordance with the warrant in order to exercise the powers referred to in subsection (1) (a) and (b) or (2) (a) and (b).

(6) When required by the director, a person must provide to the director all books of account and other records that the director considers necessary to determine whether this Act and the regulations are being or have been complied with.

(7) A person must not

(a) hinder, molest or interfere with a person doing anything that the person is authorized to do under this section, or

(b) prevent or attempt to prevent a person from doing anything that the person is authorized to do under this section.

2008-40-43.

Estimate of unremitted tax or unpaid security

44. (1) If a person who is required to file a return for tax or security under this Act fails to file a return or pay or remit tax or pay security as required under this Act, or if the records of a person do not substantiate a return of the person for tax or security, the director may make an estimate of the amount of the

(a) tax that was collected or is payable by the person and for which the person has not accounted, or

(b) security that is payable by the person and for which the person has not accounted.

(2) The amount estimated under subsection (1) is deemed to be the amount of tax collected or payable or security payable by the person in respect of whom the estimate is made.

(3) In making an estimate under this section the director must not consider or include a period longer than 4 years before the date of the first notice of assessment.

(4) Despite subsection (3), the director may enter into a written agreement with a person in which the person waives subsection (3) and allows the director, in making an estimate under this section, to consider and include any period specified in the agreement.

2008-40-44.

Assessment of tax or security

45. (1) If it appears from an inspection, audit or examination or from other information available to the director that taxes or security have not been paid or taxes have not been remitted as required under this Act, the director must

(a) calculate, in the manner and by the procedure the director considers appropriate, the tax or security not paid or tax not remitted, and

(b) assess the person liable to pay the tax or security or liable to remit the tax.

(2) If it appears from an inspection, audit or examination or from other information available to the director that a person has received a refund of an amount under this Act or has deducted an amount under section 41 (3) that was in excess of the refund amount that was due to the person, the director must make an assessment against the person in an amount equal to the excess amount refunded or deducted plus interest calculated at the rate and in the manner prescribed.

(3) In making an assessment under this section the director must not consider or include a period longer than 4 years before the date of the first notice of assessment.

(4) Despite subsection (3), in making an assessment under this section the director may consider and include any period, if the assessment relates to a contravention, of this Act or the regulations, involving wilful default or fraud.

(5) Despite subsection (3), the director may enter into a written agreement with a person in which the person waives subsection (3) and allows the director, in making an assessment under this section, to consider and include any period specified in the agreement.

2008-40-45.

Failure to collect taxes

46. (1) Subject to subsection (2), if it appears from an inspection, audit or examination or from other information available to the director that an amount of tax imposed under this Act should have been but was not collected, the director must impose on the person who should have collected the tax a penalty equal to the amount of the tax that should have been collected, plus interest calculated at the rate and in the manner prescribed.

(2) If a person is assessed for failing to pay security under section 45, the director must not impose a penalty on the person under subsection (1) of this section in respect of the fuel that gave rise to the assessment under section 45.

(3) A person who has paid an amount imposed under subsection (1) may, in a court of competent jurisdiction, sue the person who was liable to pay the tax in order to recover the amount imposed under subsection (1), and any amount recovered in the action may be retained by the plaintiff as compensation for the amount paid under subsection (1).

(4) In imposing a penalty under this section the director must not consider or include a period longer than 4 years before the date of the first notice of assessment.

(5) Despite subsection (4), in imposing a penalty under this section the director may consider and include any period, if the penalty is imposed as a result of a contravention, of this Act or the regulations, involving wilful default or fraud.

(6) Despite subsection (4), the director may enter into a written agreement with a person in which the person waives subsection (4) and allows the director, in imposing a penalty under this section, to consider and include any period specified in the agreement.

2008-40-46.

Penalty for failure to remit or pay taxes or security

47. (1) In addition to any other penalty, the director may do any of the following:

(a) if the director is satisfied that a person who collected tax or received security in respect of a fuel wilfully failed to remit the tax or pay security on the fuel to the government as required under this Act, impose on the person a penalty equal to 100% of the amount not remitted or paid;

(b) in any case other than a case referred to in paragraph (a), if the director is satisfied that a person evaded the payment of tax or security to the government by wilfully making a false or deceptive statement or by wilful default or fraud, impose on the person a penalty equal to 25% of the amount evaded;

(c) in any case other than a case referred to in paragraph (a) or (b), if the director is satisfied that a person failed to remit or pay any tax or security to the government as required under this Act, impose on the person a penalty equal to 10% of the amount not remitted or paid.

(RET) Mar 03/10 (2) If the director is satisfied that a vendor sold fuel contrary to section 15, the director must impose on the vendor a penalty equal to the security that the vendor would have been required to pay if the vendor, at the time of the sale, had been a collector.

(RET) Mar 03/10 (3) If the director is satisfied that a vendor wilfully sold fuel contrary to section 15, the director may impose on the vendor, in addition to any other penalty, a penalty equal to the amount of security that the vendor would have been required to pay if the vendor, at the time of the sale, had been a collector who was not exempt from the requirement to pay security under section 30.

2008-40-47; 2010-2-63.

Board member's liability

48. (1) Subject to this section, if a corporation has failed to collect or remit taxes, or to pay an amount of security as required under this Act, a board member of that corporation is jointly and severally liable with the corporation to pay an amount equal to

(a) the taxes that the corporation failed to collect or remit during the term of the board member, including penalties and interest on that amount, and

(b) the security that the corporation failed to pay during the term of the board member, including penalties and interest on that amount.

(2) A board member is not liable under subsection (1) unless one of the following has occurred:

(a) a certificate has been filed under section 61 with respect to the amount the corporation is liable to pay under this Act;

(b) the corporation has been dissolved or has commenced liquidation or dissolution proceedings in any jurisdiction;

(c) the corporation has, under the *Bankruptcy and Insolvency Act* (Canada),

(i) made an assignment in bankruptcy,

(ii) filed a notice of intention to make a proposal with the official receiver, or

(iii) made a proposal under Division 1 of Part III of that Act;

(d) a receiving order has been made against the corporation under the *Bankruptcy and Insolvency Act* (Canada);

(e) the corporation has obtained a court order granting a stay of proceedings under section 11 (3) of the *Companies' Creditors Arrangement Act* (Canada);

(f) the corporation has been or is subject in any jurisdiction to a proceeding of a similar nature to a proceeding referred to in paragraphs (c) to (e).

(3) A board member is not liable under subsection (1) if the board member exercised the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances to prevent the corporation's failure to collect or remit taxes or to pay security as required under this Act.

2008-40-48.

Refunds when joint and several liability

49. (1) Despite sections 36 (2) and 37, or any regulation that requires the payment of a refund of amounts collected or security to a corporation, if the director is satisfied that the total of the amount paid by one or more board members who are jointly and severally liable with the corporation under section 48 and the amount, if any, paid by the corporation exceeds the amount owed by the corporation under this Act for the period that the board members, who made the payments, were jointly and severally liable with the corporation, the director must pay a refund from the consolidated revenue fund in accordance with the following:

(a) if only one board member paid all or part of the amount for which one or more board members and the corporation were jointly and severally liable under section 48 (1), refund to the board member the amount of the excess, up to the amount paid by the board member;

(b) if 2 or more board members paid the amount or a part of the amount for which board members and the corporation were jointly and severally liable under section 48, refund to the board members the amount of the excess divided proportionately between the board members, up to the amount paid by each board member;

(c)

after making the payment under paragraph (a) or (b), refund to the corporation any remaining amount of the excess, up to the amount paid by the corporation.

(2) A refund under subsection (1) (b) must be based on the ratio of the amounts paid by the board members who are jointly and severally liable under section 48 (1) for the applicable period of the refund.

(3) A refund may be paid under subsection (1) only to a board member or corporation who has applied for a refund.

2008-40-49.

Deemed board member

50. (1) If the director has reason to believe that a person who was not a member of the board of directors of a corporation performed some or all of the functions of a member of the board of directors of the corporation, the director may request the person and the corporation to provide to the director the records and information required by the director to confirm or rebut that belief.

(2) Subject to subsection (3), the director may decide that a person performed some or all of the functions of a member of the board of directors of a corporation if

(a) the person or the corporation that has been requested to provide records or information to the director under subsection (1) fails or refuses to comply with the request within a period of time considered by the director to be reasonable in the circumstances, or

(b) the records or information provided to the director under this section confirm that the person performed some or all of the functions of a member of the board of directors of the corporation.

(3) The director must not decide under subsection (2) (b) that a person performed some or all of the functions of a member of the board of directors of a corporation if the decision is based solely on

(a) the person participating in the corporation's management under the direction or control of a shareholder, one or more members of the board of directors or a senior officer of the corporation,

(b) the person being a lawyer, accountant or other professional whose primary participation in the management of the corporation was the provision of professional services to the corporation,

(c) the corporation being bankrupt and the person being a trustee in bankruptcy who participates in the management of the corporation or exercises control over its property, rights and interests primarily for the purposes of the administration of the bankrupt's estate, or

(d) the person being a receiver, receiver manager or secured creditor who participates in the management of the corporation or exercises control over any of its property, rights and interests primarily for the purposes of enforcing a debt obligation of the corporation.

(4) If the director decides under subsection (2) that a person performed some or all of the functions of a member of the board of directors of a corporation, the person is deemed a board member of the corporation for the purposes of this Act for a term that equals the period the person performed those functions.

(5) Immediately after the director makes a decision under subsection (2), the director must notify in writing the person to whom the decision relates and the corporation of this decision.

2008-40-50.

Notice of assessment

51. (1) On making an estimate or assessment under section 44, 45 or 52 or imposing a penalty under section 46 or 47, the director must issue a notice of assessment to the person liable to pay the amount estimated, assessed or imposed.

(2) Evidence that a notice of assessment under subsection (1) has been issued is proof, in the absence of evidence to the contrary, that the amount estimated, assessed or imposed under this Act is due and owing, and the onus of proving otherwise is on the person liable to pay the amount estimated, assessed or imposed.

(3) Subject to being amended, changed or varied on appeal or by reassessment, an estimate, assessment or penalty made or imposed under this Act is valid and binding despite any error, defect or omission in the estimate, assessment or penalty or in procedure.

2008-40-51.

Assessment against board member

52. (1) If the director decides that a board member is jointly and severally liable for an amount under section 48, the director may assess the board member for

(a) the amount assessed under section 45 or 46 or both against the corporation for the corporation's failure to collect or remit taxes or pay security or both as required during the term of the board member, including penalties and interest on that amount, and

(b) the amount estimated under section 44

(i) as the tax the corporation collected, or

(ii) as the security payable by the corporation

during the term of the board member, including penalties and interest on that amount.

(2) The director must not make an assessment under subsection (1) in respect of the liability of a board member under section 48 if

(a) the person is no longer a board member of that corporation, and

(b) it is more than 2 years after the last date that the person was a board member of that corporation.

2008-40-52.

Certificate required for sales in bulk

53. (1) In this section, **"sale in bulk"** means

(a) a sale of fuel out of the usual course of business of a vendor, wholesale dealer or retail dealer,

(b) a sale of substantially all the fuel of a vendor, wholesale dealer or retail dealer, or

(c) a sale of an interest in the business of a vendor, wholesale dealer or retail dealer.

(2) A vendor, wholesale dealer or retail dealer must not dispose of fuel through a sale in bulk without first obtaining a certificate in duplicate from the director that all

amounts owing under this Act by that person have been paid.

(3) A person buying fuel through a sale in bulk must obtain from the person selling the fuel the duplicate copy of the certificate obtained under subsection (2).

(4) If the person buying fuel fails to obtain the duplicate copy as required by subsection (3), that person is responsible for payment to the director of all amounts owing under this Act by the person selling the fuel.

2008-40-53.

Irregularities

54. An estimate or assessment made, or a penalty imposed, by the director under this Act must not be varied or disallowed by a court because of an irregularity, informality, omission or error on the part of a person in the observation of any directory provision up to the date of the issuing of the notice of assessment.

2008-40-54.

Interest on amount payable

55. (1) In addition to any amount payable under this Act, interest, calculated at the rate and in the manner prescribed, is payable on the amount due from the time it was due or a later prescribed time.

(2) The director may assess at any time interest payable under subsection (1).

2008-40-55.

PART 8 – Appeals

Appeal to minister

56. (1) An appeal to the minister lies from a decision of the director about any of the following:

(RET) Feb 16/11 (a) a refund of tax paid or remitted or security paid under this Act;

(AM) Jan 01/10 (b) refusal to appoint a collector or refiner collector or to issue a registration certificate, registered consumer certificate, registered air service certificate or registered marine service certificate;

(AM) Jan 01/10 (c) a cancellation of an appointment of a collector or refiner collector or a registration certificate, registered consumer certificate, registered air service certificate or registered marine certificate under section 23 (4) (a), (b) or (b.1);

(d) an estimate, assessment or imposition of a penalty under sections 44, 45, 46, 47, 52 or 55;

(e) a decision of the director under section 50 (2) (b) or 64 (11) (b);

(f) a refusal under section 30 (6), 31 (2) or 32 (2) to exempt a collector, deputy collector or retail dealer from the requirement to pay security.

(AM) Jan 01/10 (2) If the director cancels a collector's or refiner collector's appointment or cancels a registration certificate, registered consumer certificate, registered air service certificate or registered marine service certificate under section 23 (4) (c), an appeal lies from the decision of the director to the minister, unless an appeal is not permitted under the regulations.

(3) Written notice of the appeal must be served on the minister within 90 days after the date on the director's notice of the decision.

(4) The appellant must set out in the notice of appeal a statement of all material facts and the reasons in support of the appeal.

(5) On receiving the notice of appeal, the minister must

(a) consider the matter,

(b) subject to subsections (6) and (7), affirm, amend or change the assessment, decision, estimate, amount imposed or the nature of the assessment, and

(c) promptly notify the appellant in writing of the result of the appeal.

(6) If an appeal relates to a matter referred to in subsection (1) (b), the minister may

(AM) Jan 15/10 (a) affirm the decision of the director, or

(b) direct the director to

(AM) Jan 01/10 (i) appoint the appellant as a collector or refiner collector subject to the conditions and limitations that the director specifies, or

(ii) issue a certificate of the type that was the subject of the appeal to the appellant, subject to the conditions and limitations that the director specifies.

(7) If an appeal relates to a matter referred to in subsection (1) (f), the minister may

(a) affirm the decision of the director, or

(b) direct the director to exempt the appellant from the requirement to pay security, subject to the conditions that the director specifies.

2008-40-56; 2009-14-29 (B.C. Reg. 292/2009); B.C. Reg. 18/2010, Sch. 8; 2011-9-10.

Appeal to court

(AM) Jul 01/10 (SUB) Jul 01/10

57. (1) A decision of the minister under section 56 may be appealed to the Supreme Court by way of a petition proceeding.

(2) The Supreme Court Civil Rules relating to petition proceedings apply to appeals under this section, but Rule 18-3 of those rules does not apply.

(3) A petition must be filed in the court registry within 90 days after the date on the minister's notification of decision.

(4) Within 14 days after the filing of the petition under subsection (3), it must be served on the government in accordance with section 8 of the *Crown Proceeding Act* and the government must be designated "Her Majesty the Queen in right of the Province of British Columbia".

(5) An appeal under this section is a new hearing that is not limited to the evidence and issues that were before the minister.

(6) The court may dismiss the appeal, allow the appeal, vary the decision from which the appeal is made or refer the decision back to the director for reconsideration.

(7) An appeal lies from a decision of the court to the Court of Appeal with leave of a justice of the Court of Appeal.

2008-40-57; 2010-6-91,93 (Schs 1&3).

Pending appeal not to affect tax collection

58. (1) Neither the giving of a notice of appeal by a person nor a delay in the hearing of an appeal

(a) affects the date of payment, the interest or penalties or any liability for payment under this Act in respect of the amount estimated, assessed or imposed that is the subject matter of the appeal, or

(b) delays the collection of the amount estimated, assessed or imposed.

(2) If the director's or the minister's decision is set aside or the amount of an estimate or assessment or an amount imposed is reduced on appeal, the director must refund from the consolidated revenue fund to the appellant

(a) the amount or excess amount paid, and

(b) any additional interest or penalty imposed and paid.

2008-40-58.

PART 9 – Recovery of Amounts Owing

Collection bond

(AM) Jul 01/10 **59.** (1) The director may require a collector, the holder of a motive fuel user permit, a retail dealer of natural gas, a registered consumer, registered air service or registered marine service to deposit with the director a bond, by way of cash or other security, satisfactory to the director.

(2) The amount of the bond is to be determined by the director, but it must not be greater than 6 times the estimated amount of the monthly tax collection or payment, determined in a manner the director considers appropriate.

(AM) Jul 01/10 (3) The amount of a bond under subsection (2) for a retail dealer of natural gas must not be greater than 6 times the estimated amount of the monthly tax collection or payment related to natural gas, determined in a manner the director considers appropriate.

(4) If a person, who has deposited a bond under subsection (1), fails to collect, remit or pay tax or pay security in accordance with this Act, the director, after giving written notice to the person who is bonded, may apply all or part of the bond to the amount that should have been collected, remitted or paid by the person, and to the interest due on that amount under this Act.

2008-40-59; 2009-14-23; 2010-2-62.

Court action to recover amount owing

60. An amount owing to the government under this Act may be recovered by action in a court.

2008-40-6.

Summary proceedings without action

61. (1) If a person fails to pay or remit an amount owing to the government under this Act, the director may issue a certificate specifying the amount owed and the name of the person who owes it.

(2) The director may file with the Supreme Court a certificate issued under subsection (1).

(3) A certificate filed under subsection (2) has the same effect and is enforceable in the same manner as a judgment of the court in favour of the government for the recovery of a debt in the amount specified in the certificate.

2008-40-61.

Alternate remedies

62. (1) Remedies available to the government for the recovery of an amount owing under this Act may be exercised separately, concurrently or cumulatively.

(2) The liability of a person for the payment of an amount owing under this Act is not affected by a fine or penalty imposed on or paid by the person for contravention of this Act.

2008-40-62.

Attachment of funds

63. (1) In this section, **"taxpayer"** means any person who is liable to pay or remit an amount under this Act.

(2) If the director knows or suspects that a person is or is about to become indebted or liable to make a payment to a taxpayer, the director may demand that that person pay all or part of the money otherwise payable to the taxpayer to the government on account of the taxpayer's liability under this Act.

(3) Without limiting subsection (2), if the director knows or suspects that a person is about to advance money to, or make a payment on behalf of a taxpayer, or make a payment in respect of a negotiable instrument issued by a taxpayer, the director may demand that that person pay to the government on account of the taxpayer's liability under this Act the money that would otherwise be advanced or paid.

(4) A demand under this section may be served by

(a) personal service,

(b) registered mail, or

(c) electronic mail or fax.

(5) If, under this section the director demands that a person pay to the government, on account of the liability under this Act of a taxpayer, money otherwise payable by that person to the taxpayer as interest, rent, remuneration, a dividend, an annuity or other periodic payment, the demand

(a) is applicable to all of those payments to be made by the person to the taxpayer until the liability under this Act is satisfied, and

(b) operates to require payments to the government out of each payment of the amount stipulated by the director in the demand.

(6) Money or a beneficial interest in money in a savings institution

(a) on deposit to the credit of a taxpayer at the time a demand is served, or

(b) deposited to the credit of a taxpayer after a demand is served,

is money for which the savings institution is indebted to the taxpayer within the meaning of this section, but money on deposit or deposited to the credit of a taxpayer as described in paragraph (a) or (b) does not include money on deposit or deposited to the credit of the taxpayer in the taxpayer's capacity as a trustee.

(7) A demand under this section continues in effect until

(a) the demand is satisfied, or

(b) 90 days after the demand is served,

whichever is earlier.

(8) Despite subsection (7), if a demand is made in respect of a periodic payment referred to in subsection (5), the demand continues in effect until it is satisfied unless no periodic payment is made or is liable to be made within 90 days after the demand is served, in which case the demand ceases to have effect at the end of that period.

(9) Money demanded from a person by the director under this section becomes payable

(a) as soon as the person is served with the demand, if the person is indebted or liable to make a payment to the taxpayer at the time the demand is served, or

(b) as soon as the person becomes indebted or liable to make a payment to the taxpayer, in any other case.

(10) A person who fails to comply with a demand under subsection (2) or (5) is liable to pay to the government an amount equal to the amount that the person was required to pay under subsection (2) or (5).

(11) A person who fails to comply with a demand under subsection (3) is liable to pay to the government an amount equal to the lesser of

(a) the aggregate of the money advanced or paid, and

(b) the amount that the person was required to pay under subsection (3).

(12) The receipt of the director for money paid under this section is a sufficient discharge of the original liability to the extent of the payment.

(13) Money paid by any person to the government in compliance with a demand under this section is deemed to have been paid by that person to the taxpayer.

2008-40-63.

Lien

64. (1) In this section:

"associated corporation" means a corporation that

(a) is associated with another corporation within the meaning of section 256 of the *Income Tax Act* (Canada), or

(b) is determined under subsection (11) to be associated with another corporation for the purposes of this section;

"collateral" has the same meaning as in the *Personal Property Security Act*;

"financing statement" has the same meaning as in the *Miscellaneous Registrations Act, 1992*;

"inventory" has the same meaning as in the *Personal Property Security Act*;

"personal property registry" means the registry under the *Personal Property Security Act*;

"proceeds" has the same meaning as in the *Personal Property Security Act*;

"property" , when referring to the property of an associated corporation or a related individual, means property that is used in, or in conjunction with, the business in respect of which the amount referred to in subsection (2) is required to be collected, remitted or paid;

"purchase money security interest" has the same meaning as in the *Personal Property Security Act*;

"related individual" has the same meaning as in the *Property Transfer Tax Act*;

"secured party" has the same meaning as in the *Personal Property Security Act*;

"security interest" has the same meaning as in the *Personal Property Security Act*.

(2) If a person is required to pay or remit an amount under this Act and does not pay or remit that amount, the director may register a lien

(a) against the real property of

(i) the person,

(ii) an associated corporation of the person, or

(iii) a related individual of the person

by registering a certificate of lien in the prescribed form in the appropriate land title office in the same manner that a charge is registered under the *Land Title Act*, and

(b) against the personal property of

(i) the person,

(ii) an associated corporation of the person, or

(iii) a related individual of the person by registering a financing statement in the personal property registry.

(3) On registration of a certificate of lien against the real property of a person under subsection (2) (a), a lien is created on the real property against which the lien is registered for the amount remaining unpaid and any related penalty or interest on that amount.

(4) On registration of a lien against the personal property of a person under subsection (2) (b), a lien is created on the personal property in which the person has a legal or equitable interest, including, in the case of a lien referred to in paragraph (a) of this subsection, any portion of the property that is subject to a prior lien or security interest, for the following:

(a) if the lien relates to

(i) taxes that were required to be collected before registration,

(ii) taxes that were collected but not remitted before registration, or

(iii) security that was required to be paid before registration,

the amount of those taxes remaining uncollected or unremitted, the security remaining unpaid and any related interest and penalty on those taxes and that security;

(b) if the lien relates to taxes that are to be paid before registration, the amount of those taxes remaining unpaid, and any related interest and penalty on those taxes.

(5) Subject to subsections (6) and (7), a lien, other than a lien referred to in subsection (4) (b), that is registered under subsection (2) (b) against personal property

(a) is not limited to the equity that the person against whose personal property the lien is registered has in the personal property, and

(b) despite the provisions of any other enactments, has priority over a security interest or other lien, whether or not the security interest or other lien existed before the lien was registered under subsection (2) (b).

(6) A lien registered under subsection (2) (b) against personal property does not have priority over

(a) a security interest that secures unpaid wages under section 87 (3) of the *Employment Standards Act*, regardless of when that security interest arises, or

(b) a purchase money security interest in collateral other than collateral that at the time the purchase money security interest attaches is inventory or its proceeds.

(7) If

(a) one or more liens are registered under subsection (2) (b) against the personal property of a person, and

(b) the property referred to in paragraph (a) is subject to

(i) a security interest perfected under the *Personal Property Security Act* before the registration of the first lien under subsection (2) (b), or

(ii) another lien created before the registration of the first lien under subsection (2) (b),

the total amount secured by all the liens registered under subsection (2) (b), other than liens referred to in subsection (4) (b), is limited in amount, with respect to all the prior security interests or other liens referred to in paragraph (b) of this subsection, to the sum of the amount of

(AM) Dec 06/10

(c) taxes remaining uncollected or unremitted, or both, that were required to be collected or were collected by the person for the 6 calendar months before the date of the most recent registration of a lien under subsection (2) (b), and

(d) security remaining unpaid that was required to be paid by the person for the 6 calendar months before the date of the most recent registration of a lien under subsection (2) (b).

(8) If a lien results from an estimate under section 44 and the estimate is for an amount that is different from the actual amount of the lien as established under subsections (3) and (4), the director may correct the amount by registering a new lien in the revised amount and discharging the original lien, but for the purpose of subsection (7) the new registration is deemed to be registered at the same time as the registration it revises.

(AM) Jun 03/10

(9) Despite section 71 (1), the director must,

(a) on the oral or written request of a person, disclose in writing whether a lien is registered against the personal or real property of a named person, or

(b) on the written request of a person accompanied by the written consent of a named person, disclose in writing whether a lien is registered against the personal or real property of the named person and, if a lien is registered, the amount of the lien and the date of its registration.

(10) If the director believes that one corporation is associated with another corporation within the meaning of section 256 of the *Income Tax Act* (Canada), the director may request one or both of the corporations to provide to the director the records and information required by the director to confirm or rebut that belief.

(11) The director may determine that the corporations are associated corporations for the purposes of this section if

(a) a corporation that has been requested to provide records or information to the director under subsection (10) fails or refuses to comply with that request within a period of time considered by the director to be reasonable in the circumstances, or

(b) the records or information provided to the director under this section confirms the director's belief that the corporations are associated.

(12) Immediately after a corporation is determined under this section to be associated with a person referred to in subsection (2) (a) (i) and (b) (i), the director

(a) must notify the corporation of this in writing, and

(b) may register a lien under this section against the real and personal property of the corporation.

(13) The director may seize personal property against which a lien is registered under subsection (12) at any time after the registration of the lien, but must not take any action to realize on those assets until the later of

(a) the date that is 90 days after the date on which the notice required under subsection (12) (a) was sent to the corporation, and

(b) if a notice of appeal is served on the minister in respect of the determination within the time provided by section 56, the date on which the minister upholds the determination under that appeal.

(14) If, at any time, the director becomes convinced that the corporations were not associated within the meaning of section 256 of the *Income Tax Act* (Canada) at the time that the lien was registered under subsection (12) (b) of this section or if

the minister or a court of competent jurisdiction upholds the corporation's appeal against the director's determination on the basis that the corporations were not associated at the time that the lien was registered, the director must,

(a) if the director has not realized on any of the assets against which the lien was registered, promptly release the lien, and

(b) if the director has realized on some or all of the assets against which the lien was registered, promptly release the lien against the remaining assets and pay the proceeds realized from the sale of the realized assets, minus any costs or expenses incurred in the sale,

(i) to the corporation, or

(AM) Jul 01/10

(ii) if the director considers it appropriate to do so, into the Supreme Court under Rule 10-3 of the Supreme Court Civil Rules.

(15) The release of the lien under subsection (14) (a) or the release of the lien and payment of the applicable net sale proceeds under subsection (14) (b) is deemed to be full satisfaction of all claims any person, including the corporation, might have arising out of or in any way connected with the determination made under subsection (11), the registration of the lien or the seizure or sale of any or all of the assets against which the lien was registered.

2008-40-64; 2010-21-44; 2010-6-92 (Sch 2); B.C. Reg. 357/2010, Sch. 6.

Responsibility of person having control of property

65. (1) This section applies to a person who, as assignee, liquidator, administrator, receiver, receiver manager, trustee, secured party as defined in section 64 or similar person, other than a trustee appointed under the *Bankruptcy and Insolvency Act* (Canada), takes control or possession of the property of a person who has collected tax, is required to collect or remit tax or is required to pay security under this Act.

(2) Before distributing the property referred to in subsection (1), or the proceeds from the realization of it, a person to whom this section applies must obtain from the director a certificate that the amount that constituted a lien under section 64 has been paid or that a bond or other security acceptable to the director has been given.

(3) If a person to whom this section applies distributes the property referred to in subsection (1), or the proceeds of the realization of it, without having obtained the certificate required by subsection (2), the person is personally liable to the government for an amount equal to the amount required to be paid to obtain the certificate.

2008-40-65.

Notice of enforcement proceedings

66. (1) Before taking proceedings for the recovery of an amount owing under this Act, the director must give to the person who owes the amount notice of the director's intention to enforce payment.

(2) Failure to give notice under subsection (1) does not affect the validity of proceedings taken for the recovery of an amount owing under this Act.

2008-40-66.

Limitation period

67. (1) In this section, **"proceeding"** means

(a) an action for the recovery of taxes,

(b) the filing of a certificate,

(c) the making of a demand, and

(d) the registration or enforcement of a lien

under this Act.

(2) A proceeding may be commenced at any time within 7 years after the date of an assessment or reassessment of the amount claimed in the proceeding.

(3) Despite subsection (2), a proceeding that relates to a contravention of this Act or the regulations and that involves wilful default or fraud may be commenced at any time.

2008-40-67.

Application for injunction

68. The director may apply to the Supreme Court for an injunction ordering a person who sells or offers to sell fuel in British Columbia to cease selling or offering to sell fuel until the person complies with this Act and the regulations and the person's obligations under this Act are fulfilled.

2008-40-68.

PART 10 – General

Appointment of director

69. The minister may appoint a person as director for the purpose of administering this Act.

2008-40-69.

Delegation

70. (1) The director may, in writing, delegate any of the director's powers or duties under this Act.

(2) The delegation under subsection (1) may be to a named person or to a class of persons.

(RET) Jul 01/08 (3) Without limiting subsection (1), the director's powers and duties with respect to IFTA commercial vehicles to which this Act applies may be delegated by the director to a named person or class of persons in a government corporation, as defined in the *Financial Administration Act*, or a ministry of the government.

2008-40-70; 2009-14-30.

Confidentiality

71. (1) A person who has custody or control over information or records under this Act must not disclose the information or records to any other person except

(a) in the course of administering or enforcing this or another taxation Act,

(b) in court proceedings relating to this or another taxation Act,

(c) as provided in, or ordered under, section 39 (3), 40 (1), 99 (5) or 100 (1) of the *Family Relations Act* or section 8 (3) or 9 (2) of the *Family Maintenance Enforcement Act*,

(d) under an agreement that

(i) is between the government and another government,

(ii) relates to the administration or enforcement of taxation enactments, and

(iii) provides for disclosure of information and records to and the exchange of similar information with that other government, or

(e) for the purpose of the compilation of statistical information by the government or the government of Canada.

(ADD) Jun 03/10 (2) The prohibition in subsection (1) does not apply in respect of the names and addresses of collectors.

2008-40-71; 2010-21-45.

Demand for information

72. (1) For any purpose related to the administration or enforcement of this Act or the regulations, the director may, by demand notice, require from any person

(a) a return,

(b) any information or additional information,

(c) the production of any records, or

(d) a written statement.

(2) A demand notice under subsection (1)

(a) must be delivered to the person by personal service, registered mail, electronic mail or fax,
(b) must specify a reasonable time by which the person must comply with the demand notice, and
(c) in relation to a requirement under subsection (1) (d), may require the written statement to be made by way of affidavit or statutory declaration.

(3) A person to whom a demand notice is delivered under this section must comply with the notice within the time specified in the notice.

(4) Under this Act, an affidavit by the director in which are stated the facts necessary to establish
(a) compliance by the director with this section, or
(b) default by a person on whom a demand was made under this section

must be admitted as evidence in any court and is proof, in the absence of evidence to the contrary, of the facts stated.

2008-40-72.

Service of notices

73. (1) If service of a notice or other document by the director is required or authorized under this Act, the notice or document is conclusively deemed to have been served if
(a) served on the person,
(b) sent by registered mail to the last known address of the person according to the records of the director, or
(c) sent by electronic mail or fax to the last known electronic mail address or fax number of the person according to the records of the director.

(2) If service of a notice or other document on the minister is required or authorized under this Act, the notice or document is conclusively deemed to have been served if delivered to the office of the deputy minister.

(3) If service under subsection (1) is by registered mail, electronic mail or fax, the notice or document is conclusively deemed to be served when sent.

(4) If a person carries on business under a name or style other than the person's own name, the notice or document may be addressed to the name or style under which the person carries on business and, in the case of personal service, is deemed to have been validly served if it was left with an adult employed at the place of business of the addressee.

(5) If persons carry on business in partnership, the notice or document may be addressed to the partnership name and, in the case of personal service, is deemed to have been validly served if it was served on one of the partners or left with an adult employed at the place of business of the partnership.

(6) In the case of personal service, a notice or document is deemed to have been validly served
(a) on a corporation, if it was delivered to any board member, senior officer, liquidator or receiver manager of the corporation, and
(b) on an extraprovincial corporation, if it was delivered to a person referred to in paragraph (a) or to an attorney for the extraprovincial corporation.

(7)

Proof of the receipt by a person of any document or notice may be established in any court by showing that the document or notice was served or sent in a manner provided in this section, and the burden of proof is on the person seeking to establish the fact that the document or notice was not received by the person.

(8) In a prosecution or any proceeding for any matter arising under this Act, the facts necessary to establish compliance on the part of the director with this section may be sufficiently proved in any court by the production of an affidavit of the director setting out the facts.

2008-40-73.

Conversion of measurement

74. For the purpose of determining the amount of tax that is payable under this Act, the director may establish a formula for converting a measure of an amount of a fuel or combustible into a different measure of the amount of the fuel or combustible.

2008-40-74.

PART 11 – Offences and Penalties

Offences

(AM) Jun 03/10

75. (1) A person who contravenes section 71 (1) commits an offence and is liable to a fine of not more than $2 000.

(2) A person who does any of the following commits an offence:

(a) makes or participates in, assents to or acquiesces in the making of a false or deceptive statement in a return, certificate or form required to be made or filed under this Act;

(b) in order to evade payment of an amount to be paid or remitted under this Act, destroys, alters, mutilates, hides or otherwise disposes of a record or book of account;

(c) makes or assents to or acquiesces in the making of a false or deceptive entry in a record or book of account, or omits or assents to or acquiesces in the omitting to enter in a record or book of account a material particular related to an amount to be paid or remitted under this Act;

(d) refuses to produce records or books of account or hinders or molests or interferes with an inspection, audit or examination, or prevents or attempts to prevent a person from carrying out an inspection, audit or examination under this Act;

(e) wilfully, in any manner, fails to comply with this Act or the regulations;

(f) wilfully, in any manner, evades or attempts to evade compliance with this Act or the regulations or remittance or payment of taxes or payment of security required under this Act;

(g) conspires with any person to do anything described in paragraphs (a) to (f).

(3) A person who commits an offence under subsection (2) is liable

(a) to a fine of not more than $10 000 or to imprisonment for not more than 2 years or to both fine and imprisonment, and

(b) in addition, to a fine equal to the amount of any tax or security not collected, remitted or paid.

(4) In a prosecution under subsection (2), a certificate signed by the director stating the amount of tax or security referred to in subsection (3) (b) is evidence of the amount of tax or security referred to in subsection (3) (b).

2008-40-75; 2010-21-44.

Onus of proof

76. In a prosecution for failure to collect, remit or pay an amount under this Act, the onus is on the accused to prove that the amount was collected by the accused or was paid or remitted, as the case may be, to the government.

2008-40-76.

Analyst and certificate of analyst

77. (1) In this section, **"analyst"** means a person designated as an analyst under subsection (2).

(2) The director may designate a person as an analyst for the purpose of the enforcement of this Act.

(3)

In a prosecution under this Act, a certificate of an analyst stating that the analyst has analyzed or examined a substance submitted to the analyst and stating the results of the analysis or examination is evidence of the statements contained in the certificate.

(4) The party against whom a certificate of an analyst is produced under subsection (3) may, with leave of the court, require the attendance of the analyst for the purpose of cross examination.

(5) A certificate must not be received in evidence under subsection (3) unless the party intending to produce it has, before the trial, given to the party against whom it is intended to be produced reasonable notice of that intention together with a copy of the certificate.

2008-40-77.

Evidence

78. (1) In a prosecution, evidence that a person applied to be appointed a collector or applied to obtain a registration certificate, registered consumer certificate, registered air service certificate or registered marine service certificate is evidence that the person is appointed as a collector or holds the certificate for which the person applied.

(2) In a prosecution, a notice of assessment is evidence that the amount stated in the notice of assessment is due and owing.

2008-40-78.

Offence by corporation

79. If a corporation commits an offence under this Act, an employee, officer, board member or agent of the corporation who authorized, permitted or acquiesced in the offence also commits that offence, whether or not the corporation is prosecuted or convicted.

2008-40-79.

Time limit on prosecution

80. No prosecution for an offence against this Act or the regulations may be instituted more than 6 years after the day the alleged offence was committed.

2008-40-8.

Section 5 of the *Offence Act*

81. Section 5 of the *Offence Act* does not apply to this Act or the regulations.

2008-40-81.

PART 12 – Regulations

Definition

82. In this Part, **"greenhouse gas"** has the same meaning as in the *Greenhouse Gas Reduction Targets Act*.
2008-40-82.

(REP) **Repealed**
Jul
01/11

83. (1) to (5) *Repealed.*   [2008-40-83(6)]
(6) *[Spent]*

Regulations

84. (1) The Lieutenant Governor in Council may make regulations referred to in section 41 of the *Interpretation Act*.

(2) The Lieutenant Governor in Council may make regulations respecting any matter for which regulations by the Lieutenant Governor in Council are contemplated by this Act.

(AM) May 14/12

(3) Without limiting this section, the Lieutenant Governor in Council may make regulations, including regulations that are considered necessary as a result of an amendment to Schedule 1 or 2, as follows:

(RET) May 01/12

(a) prescribing records to be kept by vendors, wholesale dealers, retail dealers, collectors, deputy collectors, persons who sell fuel in sales to which section 1.1 (2) (a) to (c) applies, registered consumers, registered air services, registered marine services, motive fuel user permit holders and persons who are required to file returns for the payment of tax under this Act;

(b) requiring a person who sells fuel to furnish prescribed information to the person who buys the fuel in prescribed circumstances;

(c) respecting the duties of vendors, wholesale dealers, retail dealers, collectors, deputy collectors, registered consumers, registered air services, registered marine services and persons who are required to file returns for the payment of tax under this Act;

(RET) May 01/12

(c.1) setting conditions or limitations on the application of section 1.1 (2) (a) to (c) to a sale;

(RET) May 01/12

(c.2) respecting the minimum amount prescribed for a prescribed type of fuel, a prescribed subcategory of a type of fuel or a prescribed class of fuel for the purposes of section 1.1 (3) (a) (ii);

(d) respecting the manner of payment, collection and remittance of tax and payment of security and any other conditions or requirements affecting the payment, collection and remittance of tax or security;

(e) establishing, for the purposes of section 13, an amount of tax payable, or a method for determining the amount of tax payable, for a blend or mixture;

(f) respecting the payment of an allowance under section 35, including, without limitation, the following:
   (i) determining the amount of an allowance;
   (ii) determining the circumstances in which an allowance or a portion of an allowance is not to be paid;

(iii) establishing a manner of payment of an allowance;

(g) defining a word or expression used but not defined in this Act;

(h) for the purpose of the definition of "use", prescribing circumstances in which a type of activity is a use;

(i) establishing a system of permits for retail dealers, wholesale dealers and vendors who sell a fuel on which tax is not payable under this Act and, without limitation, for the purpose of establishing a system of permits, may also

(i) prohibit these dealers and vendors from acquiring and selling the fuel on which tax is not payable under this Act in British Columbia unless authorized by a permit,

(ii) prohibit persons from selling the fuel on which tax is not payable under this Act to these dealers and vendors unless the dealer or vendor is authorized to sell that fuel by a permit,

(iii) provide for the issue, refusal to issue, suspension and cancellation of the permits by the director, and

(RET) Sep 02/09

(iv) provide for appeals from a decision related to a permit;

(j) with respect to refunds under paragraph (l), (n) or (o), may, without limiting those provisions, do the following:

(i) permit or require the payment of a refund to a person or a class of persons;

(ii) establish circumstances in which a refund may or must be paid;

(iii) set conditions of, or limitations on, the payment of a refund;

(k) with respect to granting exemptions under paragraph (m), (n) or (o), may, without limiting those provisions, do the following:

(i) provide a full or partial exemption from the payment, collection or remittance of tax or security under one of more provisions of this Act;

(ii) establish circumstances in which an exemption applies;

(iii) set conditions of, or limitations on, the application of an exemption;

(l) providing for refunds of all or part of a tax, security or other amount paid or remitted under this Act;

(m) providing for exemptions from one or more provisions of this Act;

(n) providing for exemptions from the payment of tax, or for refunds of all or part of the tax paid, with respect to a fuel or combustible that is the source for greenhouse gas emissions that are subject to

(i) section 2 (1) (b) of the *Greenhouse Gas Reduction (Cap and Trade) Act*,

(ii) section 76.3 (1) of the *Environmental Management Act*, if equivalent emissions are captured and stored, or captured and sequestered, in accordance with subsection (2) of that section, or

(iii) section 76.4 (b) of the *Environmental Management Act*;

(o) providing for exemptions from the payment of tax, or for refunds of all or part of the tax paid, with respect to a fuel or combustible that

(i) is used to operate equipment that captures and stores, or captures and sequesters, greenhouse gas in accordance with the regulations, or

(ii) does not or did not emit greenhouse gas into the atmosphere when the fuel or combustible is or was used, as a result of the greenhouse gas being captured and stored, or captured and sequestered, in accordance with the regulations;

(RET) Feb 16/11

(o.1) respecting the provision of biomethane credits, including, without limitation, the following:
   (i) limiting the retail dealers of natural gas or classes of retail dealers of natural gas, to whom section 14.1 applies;
   (ii) limiting the purchasers or classes of purchasers, to whom section 14.1 applies;
   (iii) establishing circumstances in which biomethane credits must or must not be provided;
   (iv) setting conditions or limitations on the provision of biomethane credits;
   (v) respecting the duties of retail dealers of natural gas who are required to provide biomethane credits;

(RET) Feb 16/11

(o.2) respecting refunds under section 14.2, including, without limitation, the following:
   (i) establishing circumstances in which refunds must or must not be paid;
   (ii) setting conditions or limitations on the payment of refunds;
   (iii) respecting the repayment of refunds to the government by retail dealers of natural gas;

(p) prescribing interest rates and the manner of calculating interest for the purposes of this Act;

(q) respecting fees for certificates under sections 53 and 65, including setting the fee and time and manner of payment of the fee;

(r) respecting appeals to the minister under section 56, including, without limitation, establishing circumstances in which an appeal to the minister under section 56 (2) is not permitted;

(s) respecting duties of persons that own or operate IFTA commercial vehicles to which this Act applies, including, without limitation,
   (i) the payment and refund of deposits, and
   (ii) authorizing the director to determine the amount of deposits;

(t) establishing circumstances in which a retail dealer is exempt from the requirement to collect tax and permitting the director to establish rules for the collection of tax in those circumstances.

(4) For the purposes of a regulation under subsection (3) (p), interest may be calculated in a manner that applies, or has the effect of applying, different rates of interest to all or part of an assessment if a person is entitled to a refund under this Act.

(5) In making a regulation under this Act, the Lieutenant Governor in Council may do one or more of the following:
   (a) delegate a matter to a person;
   (b) confer a discretion on a person;
   (c) make different regulations for different persons, fuels, combustibles, places, things, uses or transactions, or classes of persons, fuels, combustibles, places, things, uses or transactions;
   (d) establish or define classes of persons, fuels, combustibles, places, things, uses or transactions.

(REP) Jul 01/11

(6) *Repealed.*   [2008-40-84(7)]

(RET) Sep 02/09

(6.1) A regulation made before December 31, 2009 under section 21 or 39 or subsection (3) (g), (j), (k), (l) or (m) of this section may be made retroactive to

July 1, 2008 or a later date, and if made retroactive is deemed to have come into force on the specified date.

(RET) Sep 02/09 (6.2) A regulation made before December 31, 2009 under subsection (3) (i) (iv) of this section may be made retroactive to September 2, 2009 or a later date, and if made retroactive is deemed to have come into force on the specified date.

(RET) Feb 16/11 (6.3) A regulation that relates to Division 2 of Part 4 made before December 31, 2011 under this section may be made retroactive to February 16, 2011 or a later date, and if made retroactive is deemed to have come into force on the specified date.

(RET) May 01/12 (6.4) A regulation made before December 31, 2012 under this section in relation to section 1.1 may be made retroactive to May 1, 2012 or a later date, and if made retroactive is deemed to have come into force on the specified date.

(REP) May 14/12 (7) *Repealed.* [2012-8-16]

2008-40-84; 2009-14-31; 2011-9-11; 2008-40-84(7); 2012-8-16.

(REP) Jul 01/11 **Repealed**

85. (1) to (3) *Repealed.*   [2008-40-85(4)]

(4) *[Spent]*

PART 13 – Transitional Provisions

Division 1 – *Carbon Tax Act*

Transition — imposition of tax on purchase

86. (1) If a purchaser buys fuel before July 1, 2008 and the purchaser receives delivery of the fuel on or after that date, the purchaser must pay to the government tax on the fuel at the rate for that type of fuel set out in the column of the Table in Schedule 1 that applies for the period of time in which the purchaser receives delivery.

(2) If a retail dealer sells a fuel to a purchaser before July 1, 2008 and the purchaser receives delivery of the fuel on or after that date, the retail dealer must collect tax on that fuel at the rate for that type of fuel set out in the column of the Table in Schedule 1 that applies for the period of time in which the purchaser receives delivery.

(3) A reference to "purchaser" in this section does not include a person who is a registered consumer with respect to the type or subcategory of a type of fuel specified on that person's registered consumer certificate.

2008-40-86.

Transition — imposition of tax on use

87. (1) Subject to subsection (2), a person who uses a fuel on or after July 1, 2008 is not required to pay tax on the use of the fuel under section 11, if tax was paid on the fuel under section 86 or if the fuel was, before that date,

(a) bought and received,

(b) transferred, or

(c) brought into British Columbia

within the meaning of section 8, 9 or 10.

(2) Subsection (1) does not apply to a registered consumer who uses fuel on or after July 1, 2008 if the fuel used is the type or subcategory of a type specified on the registered consumer certificate of the registered consumer.

(3) Section 11 applies to a registered consumer referred to in subsection (2) even if the fuel used by the registered consumer was, before July1, 2008,

(a) bought and received,

(b) transferred, or

(c) brought into British Columbia

within the meaning of section 8, 9 or 10.

2008-40-87.

Transition — change in rate of tax and payment of security

88. (1) If

(a) a deputy collector or retail dealer owns fuel on July 1, 2008, and

(b) security would have been payable by the deputy collector or retail dealer if this Act were in force on the date the deputy collector or retail dealer bought the fuel,

the deputy collector or retail dealer must provide to the director by August 15, 2008 an inventory of that fuel, in accordance with the instructions of the director.

(2) For the purposes of subsection (1), if a retail dealer entered into an agreement to sell fuel to a purchaser before July 1, 2008 and the purchaser has not received delivery of the fuel before July 1, 2008, the retail dealer is deemed to own the fuel.

(3) For the purposes of subsection (1), a deputy collector or retail dealer, as the case may be, who meets the requirements of paragraphs (a) to (c), is deemed to own a fuel on July 1, 2008 if

(a) the deputy collector or retail dealer has entered into an agreement to buy the fuel and the agreement provides that the deputy collector or retail dealer owns the fuel on July 1, 2008,

(b) the deputy collector or the retail dealer has not received delivery of the fuel before July 1, 2008, and

(c) the deputy collector or the retail dealer has not entered into an agreement with another person that provides that the other person owns the fuel on July 1, 2008.

(4) Subject to the regulations, the director may pay an allowance of $250 to a deputy collector or retail dealer who provided an inventory by August 15, 2008 under subsection (1).

(5) Subject to the regulations, a deputy collector or retail dealer who is required to provide an inventory under subsection (1) must pay to the director by August 15, 2008 the amount of security on fuel included in the inventory equal to the tax that would be collectable if the fuel were sold to a purchaser on July 1, 2008.

2008-40-88.

Transition — fixed price contracts

89. (1) Subject to subsection (2), if, on or after July 1, 2008 a purchaser takes delivery of fuel and pays to the government tax on the purchase of the fuel under this Act, the director, on application and on receipt of evidence satisfactory to the director, must pay to the purchaser, from the consolidated revenue fund, a refund of tax paid if the delivery is taken, under a fixed-price contract made by the purchaser with the seller before February 20, 2008, in respect of a quantity of fuel that does not exceed the quantity specified in the contract.

(2) No refund is to be paid under subsection (1) if the purchaser

(a) is entitled, under the fixed-price contract, to recover the tax on the fuel imposed under this Act, or

(b) receives delivery of the fuel after June 30, 2009.

2008-40-89.

Division 2 – *Motor Fuel Tax Act*

Transition — collector

90. (1) Effective on July 1, 2008, a person who, immediately before that date, was a collector appointed under section 28 (1) or 32 (2) of the *Motor Fuel Tax Act*, as those provisions read before the date this Act receives Royal Assent, is deemed to be appointed as a collector under section 28 of the *Motor Fuel Tax Act*, as enacted by this Act.

(2) An appointment deemed to be made under subsection (1) has a term that ends on the date that is the earliest of the following:

(a) the end of the day on December 31, 2008;

(b) the date the deemed appointment as a collector is suspended or cancelled under the *Motor Fuel Tax Act*, as amended by this Act;

(c) the date the person is appointed as a collector under section 28, as enacted by this Act.

(3) If the appointment of a person as a collector under section 28 (1) or 32 (2) of the *Motor Fuel Tax Act*, as those provisions read before the date this Act receives Royal Assent, is subject to terms and conditions, the deemed appointment of a person as a collector under subsection (1) of this section is subject to the same terms and conditions, unless the director specifies different terms and conditions.

(4) If the appointment of a person as a collector under section 28 (1) or 32 (2) of the *Motor Fuel Tax Act*, as those provisions read before the date this Act receives Royal Assent, is not subject to terms and conditions, the director may specify terms and conditions for the deemed appointment of the person as a collector under subsection (1) of this section.

2008-40-90.

Transition — relabelling of fuel

91. If, at the time section 110 of this Act comes into force, a person was appointed as a collector under section 29 (2) of the *Motor Fuel Tax Act*, as it read before the coming into force of section 110, the person is deemed to be authorized to sell a substance as a type of fuel in circumstances in which the person bought the substance as another type of fuel, subject to the conditions the director specifies, if any, until the date that is earliest of the following:

(a) the end of the day on December 31, 2008;

(b) the date the authorization is suspended or cancelled by the director;

(c) the date the person is

(AM) Dec 06/10

(i) appointed as a collector under section 28 of the *Motor Fuel Tax Act*, as enacted by this Act, or

(ii) authorized by the director, under section 29 (2) of the *Motor Fuel Tax Act*, as enacted by this Act.

2008-40-91; B.C. Reg. 357/2010, Sch. 6.

Transition — registered consumer

92. (1) Effective on July 1, 2008, a person who, immediately before that date, was a registered consumer, as defined in section 1 of the *Motor Fuel Tax Act* as it read before the coming into force of section 98 of this Act, is deemed to have been issued a registered consumer certificate under section 37 of the *Motor Fuel Tax Act*, as enacted by this Act.

(2) The certificate deemed to be issued under subsection (1) has a term that ends on the date that is the earliest of the following:

(a) the end of the day on December 31, 2008;

(b) the date the deemed registered consumer certificate is suspended or cancelled under the *Motor Fuel Tax Act*, as amended by this Act;

(c) the date the person is issued a registered consumer certificate under section 37 of the *Motor Fuel Tax Act*, as enacted by this Act.

(3) If a person holds a registered consumer certificate under section 37 of the *Motor Fuel Tax Act*, as it read before the coming into force of section 118 of this Act, that is subject to terms and conditions, the deemed registered consumer certificate under subsection (1) is subject to the same terms and conditions, unless the director specifies different terms and conditions.

(4) If a registered consumer certificate issued to a person under section 37 the *Motor Fuel Tax Act*, as it read before the coming into force of section 118 of this Act, is not subject to terms and conditions, the director may specify terms and conditions for the registered consumer certificate that is deemed to be issued to the person under subsection (1).

2008-40-92.

Transition — imposition of tax

93. If a retail dealer sells fuel to a licensed carrier before July 1, 2008 and the licensed carrier receives delivery of the fuel on or after that date, the retail dealer must collect tax on that fuel at the rate that applies at the time the licensed carrier receives delivery of the fuel.

2008-40-93.

Transition — refunds

94. The *Motor Fuel Tax Act*, as it read immediately before the date this Act receives Royal Assent, continues to apply to

(a) an application for a refund received by the director under that Act, and

(b) an action commenced under that Act

before July 1, 2008.

2008-40-94.

Transition — penalty for failure to remit tax or pay security

95. The director may impose a penalty on a person referred to in section 45 of the *Motor Fuel Tax Act*, as amended by section 128 of this Act, in respect of a failure by the person to remit tax or pay security before July 1, 2008.

2008-40-95.

SCHEDULE 1

Interpretation

(AM) Jan 01/10

1. (1) In this Schedule:

"aviation fuel" means a substance suitable to power an aircraft that is not propelled by a turbine;

(ADD) Jan 01/10

"biodiesel" means a substance that is made up of mono-alkyl esters of long chain fatty acids derived from plant or animal matter;

"diesel engine" means an internal combustion engine, including a stationary engine, in which internal combustion is initiated by compression;

(ADD) Jan 01/10

"gas liquids" means a mixture of two or more of ethane, propane, butane or pentanes plus, whether in gaseous or liquid form, that

(a) is obtained from the processing of natural gas or crude oil, and
(b) has never been processed into separate identifiable fuels,

but does not include a mixture of ethane, propane, butane or pentanes plus that is created after the ethane, propane, butane or pentanes plus have been processed into separate identifiable fuels and then remixed into a blend of one or more of the fuels;

"gasoline" means a substance suitable for generating power by means of an internal combustion engine, other than a diesel engine, but does not include any other fuel;

"heavy fuel oil" means a substance that is a distillate or a residual of crude oil and that has a viscosity of greater than 14 centistokes at 50°C;

"high heat value coal" means bituminous coal and any other coal with a heating value greater than 27 000 kJ per kg;

(ADD) Jan 01/10

"hydrogenated-derived renewable diesel fuel" means a substance that is made from plant or animal matter using a hydrogenation process;

"internal combustion engine" includes a turbine engine that generates power by the use of fuel;

"jet fuel" means a substance suitable to power an aircraft that is propelled by a turbine;

(SUB) Jan 01/10

"light fuel oil" means a substance that is

(a) a distillate of crude oil that has a viscosity of not greater than 14 centistokes at 50°C,
(b) renewable diesel fuel, or
(c) a combination of substances including the substances referred to in paragraphs (a) and (b),

and is suitable

(d) for generating power by means of a diesel engine, or
(e) for use in a furnace, boiler or open flame burner,

but does not include butane, ethane, gas liquids, jet fuel, kerosene, naphtha, propane, pentanes plus or refinery gas;

"low heat value coal" means sub-bituminous coal and any other coal with a heating value up to and including 27 000 kJ per kg;

(ADD) Jan 01/10

"natural gas" means natural gas, whether or not the natural gas

(a) occurs naturally or results from processing, or
(b) contains gas liquids,

but does not include refinery gas;

(ADD) Jan 01/10

"pentanes plus" means pentane, heavier hydrocarbons or a combination of both, but does not include any other fuel;

"refinery gas" means gas for use in an oil refinery that is produced as a result of distillation, cracking, reforming or other oil refining processes;

(ADD) Jan 01/10

"renewable diesel fuel" means

(a) biodiesel fuel, or

(b) hydrogenated-derived renewable diesel fuel;

"standard reference conditions" means, in the case of

(a) a gas, a temperature of 15°C and an atmospheric pressure of 101.325 kPa, and

(b) a liquid, a temperature of 15°C.

(2) For calculating the amount of tax payable for a fuel set out in column 2 of the Table, when the rate of tax is based on litres, the rate of tax must be multiplied by the amount of liquids or gaseous fuels measured in litres at standard reference conditions.

(RET) Jul 01/08

(3) For calculating the amount of tax payable for a fuel set out in column 2 of the Table, when the rate of tax is based on cubic metres, the rate of tax must be multiplied by the amount of liquids or gaseous fuels measured in cubic metres at standard reference conditions.

(ADD) Jan 01/10

(4) For the purpose of calculating the amount of tax payable for a fuel set out in column 2 of the Table,

(a) gas liquids are a separate fuel when the gas liquids are separated from natural gas or crude oil for the first time as a result of processing and have not been

(i) separated into ethane, propane, butane or pentanes plus as a result of processing, or

(ii) separated into ethane, propane, butane or pentanes plus as a result of processing and then remixed into a blend of one or more of the fuels, and

(b) ethane, propane, butane and pentanes plus are separate fuels when they have been processed and are identifiable as separate fuels as a result of processing.

2008-40-Sch.; 123/2008; 124/2008; 2009-14-33; 2009-14-32.

TABLE

[2009-14-34; 2010-2-65; 2012-8-17.]

Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8
Item	**Type of fuel**	**Rate of tax for the year starting July 1, 2008**	**Rate of tax for the period starting July 1, 2009 and ending December 31, 2009**	**Rate of tax for the period starting January 1, 2010 and ending June 30, 2010**	**Rate of tax for the year starting July 1, 2010**	**Rate of tax for the year starting July 1, 2011**	**Rate of tax for the year starting July 1, 2012 and each subsequent year starting July 1**
1	Aviation Fuel	2.46 ¢/L	3.69 ¢/L	3.69 ¢/L	4.92 ¢/L	6.15 ¢/L	7.38 ¢/L
2	Gasoline	2.34 ¢/L	3.51 ¢/L	3.33 ¢/L	4.45 ¢/L	5.56 ¢/L	6.67 ¢/L
3	Heavy Fuel Oil	3.15 ¢/L	4.73 ¢/L	4.73 ¢/L	6.30 ¢/L	7.88 ¢/L	9.45 ¢/L
4	Jet Fuel	2.61 ¢/L	3.92 ¢/L	3.92 ¢/L	5.22 ¢/L	6.53 ¢/L	7.83 ¢/L
5	Kerosene	2.54 ¢/L	3.81 ¢/L	3.81 ¢/L	5.22 ¢/L	6.53 ¢/L	7.83 ¢/L
6	Light Fuel Oil	2.69 ¢/L	4.04 ¢/L	3.84 ¢/L	5.11 ¢/L	6.39 ¢/L	7.67 ¢/L
7	Methanol	1.09 ¢/L	1.64 ¢/L	1.64 ¢/L	2.18 ¢/L	2.73 ¢/L	3.27 ¢/L
8	Naphtha	2.55 ¢/L	3.83 ¢/L	3.83 ¢/L	5.10 ¢/L	6.38 ¢/L	7.65 ¢/L
9	Butane	1.76 ¢/L	2.64 ¢/L	2.64 ¢/L	3.52 ¢/L	4.40 ¢/L	5.28 ¢/L
10	Coke Oven Gas	1.61 ¢/m^3	2.42 ¢/m^3	2.42 ¢/m^3	3.22 ¢/m^3	4.03 ¢/m^3	4.83 ¢/m^3
11	Ethane	0.98 ¢/L	1.47 ¢/L	1.47 ¢/L	1.96 ¢/L	2.45 ¢/L	2.94 ¢/L
12	Propane	1.54 ¢/L	2.31 ¢/L	2.31 ¢/L	3.08 ¢/L	3.85 ¢/L	4.62 ¢/L
13	Natural Gas	1.90 ¢/m^3	2.85 ¢/m^3	2.85 ¢/m^3	3.80 ¢/m^3	4.75 ¢/m^3	5.70 ¢/m^3
14	Refinery Gas	1.76 ¢/m^3	2.64 ¢/m^3	2.64 ¢/m^3	3.52 ¢/m^3	4.40 ¢/m^3	5.28 ¢/m^3
15	High Heat Value Coal	20.77 $/tonne	31.16 $/tonne	31.16 $/tonne	41.54 $/tonne	51.93 $/tonne	62.31 $/tonne
16	Low Heat Value Coal	17.77 $/tonne	26.66 $/tonne	26.66 $/tonne	35.54 $/tonne	44.43 $/tonne	53.31 $/tonne
17	Coke	24.87 $/tonne	37.31 $/tonne	37.31 $/tonne	49.74 $/tonne	62.18 $/tonne	74.61 $/tonne
18	Petroleum Coke	3.67 ¢/L	5.51 ¢/L	5.51 ¢/L	7.34 ¢/L	9.18 ¢/L	11.01 ¢/L

19	Gas Liquids			2.48 ¢/L	3.30 ¢/L	4.13 ¢/L	4.95 ¢/L
20	Pentanes Plus			2.64 ¢/L	3.52 ¢/L	4.40 ¢/L	5.28 ¢/L

SCHEDULE 2 — TABLE

[2008-40-Sch; 2012-8-18.]

Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7
Item	**Type of Combustible**	**Rate of tax for the year starting on July 1, 2008**	**Rate of tax for the year starting on July 1, 2009**	**Rate of tax for the year starting on July 1, 2010**	**Rate of tax for the year starting on July 1, 2011**	**Rate of tax for the year starting on July 1, 2012 and each subsequent year starting on July 1**
1	Peat	10.22 $/tonne	15.33 $/tonne	20.44 $/tonne	25.55 $/tonne	30.66 $/tonne
2	Tires — Shredded	23.91 $/tonne	35.87 $/tonne	47.82 $/tonne	59.78 $/tonne	71.73 $/tonne
3	Tires — Whole	20.80 $/tonne	31.20 $/tonne	41.60 $/tonne	52.00 $/tonne	62.40 $/tonne

Appendix B-5

Clean Energy Act

PDF Version
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CLEAN ENERGY ACT

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Updated To:
[includes 2010 Bill 17, c. 22 amendments (effective July 1, 2011)]

CLEAN ENERGY ACT

CHAPTER 22 [SBC 2010]

[includes 2010 Bill 17, c. 22 amendments (effective July 1, 2011)]

Contents

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Definitions

1. (1) In this Act:

"acquire" , used in relation to the authority, means to enter into an energy supply contract;

"authority" has the same meaning as in section 1 of the *Hydro and Power Authority Act*;

"British Columbia's energy objectives" means the objectives set out in section 2;

"Burrard Thermal" means the gas-fired generation asset owned by the authority and located in Port Moody, British Columbia;

"clean or renewable resource" means biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource;

"demand-side measure" means a rate, measure, action or program undertaken

(a) to conserve energy or promote energy efficiency,

(b) to reduce the energy demand a public utility must serve, or

(c) to shift the use of energy to periods of lower demand,

but does not include

(d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or

(e) any rate, measure, action or program prescribed;

"electricity self-sufficiency" means electricity self-sufficiency as described in section 6 (2);

"expenditure for export" means the amount of an expenditure for the construction or extension of a plant or system or for an acquisition of electricity that is in addition to the amount the authority would have had to spend

(a) to achieve electricity self-sufficiency, and

(b) to undertake anything referred to in section 7 (1), except to the extent the expenditure is accounted for in paragraph (a);

"feed-in tariff program" means a program, that may be established under section 16, under which the authority offers to enter into energy supply contracts with persons generating electricity from clean or renewable resources using prescribed technologies in prescribed regions of British Columbia;

"greenhouse gas" has the same meaning as in section 1 of the *Greenhouse Gas Reduction Targets Act*;

"heritage assets" means

(a) any equipment or facilities for the transmission or distribution of electricity in respect of which, on the date on which this Act receives First Reading in the Legislative Assembly, a certificate of public convenience and necessity has been granted, or has been deemed to have been granted, to the authority or the transmission corporation under the *Utilities Commission Act*,

(b) generation and storage assets identified in Schedule 1 of this Act, and

(c) equipment and facilities that are for the transmission or distribution of electricity and that are identified in Schedule 1 of this Act;

"integrated resource plan" means an integrated resource plan required to be submitted under section 3;

"transmission corporation" means British Columbia Transmission Corporation.

(2) Words and expressions used but not defined in this Act or the regulations, unless the context otherwise requires, have the same meanings as in the *Utilities*

Commission Act.

2010-22-1.

PART 1 — British Columbia's Energy Objectives

British Columbia's energy objectives

2. The following comprise British Columbia's energy objectives:

(a) to achieve electricity self-sufficiency;

(b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;

(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

(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;

(e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers;

(f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;

(g) to reduce BC greenhouse gas emissions

(i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,

(ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

(iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

(iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

(v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

(j) to reduce waste by encouraging the use of waste heat, biogas and biomass;

(k) to encourage economic development and the creation and retention of jobs;

(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;

(m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;

(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in

British Columbia;

(o) to achieve British Columbia's energy objectives without the use of nuclear power;

(p) to ensure the commission, under the *Utilities Commission Act*, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.

2010-22-2.

Integrated resource plans

3. (1) The authority must submit to the minister, in accordance with subsection (6), an integrated resource plan that is consistent with good utility practice and that includes all of the following:

(a) a description of the authority's forecasts, over a defined period, of its energy and capacity requirements to achieve electricity self-sufficiency;

(b) a description of what the authority plans to do to achieve electricity self-sufficiency and to respond to British Columbia's other energy objectives, including plans respecting

(i) the implementation of demand-side measures,

(ii) the construction or extension of facilities,

(iii) the acquisition of electricity from other persons, and

(iv) the use of rates, including rates to encourage

(A) energy conservation or efficiency,

(B) the use of energy during periods of lower demand,

(C) the reduction of the energy demand the authority must serve, or

(D) the development and use of electricity from clean or renewable resources;

(c) a description of the consultations carried out by the authority respecting the development of the integrated resource plan;

(d) a description of

(i) the expected export demand during a defined period,

(ii) the potential for British Columbia to meet that demand,

(iii) the actions the authority has taken to seek suitable opportunities for the export of electricity from clean or renewable resources, and

(iv) the extent to which the authority has arranged for contracts for the export of electricity and the transmission or other services necessary to facilitate those exports;

(e) if the authority plans to make an expenditure for export, a specification of the amount of the expenditure and a rationale for making it.

(2) In the first integrated resource plan the authority submits to the minister, and in any other integrated resource plan the minister by order specifies, the authority must include a description of the authority's infrastructure and capacity needs for electricity transmission for the period ending 30 years after the date the integrated resource plan is submitted.

(3) The description referred to in subsection (2) must include an assessment of the potential for developing, during the period referred to in subsection (2), grouped by geographic area, electricity generation from clean or renewable resources in British Columbia.

(4) The authority must carry out any consultations required by a regulation under section 35 (g) and submit a report to the minister, within the time prescribed, respecting those consultations.

(5) The authority must plan to rely on no energy and no capacity from Burrard Thermal, except in the case of emergency or as authorized by regulation.

(6) An integrated resource plan must be submitted

(AM) Jun 02/11

(a) within 30 months from the date this Part comes into force, and

(b) once every 5 years after the submission under paragraph (a), unless a submission date is prescribed for the purposes of this subsection, in which case an integrated resource plan must be submitted by the prescribed submission date.

(7) The authority may submit an amendment to an integrated resource plan approved under section 4, and section 4 applies to the submission.

(8) If the Lieutenant Governor in Council approves an amendment submitted under subsection (7), the approved amendment is to be considered a part of the approved integrated resource plan.

2010-22-3; 2011-13-31.

Approval and procurement

4. (1) After the minister receives an integrated resource plan, the Lieutenant Governor in Council, for the purposes of sections 44.2 (5.1), 46 (3.3) and 71 (2.21) and (2.51) of the *Utilities Commission Act*, may, by order,

(a) approve or reject the plan, and

(b) if the Lieutenant Governor in Council is satisfied that it is in the interests of British Columbians to pursue opportunities for export, require the authority, its subsidiaries or both to do the following:

(i) begin a process or processes by the time specified in the order to acquire the specified amount per year of energy and capacity from clean or renewable resources;

(ii) acquire the energy and capacity referred to in subparagraph (i) within the time specified in the order;

(iii) secure the necessary transmission capacity;

(iv) submit, for the purposes of subsection (2), a report to the minister respecting the expenditures for export resulting from compliance with subparagraphs (i) to (iii).

(2) In an order under subsection (1) (b) of this section, the Lieutenant Governor in Council may exempt the authority from sections 45 to 47 of the *Utilities Commission Act* with respect to anything to be done under subsection (1) (b) (iii) of this section.

(3) The authority and its subsidiaries and persons and their successors and assigns who enter into an energy supply contract as a result of a process referred to in subsection (1) (b) (i) of this section are exempt from section 71 of the *Utilities Commission Act* with respect to the energy supply contract.

(4) The Lieutenant Governor in Council, for the purposes of subsection (5) (a), may approve a report submitted under subsection (1) (b) (iv).

(5) In setting rates for the authority, the commission must ensure that the rates do not allow the authority to recover

(a) its expenditures for export as set out in a report approved by the Lieutenant Governor in Council under subsection (4), and

(b) any other expenditures for export.

2010-22-4.

Status report

5. (1) The authority must submit to the minister, by the time the minister requires, a status report respecting the authority's most recently approved integrated resource plan.

(2) The minister must make public a status report submitted under subsection (1) in the same manner and at the same time that the minister makes public a service plan under the *Budget Transparency and Accountability Act*.

2010-22-5.

Electricity self-sufficiency

6. (1) In this section:

"electricity supply obligations" means

(a) electricity supply obligations for which rates are filed with the commission under section 61 of the *Utilities Commission Act*, and

(b) any other electricity supply obligations that exist at the time this section comes into force,

determined by using the authority's prescribed forecasts of its energy requirements and peak load, taking into account demand-side measures, that are in an integrated resource plan approved under section 4;

"heritage energy capability" means the maximum amount of annual energy that the heritage assets that are hydroelectric facilities can produce under prescribed water conditions.

(2) The authority must achieve electricity self-sufficiency by holding,

(a) by the year 2016 and each year after that, the rights to an amount of electricity that meets the electricity supply obligations, and

(b) by the year 2020 and each year after that, the rights to 3 000 gigawatt hours of energy, in addition to the amount of electricity referred to in paragraph (a), and the capacity required to integrate that energy

solely from electricity generating facilities within the Province,

(c) assuming no more in each year than the heritage energy capability, and

(d) relying on Burrard Thermal for no energy and no capacity, except as authorized by regulation.

(3) The authority must remain capable of meeting its electricity supply obligations from the electricity referred to in subsection (2) (a) and (b), except to the extent the authority may be permitted, by regulation, to enter into contracts in the prescribed circumstances and on the prescribed terms and conditions.

(4) A public utility, in planning in accordance with section 44.1 of the *Utilities Commission Act* for

(a) the construction or extension of generation facilities, and

(b) energy purchases,

must consider British Columbia's energy objective to achieve electricity self-sufficiency.

2010-22-6.

Exempt projects, programs, contracts and expenditures

7. (1) The authority is exempt from sections 45 to 47 and 71 of the *Utilities Commission Act* to the extent applicable, and from any other sections of that Act that the minister may specify by regulation, with respect to the following projects, programs, contracts and expenditures of the authority, as they may be further described by regulation:

(a) the Northwest Transmission Line, a 287 kilovolt transmission line between the Skeena substation and Bob Quinn Lake, and related facilities and contracts;

(b) Mica Units 5 and 6, a project to install two additional turbines and related works and equipment at Mica;

(c) Revelstoke Unit 6, a project to install an additional turbine and related works and equipment at Revelstoke;

(d) Site C, a project to build a third dam on the Peace River in northeast British Columbia to provide approximately

(i) 4 600 gigawatt hours of energy each year, and

(ii) 900 megawatts of capacity;

(e) a bio-energy phase 2 call to acquire up to 1 000 gigawatt hours per year of electricity;

(f) one or more agreements with pulp and paper customers eligible for funding under Canada's Green Transformation Program under which agreement or agreements the authority acquires, in aggregate, up to 1 200 gigawatt hours per year of electricity;

(g) the clean power call request for proposals, issued on June 11, 2008, to acquire up to 5 000 gigawatt hours per year of electricity from clean or renewable resources;

(h) the standing offer program described in section 15;

(i) the feed-in tariff program described in section 16;

(j) the actions taken to comply with section 17 (2) and (3);

(k) the program described in section 17 (4).

(2) The persons and their successors and assigns who enter into an energy supply contract with the authority related to anything referred to in subsection (1) are exempt from section 71 of the *Utilities Commission Act* with respect to the energy supply contract.

(3) The commission must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent the authority from doing anything referred to in subsection (1).

2010-22-7.

Rates

8. (1) In setting rates under the *Utilities Commission Act* for the authority, the commission must ensure that the rates allow the authority to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to

(a) the achievement of electricity self-sufficiency, and

(b) a project, program, contract or expenditure referred to in section 7 (1), except

(i) to the extent the expenditure is accounted for in paragraph (a), and

(ii) for costs, prescribed for the purposes of this section, respecting the feed-in tariff program.

(2) Subject to subsection (1) of this section, the commission must set under the *Utilities Commission Act* a rate proposed by the authority with respect to the project referred to in section 7 (1) (a) of this Act.

(3) The commission must not, except on application by the authority, cancel, suspend or amend a rate set in accordance with subsection (2).

(4) The authority must provide to the minister, in accordance with the regulations, an annual report comparing the electricity rates charged by the authority with electricity rates charged by public utilities in other jurisdictions in North America, including an assessment of the extent to which the authority's electricity rates continue to be competitive with those other rates.

2010-22-8.

Domestic long-term sales contracts

9. The authority must establish, in accordance with the regulations, a program to develop potential offers respecting domestic long-term sales contracts for availability to prescribed classes of customers on prescribed terms, including terms respecting price, for prescribed volumes of energy over prescribed periods.

2010-22-9.

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PART 2 — Prohibitions

Two-rivers system development

10. In this Part:

"approval" includes a certificate, licence, permit or other authorization;

"prohibited projects" means

(a) a project of the authority, referred to in Schedule 2 of this Act, for electricity generation on a stream, and
(b) a project for electricity generation on a stream with a storage capability in excess of a prescribed storage capability,

but does not include the two-rivers projects;

"stream" has the same meaning as in section 1 of the *Water Act*;

"two-rivers projects" means

(a) the authority's facilities, on the Peace River and the Columbia River System, existing on the date this section comes into force and upgrades or extensions to those facilities, and
(b) the project commonly known as Site C.

2010-22-10.

Project prohibitions

11. (1) Despite any other enactment, a minister, or an employee or agent of the government or of a municipality or regional district, must not issue an approval under an applicable enactment for a person to

(a) undertake a prohibited project, or

(b) construct all or part of the facilities of a prohibited project.

(2) Despite any other enactment, an approval under another enactment is without effect if it is issued contrary to subsection (1).

2010-22-11.

Prohibited acquisitions

12. (1) In this section:

"facility" means a facility for the generation of electricity and any transmission or distribution equipment to deliver that electricity to the point of interconnection with the authority's integrated service area;

"protected area" means

(a) a park, recreation area, or conservancy, as defined in section (1) of the *Park Act*,
(b) an area established under the *Environment and Land Use Act* as a park or protected area, or
(c) an area established or continued as an ecological reserve under the *Ecological Reserve Act* or by the *Protected Areas of British Columbia Act*.

(2)

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The authority must not make an offer to acquire electricity from a person whose proposed facility is to be located, in whole or in part, in a protected area, unless the location is permitted under the enactments referred to in the definition of "protected area" in subsection (1).

(3) A person referred to in subsection (2) must not offer to sell electricity to the authority.

2010-22-12.

Burrard Thermal

13. The authority must not operate Burrard Thermal, except

(a) in the case of emergency,

(b) to provide transmission support services, or

(c) as authorized by regulation.

2010-22-13.

PART 3 — Preserving Heritage Assets

Sale of heritage assets prohibited

14. (1) The authority must not sell or otherwise dispose of the heritage assets.

(2) Nothing in subsection (1) prevents the authority from disposing of heritage assets if the assets disposed of are no longer used or useful for their intended purpose, or they are to be replaced with one or more assets that will perform similar functions.

2010-22-14.

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PART 4 — Standing Offer and Feed-in Tariff Programs

Standing offer program

15. (1) In this section:

"eligible facility" means a generation facility that

(a) either

(i) has only one generator and the generator's nameplate capacity is less than or equal to the maximum nameplate capacity or has more than one generator and the total nameplate capacity of all of them is a capacity less than or equal to the maximum nameplate capacity, or

(ii) meets the prescribed requirements, and

(b) either

(i) is a high-efficiency cogeneration facility, or

(ii) generates energy by means of a prescribed technology or from clean or renewable resources,

but does not include a prescribed generation facility or class of generation facilities;

"maximum nameplate capacity" means 10 megawatts or, if another capacity is prescribed for the purposes of this section, the prescribed capacity.

(2) The authority must establish and, except in the prescribed circumstances, maintain a standing offer program to acquire electricity from eligible facilities.

(3) The authority may establish, in accordance with the prescribed requirements, if any, the criteria, terms and conditions on which offers under the standing offer program under subsection (2) are to be made.

2010-22-15.

Feed-in tariff program

16. (1) To facilitate the achievement of one or more of British Columbia's energy objectives, the Lieutenant Governor in Council, by regulation, may require the authority to establish a feed-in tariff program.

(2) If the authority is required to establish a feed-in tariff program, the authority may establish, in accordance with the prescribed requirements, if any, the criteria, terms and conditions under which offers may be made under the feed-in tariff program.

(3) The authority may not enter into an energy supply contract as a result of an offer made under the feed-in tariff program if the energy supply contract, by itself or in aggregate with other energy supply contracts entered into under the feed-in tariff program, would result in an expenditure that exceeds the prescribed amount in the prescribed period.

(4) Without limiting section 34 (2) (c),

(a) requirements prescribed by the Lieutenant Governor in Council, and

(b) criteria, terms and conditions established by the authority

made for the purpose of subsection (2) may be made with respect to different regions, prices and technologies.

2010-22-16.

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PART 5 — Energy Efficiency Measures and Greenhouse Gas Reductions

Smart meters

17. (1) In this section:

"private dwelling" means

(a) a structure that is occupied as a private residence, or

(b) if only part of a structure is occupied as a private residence, that part of the structure;

"smart grid" means the prescribed equipment;

"smart meter" means a meter that meets the prescribed requirements, and includes related components, equipment and metering and communication infrastructure that meet the prescribed requirements.

(2) Subject to subsection (3), the authority must install and put into operation smart meters and related equipment in accordance with and to the extent required by the regulations.

(3) The authority must complete all obligations imposed under subsection (2) by the end of the 2012 calendar year.

(4) The authority must establish a program to install and put into operation a smart grid in accordance with and to the extent required by the regulations.

(5) The authority may, by itself, or by its engineers, surveyors, agents, contractors, subcontractors or employees, enter on any land, other than a private dwelling, without the consent of the owner, for a purpose relating to the use, maintenance, safeguarding, installation, replacement, repair, inspection, calibration or reading of its meters, including smart meters, or of its smart grid.

(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.

2010-22-17.

(ADD) **Improvement financing**
Jun
02/11

17.1 (1) In this section:

"borrower" means an eligible person who receives financing under a financing agreement and includes a person to whom obligations are transferred as described in subsection (4) (a) or (6);

"eligible person" means a person who

(a) receives or will receive service in British Columbia from a prescribed public utility,

(b) has obtained an energy report from a qualified energy advisor, and

(c) meets the prescribed requirements, if any;

"energy report" means a report that

(a) is made and signed by a qualified energy advisor,

(b) evaluates the energy efficiency of a building, or a part of a building, owned or occupied by an eligible person,

(c) includes recommendations by the qualified energy advisor for improving the energy efficiency of the building, or the part of the building, referred to in paragraph (b), and

(d) meets the other prescribed requirements, if any;

"financing agreement" means an agreement entered into as a result of an offer made under the program;

"landlord" means a landlord as defined in

(a) the *Residential Tenancy Act*, and

(b) the *Commercial Tenancy Act*;

"program" means a program established under subsection (2);

"qualified energy advisor" means an energy advisor who meets the prescribed qualifications;

"qualified person" means a person who meets the prescribed qualifications;

"tenant" means a tenant as defined in

(a) the *Residential Tenancy Act*, and

(b) the *Commercial Tenancy Act*.

(2) A prescribed public utility must establish and maintain a program to offer financing to eligible persons for improving the energy efficiency of a building, or a part of a building, owned or occupied by a borrower.

(3) Subject to subsection (4), a prescribed public utility may establish, in accordance with the prescribed requirements, if any, the criteria, terms and conditions on which offers under the program are to be made.

(4) A financing agreement must include the following terms:

(a) a borrower may transfer the borrower's obligations under a financing agreement to another person who has applied for service from the prescribed public utility at the building, or the part of the building, that is the subject of the financing agreement;

(b) a borrower's obligations under the borrower's financing agreement are not discharged until

(i) the full amount payable under the financing agreement has been paid,

(ii) the borrower has provided to the prescribed public utility a notice, in a form prescribed by the minister, of a transfer referred to in paragraph (a) or subsection (6), or

(iii) the obligations have been transferred under subsection (6) (a) or (b);

(c) a borrower who is a tenant must,

(i) before entering into the financing agreement, obtain written consent from the tenant's landlord to enter into the financing agreement, and

(ii) before obtaining the consent referred to in subparagraph (i), notify the landlord of the operation of subsection (6);

(d) an improvement financed under the financing agreement must be

(i) an improvement that is

(A) recommended in the energy report respecting the building, or the part of the building, owned or occupied by the borrower, and

(B) in a class of prescribed improvements, and

(ii) carried out by a qualified person.

(5) Subject to subsections (4) (b) and (6), if a borrower transfers a financing agreement to a person referred to in subsection (4) (a), the borrower's obligations

under the financing agreement are transferred to the person on the date that the person begins to receive service from the prescribed public utility.

(6) If a landlord either transfers obligations under a financing agreement to a tenant under subsection (4) (a) or grants to a borrower the written consent referred to in subsection (4) (c), certain of the borrower's obligations under the financing agreement are transferred as follows:

(a) obligations that become due on or after the date that the borrower's tenancy with the landlord ends are transferred from the borrower to the landlord on that date;

(b) subject to subsection (7), obligations that become due on or after the date that a person begins a subsequent tenancy with the landlord respecting the rental unit previously occupied by the borrower are transferred from the landlord to the person on that date.

(7) A landlord referred to in subsection (6) must provide notice, as prescribed, to prospective tenants of the rental unit referred to in that subsection advising those prospective tenants of the operation of subsection (6) (b).

(8) A prescribed public utility may not enter into a financing agreement if doing so would result in the prescribed public utility having an aggregate outstanding balance of all of its financing agreements that exceeds the prescribed amount in the prescribed period.

(9) In setting rates under the *Utilities Commission Act* for a prescribed public utility that has entered into a financing agreement, the commission must incorporate the financing agreement into those rates.

(10) A prescribed public utility has the same remedies in the event of a borrower's failure to pay an amount under a financing agreement that has been incorporated into its rates as it has for a borrower's failure to pay any other rates the borrower is obligated to pay as a customer of the public utility.

(11) Without limiting section 36 (1) (c),

(a) a requirement prescribed by the minister, and

(b) criteria, terms and conditions established by a prescribed public utility

made for the purposes of subsection (3) of this section may be made with respect to different regions and improvements and, in the case of a requirement prescribed by the minister, with respect to different prescribed public utilities.

2011-5-33.

Greenhouse gas reduction

18. (1) In this section, **"prescribed undertaking"** means a project, program, contract or expenditure that is in a class of projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in British Columbia.

(2) In setting rates under the *Utilities Commission Act* for a public utility carrying out a prescribed undertaking, the commission must set rates that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking.

(3) The commission must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent a public utility referred to in subsection (2) from carrying out a prescribed undertaking.

(4) A public utility referred to in subsection (2) must submit to the minister, on the minister's request, a report respecting the prescribed undertaking.

(5)

A report to be submitted under subsection (4) must include the information the minister specifies and be submitted in the form and by the time the minister specifies.

2010-22-18.

Clean or renewable resources

19. (1) To facilitate the achievement of British Columbia's energy objective set out in section 2 (c), a person to whom this subsection applies

(a) must pursue actions to meet the prescribed targets in relation to clean or renewable resources, and

(b) must use the prescribed guidelines in planning for

(i) the construction or extension of generation facilities, and

(ii) energy purchases.

(2) Subsection (1) applies to

(a) the authority, and

(b) a prescribed public utility, if any, and a public utility in a class of prescribed public utilities, if any.

2010-22-19.

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PART 6 — First Nations Clean Energy Business Fund

First Nations Clean Energy Business Fund

20. (1) In this section:

"first nation" means

(a) a band, as defined in the *Indian Act* (Canada), and

(b) an aboriginal governing body, however organized and established by aboriginal people;

"power project" means an electricity generation or transmission project

(a) that is in a class of projects prescribed for the purposes of this section, other than a project of any organization in the government reporting entity, as defined in the *Budget Transparency and Accountability Act*,

(b) for which a licence, if applicable, under the *Water Act* for a power purpose, as defined section 1 of that Act, is issued after the date this section comes into force, and

(c) for which a prescribed authorization, if applicable, under an enactment respecting land is granted after this section comes into force;

"special account" means the special account, as defined in section 1 of the *Financial Administration Act*, established under subsection (2) of this section.

(2) A special account, to be known as the First Nations Clean Energy Business Fund special account, is established.

(3) The initial balance of the special account is an amount, not to exceed $5 million, prescribed by Treasury Board.

(4) The balance of the special account is increased by

(a) any other amount received by the government for payment into the account, and

(b) a prescribed percentage of the prescribed land and water revenues the government derives from power projects.

(5) Despite section 21 (3) of the *Financial Administration Act*, the minister, in accordance with a spending plan approved by Treasury Board, may pay an amount of money out of the special account for any of the following purposes:

(a) to share the revenues referred to in subsection (4) (b), up to a prescribed percentage of the revenue, under an agreement or agreements with one or more first nations;

(b) to facilitate the participation of first nations and aboriginal people in the clean energy sector;

(c) to pay the costs of administering the special account.

2010-22-20.

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PART 7 — Transmission Corporation

Part 7: Division 1 – Transfer of Property, Shares and Obligations

(ADD)**Definitions**
Jul
05/10

21. (1) In this Division:

"excluded contract" means a contract that was entered into, assumed by or assigned to the transmission corporation and that is governed by the law of a jurisdiction other than British Columbia;

"excluded permit" means a permit, approval, registration, authorization, licence, exemption, order or certificate issued, granted or provided to the transmission corporation under the law of a jurisdiction other than British Columbia;

"included contract" includes any contract entered into, assumed by or assigned to the transmission corporation, but does not include an excluded contract;

"included permit" includes a permit, approval, registration, authorization, licence, exemption, order or certificate, including a certificate of public convenience and necessity under the *Utilities Commission Act*, but does not include an excluded permit;

"right" , in relation to a right held by the authority or the transmission corporation, includes a right under a trust, a cause of action and a claim.

2010-22-21.

(ADD)**Transfer of property**
Jul
05/10

22. (1) Subject to subsection (2) and despite any enactment or law to the contrary, on the coming into force of this Part, all of the transmission corporation's rights, property, assets, included contracts and included permits are transferred to and vested in the authority.

(2) Subsection (1) does not apply to excluded contracts and excluded permits.

(3) Despite any enactment or law to the contrary, on the coming into force of this Part, the shares of the transmission corporation are transferred to and vested in the authority.

(4) The shares transferred to and vested in the authority under subsection (3) must not be sold or otherwise disposed of, but may be surrendered for cancellation.

(5) Despite any enactment or law to the contrary,

(a) the transfer and vesting effected by subsections (1) and (3) take effect without

(i) the execution or issue of any record, or

(ii) any registration or filing of this Act or any other record in or with any registry or other office,

(b) the transfer and vesting effected by subsections (1) and (3) take effect despite

(i) any prohibition on all or any part of the transfer and vesting, and

(ii) the absence of any consent or approval that is or may be required for all or any part of the transfer and vesting,

(c) if any right, property, asset, included contract or included permit referred to in subsection (1) is registered or otherwise recorded in the name of the transmission corporation, the registration or record may remain but is deemed, for all purposes of this and all other enactments and law, to reflect that the right, property, asset, included contract or included permit is owned by and vested in or held by the authority, and

(d) in any record in or by which the authority deals with a right, property, asset, included contract or included permit referred to in subsection (1), it is sufficient to cite this Act as effecting and confirming the transfer from the transmission corporation to the authority of the included contract or included permit or of the title to the right, property or asset and the vesting of that title in the authority.

(6) For the purposes of this section, assets that become assets of the authority under this section include records and parts of records, and, without limiting this, all of the records and parts of records of the transmission corporation are transferred to and become the records of the authority on the coming into force of this Part.

(7) Without limiting subsection (5) (c) of this section, or section 383.1 of the *Land Title Act*, if a right, property or asset referred to in subsection (1) of this section is registered or recorded in the name of the transmission corporation,

(a) the authority may, in its own name,

(i) effect a transfer, charge, encumbrance or other dealing with the right, property or asset, and

(ii) execute any record required to give effect to that transfer, charge, encumbrance or other dealing, and

(b) an official

(i) who has authority over a registry or office, including, without limitation, the personal property registry and a land title office, in which title to or interests in the right, property or asset is registered or recorded, and

(ii) to whom a record referred to in paragraph (a) (ii) executed by or on behalf of the authority is submitted in support of the transfer, charge, encumbrance or other dealing

must give the record the same effect as if it had been duly executed by the transmission corporation.

2010-22-22.

(ADD)**Transfer of obligations and liabilities**

Jul
05/10

23. On the coming into force of this Part, all obligations and liabilities of the transmission corporation, except for obligations and liabilities under an excluded contract or excluded permit,

(a) are transferred to and assumed by the authority,

(b) become the authority's obligations and liabilities,

(c) cease to be obligations and liabilities of the transmission corporation, and

(d) may be enforced against the authority as if the authority had incurred them.

2010-22-23.

(ADD)**Records of transferred assets and liabilities**

Jul
05/10

24. (1) Subject to subsection (2), a reference to the transmission corporation in any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate that relates to anything transferred to the authority under this Part, is deemed to be a reference to the authority.

(2) If, under this Part, a part of a right, property, asset, obligation or liability is transferred to the authority, any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate that relates to anything transferred to the authority under this Part, is deemed to be amended to reflect the authority's interests in that right, property, asset, obligation or liability.

2010-22-24.

(ADD)**Transfer is not a default**
Jul
05/10

25. Despite any provision to the contrary in any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate, the transfer to the authority of a right, property, asset, included contract, included permit, share, obligation or liability under sections 22 and 23 does not constitute a breach or contravention of, or an event of default under, or confer a right to terminate the document, and, without limiting this, does not entitle any person who has an interest in the right, property, asset, included contract, included permit, share, obligation or liability to claim any damages, compensation or other remedy.

2010-22-25.

(ADD)**Legal proceedings**
Jul
05/10

26. (1) Any legal proceeding being prosecuted or pending by or against the transmission corporation on the date this Part comes into force may be prosecuted, or its prosecution may be continued, by or against the authority, and may not be prosecuted or continued against the transmission corporation.

(2) A conviction against the transmission corporation may be enforced against the authority, and may not be enforced against the transmission corporation.

(3) A ruling, order or judgment in favour of or against the transmission corporation may be enforced by or against the authority, and may not be enforced by or against the transmission corporation.

(4) A cause of action or claim against the transmission corporation existing on the date this Part comes into force must be prosecuted against the authority.

(5) Subject to subsections (1) to (4), a cause of action, claim or liability to prosecution existing on the date this Part comes into force is unaffected by anything done under this Part.

2010-22-26.

Part 7: Division 2 – Employees

Definitions

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(ADD)
Jul
05/10

27. In this Division:

"adjustment plan" means an adjustment plan under section 54 of the *Labour Relations Code*;

"collective agreement" has the same meaning as in section 1 (1) of the *Labour Relations Code*.

2010-22-27.

(ADD)**Transfer of employees**
Jul
05/10

28. (1) It is deemed that the persons who were, immediately before the coming into force of this Part, employees of the transmission corporation are, on the coming into force of this Part, transferred to and become employees of the authority.

(2) A question or difference between the authority and

(a) a transferred employee who is a member of a unit of employees for which a trade union has been certified under the *Labour Relations Code*, or

(b) a trade union representing transferred employees,

respecting the application of the *Labour Relations Code*, or the interpretation or application of this Division, may be referred to the Labour Relations Board in accordance with the procedure set out in the *Labour Relations Code* and its regulations.

(3) The Labour Relations Board may decide a question or difference referred to in subsection (2) in any of the ways, and by applying any of the remedies, available under the *Labour Relations Code*.

(4) On the date this Part comes into force, in respect of employees who are members of units of employees for which a trade union has been certified under the *Labour Relations Code*, the authority is the successor employer of those employees for the purposes of section 35 of the *Labour Relations Code*, without prejudice to the authority's right to apply for consolidation or merger of the bargaining units.

(5) If the authority or any trade union representing transferred employees makes an application to the Labour Relations Board to consolidate or merge the bargaining units representing transferred employees into a single bargaining unit for each trade union, the Labour Relations Board must consider that application having regard to the principles of business efficiency and without reference to the labour relations history at the authority or the transmission corporation relating to the presence of more than one bargaining unit for each trade union.

2010-22-28.

(ADD)**Continuous employment**
Jul
05/10

29. (1) The transfer of a transferred employee does not constitute a termination of the transferred employee's employment for the purposes of

(a) an applicable collective agreement,

(b) any employment contract involving the transferred employee, and

(c) the *Employment Standards Act*.

(2) A transferred employee who is not subject to a collective agreement is deemed to have been employed by the authority without interruption in service.

(3) The service, with the transmission corporation, of a transferred employee who is not subject to a collective agreement is deemed to be service with the authority for the purpose of determining probationary periods and benefits, and any other employment related entitlements, under

(a) the *Employment Standards Act*,

(b) any other enactment, and

(c) any employment contract.

(4) For the purposes of seniority, a transferred employee who is subject to a collective agreement is deemed to have been employed by the authority without interruption in service, unless the authority and the trade union representing the transferred employee have agreed to other seniority terms in an adjustment plan within 60 days after notice under section 54 of the *Labour Relations Code* is given, in which case the applicable terms respecting seniority in the adjustment plan apply.

(5) The service, with the transmission corporation, of a transferred employee who is subject to a collective agreement is deemed to be service with the authority for the purpose of determining probationary periods and benefits, and any other employment related entitlements, under

(a) the *Employment Standards Act*,

(b) any other enactment, and

(c) any collective agreement,

unless the authority and the trade union representing the transferred employee have agreed to other probationary periods, benefits and entitlements in an adjustment plan within 60 days after notice under section 54 of the *Labour Relations Code* is given, in which case the applicable terms respecting probationary periods, benefits and entitlements in the adjustment plan apply.

(6) A transferred employee is deemed not to have been constructively dismissed solely by virtue of the transfer under section 28.

(7) Nothing in this Part

(a) prevents the employment of a transferred employee from being lawfully terminated after the transfer under section 28,

(b) prevents any term or condition of the employment of a transferred employee from being lawfully changed after the transfer under section 28, or

(c) removes any right or remedy of a person who is terminated after the transfer under section 28 or in respect of whom a term or condition of employment has been changed after the transfer under section 28.

2010-22-29.

(ADD)**Pensions**
Jul
05/10

30. (1) For the purposes of the *Pension Benefits Standards Act*, the transfer of a transferred employee does not constitute a termination of membership in the transmission corporation's registered pension plan, or any other pension arrangement sponsored by the transmission corporation.

(2) Despite section 36 (1) of the *Hydro and Power Authority Act*, the authority does not require the approval of the Lieutenant Governor in Council to amend the authority's registered pension plan to implement the provisions of this Part, including the authority's assumption of all liability for the pension benefits payable under the transmission corporation's registered pension plan.

(3) Despite any enactment or law to the contrary, on the coming into force of this Part, all of the rights, property and assets that comprise

(a) the balance of fund account of the pension fund of the transmission corporation's registered pension plan are transferred to and vested in the balance of fund account of the pension fund of the authority's registered pension plan, and

(b) the index reserve account and past service index reserve account of the pension fund of the transmission corporation's registered pension plan are transferred to and vested in the index reserve account of the pension fund of the authority's registered pension plan,

and the resulting pension fund must be held by the trustee of the pension fund of the authority's registered pension plan.

(4) Section 22 (5) applies to the transfer and vesting effected by subsection (3) of this section.

2010-22-30.

Part 7: Division 3 – General

(REP) **Repealed**
Jul
01/11

31. (1) and (2) *Repealed.* [2010-22-31(3)]

(3) *[Spent]*

(ADD) ***Utilities Commission Act***
Jul
05/10

32. (1) No approval, authorization, permit, certificate, exemption, permission, registration or order is required under the *Utilities Commission Act* with respect to

(a) the transmission corporation's ceasing to provide the service referred to in subsection (2) (a), or

(b) any transfer under this Part.

(2) The authority is deemed to have all the approvals, authorizations, permits, certificates, exemptions, permissions, registrations or orders that, under the *Utilities Commission Act*, are or may be required to continue

(a) to provide the service the transmission corporation provided immediately before the coming into force of this Part, and

(b) to charge, collect and enforce the rates the transmission corporation charged, collected and enforced immediately before the coming into force of this Part.

(REP)
Jul
01/11

(3) *Repealed.* [2010-22-32(4)]

(4) *[Spent]*

2010-22-32; 2010-22-31(4); 2010-22-32(4).

(ADD) **Designated agreements**
Jul

05/10

33. On the coming into force of this Part, the agreements designated under section 3 of the *Transmission Corporation Act* have no force or effect.

2010-22-33.

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PART 8 — Regulations

Part 8: Division 1 – Regulations by Lieutenant Governor in Council

General

34. (1) The Lieutenant Governor in Council may make regulations referred to in section 41 of the *Interpretation Act*.

(2) In making a regulation under this Act, the Lieutenant Governor in Council may do one or more of the following:

(a) delegate a matter to a person;

(b) confer a discretion on a person;

(c) make different regulations for different persons, places, things, decisions, transactions or activities.

2010-22-34.

Regulations

35. Without limiting section 34 (1), the Lieutenant Governor in Council may make regulations as follows:

(a) respecting forecasts for the purposes of the definition of "electricity supply obligations" in section 6 (1);

(b) adding a heritage asset to Schedule 1 of this Act;

(c) prescribing water conditions for the purposes of the definition of "heritage energy capability" in section 6 (1);

(d) modifying or adding to British Columbia's energy objectives, except for the objective specified in section 2 (g);

(e) for the purposes of sections 44.1, 44.2, 46 and 71 of the *Utilities Commission Act*, respecting the application of British Columbia's energy objectives to public utilities other than the authority;

(f) establishing factors or guidelines the commission must follow in respect of British Columbia's energy objectives, including guidelines regarding the relative priority of the objectives set out in section 2;

(g) respecting consultations the authority must carry out in relation to

(i) the development of an integrated resource plan and of an amendment to an integrated resource plan,

(ii) an integrated resource plan submitted under section 3 (6), and

(iii) an amendment to an integrated resource plan submitted under section 3 (7);

(h) prescribing submission dates for the purposes of section 3 (6);

(i) respecting the authority's obligation under section 6 (3), including, without limitation, regulations permitting the authority to enter into contracts respecting the electricity referred to in section 6 (2) (a) and (b) and prescribing the terms and conditions on which, and the volume of electricity about which, the contracts may be entered into;

(j) respecting the program referred to in section 9, including prescribing classes of customers and terms;

(k) prescribing storage capability for the purposes of the definition of "prohibited projects" in section 10, including, without limitation, prescribing storage capability in terms of time, impoundment, mechanism or area;

(l) respecting the standing offer program to be established under section 15, including, without limitation, regulations that

(i) prescribe requirements, technologies, generation facilities and classes of generation facilities for the purposes of the definition of "eligible facility" in section 15 (1),

(ii) prescribe a capacity for the purposes of the definition of "maximum nameplate capacity" in section 15 (1),

(iii) prescribe circumstances for the purposes of section 15 (2), and

(iv) prescribe requirements for the purposes of section 15 (3);

(m) respecting the feed-in tariff program that may be established under section 16, including, without limitation, regulations that

(i) prescribe regions and technologies for the purposes of the definition of "feed-in tariff program" in section 1 (1),

(ii) require the authority to establish the feed-in tariff program,

(iii) prescribe requirements for the purposes of section 16 (2),

(iv) prescribe costs for the purposes of section 8 (1) (b);

(n) for the purposes of the definition of "prescribed undertaking" in section 18, prescribing classes of projects, programs, contracts or expenditures that encourage

(i) the use of

(A) electricity, or

(B) energy directly from a clean or renewable resource

instead of the use of other energy sources that produce higher greenhouse gas emissions, or

(ii) the use of natural gas, hydrogen or electricity in vehicles, and the construction and operation of infrastructure for natural gas or hydrogen fueling or electricity charging.

2010-22-35.

Part 8: Division 2 – Regulations by Minister

General

36. (1) In making a regulation under this Act, the minister may do one or more of the following:

(a) delegate a matter to a person;

(b) confer a discretion on a person;

(c) make different regulations for different persons, places, things, decisions, transactions or activities.

(2) The minister may make a regulation defining, for the purposes of this Act, a word or expression used but not defined in this Act.

2010-22-36.

Regulations

37. The minister may make regulations as follows:

(a) prescribing resources for the purposes of the definition of "clean or renewable resource" in section 1 (1);

(b) prescribing exclusions for the purposes of the definition of "demand-side measure" in section 1 (1);

(c) authorizing the authority for the purposes of sections 3 (5), 6 and 13;

(d) describing the projects, programs, contracts and expenditures referred to in section 7 (1), including, without limitation, by specifying the property, interests, rights, activities, contracts and rates that comprise the projects, programs, contracts and expenditures;

(e) specifying sections of the *Utilities Commission Act* for the purposes of section 7 (1);

(f) respecting reports to be provided to the minister by the authority under section 8 (4), including, without limitation, regulations respecting the jurisdictions with which comparisons are to be made, the rate classes to be considered, the factors to be used in making the comparisons and conducting the assessments, and the meaning to be given to the word "competitive";

(g) for the purposes of section 17, respecting smart meters and smart-grids and their installation, including, without limitation,

(i) prescribing the types of smart meters to be installed, including the features or functions each meter must have or be able to perform,

(ii) prescribing types of smart grids to be installed, including, without limitation, equipment to detect unauthorized use or consumption of electricity, equipment to facilitate distributed generation and associated telecommunication and back-up systems, and

(iii) prescribing the classes of users for whom smart meters must be installed, and, without limiting section 36 (1) (c), requiring the authority to install different types of smart meters for different classes of users;

(ADD) Jun 02/11

(g.1) for the purposes of section 17.1, including, without limitation,

(i) prescribing requirements for the purposes of the definitions of "eligible person" and "energy report" in section 17.1 (1),

(ii) prescribing qualifications for the purposes of the definitions of "qualified person" and "qualified energy advisor" in section 17.1 (1),

(iii) prescribing public utilities and classes of public utilities to which section 17.1 (2) applies,

(iv) prescribing requirements for the purposes of section 17.1 (3),

(v) prescribing forms for the purposes of section 17.1 (4) (b) (ii),

(vi) prescribing classes of improvements for which financing agreements may be made,

(vii) respecting the notice referred to in section 17.1 (7), and

(viii) prescribing amounts and periods for the purposes of section 17.1 (8);

(h) prescribing targets, guidelines, public utilities and classes of public utilities for the purposes of section 19;

(i) issuing a direction for the purposes of section 31.

2010-22-37; 2011-5-34.

Part 8: Division 3 – Regulations by Treasury Board

Regulations

38. Treasury Board may make regulations as follows:

(a) prescribing classes of projects and authorizations for the purposes of the definition of "power project" in section 20 (1), including, without limitation, prescribing classes of projects by reference to whether, or the extent to which, a project is a project of any organization of the government reporting entity, within the meaning of that definition;

(b) prescribing amounts and percentages for the purposes of section 20 (3), (4) (b) and (5) (a).

2010-22-38.

PART 9 — Transition

Transition

39. (1) The Lieutenant Governor in Council may make regulations considered appropriate for the purpose of more effectively bringing this Act into operation, and to remedy any transitional difficulties encountered in doing so, and for that purpose, may make regulations disapplying or varying any provision of this Act.

(2) Subject to subsection (3), this section is repealed on the date that is 2 years after the coming into force of this section and, on this section's repeal, any regulations made under it are also repealed.

(3) The Lieutenant Governor in Council, by regulation, may substitute for the date referred to in subsection (2) a date that is no later than 3 years after the coming into force of this section.

2010-22-39.

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SCHEDULE 1

[2010-22-Sch. 1.]

Heritage Assets

Those generation and storage assets commonly known as the following:

Aberfeldie
Alouette
Ash River
Bridge River
Buntzen/Coquitlam
Burrard Thermal
Cheakamus
Clowhom
Duncan
Elko
Falls River
Fort Nelson
G. M. Shrum
Hugh Keenleyside Dam (Arrow Reservoir)
John Hart
Jordan
Kootenay Canal
La Joie
Ladore
Mica, including units 1 to 6
Peace Canyon
Prince Rupert
Puntledge
Revelstoke, including units 1 to 6
Ruskin
Site C
Seton
Seven Mile
Shuswap
Spillimacheen
Stave Falls
Strathcona
Waneta
Wahleach
Walter Hardman
Whatshan

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SCHEDULE 2

[2010-22-Sch. 2.]

Prohibited Projects

The projects of the authority, as set out in appendix F-8 of the authority's long-term acquisition plan, exhibit B-1-1, filed with the commission on June 12, 2008, are prohibited projects for the purposes of section 10, in particular, the following projects identified in appendix F-8:

(a) Murphy Creek
(b) Border;
(c) High Site E;
(d) Low Site E;
(e) Elaho;
(f) McGregor Lower Canyon;
(g) Homathko River;
(h) Liard River;
(i) Iskut River;
(j) Cutoff Mountain;
(k) McGregor River Diversion.

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Appendix B-6

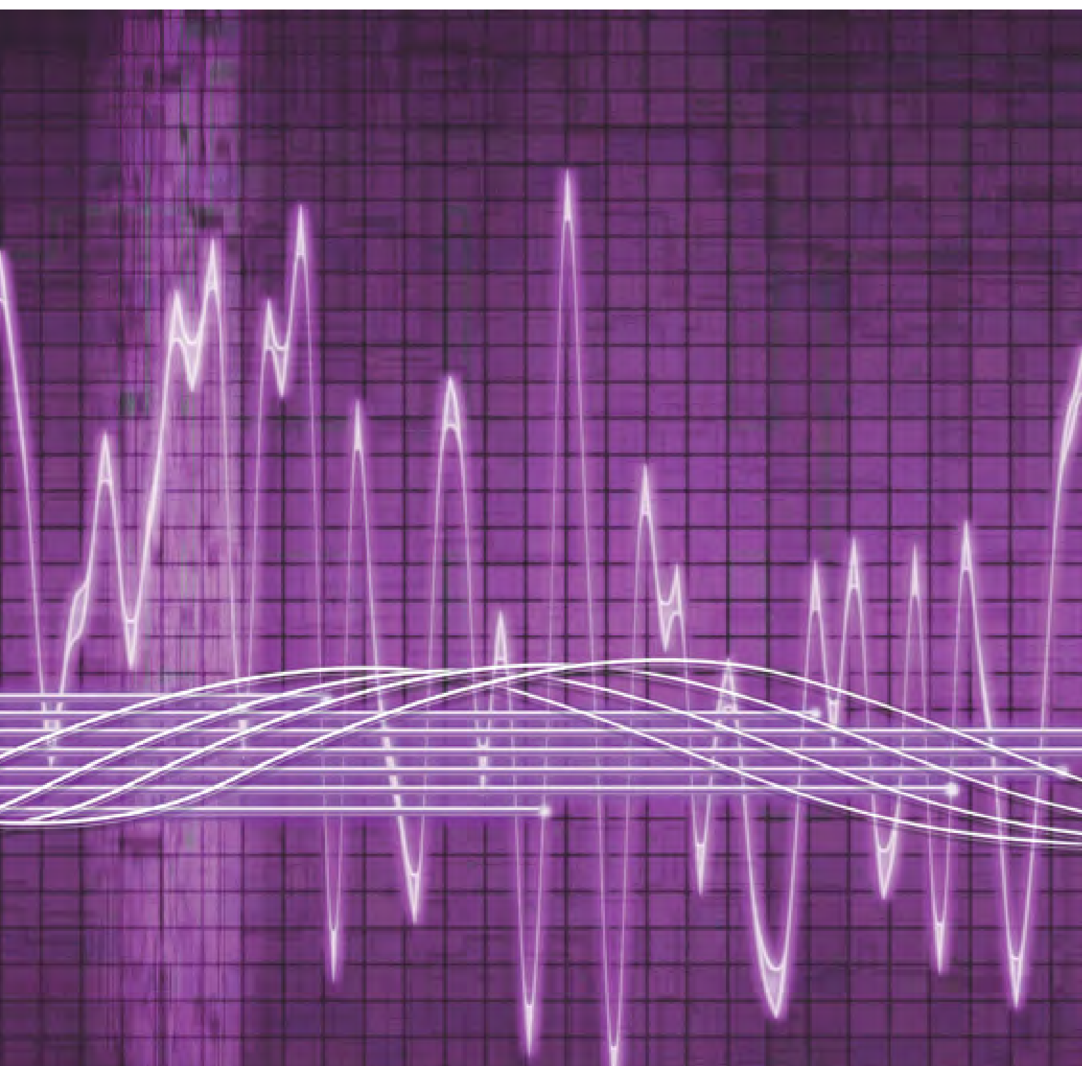
Health Canada Safety Code 6

Health Canada | Santé Canada

Your health and safety… our priority. | *Votre santé et votre sécurité… notre priorité.*

Limits of Human Exposure to Radiofrequency Electromagnetic Energy in the Frequency Range from 3 kHz to 300 GHz

Safety Code 6 (2009)



Canada

Errata

Section 2.3, page 19

“For frequencies between 3 kHz and 100 kHz, the averaging time for induced and contact currents shall be 1 second (Section 2.1.2). For frequencies greater than 100 kHz and up to 15 000 MHz, time averaging provisions in this code take into account that the basic restrictions are designed to limit temperature increases in tissues. Temperature increases in living tissue due to RF energy absorption follow a well-defined pattern with a time constant of approximately 6 minutes (thermal time constant), where ~~67%~~ **63%** of the steady state temperature increase occurs within 6 min. Time averaging permits exposures to be greater than the limits outlined in Sections 2.1 and 2.2 over short periods of time, provided that the total absorbed energy in any 6 min period does not exceed the energy absorbed from a constant (time invariant) exposure at the limits outlined in Sections 2.1 and 2.2. Since time averaging is based on absorbed energy considerations, the electric and magnetic field intensities shall be squared before time averaging is applied, while the power density and SAR are applied directly.”

Limits of Human Exposure to Radiofrequency Electromagnetic Energy in the Frequency Range from 3 kHz to 300 GHz

Consumer and Clinical Radiation Protection Bureau
Environmental and Radiation Health Sciences Directorate
Healthy Environments and Consumer Safety Branch
Health Canada

Safety Code 6 (2009)

Health Canada is the federal department responsible for helping the people of Canada maintain and improve their health. *We assess the safety of drugs and many consumer products, help improve the safety of food, and provide information to Canadians to help them make healthy decisions. We provide health services to First Nations people and to Inuit communities. We work with the provinces to ensure our health care system serves the needs of Canadians.*

Published by authority of the Minister of Health.

Limits of human exposure to radiofrequency electromagnetic energy in the frequency range from 3 kHz to 300 GHz is available on the Internet at the following address:
www.hc-sc.gc.ca/ewh-semt/pubs/radiation/index-eng.php

Également disponible en français sous le titre :
Limites d'exposition humaine à l'énergie électromagnétique radioélectrique dans la gamme de fréquences de 3 kHz à 300 GHz

This publication can be made available on request on diskette, large print, audio-cassette and braille.

For further information or to obtain additional copies, please contact:
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Preface

This document is one of a series of safety codes prepared by the Consumer and Clinical Radiation Protection Bureau, Health Canada. These safety codes specify the requirements for the safe use of, or exposure to, radiation emitting devices. This revision replaces the previous version of Safety Code 6 (99–EHD–237) published in 1999.

The purpose of this code is to establish safety limits for human exposure to radiofrequency (RF) electromagnetic energy in the frequency range from 3 kHz to 300 GHz. The safety limits in this code apply to all individuals working at, or visiting, federally regulated sites. These guidelines may also be adopted by the provinces, industry or other interested parties. The Department of National Defence shall conform to the requirements of this safety code, except in such cases where it considers such compliance to have a detrimental effect on its activities in support of training and operations of the Canadian Forces. This code has been adopted as the scientific basis for the equipment certification specifications outlined in Industry Canada's regulatory compliance documents[1–3], that govern the use of wireless devices in Canada, such as cell phones, cell towers (base stations) and broadcast antennae. Safety Code 6 does not apply to the deliberate exposure for treatment of patients by, or under the direction of, medical practitioners. Safety Code 6 is not intended for use as a product performance specification document, as the limits in this safety code are for controlling human exposure and are independent of the source of RF energy.

In a field where technology is advancing rapidly and where unexpected and unique problems may occur, this code cannot cover all possible situations. Consequently, the specifications in this code may require interpretation under special circumstances. This interpretation should be done in consultation with scientific staff at the Consumer and Clinical Radiation Protection Bureau, Health Canada.

The safety limits in this code are based on an ongoing review of published scientific studies on the health impacts of radiofrequency electromagnetic energy. This code is periodically revised to reflect new knowledge in the scientific literature and the exposure limits may be modified, if deemed necessary.

Table of Contents

1. Introduction

Electromagnetic radiation is emitted by many natural and man-made sources and is a fundamental aspect of our lives. We are warmed by electromagnetic radiation emitted from the sun and our eyes can detect the visible light portion of the electromagnetic spectrum. Radiofrequency (RF) energy is a portion of the electromagnetic spectrum with frequencies ranging from 3 kHz to 300 GHz, below that of visible light and above that of extremely low frequency (ELF) electromagnetic energy. RF energy is produced by many man-made sources including cellular (mobile) phones and base stations, television and radio broadcasting facilities, radar, medical equipment, microwave ovens, RF induction heaters as well as a diverse assortment of other electronic devices within our living and working environments.

It has long been recognized that sufficiently intense RF energy can cause heating of materials with finite conductivity, including biological tissues. A number of well established biological effects and adverse health effects from acute exposure to intense RF energy have been documented[(4–9)]. For the most part, these effects relate to localized heating or stimulation of excitable tissue from intense RF energy exposure. The specific biological responses to RF energy are generally related to the rate of energy absorbed. The rate and distribution of RF energy absorption depends strongly on the frequency, intensity and orientation of the incident fields as well as the body size and its constitutive properties (dielectric constant and conductivity). At frequencies between 100 kHz and 6 GHz, RF energy absorption is commonly described in terms of the specific absorption rate (SAR), which is a measure of the rate of energy deposition per unit mass of body tissue and is usually expressed in units of watts per kilogram (W/kg). Based on a large amount of historical knowledge, national and international exposure limits have been established to protect the general public against adverse effects associated with acute RF energy exposures[(8–9)].

The exposure limits specified in Safety Code 6 have been 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[(8–12)]. 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.

In the following sections, the maximum exposure levels for persons in both controlled and uncontrolled environments are specified. These levels shall not be exceeded.

1.1 Purposes of the Code

The purposes of this code are to:

(a) specify maximum levels of human exposure to RF energy at frequencies between 3 kHz and 300 GHz, to prevent adverse human health effects;

(b) specify maximum allowable RF contact and induced body currents to prevent the physical perception of internal currents resulting from RF energy in uncontrolled environments, and to prevent RF shock or burns to personnel in controlled environments;

(c) provide guidance for evaluating RF exposure levels, to ensure that personnel in controlled and uncontrolled environments are not exposed at levels greater than the limits specified in this code.

2. Maximum Exposure Limits

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).

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. 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.

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. Experimental studies have demonstrated that exogenous electric and magnetic field exposures can induce *in situ* electric fields and currents within biological tissue that can lead to nerve and muscle depolarization(5, 8–9, 31–32). Limits for maximum external electric and magnetic field strengths have been established in Safety Code 6 to avoid *in situ* electric field strengths greater than that of the minimum excitation threshold for excitable tissues.

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 ^{o}C, 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.

Peak (spatial-average) SAR limits have also been established in Safety Code 6 to avoid excessive thermal effects (hot-spots) in localized human tissues. The peak SAR limits reflect the highly non-homogenous nature of typical RF energy exposures and the differing thermoregulatory properties of various body tissues. The peak SAR limits pertain to discrete tissue volumes (1 or 10 g), where thermoregulation can efficiently dissipate heat and avoid changes (>1^{o}C) in core body temperature. As such, the peak SAR limits for exposures in controlled environments are 20 W/kg for the limbs and 8 W/kg for the head, neck and trunk. For exposures in uncontrolled environments, the peak SAR limits are 4.0 W/kg for the limbs and 1.6 W/kg for the head, neck and trunk. There are also limits in Safety Code 6 for the avoidance of painful shocks or burns from contact currents.

The basic restrictions which shall not be exceeded are given in terms of the currents in the body, either by induction or contact with energized metallic objects, or in terms of the rate at which RF electromagnetic energy is absorbed in the body (i.e. SAR). In practice, direct measurements of SAR are only feasible under laboratory conditions. Therefore, recommended maximum exposure levels in terms of unperturbed electric and magnetic field strength as well as power density are given in addition to the SAR limits. These maximum field intensities are at levels that ensure that the SAR or induced body current will be no greater than that of the basic restrictions. Additional factors such as temporal variations in intensity and spatial distribution of the exposure fields are accounted for by provisions for time and spatial averaging. Exposure to RF energy in excess of the limits given in this safety code, when time and spatially-averaged, may cause adverse health effects.

For the purpose of this code, controlled environments are defined as those where all of the following conditions are satisfied:

(a) the RF field intensities in the controlled area have been adequately characterized by means of measurements, calculations or modeling (such as with the use of FDTD [finite difference time domain] software),

(b) the exposure is incurred by persons who are aware of the potential for RF exposure and are cognizant of the intensity of the RF energy in their environment and,

(c) the exposure is incurred by persons who are aware of the potential health risks associated with RF energy exposures and whom can control their risk using mitigation strategies.

All situations that do not meet the specifications above are considered to be uncontrolled environments. Uncontrolled environments are defined as areas where either insufficient assessment of RF energy has been conducted or where persons who are allowed access to these areas have not received proper RF awareness training and have no means to assess or, if required, mitigate their exposure to RF energy.

To determine whether the maximum exposure levels are exceeded, full consideration shall be given to such factors as:

(a) nature of exposure environment (controlled or uncontrolled);

(b) duration of exposure and/or time-averaging (including ON/OFF times of the RF source, direction of the beam, duty factors, sweep times, etc...);

(c) spatial characteristics of exposure (i.e. whole body or parts thereof);

(d) uniformity of the exposure field (i.e. spatial averaging).

In certain circumstances, higher exposure levels may be permitted for short durations. If this is the case, the field strengths and power densities should be averaged over any one tenth-hour period (0.1 h or 6 min). Graphs are provided in Appendix I for easy identification of maximum exposure levels at various frequencies.

SI units are used throughout this document unless specified otherwise.

2.1 Basic Restrictions

2.1.1 Specific Absorption Rate (SAR) Limits

The specific absorption rate (SAR) is a measure of the rate at which electromagnetic energy is absorbed in the body. At frequencies between 100 kHz and 6 GHz, SAR limits take precedence over field strength and power density limits and shall not be exceeded.

The SAR should be determined for situations where exposures occur at a distance of 0.2 m or less from the source. In cases where SAR determination is feasible, the values in Table 1 shall not be exceeded. For conditions where SAR determination is impractical, field strength or power density measurements shall be carried out and the limits outlined in Section 2.2 shall be respected.

Table 1. SAR Exposure Limits for Controlled and Uncontrolled Environments.

Condition	SAR Limit (W/kg)	
	Controlled Environment	Uncontrolled Environment
The SAR averaged over the whole body mass.	0.4	0.08
The spatial peak SAR for the head, neck and trunk, averaged over any one gram (g) of tissue*.	8	1.6
The spatial peak SAR in the limbs as averaged over any 10 g of tissue*.	20	4

* Defined as a tissue volume in the shape of a cube. A 10 g mass of tissue represents a volume of approximately 10 cm^3, while 1 g of tissue represents a volume of approximately 1 cm^3.

Note: Although not a requirement of the code, it is suggested that whenever possible, the organ-averaged SAR for the eye should not exceed 0.4 W/kg in the controlled environment and 0.2 W/kg in the uncontrolled environment.

2.1.2 Induced and Contact Current Limits

Limits for induced and contact currents are intended to reduce the potential for RF shock or burns as follows:

(a) For free standing individuals (standing upright, no contact with metallic objects), current induced in the human body by electromagnetic energy in the frequency bands listed in Column 1 of Tables 2 and 3, shall not exceed the values specified in Column 2 of:

(i) Table 2 for Controlled Environments.

(ii) Table 3 for Uncontrolled Environments.

An evaluation for compliance with the limits of induced currents should be made with an appropriate instrument. Measurements should be made with a person or a human equivalent antenna standing upright.

Note: Induced current through both feet can be measured by using a clamp-on current probe or a low profile platform consisting of two parallel conductive plates isolated from each other and one located above the other. If the latter is used, the platform should be placed on the surface where the person stands, and a person or a human equivalent antenna is placed on the upper plate of the platform. A voltage drop on a low-inductance resistor connected between the plates provides a measure of the induced current.

(b) No object, with which an individual may come into contact by hand grip, shall be energized by electromagnetic energy in the frequency bands listed in Column 1 of Tables 2 and 3, to such an extent that the maximum current flow through a human body, exiting through the feet, exceeds the values specified in Column 3 of:

(i) Table 2 for Controlled Environments.

(ii) Table 3 for Uncontrolled Environments.

Note 1: For any conducting metallic object that a person may come into contact with, that is located near a high-intensity RF field, contact currents shall be measured using an instrument consisting of an electrical circuit having the impedance of the human body.

Note 2: In controlled environments, the maximum permitted currents may be perceptible (such as a tingling or warming sensation), but are not sufficient to cause any pain or damage such as burns.

(c) Where the electromagnetic energy consists of a number of frequencies in the same or different frequency bands shown in Column 1 of Tables 2 and 3, the ratio of the square of the measured current in each frequency to the square of the limit at that given frequency shown in Column 2 or 3 (depending on whether it is induced or contact current) shall be determined and the sum of all ratios thus obtained for all frequencies shall not exceed unity, when time averaged. The limit, as applied to multiple frequencies, can be expressed as:

$$\sum_{f = 3\text{ kHz}}^{110\text{ MHz}} r_f \leq 1 \tag{2.1}$$

where f is the frequency for which measurements were taken and r_f is the ratio of the square of the measured current in each frequency to the square of the limit at that given frequency, expressed as:

$$r_f = \left[\frac{\textit{Measured Time-Averaged Value of Current at } f}{\textit{Current Limit at } f}\right]^2 \tag{2.2}$$

Table 2. Induced and Contact Current Limits for Controlled Environments.

1 Frequency (MHz)	2 Rms Induced Current (mA) Through		3 Rms Contact Current (mA) Hand Grip and Through Each Foot	4 Averaging Time
	Both Feet	Each Foot		
0.003 - 0.1	2000 f	1000 f	1000 f	1 s
0.1 - 110	200	100	100	6 min

Notes: 1. Frequency, f, is in MHz.

2. The above limits may not adequately protect against startle reactions and burns caused by transient spark discharges for intermittent contact with energized objects.

Table 3. Induced and Contact Current Limits for Uncontrolled Environments.

1 Frequency (MHz)	2 Rms Induced Current (mA) Through		3 Rms Contact Current (mA) Hand Grip and Through Each Foot	4 Averaging Time
	Both Feet	Each Foot		
0.003 - 0.1	900 f	450 f	450 f	1 s
0.1 - 110	90	45	45	6 min

Notes: 1. Frequency, f, is in MHz.
2. The above limits may not adequately protect against startle reactions and burns caused by transient spark discharges for intermittent contact with energized objects.

(d) For frequencies between 3 kHz and 100 kHz, the averaging time to be applied to the induced and contact current measurements shall be 1 second. For frequencies between 100 kHz and 110 MHz, time averaging shall be applied to the square of the induced and contact currents and shall be consistent with the averaging time in Tables 5 and 6, provided that the time-averaged square of the current in any 6 min (or 0.1 h) period does not exceed the limit given in the following relation:

$$I_{av}^{2} = I_{lm}^{2} \frac{6}{T_{exp}} \tag{2.3}$$

where I_{av} is the maximum allowable time-averaged current for exposure times less than 6 min, I_{lm} is the current limit through each foot (100 mA for controlled environment and 45 mA for uncontrolled environment) as specified in Tables 2 and 3, and T_{exp} is the exposure time in minutes during any 6 min period. Shown in Table 4 are the higher values of I_{av} that may be allowed for exposure times less than 6 min.

Table 4. Time-Averaged Induced and Contact Current Limits for Different Exposure Times for the Frequency Band 0.1-110 MHz, Applicable to Controlled and Uncontrolled Environments.

Exposure Time (min)	Time-Averaged Induced/Contact Current (rms) through Each Foot (mA)	
	Controlled Environment	Uncontrolled Environment
≥ 6	100	45
5	110	49
4	123	55
3	141	64
2	173	78
1	245	110
0.5	346	155
< 0.5	350	155

Note: The above limits may not adequately protect against startle reactions and burns caused by transient spark discharges for intermittent contact with energized objects.

2.2 Electric and Magnetic Field Strength Limits

In the far-field zone, electric field strength, magnetic field strength and power density are interrelated by simple mathematical expressions, where any one of these parameters defines the remaining two. In the near-field zone, both the unperturbed electric and magnetic field strengths shall be measured, since there is no simple relationship between these two quantities. Instrumentation for the measurement of magnetic fields at certain frequencies may not be commercially available. In this case, the electric field strength shall be measured and used for assessing compliance with the basic restrictions in this code.

Individuals should not be exposed to electromagnetic energy in a frequency band listed in Column 1 of Tables 5 and 6, if:

(a) the electric or magnetic field strengths exceed the values, when averaged spatially and over time, specified in Column 2 or 3 of:

(i) Table 5 for Controlled Environment.

(ii) Table 6 for Uncontrolled Environment.

(b) the power density exceeds the values, when averaged spatially and over time, specified in Column 4 of:

(i) Table 5 for Controlled Environment.

(ii) Table 6 for Uncontrolled Environment.

Spatial averaging is to be carried out over an area equivalent to the vertical cross-section of the human body (Section 2.4). A time-averaging period of 6 min should be employed for frequencies up to 15 000 MHz. For frequencies above 15 000 MHz, the averaging time to be used, in minutes, shall be:

$$\text{Averaging Time} = 616\,000/\, f^{1.2}$$

where f is the frequency in MHz.

Where the electromagnetic energy consists of a number of frequencies in the same or different frequency bands shown in Column 1 of Tables 5 and 6, then the ratio of the measured value at each frequency to the limit at that given frequency shown in Column 2, 3, or 4 shall be determined and the sum of all ratios thus obtained for all frequencies shall not exceed unity, when averaged spatially and over time. For field strength measurements, the measured values and the limits shall be squared before determining the ratios. The limit, as applied to multiple frequencies, can be expressed as:

$$\sum_{f\,=\,3\text{ kHz}}^{300\text{ GHz}} R_f \;\leq\; 1 \qquad (2.4)$$

where f is the frequency for which measurements were taken and R_f is the ratio of the measured value at each frequency to the exposure limit at that given frequency, and where the electric or magnetic field strength is measured,

$$R_f \;=\; \left[\frac{\textit{Measured Value of Field Strength at } f}{\textit{Exposure Limit of Field Strength at } f}\right]^2 \qquad (2.5)$$

or where the power density is measured,

$$R_f = \frac{\textit{Measured Value of Power Density at } f}{\textit{Exposure Limit of Power Density at } f} \tag{2.6}$$

Table 5. Exposure Limits for Controlled Environments.

1 Frequency (MHz)	2 Electric Field Strength; rms (V/m)	3 Magnetic Field Strength; rms (A/m)	4 Power Density (W/m²)	5 Averaging Time (min)
0.003 - 1	600	4.9		6
1 - 10	$600/f$	$4.9/f$		6
10 - 30	60	$4.9/f$		6
30 - 300	60	0.163	10*	6
300 - 1 500	$3.54f^{0.5}$	$0.0094f^{0.5}$	$f/30$	6
1 500 - 15 000	137	0.364	50	6
15 000 - 150 000	137	0.364	50	$616\,000\,/f^{1.2}$
150 000 - 300 000	$0.354f^{0.5}$	$9.4 \times 10^{-4}f^{0.5}$	$3.33 \times 10^{-4}f$	$616\,000\,/f^{1.2}$

* Power density limit is applicable at frequencies greater than 100 MHz.

Notes: 1. Frequency, f, is in MHz.
2. A power density of 10 W/m^2 is equivalent to 1 mW/cm^2.
3. A magnetic field strength of 1 A/m corresponds to 1.257 microtesla (µT) or 12.57 milligauss (mG).

Table 6. Exposure Limits for Uncontrolled Environments.

1 Frequency (MHz)	2 Electric Field Strength; rms (V/m)	3 Magnetic Field Strength; rms (A/m)	4 Power Density (W/m^2)	5 Averaging Time (min)
0.003 - 1	280	2.19		6
1 - 10	$280/f$	$2.19/f$		6
10 - 30	28	$2.19/f$		6
30 - 300	28	0.073	2*	6
300 - 1 500	$1.585f^{0.5}$	$0.0042f^{0.5}$	$f/150$	6
1 500 - 15 000	61.4	0.163	10	6
15 000 - 150 000	61.4	0.163	10	$616\,000/f^{1.2}$
150 000 - 300 000	$0.158f^{0.5}$	$4.21 \times 10^{-4}f^{0.5}$	$6.67 \times 10^{-5}f$	$616\,000/f^{1.2}$

* Power density limit is applicable at frequencies greater than 100 MHz.

Notes: 1. Frequency, f, is in MHz.
2. A power density of 10 W/m^2 is equivalent to 1 mW/cm^2.
3. A magnetic field strength of 1 A/m corresponds to 1.257 microtesla (µT) or 12.57 milligauss (mG).

2.2.1 Peak Field Strength Limit for Pulsed Fields

While the average power density of pulsed waves shall be within the limits specified in Tables 5 and 6, the peak value of the instantaneous electric field strength (temporal peak) in the frequency range of 0.1 to 300 000 MHz shall not exceed 100 kV/m.

For exposures to pulsed RF fields in the range of 0.1 to 300 000 MHz, peak pulse power densities are limited by the use of time averaging and the limit on peak electric field, with one exception: the total incident energy density during any one-tenth second period within the averaging time shall not exceed one-fifth of the total energy density permitted during the entire averaging time for a continuous field(9).

This can be expressed as:

$$\sum^{0.1s} W_p \, T \;\le\; \frac{W_a \; T_a}{5} \qquad (2.7)$$

where,
W_p = peak RF power density, in W/m^2
W_a = power density limit as specified in column 4 of Table 5 or 6, in W/m^2
T = pulse duration, in seconds
T_a = averaging time as specified in column 5 of Table 5 or 6, in seconds.

A maximum of five pulses with pulse durations less than 100 ms is permitted during any period equal to the averaging time. If there are more than five pulses during the averaging time, or if the pulse duration is greater than 100 ms, normal time averaging calculations apply.

2.3 Time Averaging

For frequencies between 3 kHz and 100 kHz, the averaging time for induced and contact currents shall be 1 second (Section 2.1.2). For frequencies greater than 100 kHz and up to 15 000 MHz, time averaging provisions in this code take into account that the basic restrictions are designed to limit temperature increases in tissues. Temperature increases in living tissue due to RF energy absorption follow a well-defined pattern with a time constant of approximately 6 minutes (thermal time constant), where **63%** of the steady state temperature increase occurs within 6 min. Time averaging permits exposures to be greater than the limits outlined in Sections 2.1 and 2.2 over short periods of time, provided that the total absorbed energy in any 6 min period does not exceed the energy absorbed from a constant (time invariant) exposure at the limits outlined in Sections 2.1 and 2.2. Since time averaging is based on absorbed energy considerations, the electric and magnetic field intensities shall be squared before time averaging is applied, while the power density and SAR are applied directly.

In situations where the exposure intensity varies significantly with time within a period of 6 min, time-averaged values must be calculated from multiple measurements, otherwise a single measurement is sufficient. Some instruments have time averaging capabilities; however, if this feature is not available, time averaged values over 6 min can be obtained by using the following formulae:

(a) To obtain the time-averaged rms electric (E) or magnetic (H) field strength, use the applicable formula:

$$E = \left[\frac{1}{6} \sum_{i=1}^{n} E_i^2 \Delta t_i \right]^{0.5} \quad (2.8)$$

or

$$H = \left[\frac{1}{6} \sum_{i=1}^{n} H_i^2 \Delta t_i \right]^{0.5} \quad (2.9)$$

where E_i and H_i are the sampled rms electric and magnetic field strengths, respectively, which are considered to be constant in the ith time period, Δt_i is the time duration, in minutes, of the ith time period and n is the number of time periods within 6 min.

(b) To obtain the time-averaged power density W, use the formula:

$$W = \frac{1}{6} \sum_{i=1}^{n} W_i \, \Delta t_i \quad (2.10)$$

where W_i is the sampled power density in the ith time period.

(c) To obtain the time averaged SAR, use the formula:

$$SAR = \frac{1}{6} \sum_{i=1}^{n} (SAR)_i \, \Delta t_i \quad (2.11)$$

where $(SAR)_i$ is the sampled SAR in the ith time period.

Note 1: In all of the previous formulae, the following relationship shall be satisfied:

$$\sum_{i=1}^{n} \Delta t_i = 6 \text{ min} \quad (2.12)$$

Note 2: For pulsed fields, E_i and H_i are rms values, and W_i is the value averaged over the time interval Δt_i. If peak values are measured, the rms or average values shall be calculated.

2.4 Spatial Averaging

Spatial averaging takes into account that the maximum exposure limits for electric and magnetic field strengths and power density are derived from the basic restrictions for whole body averaged SAR (Section 2.1). The whole body averaged SAR will be equal to or less than the value in Table 1 for exposure to a uniform plane wave of intensity given in Table 5 or 6, respectively, for polarization along the body axis and for all human body sizes. It is important to note that the limits in Tables 5 and 6 represent the worst case coupling of absorbed power for all human body sizes at all frequencies. In most realistic situations, the exposure field is not uniform and therefore the field strength or power density should be spatially averaged before being compared to the maximum exposure limit.

Measurements to determine conformity with the limits specified in Section 2.2 shall be performed with field sensors (probes) placed at least 0.2 m away from any object or person. To determine the spatially averaged value, local values (including the maximum value) shall be measured over the projected surface area (flat plane), equivalent to the head and trunk region of persons (adults or children) who would occupy the area of the incident fields. It is advisable that the measurement points are uniformly spaced within the sampling area. Local values should be measured in nine or more points. Where the field is reasonably uniform (within 20%), a measurement in one location representative of the space that is occupied by a person is sufficient. Otherwise, the spatially averaged values shall be calculated from the following formulae:

$$E = \left[\frac{1}{n}\sum_{i=1}^{n} E_i^2\right]^{0.5} \tag{2.13}$$

$$H = \left[\frac{1}{n}\sum_{i=1}^{n} H_i^2\right]^{0.5} \tag{2.14}$$

$$W = \frac{1}{n}\sum_{i=1}^{n} W_i \tag{2.15}$$

where n is the number of locations, E_i, H_i and W_i are the electric field strength, the magnetic field strength and the power density, respectively, measured in the i^{th} location.

Definitions

antenna – A device for radiating or receiving radiofrequency (RF) energy.

basic restriction – Dosimetric limit directly related to established health effects that incorporate safety factors and are expressed in terms of internal body currents or specific absorption rate (100 kHz to 6 GHz).

contact current – Current flowing between an energized, isolated, conductive (metal) object and ground, through the human body.

continuous wave (CW) – Successive oscillations which are identical under steady-state conditions (an unmodulated electromagnetic wave).

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 can control their risk using mitigation strategies.

electric field – The region surrounding an electric charge, in which the magnitude and direction of the force on a hypothetical test charge is defined at any point.

electromagnetic radiation – The propagation of time-varying electric and magnetic fields through space at the velocity of light.

extremities – Limbs of the body, including upper arms and thighs.

far-field zone – The space beyond an imaginary boundary around an antenna. The boundary marks the beginning where the angular field distribution is essentially independent of the distance from the antenna. In this zone, the field has a predominantly plane-wave character.

field strength – The magnitude of the electric or magnetic field, normally a root-mean-square (rms) value.

frequency – The number of sinusoidal cycles made by electromagnetic waves in one second; usually expressed in units of hertz (Hz).

general public – Individuals of all ages, body sizes and varying health status, some of whom may qualify for the conditions defined for the controlled environment in certain situations.

induced current – Current induced in a human body exposed to RF fields.

magnetic field – A region of space surrounding a moving charge (e.g. in a conductor) being defined at any point by the force that would be experienced by another hypothetical moving charge. A magnetic field exerts a force on charged particles only if they are in motion, and charged particles produce magnetic fields only when they are in motion.

near-field zone – A volume of space generally close to an antenna or other radiating structure, in which the electric and magnetic fields do not have a substantially plane-wave character, but vary considerably from point to point.

non-thermal effects – Biological effects ascribed to exposure to low-level electromagnetic fields, at levels below the threshold to induce thermally-related biological effects.

power density – The rate of flow of electromagnetic energy per unit surface area usually expressed in W/m^2 or mW/cm^2 or $\mu W/cm^2$.

radiofrequency (RF) – A frequency or rate of oscillation within the range of about 3 kHz to 300 GHz.

radiation (electromagnetic) – The emission or transfer of energy through space in the form of electromagnetic waves.

RF device – A device which generates and/or utilizes RF energy.

rms – root mean square. Mathematically, it is the square root of the average of the square of the instantaneous field or current taken throughout one period.

safety – The absence of detrimental health effects from RF exposures.

SI – An acronym of Système international d'unités (International System of Units).

specific absorption rate (SAR) – The rate of RF energy absorbed in tissue per unit mass. Quantitatively, it is the time derivative (rate) of the incremental energy (dW) absorbed by an incremental mass (dm) contained in a volume element (dV) of given mass density (ρ).

$$SAR = \frac{d}{dt}\left[\frac{d\mathrm{W}}{dm}\right] = \frac{d}{dt}\left[\frac{d\mathrm{W}}{\rho d\mathrm{V}}\right]$$

SAR is expressed in units of watts per kilogram (W/kg). Also,

$$SAR = \frac{\sigma E^2}{\rho}$$

where σ is the tissue conductivity (S/m), E is the rms electric field strength induced in the tissue (V/m) and ρ is the mass density (kg/m^3).

thermal effects – Biological effects resulting from heating of the whole body or a localized region, where a sufficient temperature increase has occurred that results in a physiologically significant effect.

uncontrolled environment – A condition or area where exposures are incurred by persons that do not meet the criteria defined for the controlled environment.

wavelength – The distance travelled by a propagating wave in one cycle of oscillation.

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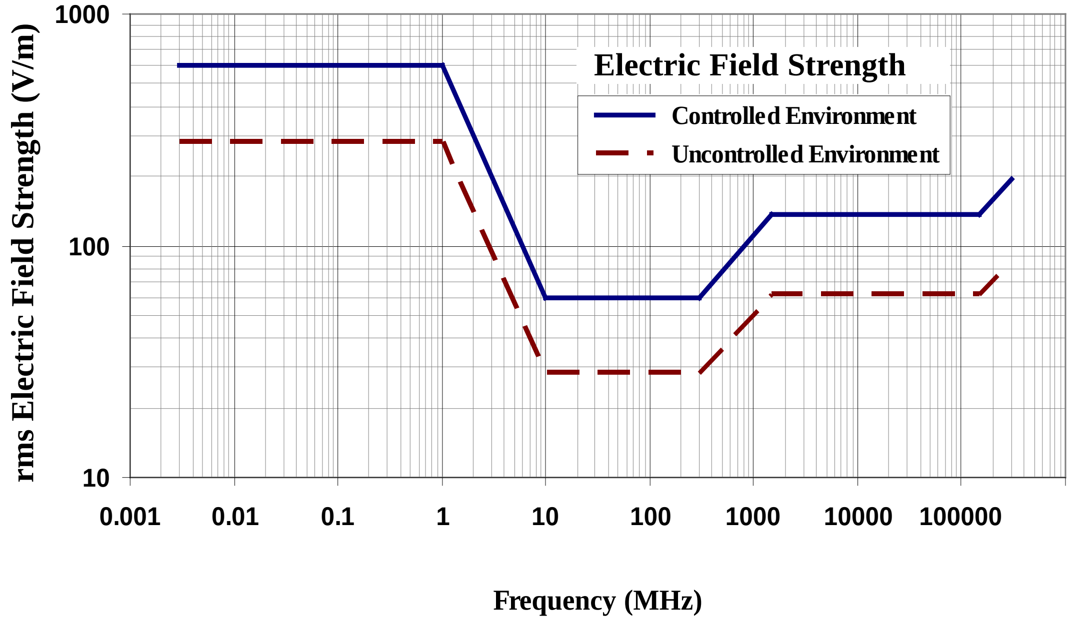
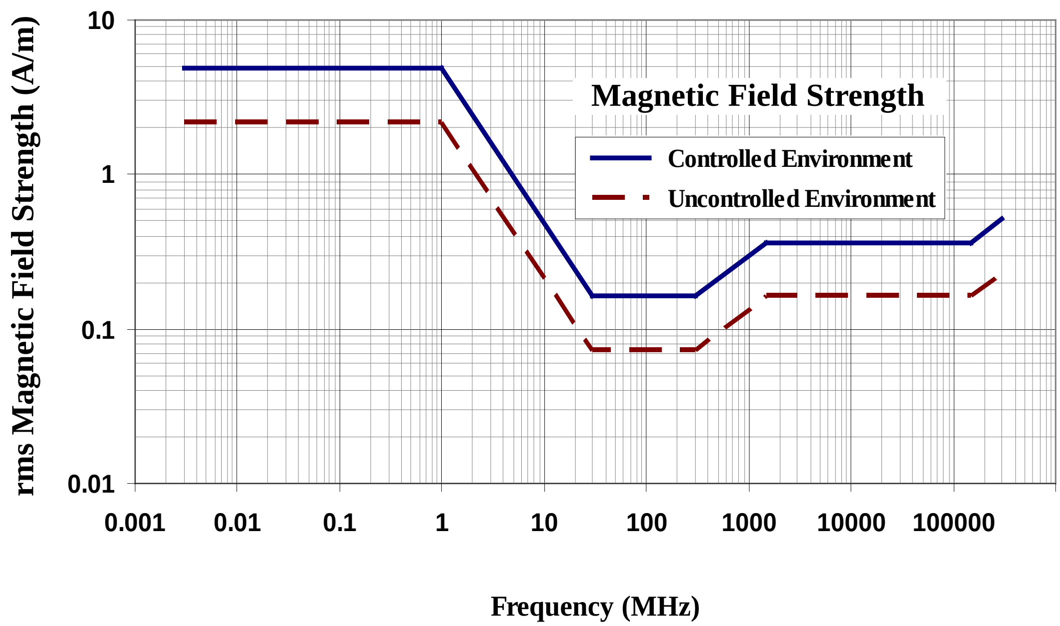
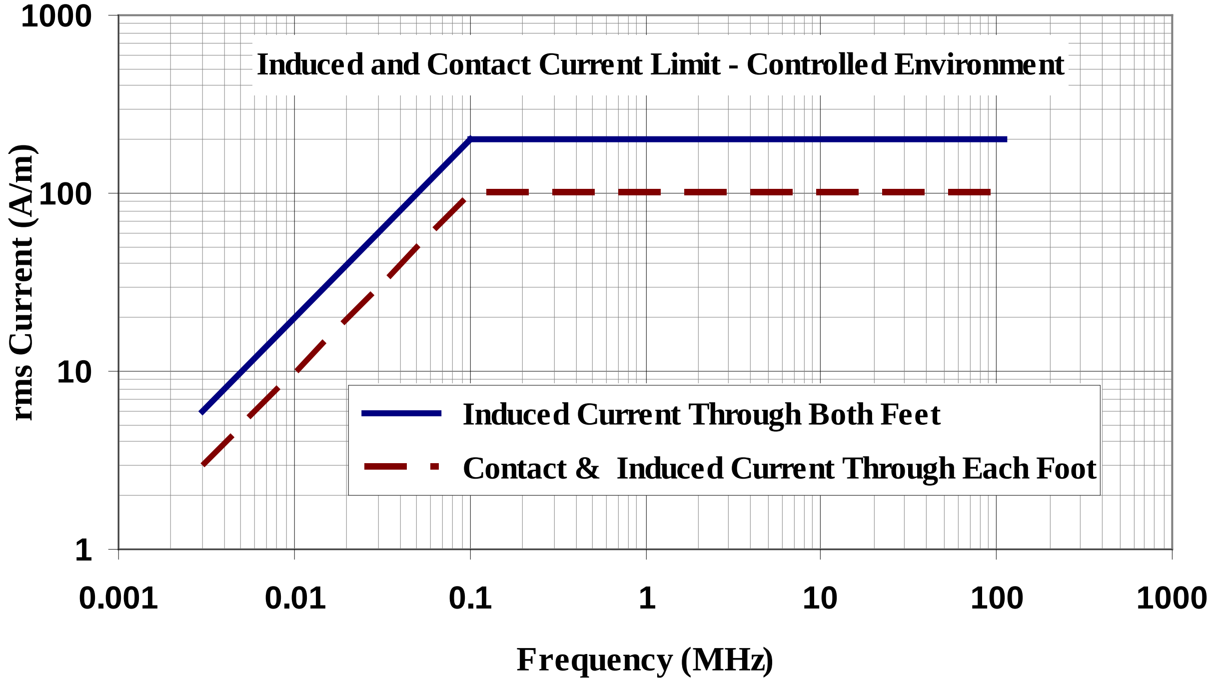
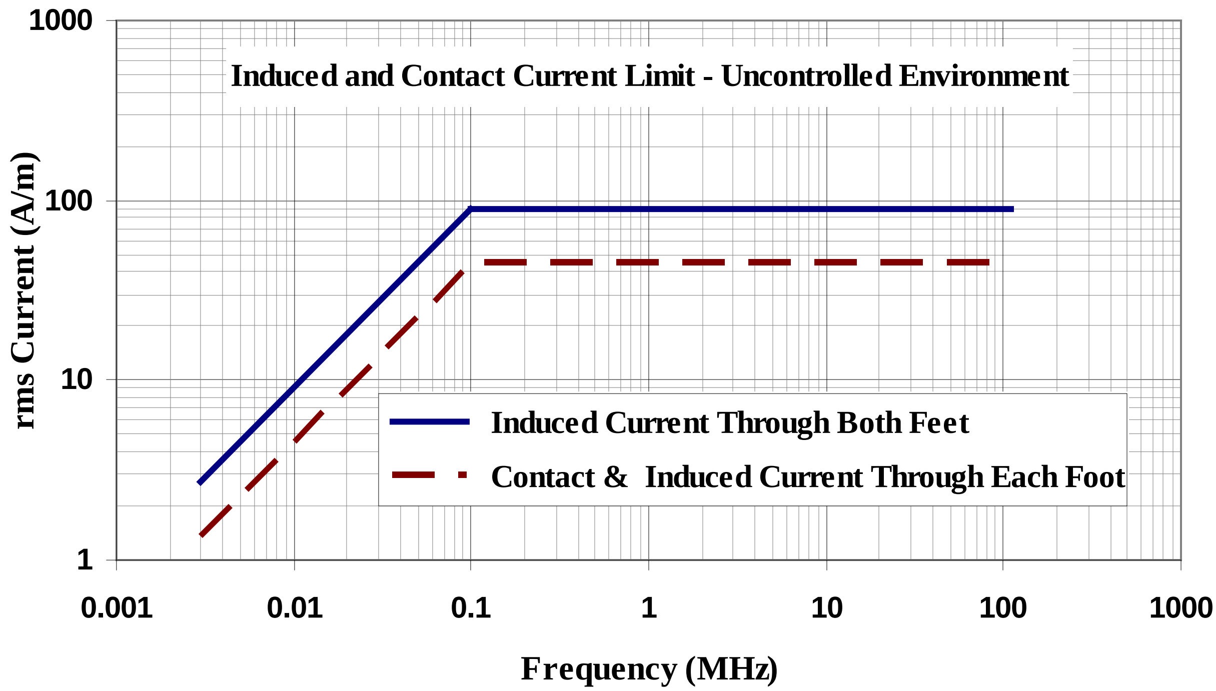
Appendix I – Maximum Exposure Limits for RF energy






Induced and Contact Current Limit - Controlled Environment
rms Current (A/m)
1000
100
10
1
0.001
0.01
0.1
1
10
100
1000
Frequency (MHz)
Induced Current Through Both Feet
Contact & Induced Current Through Each Foot


Induced and Contact Current Limit - Uncontrolled Environment
rms Current (A/m)
1000
100
10
1
0.001
0.01
0.1
1
10
100
1000
Frequency (MHz)
Induced Current Through Both Feet
Contact & Induced Current Through Each Foot

Appendix B-7

Measurement Canada Statistical Method S-S-06

Measurement Canada Mesures Canada

An Agency of Industry Canada Un organisme d'Industrie Canada

Specifications

Category: **STATISTICAL METHODS**	Specification: **S-S-06**	Page: **1 of 12**
Document(s):	Issue Date: **2010-xx-xx**	Effective Date: **2010-xx-xx**
	Supersedes: **PS-S-04**, **LMB-EG-04**	

Sampling Plans for the Inspection of Isolated Lots of Meters in Service

1.0 Scope

This specification establishes the requirements that are applicable to in-service isolated lots of homogeneous electricity or gas meters, where a meter owner has chosen to utilize sampling inspection for the purposes of extending the reverification period of an in-service lot of meters. Where applicable, this specification may be utilized as an alternative to performing 100% meter reverification, upon expiry of a meter lot's initial or subsequent reverification period.

NOTE: Sampling plans, by design, contain inherent risks and limitations with regard to their usage and the conclusions they may or may not provide. Meter owners are therefore advised that, although conformity with the requirements of this specification may allow for the extension of a meter's reverification period, relying solely on the use of the sampling plans contained in this specification will not provide users with an assurance of compliance with the metering accuracy obligations prescribed under the *Electricity and Gas Inspection Act*.

2.0 Authority

This specification is issued under the authority of section 19 of the *Electricity and Gas Inspection Regulations*.

3.0 Normative References

3.1 ISO 2859-2:1985, *Sampling procedures for inspection by attributes – Part 2: Sampling plans indexed by limiting quality (LQ) for isolated lot inspection*. Table A - Single sampling plans indexed by limiting quality (LQ) (Procedure A).

3.2 S-S-01, *Specifications for Random Sampling and Randomization*

3.3 Relevant Measurement Canada specification for the verification and reverification of the meter under test.

4.0 Administrative Requirements

Sampling inspection shall be carried out well in advance of the expiry of the reverification period of the meters so that in the case of non-conformity with the requirements, all meters forming part of the lot can be removed from service prior to the expiry of the reverification period.

Canada

5.0 Sampling Inspection Requirements

5.1 Lot Formation

5.1.1 The lot shall be formed from meters that are homogeneous with respect to the requirements in Annex A.

5.1.2 At the discretion of a meter owner, larger lots may be reformed into multiple lots of smaller size.

5.2 Sample Selection

5.2.1 The sample shall be drawn at random, without replacement, from the lot listing, using authorized random sampling software that meets the requirements referenced in section 3.2. (Systematic sampling shall not be used).

5.2.2 The size of the sample shall be one obtained from the table in Annex C as per the sampling instructions provided by this specification. The sample selected from the lot shall correspond to a value between n_{min} and n_{max} as identified in the table of Annex B.

5.2.3 Meter owners shall be responsible for assuring that the meters which are included in the sample meet the following criteria:

(a) the identified meter is one which is currently installed in service;

(b) the identified meter's metrological parameters have not been adjusted post installation;

(c) the identified meter is homogeneous with regard to the criteria of A.1 of Annex A: and

(d) the identified meter meets the total time in service usage criteria of A.2 of Annex A.

5.2.4 Where a sample meter does not qualify for inclusion as per the requirements of 5.2.3, meter owners shall not consider this meter as part of the sample group for performance testing purposes and shall replace it with the sequentially subsequent meter on the preselected unsorted sample meter listing meeting the applicable criteria. The exclusion rationale for the subject meter(s) shall be reported as per the requirements of 5.3.4.

5.2.5 Meters which have been excluded as sample meters as a result of not satisfying either 5.2.3 a), 5.2.3 (b), 5.2.3 (c) or 5.2.3 (d) shall not be returned to the parent lot.

5.2.6 Where a meter, which has been removed from service, is not capable of having its performance assessed in accordance with the requirements of this document, the meter owner shall replace it with the sequentially subsequent meter on the preselected unsorted sample listing of meters available for testing. All meters and their associated test results shall be included unless compelling evidence for exclusion is identified and reported as per the requirements of 5.3.4.

5.2.7 Lots failing to meet the minimum sample size (n_{min}) criterion as a result of the total number of exclusions under 5.2.3, are not considered to be homogeneous and are not acceptable for seal extension. Where a lot is deemed to be nonhomogeneous, meter owners shall:

(a) Re-form the lot on the basis of both the lot and sample homogeneity criteria contained in Annex A; or

(b) Assign a lower initial reverification period to the lot as per the requirements of section 5.7;

(c) Remove the lot from service.

5.3 Meter Sampling Records

5.3.1 For each lot assessed, a meter owner shall maintain records documenting:

(a) a unique, owner-assigned lot number or record reference which includes an ordinal number indicating the lot's occurrence for assessment under this specification (including the current - i.e. 1^{st}, 2^{nd}, 3^{rd}, etc.);

(b) the homogeneity criteria details specified in A.1;

(c) the utility number and manufacturer's serial number for each meter.

5.3.2 All meters identified by the owner as forming part of the lot, shall be listed in ascending order based on meter identification numbers.

5.3.3 The identification of each unsorted sample meter (n_{min} to n_{max}) selected from the lot, the sample meters tested, the quality characteristics examined, and the test results obtained, shall be documented.

5.3.4 All sample meters selected but not involved in the final calculations shall be accounted for by the meter owner and the reasons for exclusion shall be documented and, on request, made available for Measurement Canada review. Evidence of deliberate exclusion or improper accounting may disqualify the results of the sample's analysis.

5.4 Meter Inspection, Quality Characteristics, and Corrective Actions

5.4.1 Each sample meter shall be examined for conformance to all pertinent requirements as prescribed by reference 3.3.

5.4.2 Sample meters shall be inspected under identical conditions and within as short a time period as is practicable to achieve valid inspection results.

5.4.3 Each defective meter excluded from the final calculations shall be preserved for Measurement Canada review and shall be the subject of an investigation by the meter owner to determine the cause of the defect or defects. In the case of defective meters, a report shall be prepared and shall include the following information associated with this investigation:

(a) details of the meter's make, model, seal year, and identification numbers;

(b) a description of the defect and its effect on the meter's operation, including performance test results where feasible;

(c) a description of the steps taken to investigate the cause of the defect, including identification of the personnel both performing the investigation and providing information for its purpose;

(d) an explanation of how the defect occurred, including where it occurred in the process;

(e) an evaluation of the extent of the defect in the immediate situation as well as in situations likely to be similarly affected; and

(f) details of the corrective and preventive action proposed or performed to address the cause and symptoms of the defect.

5.4.4 In cases where a defective meter is encountered, the report required by clause 5.4.3 shall be provided to the local Measurement Canada representative for review prior to deciding upon the acceptability of the affected lot. Decisions regarding acceptability of the affected lot and the possible need for further investigation or corrective action shall not be made until Measurement Canada has evaluated the report and the statistical analysis of the data from the sample meters involved in the final calculations.

5.5 Acceptance Criteria

5.5.1 Individual Meters

5.5.1.1
Each meter in the sample can be considered acceptable if the following conditions are met:

(a) the meter complies with all specified reverification performance requirements (reference 3.3);

(b) the meter does not possess any defect which could affect its ability to meet specified requirements during its usage;

(c) the meter has been obtained from a population whose seal year is still valid;

(d) the meter has been received with a broken seal and an exclusion as per 5.3.4 cannot be justified.

5.5.1.2
To maintain overall homogeneity of the lot, sample meters, obtained from lots qualifying for an extension, which meet reverification requirements and which have been granted the same extension as the parent lot, shall, wherever possible, be returned to the parent lot and reinstalled following acceptance of the lot. Alternatively, these meters can be reverified.

5.5.1.3
Where sample meters require their seals to be broken in order to conduct meter performance testing, precautions should be taken to ensure the integrity of the results. If the lot is acceptable, the individual sample meters that are also acceptable shall be resealed with an additional identifier indicating the original seal year in the sealing assembly. Alternatively, these meters shall be reverified.

5.5.1.4
Sample meters that meet reverification requirements, yet have been obtained from lots not qualifying for an extension or sample meters not returned to the parent lot, shall be governed by Measurement Canada bulletins E-26 *Reverification Periods for Electricity Meters and Metering Installations* or G-18 *Reverification Periods for Gas Meters, Ancillary Devices and Metering Installations,* with respect to the assigned reverification period.

5.5.2 Lot

5.5.2.1
The sampling plan parameters of ISO 2859-2 (reference 3.1) as modified in Annex C, shall be utilized for the inspection of isolated lots of meters in service.

5.5.2.2
The acceptability of the lot for the purposes of extending its reverification period, shall be established on the basis of the performance results of the sample with regard to the number of marginally conforming meters (C_1) and the number of nonconforming meters (C_2) evidenced.

5.5.2.3
Contractors are responsible for ensuring the performance quality of the in-service meter lots which they own. Where a seal extension period is available under this specification, contractors shall give consideration to their statutory obligation for keeping meters in good repair, when selecting the seal extension period to be applied from those which are available. Specifically, the conformance quality of an in-service lot of meters shall, in all cases, meet or exceed the declared limiting quality that is associated with level 5.

5.5.3 Meter Performance Test Limits

5.5.3.1
For all performance tests, required to be conducted as per the reverification specification applicable to the subject meter type or class, a Type 1 (C_1) marginally conforming meter is one whose performance error exceeds +/- 2.0% at any test point.

5.5.3.2
For all performance tests, required to be conducted as per the reverification specification applicable to the subject meter type or class, a Type 2 (C_2) nonconforming meter is one whose performance error exceeds +/- 2.9% at any test point.

5.5.3.3
For the purposes of section 5.5.2.2, a Type 2 (C_2) nonconforming meter is also counted as a Type 1 (C_1) marginally conforming meter.

5.5.4 Seal Extension Levels

5.5.4.1
Where a lot of meters is assessed against the requirements of this specification, the maximum level of seal extension available for application to the lot, shall be established on the basis of satisfying the following criteria when applied to the n_{min} sample size as specified in a column of the applicable Annex C table:

Maximum Extension Level Criteria:

(I) $c1 \leq Ac_{\text{type 1}}$
(ii) $c2 \leq Ac_{\text{type 2}}$

5.5.4.2
Subject to the requirements of section 5.6, the maximum seal extension level that may be available for application to a lot, is the seal extension level associated with the limiting quality column of the applicable table in Annex C, C-1 or C-2 which satisfies the requirements of 5.5.4.1 for the established sample size n_{min}.

5.5.4.3
Where the maximum level of extension available to a lot of meters is determined to be level 4, the applicable seal extension period, as determined under Annex E, may be repeated without limitation on an ongoing basis where the applicable level 4 limiting quality criteria of Annex C, C-1 or C-2 and the Time on Test criteria of Annex E are met.

5.5.4.4
Subject to section 5.5.4.5, lots failing to meet at least level 4 criteria are not acceptable for extension. All meters in non-acceptable lots shall be removed from service.

5.5.4.5
Where a lot failing to meet level 4 criteria is capable of meeting the limiting quality criteria of level 5 (where available), the applicable level 4 extension period available, as per Annex E, may be applied to the lot. However, upon expiry of this period, the lot cannot be re-sampled and must be removed from service.

5.5.4.6
Where a lot fails to meet at least level 4 criteria and this failure is as a result of not meeting the requirements of sec 5.5.4.1(ii), all sample meters identified as C_2 meters under section 5.5.3.2 shall be held in storage until Measurement Canada authorizes their further processing. Sample meters shall not be required to be held in storage (without just cause) after December 31st of the calendar year in which the sampling was conducted.

5.6 Use of Sampling Tables (Annex C, C-1, and C-2)

5.6.1 The value of n_{min} shall be established on the basis of the lot size and the maximum seal extension level being targeted. Once the n_{min} sample size has been determined, it is this value that shall be utilized for establishing the maximum seal extension level, where further movement within the table is limited to either the horizontal or a diagonal downward direction.

5.6.2 Notwithstanding the seal extension level available under the requirements of section 5.5.4.1, and subject to section 5.6.3, the maximum seal extension level that may be applied to the lot shall be established on the basis of the lot's ordinal sampling occurrence under this specification as specified in Annex D.

5.6.3 Where the maximum seal extension level available to the lot under Annex D is longer in duration than the previous seal extension period granted to the lot under this specification, the period applied shall not be greater than one level better than the previous extension level and this eligibility for the application of a longer period, is limited to a single occurrence within a meter lot's in-service life.

5.6.4 Where a lot population has never been assessed against the requirements of this specification, the seal extension period of reference for the purposes of 5.6.3, shall be the last extension period granted to the lot under the previously authorized compliance sampling program.

5.6.5 Where a lot population is re-formed under the requirements of 5.1.2 or 5.2.7, the maximum seal extension levels available to the re-formed lot shall be established in accordance with the requirements of 5.6.2, 5.6.3, and 5.6.4, as applicable to the parent lot before re-formation.

5.6.6 Where a lot's population size is 500 meters or less, a meter owner may, at their discretion, utilize the sampling plan as specified in Annex C-1. Where the sampling plan of Annex C-1 is utilized, the seal extension periods available under Annex E are reduced by 50% (rounded down to the nearest whole year).

5.6.7 Where a lot's population size is 60 meters or less, a meter owner may, at their discretion, utilize the sampling plan as specified in Annex C-2. Where the sampling plan of Annex C-2 is utilized, the only seal extension periods available under Annex E are those associated with a level 4 extension.

5.7 Seal Extension Periods (Annex E)

5.7.1 For meter lots still within their initial reverification period, the time on test (TT) requirements which need to be met or surpassed by each meter in the sample (as per the homogeneity requirements of A.2), shall be established on the basis of the meter's initial reverification period and the minimum period (in months) prescribed under Annex E.

5.7.2 For meter lots still within their initial reverification period, a sample meter's time on test (in months) is established from the date the sample meter is placed into service, to the date that it is removed from service (rounded down to the nearest whole month).

5.7.3 Subject to section 5.7.5, where a meter lot is no longer within its initial reverification period, the time on test (TT) requirements that need to be met or surpassed by each meter in the sample (as per the homogeneity requirements of A.2), shall be established on the basis of the previous seal extension period granted to the lot and the applicable subsequent extension percentage prescribed for the subject row as per Annex E.

5.7.4 For meter lots no longer within their initial reverification period, a sample meter's time on test (in months) is established from the date that the certificate was issued relative to the meter lot's last seal extension, to the date that the sample meter is removed from service (rounded down to the nearest whole month). Alternatively, a meter's time on test requirement is satisfied where it can be demonstrated that the sample meter has continuous uninterupted service.

5.7.5 Meter lots that are sampled on an annual basis under this plan, are not subject to the time on test requirements of Annex E.

5.7.6 Where the time on test requirements for the 1st extension or subsequent extensions of a lot have not been met or where a sample is deemed non-homogeneous relative to the applicable time on test requirement, a lower initial reverification period (where the time on test requirements are satisfied) may be assigned to the lot.

5.7.7 Once a lower initial reverification period row has been assigned to a lot, further movement within the table is limited to either the horizontal, downward or diagonal downward directions (i.e the initial reverification period reference cannot be increased on subsequent samplings of the lot).

5.8 Reverification Date Calculations

5.8.1 Subject to 5.8.2 , where a seal period extension is granted under Annex E, the meters in the lot, less any nonconforming meters, shall be considered due for reverification on or before December 31 of the calendar year calculated as the sum of the year in which the first sample meter was removed from service and the extension period granted under Annex E (in years).

5.8.2 Where the first sample meter is removed from service in the calendar year which immediately precedes the meter lot's seal expiration year, the meters in the lot, less any nonconforming meters, shall be considered due for reverification on or before December 31 of the calendar year calculated as the sum of the lot's seal expiration year and the extension period granted under Annex E (in years).

5.8.3 Subject to 5.8.4, where a lot of meters fails to meet the requirements for an extension of its reverification period, the meters in the lot shall be considered due for reverification on the date established by the previous verification or reverification, as the case may be.

5.8.4 In the case of a lot of meters which fails to meet the requirements for an extension of its reverification period and the first sample meter was removed from service in a calendar year which preceded the meter lot's seal expiration year by more than one (1) calendar year, the meters in the lot shall be considered due for reverification, on or before December 31st of the calendar year which postdates the year in which the first sample meter was removed from service.

Annex A
(normative)

A.1 Lot Homogeneity Requirements

Where applicable, the meters in the lot shall be homogeneous with respect to the following characteristics:

Electricity Meters

(a) type (transformer or self contained).

(b) manufacturer and model, unless otherwise authorized in accordance with clause A.1.1.

(c) voltage or voltage range.

(d) maximum current range.

(e) measurement functions (e.g., measured quantities, energy, demand).

(f) firmware version, unless otherwise authorized in accordance with clause A.1.1.

(g) frequency rating.

(h) same model or type of telemetering device (if so equipped), unless otherwise authorized in accordance with clause A.1.1.

(I) configuration / form (i.e. number of elements*, wye, delta or auto configuration).

(j) status at time of last inspection (i.e., new, renewed, or reserviced).

(k) seal year (same seal year or two consecutive seal years, provided both are valid).

***With the exception that 1-element and 1.5 -element meters may be mixed to form a lot.**

Natural Gas Meters

(a) manufacturer and model, unless otherwise authorized in accordance with clause A.1.1.

(b) same or similar capacity rating, unless otherwise authorized in accordance with clause A.1.1.

(c) measurement functions (e.g., measured quantities, temperature/pressure conversion).

(d) firmware version, unless otherwise authorized in accordance with clause A.1.1.

(e) same model or type of telemetering device or auxiliary attachment (if so equipped), unless otherwise authorized in accordance with clause A.1.1.

(f) status at time of last inspection (i.e., new, renewed, or reserviced).

(g) seal year (same seal year or two consecutive seal years, provided both are valid).

A.1.1 Forming Lots with Mixed Meters

Where a lot includes meters which, for the purposes of lot homogeneity, are ones which possess a similar characteristic rather than a characteristic which can be readily identified as being the same, meter owners are responsible for maintaining documented records identifying the similarities which support the homogeneity conclusion (as concerns including these meters within the subject lot). For the purposes of compliance sampling, if an accredited organization wishes to combine, in one lot, various models or vintages of meters, and/or meters equipped with and without a telemetering device, the accredited organization shall submit a request to MC with accompanying documentation in support of their claim that these differing meters can be considered homogeneous.

A.2 Sample Homogeneity Requirements

The meters in a sample shall be homogeneous with respect to similar time in usage. For a sample meter to be considered homogeneous with regard to similar time in use, a meter shall have been in service for a time period that meets or exceeds the applicable time on test (TT) requirements of Annex E. Where this criteria is not met, a meter owner may reform the lot or reduce the seal period extensions available as per the requirements of section 5.7.

Annex B
(normative)

Table of n_{min} to n_{max} Sample Sizes

Single Sample	
n_{min}	n_{max}
30	37
42	52
44	55
65	81
80	100
125	156
200	250
315	394

Annex C - Single Sampling Plans Indexed by Quality Level (LQ)
(normative)

Lot Size		**Limiting Quality (LQ)**				
		3.15 (Level 1)	**5.0** (Level 2)	**8.0** (Level 3)	**12.5** (level 4)	**20** (Level 5)
Up to 500	n_{min}	80	65			
	Ac $_{type\ 1}$	0	0			
	Ac $_{type\ 2}$	0	0			
501 to 1200	n_{min}	125	80	65	42	42
	Ac $_{type\ 1}$	1	1	1	2	4
	Ac $_{type\ 2}$	1	0	0	0	0
1201 to 3200	n_{min}	125	125	80	65	65
	Ac $_{type\ 1}$	1	3	3	4	8
	Ac $_{type\ 2}$	1	1	0	0	0
3201 to 10000	n_{min}	200	200	125	80	80
	Ac $_{type\ 1}$	3	5	5	5	10
	Ac $_{type\ 2}$	3	3	1	1	1
10001 to 35 000	n_{min}	315	315	200	125	125
	Ac $_{type\ 1}$	5	10	10	10	18
	Ac $_{type\ 2}$	5	5	3	3	3
	n_{min}			315	200	200
	Ac $_{type\ 1}$			18	18	32
	Ac $_{type\ 2}$			5	5	5

NOTE:

As per 5.5.3.1, Type 1 (C_1) > 2.0%
As per 5.5.3.2, Type 2 (C_2) > 2.9%

Annex C1 - Single Sampling Plans Indexed by Quality Level (LQ)
Small Lot Size Plan (with increased sampling frequency)
(normative)

Lot Size		**Limiting Quality (LQ)**			
		5.0 (Level 1)	**8.0** (Level 2)	**12.5** (Level 3)	**20** (level 4)
Up to 500	n_{min}	44	44	44	44
	$Ac_{\text{type 1}}$	0	1	2	4
	$Ac_{\text{type 2}}$	0	0	0	0

NOTE:

As per 5.5.3.1, Type 1 (C_1) > 2.0%
As per 5.5.3.2, Type 2 (C_2) > 2.9%

Annex C2 - Single Sampling Plans Indexed by Quality Level (LQ)
Very Small Lot Size Plan
(normative)

Lot Size		**Limiting Quality (LQ) 5.0 (Non Conforming)**
		Level 4
Up to 60	n_{min}	30
	$Ac_{\text{type 1}}$	0
	$Ac_{\text{type 2}}$	0

NOTE:

As per 5.5.3.1, Type 1 (C_1) > 2.0%
As per 5.5.3.2, Type 2 (C_2) > 2.9%

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	Supersedes: **PS-S-04, LMB-EG-04**	

Annex D - Available Extension Levels
(normative)

Ordinal Sampling Occurrence	Maximum Seal Period Extension Levels Available			
1st	Level 1	Level 2	Level 3	Level 4
2nd		Level 2	Level 3	Level 4
3rd			Level 3	Level 4
4th (and higher)				Level 4

Annex E - Time on Test (TT) Requirements and Maximum Seal Period Extensions
(normative)

Initial Reverification Period (years)	1st Extension (Months)	Subsequent Extensions*	Maximum Seal Period Extension (years)			
			Level 1	Level 2	Level 3	Level 4
12	115	75%	10	8	5	2
11	105	75%	9	7	5	2
10	84	70%	8	6	4	2
9	75	70%	7	5	3	2
8	67	70%	6	4	3	2
7	58	70%	5	4	2	1
6	50	70%	4	3	2	1
5	42	70%		3	2	1

* Subsequent extension TT based on indicated percentage multiplied by the previous extension.

Appendix C-1

Navigant Future AMI Program Study

ADVANCED METERING INFRASTRUCTURE (AMI) FUTURE PROGRAM STUDY

Prepared for:

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March 2011

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Executive Summary

Many utilities throughout North America are in the process of rolling out advanced metering infrastructure (AMI) to provide both system operating benefits and enhanced programs to allow customers to better manage their energy usage and costs. In this report, we examine and synthesize results from more than 50 different utility pilots and programs regarding the energy and capacity that could be realized through programs enabled by AMI. These programs include the following:

- **Time-of-Use (TOU)** – rates vary time period and season reflecting the cost of providing electricity during different time periods
- **Critical Peak Pricing and Critical Peak Rebate (CPP/CPR)** – customers are charged (pricing) or provided and incentive (rebate) for usage during critical peak periods as defined by both reliability and economic considerations.
- **Inclining Block Rates** – customers are charged higher rates for any usage that exceeds a threshold amount.
- **Pre-pay** – Customers pre-pay for their electricity consumption.
- **Load Control (LC)** – switches are installed on appliances to limit the use of those appliances during peak periods.
- **In-home displays (IHD)** – the household is provided with a device showing their current electricity usage and costs, providing real-time feedback.

Based on our review of the more than 50 pilots and programs of these options, we estimate that the programs can provide significant capacity and energy benefits to Fortis BC as summarized in Figures Figure ES-1: Capacity Savings (MW) in 2018 by Program Scenario and Figure ES-2: Energy Savings (GWh) in 2018 by Program Scenario. The “with supporting” technology indicates the conservation rates and pre-pay programs also include in-home displays (IHD) and either 4 load control switches or smart appliances. The supporting technologies scenarios substantially increase the energy and capacity from the conservation rates and pre-pay programs, particularly for the opt-out scenarios. The supporting technologies opt-out scenarios both increase the responsiveness of the conservation and prepay participants but also support energy and capacity savings from the customers who do not participate in the conservation rates and pre-pay programs. These forecasted benefits are based on the savings per participating customer as identified in Table ES-1: Per Participant Savings for Possible AMI Future Programs and the range of forecasted participation rates as summarized in Table ES-2: Participation Rates by Program and Scenario.

Figure ES-1: Capacity Savings (MW) in 2018 by Program Scenario

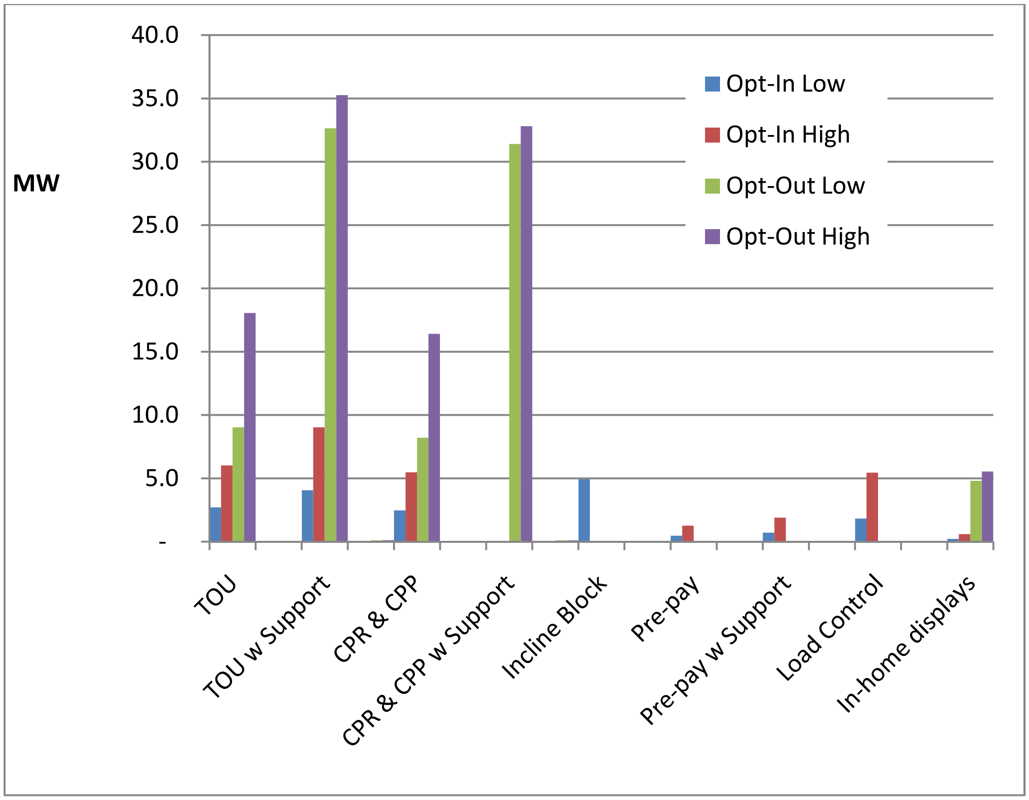

Figure ES-2: Energy Savings (GWh) in 2018 by Program Scenario

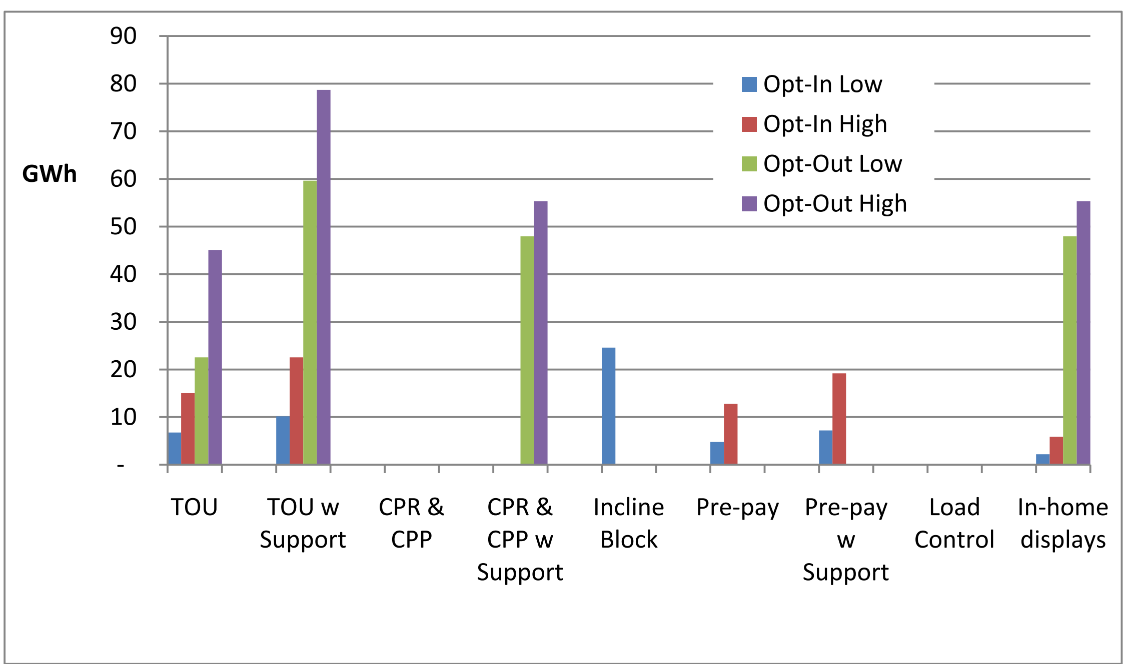

Table ES-1: Per Participant Savings for Possible AMI Future Programs and the range of forecasted participation rates as summarized in Table ES-2: Participation Rates by Program and Scenario.

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

The evaluation of utility programs demonstrates that significant benefits can be realized through the implementation of AMI future programs functionality. Conservation reductions with supporting technology range with from of $395 to $1389 per customer for FortisBC. The analysis shows that:

- Inclining block rates provide the smallest benefits. Since FortisBC plans to roll-out TOU rates in 2014, and rate changes create customer confusion, there is little value to rolling out inclining block rates as an interim program.
- The research shows that on-going communication and marketing is essential for maintaining the behavioral savings. An on-going communication and marketing program (and the associated annual costs) need to be part of the program. The capacity and energy savings benefits and customer costs analysis included applicance on-going communication and marketing costs.
- The supporting technology (IHD) and appliance controllers produce substantial additional benefits regardless of the underlying rates and should be deployed as part of any program.
- TOU supplemented with supporting technologoes provides the greatest savings at the lowest costs per participating customer.

[1] B.C, Hydro, 2010 "Conservation Rate Initiative", BC Hydro Website
[2] B.C, Hydro 2008, "2008 Residential Inclininy Block Application," February, 2008
[3] Average of range from Woodstock Hydro, 2004. "Pay-As-You-Go-Power: Treating Electricity as a Commodity," Ken Quesnelle (Vice-President), January 20, 2004

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Table ES-2: Participation Rates by Program and Scenario summarizes the program participation rates by program type and scenario. Most of the recent residential pilot programs to date have been conducted with volunteers, i.e. customers opted to participate. Thus, the reported savings represent results for the average participant. In a full-scale program, not all customers will participate. Since there are considerable ranges, uncertainty and a paucity of data on participation rates: high and low participation assumptions were developed for both an opt-in (i.e. voluntary) and an opt-out (i.e. mandatory) program. The participation rate assumptions for the in-home displays parallel the assumptions developed by the ACEEE in their meta-analysis of real-time feedback programs. The pre-pay and load control participation rates were selected to bracket the range of participation rates from the programs reviewed. Similarly, the participation rates for the opt-in conservation rates programs bracket the range from the programs and pilots reviewed. For the opt-out (or mandatory) programs one needs to recognize that some customers placed into conservation rate programs will not respond to the price signals. The low-end of the opt-out scenario is based on reconciling savings estimates from mandatory and voluntary programs and from very limited data on participation rates. The high-end participation rates for the conservation rates reflect the ACEEE assumptions for opt-in for real-time feedback (in-home displays).

Table ES-2: Participation Rates by Program and Scenario

	Opt-In		Opt-Out	
	Low	High	Low	High
TOU	9.0%	20.0%	30.0%	60.0%
CPR & CPP				
Incline Block	Not Applicable			
Pre-pay	3.0%	8.0%	Not Applicable	
Load Control	5.0%	15.0%		
In-home displays	3%	8%	65%	75%

Project Background

Background

In 2008, the BC Utility Commission (BCUC) denied FortisBC's application for implementation of Advanced Metering Infrastructure (AMI) throughout its service territory.[4] One of the reasons for the denial was that the application did not have enough cost and benefit information on the long-term vision associated with AMI.

At this time, there are a substantial number of published studies and pilot program evaluations describing the probable benefits from rates and other programs enabled by AMI. Navigant Consulting, Inc. (NCI) was engaged to provide FortisBC with an analysis of the estimated energy efficiency and demand reduction that could be realized through future AMI-enabled programs. These results are to be used as components of the new AMI business case and Application.

Scope and Objectives

The objective of this effort was to develop an analysis of the net additional benefits that could be realized within the residential market by the deployment of AMI. The components of the benefit-cost analysis include:

- The range of benefits that could be delivered by the advanced functionality of AMI focusing on near- and mid-term applications including load control (LC), time-of-use (TOU), and conservation rates;
- Customer-side costs;
- Utility infrastructure, marketing and education costs; and
- Reduction in energy and capacity purchase to meet the customer requirements.

To develop the data and estimates, NCI reviewed and summarized the experience and results from other utilities' pilots, studies and programs. The scope of this effort was focused on enhanced AMI programs. FortisBC is incurring the costs developing the rate designs and implementing meter data management (including data validation, estimation and editing – VEE) as part of its AMI application, so these costs were not included. For the purposes of this analysis, enhanced functionality was defined to include (and not include) the items as summarized in Table 1: Summary of Project Scope.

[4] British Columbia Utilities Commission, Letter regarding Certificate of Public Convenience and Necessity for the Advanced Metering Infrastructure Project. Order No. G-168-08. 2008.

Table 1: Summary of Project Scope

In Scope	Out of Scope
• Estimating the impact of conservation rates • Estimating the impact of direct load control (DLC) that is specifically enabled by AMI • Estimating the impact of supporting technologies (e.g., in-home displays – IHD, smart thermostats, and smart Appliances) • Estimates of the price elasticity of demand for residential customers based upon synthesis of AMI pilots/deployments • Estimates of costs that are incurred to enable this functionality, over and above the baseline AMI system	• Estimates of AMI baseline deployment costs • Costs associated with designing rates and implementing a meter data management system with VEE • Costs associated with the communicating dynamic prices to the customer premises • Estimates of AMI benefits such as: — Remote connects and disconnects — Outage notification and restoration notification — Tamper/theft detection • Estimates and impacts of Longer-term AMI-enabled functionality such as: — Plug-in hybrid electric vehicles — Customer-sited renewables (e.g., photovoltaics)

Methodology

NCI has evaluated other utility programs as the basis for developing the estimates of the energy and capacity savings resulting from enhanced AMI functionality. Specifically, we have used a combination of secondary research and primary research to support the program review, as described below:

- Secondary Research – Evaluated and synthesized results from relevant studies on the impacts of AMI-enabled programs that affect customer demand and energy consumption. These included published summaries of utility AMI pilots to document the benefits related to load shifting and conservation as well the corresponding costs.
- Primary Research – Interviewed 5 relevant utilities, to understand their experience, benefits and costs, and lessons learned related to AMI future programs.

Experiences in California, Ontario and other pilot programs throughout North America indicates that AMI enables the development and deployment of programs (e.g., time-of-use rates, critical peak pricing, and load control) that provide energy and demand reductions with real economic benefits to both the utility and the customer. While the focus of this study, as well as most of the other AMI studies and pilots has been on demand response (DR), pricing and load control (LC), data from AMI may also be useful for targeting and improving the focus and effectiveness of FortisBC's current and future Energy Efficiency (EE) programs This additional value from AMI is not quantified in this report.

NCI developed estimates of the energy and peak load savings for various future conservation rates and load control programs that would be enabled by AMI per participating customer. There are multiple pilots and studies with relatively consistent estimates of energy and capacity savings per participating customer (when expressed as a percent of their peak demand or annual energy use).

To estimate impacts of a system-wide offering, participation forecasts are required. There is very limited data on participation rates. Most pilots recruited customers to volunteer and did track data on how many customers were not willing to participate. There are a few studies where customers were assigned to programs randomly, allowing us to infer participation rates.

Based on the ACEEE meta-analysis described later in this document, NCI developed four participation scenarios based on the limited data available: low and high participation for both an opt-in and an opt-out program[5]. "Opt-in" refers to the approach of offering a program as an option where the customer must explicitly sign-up or enlist. "Opt-out" refers to the approach where the customer is automatically placed in the program unless they explicitly request to be excluded.

A range of potential and energy and capacity savings were forecasted for each program type as the product of the: (a) per participant savings: (b) program scenario participation rate; (c) the number of residential customers; (d) average use (and demand) per residential customer; and (e) program ramp rate (the number of years from program launch until the program penetration is attained). The results include high and low energy demand savings among Fortis' residential customer base by program type for both opt-in and opt-out scenarios.

Future Programs Enabled by AMI

Enhanced AMI functionality enables the deployment of several different strategies designed to reduce peak demands and/or conserve energy through empowering and incenting customers to manage their electricity usage. In this analysis, we examined three broad categories of future AMI enabled programs, including: (1): conservation rates; (2) in-home displays (IHD); and (3) load control (LC). In this section we provide brief description of representative offerings to residential customers within each area.

Conservation Rates

With the deployment of advanced metering, utilities are increasingly implementing alternative conservation rates deigned to encourage demand reduction and energy conservation, including:

- Time-of-Use (TOU) rates—Electric rates vary by time of day and season. The prices for each time period are fixed. Customers can reduce their electricity bills through

[5] "Opt-in" refers to the approach of offering a program as an option where the customer must explicitly sign-up or enlist. "Opt-out" refers to the approach where the customer is automatically placed in the program unless they: (1) explicitly request to be excluded; or (2) don't advantage of any aspects of the program – implicitly opting out.

conservation and/or shifting loads to lower cost time-periods. Figure 1: Sample TOU Rates includes an example TOU rate from one of the pilots in Ontario.

Figure 1: Sample TOU Rates

Time	Summer Hours (Aug 1 - Oct 31)	Price/ kWh	Winter Hours (Nov 1 - Feb 28)	Price/ kWh
Off-Peak	10 pm - 7 am weekdays; all day on weekends and holidays	3.5¢	10 pm - 7 am weekdays; all day on weekends and holidays	3.4¢
Mid-Peak	7 am - 11 am and 5 pm - 10 pm weekdays	7.5¢	11 am - 5 pm and 8 pm - 10 pm weekdays	7.1¢
On-Peak	11 am - 5 pm weekdays	10.5¢	7 am - 11 am and 5 pm - 8pm weekdays	9.7¢

Note: *Rates reflect the Regulated Pricing Plan TOU structure from Ontario Energy Board's Smart Pricing Pilot*
Source: IBM and eMeter, 2007

- Dynamic Pricing (DP) – Includes several types of rate programs where the prices change can change based upon current market conditions (both wholesale prices and/or reliability considerations). Price signals are transmitted to customers and the customers make usage decisions (perhaps, using programmed controllers or thermostats) based upon the current price. There are three major types of dynamic pricing: (1) critical peak pricing (CPP); (2) critical peak rebate (CPR): and (3) real-time (RTP) pricing. This report only examines the potential benefits of CPP and CPR and does not include the costs of communicating the time-varying prices to the customers. Brief definitions of these three types of dynamic pricing programs are provided below:
    - Critical Peak Pricing (CPP) —During critical periods (defined by reliability and/or market conditions), the customers' usage is billed at the critical peak price. CPP rates can be used with standard or TOU rates. Typically, the prices are set at predetermined level for a fixed time period with limits set on the number of times the critical-peak event can be called. Increasingly, the CPP programs may include linkage to customer home area network, and appliance controls to automatically adjust usage during events. For, example some utilities are deploying smart thermostats that adjust temperature settings, based on the customers' preferences, during the critical periods. Customers may opt to override the controls and pay the CPP for the added consumption.
    - Critical Peak Rebate (CPR)—Similar to the CPP except that the customer receives a credit or rebate for reducing usage during the critical peak period rather than paying a premium price for usage. CPR programs have similar demand reductions as CPP programs and appear to have much greater

acceptance among residential customers. CPR programs may entail higher utility administrative costs and complexity than CPP rates.

  - Real Time Prices (RTP) – Prices change hourly based upon the hourly wholesale market prices. RTP rates are usually offered only to the large commercial and industrial customers. For this reason, they are not further discussed in this report.

- Inclining Block—Electric rate that requires customers to pay more for higher usage. These rates have been adopted to provide reduced rates for low usage customers while providing a price signal to encourage higher use customers to conserve energy. For example, once a customer usage exceeds the energy consumption allowed in the initial block over a given period of time (typically one month), than this customer will be charged a higher rate for all additional energy consumed within that time period.

While AMI may not be required for adopting limited portions of some of these conservation rates, it is a critical portion of the enabling infrastructure to implement robust conservation rates as:

1) Pilots and program experience demonstrate that there is significantly more response when the rate programs are combined with supporting technologies such as in-home displays and controls;
2) Smart meters enable more flexible and customizable rate designs and programs since pricing parameters (such as period definitions) can be updated remotely and varied by customer type, location and preferences (or options selected. Flexibility and customization enhances the customer acceptance of and participation the rates and programs;
3) Time-of-use and dynamic pricing (CPP and CPR) rates require time-differentiated metering (that is, the ability to collect energy consumption and demand data for specific time intervals); and
4) Many manufacturers and third parties are developing controls, programs, and appliances that link to smart meters to provide households with better management of their energy, demand, and energy bills. The AMI infrastructure provides a platform that allows innovators to develop methods and offerings that provide customers with greater flexibility and management of the demand and energy usage, and energy costs. The addition of these 3rd party offerings can further improve the savings achieved through AMI future programs.

Pre Payment

Electricity payment option coupled with a prepayment meter or other enabling technology that only supplies energy to customers equal to the prepaid amount purchased by the customer. This option may involve working with a third party to sell the prepaid cards, but this is not a requirement for implementing pre-pay rates.

Load Control[6] (LC)

Load control (LC) programs are designed to reduce electric loads during capacity constrained periods by sending signals to customers and/or their equipment to either cease operation or reduce power usage. LC often involves the use of switches on specific end-use loads or appliances that may be activated by the utility upon utility need for load reduction. The need for load reduction (event) may be driven by either reliability or market price considerations. Load control programs typically include:

- Automatic switching off or cycling of certain appliances or loads during the events;
- An option for the customer to over-ride the utility load control signals based upon the customer's needs and preferences (there may be a cost or no credit for exercising the over-ride option); and
- Provide incentive for participating in the program (e.g. a lower rate, a payment per event, or a credit per month when the utility may use the load control events).

The most common load control programs in the residential sector control water heaters and air-conditioners. These programs typically allow the utility to switch the appliance(s) off for a defined period of time during load control events. There are many variations of these programs.

Supporting Technologies

Supporting technologies such as in-home displays, smart thermostats, and smart appliances help customers understand and respond to conservation rates and load control events. Programs utilizing supporting technologies to provide customers with information about usage and costs, and automating the control of appliances show greater savings. In fact, pilots in California, Ontario, Illinois, and New Jersey consistently show that supporting technologies increase demand savings by approximately 50 percent.

In-Home Displays (IHD)

In-home displays (IHD) allow customers to view electricity consumption and costs in real-time. IHDs display total usage and costs to-date for the month, as well current usage. Some IHDs provide additional functionality such as displaying real-time prices and can be used to support dynamic pricing programs Utilities often deploy these devices to enable customers to better manage their energy costs and encourage customer to respond to conservation rates.

For example, Hydro One (Ontario) 30,000 IHD deployment used a Blue Line Innovations PowerCost MonitorTM similar to the one depicted in Figure 2: Hydro One's In-Home Display. These devices provide customers with information on electricity consumption and energy

[6]Load control, as used in this report, refers to programs and tariffs where the utility directly controls appliances or other customer loads. These utility programs and tariffs provide customers with an incentive to allow the utility to reduce usage of selected appliances or loads during peak periods.

prices. Similarly, The Energy Detective manufactured by Energy, Inc. operates with Google's Powermeter software to track energy without a smart meter (TED, 2010).

Figure 2: Hydro One's In-Home Display

Source: Blue Line Innovations, 2010

Ameren's Power Smart Pricing (PSP) pilot used a PriceLight (a small orb that glows different colors based on the current price of electricity) for about 100 of its participating customers. Figure 3: Ameren's PriceLight In-Home Display depicts a similar device which Ameren found to improve customer response to the dynamic prices (Ameren, 2010).

Figure 3: Ameren's PriceLight In-Home Display

Source: Ameren, 2006

Smart Thermostats

Smart thermostats to receive signals from the utility during peak periods and help customers reduce load by adjusting temperature settings during these periods. Some smart thermostats also allow the customer to program settings and override utility signals if they choose. Ameren, for example, deployed smart thermostats as part of its Residential TOU Pilot Study and found them to help customers reduce load during peak periods.

Figure 4 depicts a smart thermostat deployed by Ameren.

Figure 4: Ameren's Smart Thermostat

Source: PSP, 2009

Smart Appliances

Smart appliances have the ability to receive signals from the utility to reduce load or delay start times as shown in Figure 5: General Electric's Demand Response Enabled Smart Appliances. For example, smart dryers can delay start cycles until off peak times. Other appliances such as the water heater can modify temperature settings during high rates such as General Electric's Demand Response Enabled Smart Appliances. These appliances typically communicate with the smart meter over a home area network. General Electric is currently testing load control enabled communicating appliances which can receive price signals and shift demand to off-peak periods. Other vendors are also developing intelligence into appliances that will rely on communicating with a smart meter.

Figure 5: General Electric's Demand Response Enabled Smart Appliances

Source: GE, 2010

Experience from Other Utilities and Programs

This section summarizes results and lessons learned from relevant utility pilots and programs. As mentioned in the *Methodology* section, NCI performed both secondary and primary research of selected utility AMI programs. NCI interviewed five utilities, listed in Table 2: Rationale for Selected Utility Interviews, which had highly relevant pilot and program results. Various regional and programmatic characteristics made these utilities particularly relevant to FortisBC and this study (see Table 2: Rationale for Selected Utility Interviews). The table in *Attachment 2: Utility Research Table* section contains the complete list of utility programs researched.

Table 2: Rationale for Selected Utility Interviews

Utility/Location	Key Pilots/Programs	Relevant Characteristics
Ameren/Illinois	Smart Meter Deployment; Power Smart Pricing program	High penetration of electric space heating; summer peaking; real-time pricing; behavioral based research; residential customer
Avista/Idaho	Demand Response Pilot	Low electric rates; winter peaking; high penetration of electric space heating
BC Hydro/British Columbia	Conservation Research Initiative; Smart Metering and Infrastructure Program	Geographic proximity; some demographic similarities; winter peaking
Hydro One/Ontario	IHD Program Deployment; Time-of-Use Pricing/IHD Pilot Project	Low energy prices; rural location; penetration of electric space heating; low residential rates
PG&E/California	Smart Meter and SmartRate Program; ADRS; Ancillary Services Pilot	Experience with AMI; multiple DR and pricing programs, publicly available results

Secondary Research

This section summarizes results and findings from secondary research including results from meta-studies and from individual utility pilots and programs.

Key Meta-Reviews

Several organizations have completed meta-reviews (i.e. reviews of multiple similar utility programs and pilots) to identify common trends, savings estimates, and drivers of differences where the program or pilots had different results. The estimates of energy and demand savings that could be realized by FortisBC's customers reported later in this report were based on a synthesis of the results from both the utility pilot programs completed specifically for this effort and the meta-studies' findings. Table 3: Summary of Secondary Research Findings from Relevant Studies summarizes the key findings from the meta-studies. Additional conclusions

from selected meta-reviews that were used to support the development develop estimates for specific program types are referenced in later sections.

Table 3: Summary of Secondary Research Findings from Relevant Studies

Study	Key Findings	Source
Quantifying the Benefits Of Dynamic Pricing In the Mass Market	• Of the 13 pilots reviewed, CPP programs supported with supporting technologies resulted in the largest reductions in load (15%-50% peak demand shifting) • Implementing dynamic pricing with enabling technologies is more effective than implementing these independently	(Edison Electric Institute, 2008)
Advanced Metering Initiatives and Residential Feedback Programs: A Meta-Review for Household Electricity-Saving Opportunities	• Analysis of 57 programs providing usage feedback in North America with feedback found savings ranged from 4% to 12% • Real-time feedback programs resulted in average savings of 9% • Accounting for non-participants, real-time feedback (IHD) could provide4% savings for the residential sector	(American Council for an Energy Efficient Economy, 2010
The Impact Of Informational Feedback On Energy Consumption—A Survey Of The Experimental Evidence	• IHD can improve annual energy savings by an average of 7% without dynamic pricing; • IHDs combined with prepayment results in average annual energy savings of 14%	(Faruqui, 2009)
A National Assessment of Demand Response Potential	• Demand response has the potential to reduce 4%-20% of U.S. peak demand by 2019 (dependant on customer participation scenarios)	(FERC, 2009)
Household Response To Dynamic Pricing Of Electricity—A Survey Of The Experimental Evidence	• TOU shifts peak demand by 3%-6% • CPP tariffs shift peak demand by 13%-20% or 27%-44% when combined with enabling technologies	(The Brattle Group, 2009)
Rethinking Prices: The Changing Architecture of Demand Response in America	• Sufficient price differentials between peak and off-peak rates are needed to ensure customers reduce peak demand	(PUF, 2010)
California Statewide Pricing Pilot (CA SPP)	• Fixed CPP rates shifted peak energy on critical days between 7.6-15.8% depending on the climate zone	(CRA, 2005)

Results Reported by Utility Pilots/Programs

In addition to the meta-reviews, summarized above, NCI reviewed evaluations of specific utility pilots or programs. The pilots and programs reviewed were selected based upon relevance to Fortis as well as the availability of a rigorous evaluation of the program impacts. Table 4 and Table 5 summarize the conservation and demand savings reported by utility programs or pilots respectively. Conservation benefits reduce average annual energy savings, while demand savings focus on reductions during periods of peak demand. There are some caveats and limitations to the results from these evaluations, including the following:

- Savings depend on specifics of the rate design. For example, the savings are affected by the price for on-peak usage compared to the price for off-peak consumption as well as by the length of the on-peak period and when the on-peak period begins and ends. An on-peak/off-peak price differential of 4 will produce larger peak demand savings than a differential of 2 (see graphs in the *Elasticities* section, below). We summarized the savings ranges provided in the respective evaluation reports without analyzing the details of the rate structure, and selected conservative values for estimating energy and load reductions.
- In many cases, only conservation or demand impacts were reported, based on the objectives and evaluation of the program. For example, many of the IHD programs only report energy savings. Associated load reductions were estimated either from evaluations that reported load and energy savings or by assuming that load savings were proportional to energy savings (i.e. if a household reduces their annual energy use by 5 percent, they also reduce their peak demand by 5 percent).
- The evaluations of pilots and programs have two common limitations:
  - ***Self-selection bias*** – customers who are most likely to respond to load control, dynamic prices and conservation rates will be the ones that will volunteer to participate in the pilot programs or for optional programs. Only a fraction of customers will participate in any given program. Very few evaluations control for this self-selection bias or collect data that allows one to forecast participation rates. The ACEEE meta-analysis indicates that participation rates may be on the order of 65% to 85% for opt-out programs and on the order of 5% to 10% for opt-in programs. We used the results of the ACEEE meta-analysis as best available data for developing the range of participation forecasts.
  - ***Limited data on persistence*** – there is limited evaluations of the response over multiple years. As discussed below, there appears to be some small reduction in response to TOU and dynamic prices after the first year. We assumed that the savings would decrease by 10% after the first year to provide a conservative estimate.

At the same time, some technology and market trends may result in enhanced response to conservation rates and load control programs: many companies including CISCO, Microsoft, Google, and numerous new entrants, with generous venture capital funding are developing and marketing applications and services to households to enable them to better control their energy usage. Evaluations of pilot programs show that technology enables a more robust and persistent response to conservation rates and load control programs. The offerings of these non-utility, innovators should enhance the response to conservation rates and load control programs.

Table 4: Program Impacts on Annual Energy Savings

Program	Program/Pilot	Benefits	Source
Supporting Technology	Time-of-Use Pricing Pilot Project	Added savings from IHD was 3.4% for summer energy in addition to the 3.3% energy savings from TOU.	(Hydro One, 2008)
	BC and Newfoundland real-time feedback pilot	The 2005-2007 IHD pilot resulted in 3%-18% average decrease in electricity	(CEATI, 2008)
	ACEEE meta-analysis of feedback	Real-time feedback resulted in 5.4% savings	(ACEEE, 2010)
TOU	Ontario Energy Board Smart Price Pilot	6.0% conservation effect	(IBM and eMeter, 2007)
	Time-of-Use Pricing Pilot Project	3.3% energy savings during the summer months	(Hydro One, 2008)
	BC Hydro Conservation Research Initiative (CRI)	Reductions in energy use of 11.5% and 11.1% during peak hours for years 1 and 2, respectively, annual energy savings were 7.9% and 5.5% for years 1 and 2.	(LeClair. 2010)
	Ameren Power Smart Pricing Program	1.5% overall annual energy savings and 6% savings during summer season	(Ameren, 2008)
	Newmarket Hydro TOU Pricing Program	2.8% reduction in peak period energy usage with no significant annual savings, 63% participation in the opt-out TOUprogram	(Newmarket, 2010) Newmarket, 2008)
Pre-pay (w/ pre-pay card and display unit)	Woodstock Hydro's Pay-As-You-Go	15-20% reduction on a customer's average annual consumption with supporting technology	(Woodstock Hydro, 2004)
	Salt River Project M-Power Price Plan	12% reduction on a customer's average annual energy consumption with supporting technology	(SRP, 2009)
CPR	Ontario Energy Board Smart Price Pilot	7.4% conservation effect during entire program	(IBM and eMeter, 2007)
	Ontario Energy Board Smart Price Pilot	4.7% conservation effect during entire program	(IBM and eMeter, 2007)

The results from the Newmarket Hydro's TOU Pricing program suggest an average savings during peak periods of 2.8% with minimal energy savings over the entire year. The Newmarket program was mandatory and therefore, doesn't suffer from self-selection bias. Most of the other TOU pilot programs have self-selection. BC Hydro's TOU showed significantly higher peak reductions of more than 11 percent. The BC Hydro pilot was completed with volunteers. The Hydro One pilot, with a 3.7% peak savings was also completed with volunteers. Hydro One enrolled only 13% of the customers solicited.

Table 5: Program Impacts on Peak Demands summarizes the effect on peak demand by utility programs or pilots. These peak demand shifting benefits typically estimate the average energy demand a customer shifts from peak to off-peak periods.

Table 5: Program Impacts on Peak Demands

Program	Program/Pilot	Benefits	Source
Supporting Technology	Time-of-Use Pricing Pilot Project	5.5%-8.5% combined TOU and IHD impact (1.8%-5.6% incremental impact from IHDs during summer peak periods)	(Hydro One, 2008)
	Residential TOU Pilot Study	Participants with CPP + smart thermostats roughly doubled peak load shifting compared to effect of CPP alone	(Ameren, 2006)
	Meta-Analysis of 36 programs and pilots	Real-time feedback from IHD saves 5.4% more than providing customized information and feedback on the bills	(ACEEE, 2010)
LC (w/TOU)	California Automated DR System Pilot	GoodWatts device: 43% peak reduction during 11 summer CPP days; 27% peak reduction during TOU non-CPP days	(RMI, 2006)
TOU	Conservation Research Initiative (CRI)	11.5% reduction in peak energy use during year one of program with smart meter technology (7.6% during winter peak)	(BC Hydro, 2009)
	Time-of-Use Pricing Pilot Project	3.7% load shifting during the summer months	(Hydro One, 2008)
	Newmarket Hydro TOU Pricing Pilot	2.8% reduction in on-peak energy usage for TOU only participants	(Newmarket, 2010)
	Puget Sound Energy's TOU Pilot	5% average reduction in peak energy during 15 months of the program	(Faruqui, 2003)
CPR	Ontario Energy Board Smart Price Pilot	17.5% reduction during critical peak hours (~4 hrs); 8.5% reduction during entire peak (~6 hrs)	(IBM and eMeter, 2007)

CPP	PG&E 2008 SmartRate Program	CPP SmartRate--22.6% peak reduction	(Freeman Sullivan & Co., 2009)
	Ontario Energy Board Smart Price Pilot	25.4% reduction during critical peak hours (~4 hrs); 11.9% reduction during entire peak (~6 hrs)	(IBM and eMeter, 2007)
CPP and TOU	PSE&G myPower Sense and myPower Connection	TOU + CPP—12% peak reduction; TOU + CPP + smart thermostat—18% peak reduction	(PSE&G and SBC, 2007)

Experience from Winter Peaking Utilities

Savings from conservation demand management programs may vary depending on the peak season. For example, some customers may be more willing to reduce their cooling usage during the summer in response to peak prices than they would be to reduce their space heating usage during winter months in response to peak prices. The ACEEE meta-analysis notes that short duration pilots show larger savings than long duration pilots due, in part, to the failure of shorter duration pilots to capture seasonal variations (ACEEE 2010).

Avista, found customers from its demand response pilot to be less responsive during peaking events that took place during the winter months than those that occurred during the summer months.

Puget Sound Energy (PSE), a utility located in the Pacific Northwest, also has experience implementing a TOU pilot, but was less successful due to its small rate differential between peak and off-peak periods. Like FortisBC, PSE's peak period occurs during the winter and hydro resources supply a majority of its electricity. PSE set the peak period price just 15% higher than the standard rate and the off-peak price 15% lower than the standard rate (1.3:1 ratio) to reflect its hydro-based system in the Northwest (Faruqui, 2003). Such small rate differentials did not motivate customers to make behavioral changes and shift their peak demand as they only received a small amount of savings.

BC Hydro has similar peak periods similar to those of Fortis, given its geographic proximity. Based on results from the first year of the Conservation Research Initiative (CRI), BC Hydro reduced peak period energy usage by 7.6% on average during the winter months of December, January, and February. This TOU conservation impact is larger than the TOU conservation impact observed in many of the other pilots. This suggests that, at least for energy, other factors than the season of the utility peak may be more important drivers of the observed savings.

Experience from Utilities with Results on Both Peak Shifting and Conservation

While many utility pilots only reported on savings from either peak shifting or conservation, some pilots reported both. These pilots include BC Hydro's CRI, Hydro One's TOU Pricing Pilot, and Ontario Energy Board's (OEB) Smart Price Pilot. These results are summarized in Table 6: Peak Period and Annual/Energy Savings for Canadian TOU Programs.

Table 6: Peak Period and Annual/Energy Savings for Canadian TOU Programs

Utility	Program	Critical Peak	Peak	Seasonal/Annual Energy
BC Hydro	TOU	NA	11%	5.5%
	TOU & CPP	21%		
Ontario Energy Board	TOU	5.7%	2.4%	6.0%
	TOU & CPP	25.4%	11.9%	4.7%
	TOU & CPR	17.5%	8.5%	7.4%
Hydro One	TOU	--	3.7%	3.3%
	TOU & IHD	--	8.5%	7.6%
New Market Hydro	TOU (Mandatory)	--	2.8%	0.66%

These results show that:

- Peak savings range from 4% to 11% per participant
- Annual savings range from 3% to 7.5% per participating customer
- CPP or CPR increase peak period savings to the range of 17% to 25% per participant
- Per customer savings for a mandatory program (Newmarket) may be one-fifth of the savings of the savings observed for volunteer participants, suggesting that approximately 20% of customers will respond to mandatory tariffs.

Inclining Block Rates

BC Hydro, in their application for inclining block used a price elasticity estimate of -0.1 as a conservative assumption (Orans, 2008). BC Hydro is commencing an evaluation of its inclining block rate program in the fall of 2010. This appears to be the first evaluation of the the inclining block rates for electricity.

Customers take a a while learn, understand, and adopt to new rate structures. Changing the default rate structures too frequently could create customer confusion and increases marketing costs. NCI did not find empirical evidence supporting the conservation effect of inclining block rates.[7] If FortisBC plans to implement TOU rates with the next 3 to 5 years, the Company may want to avoid having to transition customers to different deafult rate structures wihin a period of several years as may cause customer confusion.

[7] Commonwealth Edison's Smart Meter Pilot is in the process of deploying its smart meters which will test incline block rates, but results have yet to be published (PUF, 2010), BC Hydro is just initiating an evaluation of their inclining block rate in the fall of 2010.

Primary Research

This section summarizes results and findings from the utility interviews. Since NCI conducted both primary and secondary research for these utilities, some information from secondary sources is also included in this section for background.

Overview of Utility Interviews

NCI interviewed the five utilities that were previously identified in Table 2: Rationale for Selected Utility Interviews. The interviews were conducted to develop insights from their pilots and programs and lessons learned from a range of utilities with different types of AMI future program experience. These utilities also have a variety of experience with different innovative pricing programs (e.g., critical peak pricing and critical peak rebates), some programs with in-home displays, and various implementations of load control. *Attachment 1: Primary Research* section provides detailed notes from these interviews which have been paraphrased to focus on relevant content for this study.

In Table 7: Ameren Summary, we summarize the relevant program, benefits, and cost information gathered from the interview with Ameren and supplemental research.

Table 7: Ameren Summary

Ameren—Illinois	
Overview of Relevant Programs	• Smart Meter Deployment: began in 2006 and aims to improve customer service and reduce O&M costs with its installation of 1.1 million gas and electric smart meters from Landis+Gyr • Power Smart Pricing (PSP) program: started in 2007 and uses a low technology approach (e.g. incremental meters) to implement voluntary real-time pricing by notifying customers of a critical peak pricing period one day in advance via email or with an automated phone call
Benefits and Costs of Program	• PSP resulted in: a 6% reduction in average energy use during the peak summer season and 1.5% annual average reduction; an overall elasticity of -4.3% for the 2008 summer season; and 7.7% (9.1% including conservation) average annualized bill savings on customer bills compared to flat-rate charges; • Since Power Smart Pricing launched in early 2007, participants have saved an average of 17% compared with what they would have paid on the standard fixed rate (based on billing results for May 2007 through Sept. 2009)
Program Administration Activities and Costs	• Costs of the PSP program include incremental cost of metering to collect hourly usage data, additional utility expenses for software and data processing systems, and the program administrator and evaluation contracts • CNT Energy is responsible for all the marketing and customer education associated with the PSP program
Programmatic Insights	• Establish payment for vendors to correspond with verification of accurate meter reading and full system functionality rather than just meter installations. • Begin communicating early in the deployment with and helping transition employees whose jobs may be at risk with the technology automation. • Set realistic expectations for customers and involve local community partners and

	municipalities to improve customer acceptance and satisfaction.
Sources: Ameren, 2010. Personal communication. January 2010. Ameren, 2006. "Automated Meter Reading." Ameren Services. Web. 18 Sept. 2010. <http://www.ameren.com/Residential/ADC_AMR.asp>. CNT Energy and Summit Blue, "Residential Real-Time Pricing Program Achieves Savings for Utility and Customers", Draft Paper, November 2009. Summit Blue Consulting, "Power Smart Pricing 2008 Annual Report," March 31 2009. Voytas, Rick. "AmerenUE Critical Peak Pricing Pilot", presented at U.S. Demand Response Research Center Conference, Berkeley, CA., June 2006	

Table 8: Avista Summary summarizes the relevant program, benefits, and cost information gathered from the interview with Avista and supplemental research.

Table 8: Avista Summary

Avista—Idaho	
Overview of Relevant Programs	• Demand Response Pilot—spanning from July 2007-December 2009 this pilot tested the effectiveness of smart thermostats and direct control unit (DCU) switches on customer devices (e.g. water heaters, compressors, heat pumps, and AC) for over 70 residential customers.
Benefits and Costs of Program	• The pilot did not track enough data to measure the average energy reduction, but Avista estimated savings to be consistent with other pilots of this nature. • Customers tended to be less responsive to peak events during the winter when compared with the summer.
Program Administration Activities and Costs	• The pilot program cost US$123,000 for 2 years which included customer incentives, equipment costs, hosting fee for the vendors (~US$1,000/month), and marketing costs through an advertisement agency (~US$2,000). • Avista paid customers with a DCU about $10/ peak month for participating during peak events. Avista provided no cash incentives to use the smart thermostats, but these customers did receive a free thermostat.
Programmatic Insights	• Implementing price signals (e.g. dynamic rates) with the smart thermostats would have likely improved ongoing customer participation and savings. The lack of dynamic pricing meant customers had less incentive to reduce their load and participate during peak events. • Customers tended to be very enthusiastic about the smart thermostats and energy management capability at the start of the pilot, but after a few months the novelty for customers seemed to wear-off and savings dropped off. Battery failures were an issue. Decreasing savings were attributed largely to the lack of pricing signals. • Don't begin marketing the program to customers until the equipment has been tested and is ready to be deployed.
Sources: Avista, 2010. Personal communication. February 2010. Avista, 2009. "2009 Electric Integrated Resource Plan," Avista Utilities, August 2009.	

Table 9: BC Hydro Summary summarizes the relevant program, benefits, and cost information gathered from the interview with BC Hydro and supplemental research. BC Hydro's conservation research initiative (CRI) was designed to test residential customers' responses to alternative conservation rates. Because of the demographic and climatic similarities between BC Hydro's and FortisBC's service areas, their results are likely to be particularly applicable to FortisBC.

Table 9: BC Hydro Summary

BC Hydro—British Columbia	
Overview of Relevant Programs	• Smart Metering and Infrastructure (SMI) Program: aims to improve BC Hydro's O&M electric services and enable innovative conservation rate structures and customer energy management with the installation of approximately 1.8 million smart meters and their associated IT systems • Conservation Research Initiative (CRI): aims to test the effectiveness time-of-use (TOU) rates and smart meters at shifting and conserving peak load for roughly 2,000 residential customers in British Columbia
Benefits and Costs of Program	• TOU participants reduced winter peak period energy usage by 11.5% in year 1 and 11.1% in year 2, while annual energy savings was 7.9% in year 1, and 5.5% in year 2. • CPP participants provided an additional 10% reduction during peaks. • Direct load control participants peak energy consumption savings were less than 1%
Program Administration Activities and Costs	• Load control devices were difficult to implement due to installation costs and challenges; controllable thermostats are likely an easier alternative to deploy
Programmatic Insights	• When implementing alternative pricing schemes, try to choose a design that is clear and easy for customers to understand. • A considerable amount of customer support and services are required to implement a smart meter and/or TOU program.
Sources: BC Hydro, 2009. "Conservation Research Initiative." BC Hydro. Web. 18 January 2010. <http://www.bchydro.com/powersmart/residential/conservation_research_initiative.html> BC Hydro, "2009 Electricity Conservation Report", November 2009. BC Hydro's "Conservation Research Initiative", paper presented at Vaasa ETT Exchange Roundtable, by Donna LeClair, Chief Technology Officer, May 26, 2010. BC Hydro, 2010. Personal communication. January 2010.	

Table 10: Hydro One Summary summarizes the relevant program, benefits, and cost information gathered from the interview with Hydro One and supplemental research.

Table 10: Hydro One Summary

Hydro One—Ontario	
Overview of Relevant Programs	• 2005 IHD Pilot: tested effectiveness of real-time feedback on energy consumption with 500 residential IHDs • 2007 Time-of-Use Pricing/IHD Pilot Project: tested impact of TOU combined with IHDs on 486 smart metered customer volunteers • 2006-2007 IHD Program Deployment: this $5 million voluntary project distributed 30,000 IHDs to residential customers
Benefits and Costs of Program	• The IHD pilot of 500 reduced energy by 6.5% on average while the IHD deployment was 5.2%; when IHD was combined with TOU, the savings were slightly higher at 7.6% (4.3% from IHD and 3.3% from TOU) • At the start of the IHD deployment, Hydro One paid a third party (Blue Line Innovations) roughly $150 per IHD (included hardware, marketing and shipping); most customers self-installed the devices
Program Administration Activities and Costs	• The two pilots tried to minimize the amount of customer education and marketing to isolate the impact of just the technology • Customer education and marketing cost about $25-$50 per customer for the 30,000 IHD deployment which included radio, newspaper adds, customer calls, and informational instructions mailed with the devices
Programmatic Insights	• Highlighting electric heating load of homes with the IHD may have helped encourage conservation for the 2005 IHD pilot as many of the customers with electric space heating were less responsive to real time feedback (the IHD reduced load by 1.2% in these houses compared to the 6.7% average • Real-time feedback of energy consumption is effective in promoting conservation even without real-time pricing. • IHDs with two-way communication that can be remotely updated by the utility or AMI system are often more effective in promoting conservation as customers rarely program these devices on their own (e.g. programming updates to TOU periods); also IHDs powered by batteries were less reliable.
Sources: Hydro One, 2010. Personal communication. January 2010. Hydro One, "Time-of-Use Pricing Pilot Project Results", EB-2007-0086, May 2008. Hydro One, "The Impact of Real-Time Feedback on Residential Electricity Consumption: The Hydro One Pilot", March 2006.	

Table 11: PG&E Program Overview summarizes the relevant program, benefits, and cost information gathered from the interview with PG&E and supplemental research.

Table 11: PG&E Program Overview

Pacific Gas and Electric (PG&E)—California	
Overview of Relevant Programs	• Smart Meter and SmartRate™: PG&E is spending US$2.2 billion dollars to install ~10 million smart meters (54% electric and 46% gas) which will enable voluntary critical peak pricing (SmartRate™) for all customers. Since 2006, PG&E has installed 4.6 million meters and plans to finish deployment by 2012. • Ancillary Services Pilot: During the summer of 2009, worked with LBNL to test air conditioning automated demand response for 2,000 customers • Automated Demand Response System Pilot (ADRS)—In 2005 PG&E, along with other California utilities, implemented a residential-scale automated demand response technology (thermostats) for customers with critical peak pricing
Benefits and Costs of Program	• The SmartRate™ program rewards customers with a credit of nearly 3 cents (US$) for each kWh used outside of critical peak load periods (i.e. the hottest summer afternoons); customer response to the program has been positive
Program Administration Activities and Costs	• Total costs of AS Pilot were ~US$1.4 million (roughly 20% for administration, 11% for customer recruiting and education, 35% for installation/other services, and the remainder for hardware, reporting, customer surveying costs)
Programmatic Insights	• Keep the program simple and implement a pricing structure that is straightforward and clear, to help customers to understand the benefit proposition. • Too much information can be confusing for customers, so sending concise and clear education material helps reduce questions and increase participation. • Develop an implementation plan that allows time for customers to gradually adapt and gives priority to technologies that are compatible with future enhancements.
Sources: Charles River Associates. "Impact Evaluation of the California Statewide Pricing Pilot", 2005. Rocky Mountain Institute. "Automated Demand Response System Pilot: Final Report", March 2006. Freeman, Sullivan & Co. "2009 Pacific Gas and Electric Company SmartAC Ancillary Services Pilot", December 2009. PG&E, 2010. Personal Communication. January 15th, 2010.	

Lessons Learned from Utility Interviews

The interviews provided insights and lessons learned from the utility pilots and programs. While the interview discussions and questions differed slightly depending on the program experience for each utility, the lessons learned can be grouped into several key drivers of program savings: peaking period; customer persistence and satisfaction; program design.

Table 12: Summary of Lessons Learned from Interviews summarizes the key lessons learned grouped by these categories. *Attachment 1: Primary Research* section provides detailed notes from the interviews which have been paraphrased to focus on relevant content for this study.

Table 12: Summary of Lessons Learned from Interviews

Key Driver of Program Savings	Lessons Learned
Peaking Period	• If technologically possible, provide energy demand information at the customer appliance level in order to inform customers on which major appliances to adjust during peak periods, e.g. electric space heating. (Hydro One, 2010) • Provide residential customers with higher price signals during non-discretionary demand periods in the winter as customers tend to be less responsive to peak events during winter peak periods (morning and evening hours) when compared with summer peak afternoon hours (Avista, 2010)
Customer Persistence and Satisfaction	• Minimize customer activities required to operate and maintain IHDs (e.g. installation, programming updates, and replacing batteries) with automated and utility controlled technology where possible (Hydro One, 2010; Avista, 2010) • Implement price signals with enabling technologies (e.g. IHD) to incentivize ongoing customer participation (Avista, 2010). Without price signals, savings from IHD decay quickly (Avista, 2010)
Program Design	• For a voluntary program, involve local community partners and municipalities to encourage customer awareness and adoption (Ameren, 2010) • Design the program to be simple and implement a pricing structure that are clear to help customers understand the benefits of participating (BC Hydro, 2010) • Develop an implementation plan that allows time for customers to gradually adapt and gives priority to technologies that are compatible with future enhancements (PG&E) • Keep program informational materials concise and easy to understand to reduce customer questions and additional customer communication costs (PG&E)
Program Implementation	• Develop an implementation plan that allows time for customers to gradually adapt and gives priority to technologies that are compatible with future enhancements (PG&E) • Ensure meters operate and are configured correctly during rollout (BC Hydro)
Sources: Ameren, 2010. Personal communication. January 2010. Avista, 2010. Personal communication. February 2010. BC Hydro, 2010. Personal communication. January 2010. Hydro One, 2010. Personal communication. January 2010. PG&E, 2010. Personal Communication. January 15th, 2010.	

Key Issues

NCI identified several key issues which influence the overall impact of AMI Future Programs including elasticity, persistence of customer savings, energy payback, peak period, and the interactive effect of multiple programs and supporting technologies.

Elasticity

Elasticity measures the responsiveness of customers to adjust their energy consumption in response to changes in the price of energy. Table 13 summarizes elasticity estimates and measurements from various studies. The savings estimates used from various CDM pilots (see Table 13: Residential Elasticity Estimates from Research) also helps measure this responsiveness and predict customer behavior. Elasticity estimates range from a low -0.02 to a high of -0.184. A number of estimates cluster in the -0.03 to -0.06 range. Based on the findings in these studies NCI recommends FortisBC use an elasticity in the range of -0.03 to -0.06 for TOU programs for its residential sector.

Table 13: Residential Elasticity Estimates from Research

Price Elasticity Research	Source
BC Hydro's 2007 Electric Load Forecast decomposed the conservation impact of rates into rate level-induced and rate design-induced conservation components for its inclining block rates, using an elasticity of -0.05 for the lowest block and -0.1 for the higher tier.	(BC Hydro LTAP, 2008)
Ameren's 2008 PSP program had an overall elasticity for the summer season of -0.043	(PSP Annual Report, 2008)
Newmarket Hydro Time-of-Use Pricing Pilot's average participant price elasticity ranged from -0.02 to -0.05	(NCI, 2008)
PSE&G myPower Sense program TOU + CPP had a -0.085 substitution elasticity; PSE&G myPower Communication program TOU + CPP +Programmable/Communicating thermostat had a -0.137 substitution elasticity	(Edison Electric Institute, 2008)
California SPP's fixed CPP elasticity ranged from -.035 to -.054 for 2003 and 2004 respectively	(CRA, 2005)
BC Hydro TOU pilot estimated elasticity of substitution of -0.06, and price elasticity of -0.187	(Tiedemann, 2008)

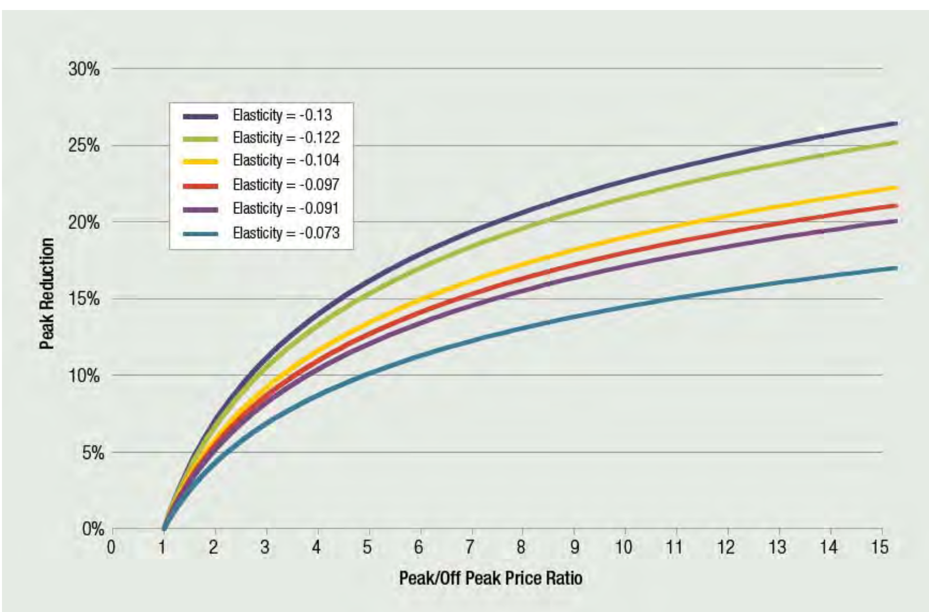
Table 14: BC Hydro's Commercial and Industrial Elasticity Forecast Estimates lists estimates for elasticity of commercial and industrial customers used by BC Hydro in their 2006 and 2007 load forecast. C&I sectors have higher elasticities (-0.1 to -0.2) than the residential sector (roughly -0.05) which 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 14: BC Hydro's Commercial and Industrial Elasticity Forecast Estimates

Sector	Short-Term Elasticity
Commercial	-0.1
Industrial	-0.2
Source: BC Hydro, "Electric Load Forecast 2006/07 to 2026/27", Market Forecasting, Energy Planning, Customer Care and Conservation.	

Figure 6: Demand Response Peak Reduction of Residential Customers on a CPP Rate with Varying Elasticities shows the relationship between price and peak reduction for varying elasticities. The Brattle Group developed this relationship based on research from multiple pilot projects (PUF, 2010). Figure 6: Demand Response Peak Reduction of Residential Customers on a CPP Rate with Varying Elasticities also highlights the variable impact of residential elasticities ranging from -0.13 to -0.073, which for a 3 to 1 peak/off peak ration results in a 7%-11% peak reduction. Because the CPP entail only a few events during the year with notification, one would expect elasticities for CPP than TOU. We recommend using the lower end of the elasticities in Figure 6: Demand Response Peak Reduction of Residential Customers on a CPP Rate with Varying Elasticities, i.e., -0.73 to -0.91. This value is higher than for TOU, consistent with some the pilots, and is a conservative value.

Figure 6: Demand Response Peak Reduction of Residential Customers on a CPP Rate with Varying Elasticities



Source: PUF, 2010 Note: The Brattle Group used elasticity data from multiple pilots to develop this graph showing the effect of dynamic pricing on customers without enabling technologies.

Persistence of Customer Savings

The limited data on persistence indicates that savings persist from year to year for CPP and CPR rates, particularly when coupled with technology. The ACEEE meta-analysis included 27 feedback studies found that the energy savings persisted as long as the feedback continued. For example, one study in the Netherlands found that the 12% savings from IHD's declined significantly in the year after the IHD's were removed.

The California Statewide Pricing Pilot (SPP) specifically evaluated demand impacts over two years from 2003-2004 (EEI, 2008). The results were that the CPP customers increased their savings slightly in 2004 relative to 2003, while the savings for the TOU customers almost disappeared in 2004. Neither group had supporting technology. The TOU on-peak rate was twice that of the off-peak rate, whereas the CPP rate was five times the off-peak rate. The higher persistence of the CPP rate impact compared to the TOU may be attributable to several factors: the fact that the utility implemented CPP rate for only a few targeted days; the CPP rate had much higher peak/off- peak differential; and the utility directly communicated with the customer on the day before or the day of the critical peak events (EEI, 2008).

The BC Hydro CRI showed peak period reductions of 11.5% in year 1 and 11.1% in year 2, suggesting that peak period reductions persist. The overall savings in the winter months declined from 7.9% reduction in year 1 to 5.5% in year 2. This decline could be a result of multiple factors including weather, economy, or lack of persistence. Overall there is very limited data on persistence of savings. We recommend assuming that there is a 10% decrease in savings following the first year of participation as a conservative assumption.

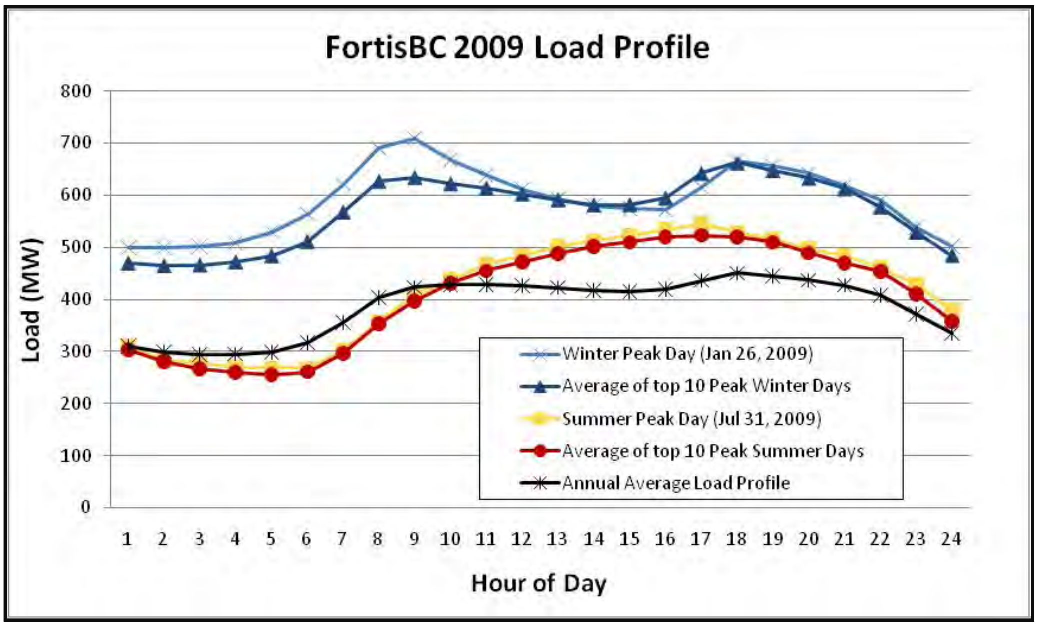
Energy Payback

Energy payback measures the extent to which peak period savings result in increased energy usage during off-peak periods. For example, load control programs generally find that appliances switched off during the peak periods tend to be used more heavily during the non-peak periods. Avista in their load control pilot estimated that peak demand reductions were .33 kW per controlled water heater and 1.5 kW per controlled space heater, yet they observed very little overall conservation effect, and even some increased consumption on the day following the control event (Avista, 2010). The California SPP found increases in off-peak usage for the TOU and CPP tariffs and found no change in total energy use across the entire year (EEI, 2008). Pilots, as summarized in Table 4: Program Impacts on Annual Energy Savings have shown a range of impacts ranging from small increases in overall consumption to annual energy savings of 5-10% overall conservation impact. The pilots with CPP and TOU rates specifically designed to be revenue neutral and with little customer communication tend to show the smallest conservation impacts. The programs (or participant groups) that were coupled with customer education and supporting technology tend to show higher conservation and peak period reductions. For example, the ACEEE meta-analysis of 36 pilots implemented between 1995 and 2010 showed an average savings of 9.2% from real-time feedback (e.g. from IHD's).

Peak Period

Utilities typically design conservation rates that reduce load during peak periods. FortisBC's peak load profile for the summer and winter periods are summarized in Figure 7: FortisBC Load Profiles for Winter/Summer Peak Days and Annual Average in 2009. The top 10 peak winter days in 2009 all occurred during December and January, while the summer top 10 all occurred during July and August. These load profiles suggests that a conservation rate such as CPR would be most effective if it was implemented during winter critical peak days in the evening (e.g. from 5-9pm) and morning hours (e.g. 8-10am). Similarly if CPR was implemented during summer critical peak days it would target reductions in load in the late afternoon hours (e.g. from 3-7pm).

Figure 7: FortisBC Load Profiles for Winter/Summer Peak Days and Annual Average in 2009



Source: FortisBC Load Data, 2010
Note: Of the top 10 winter peaks in 2009, the highest load occurred during the evening period for nine out of the ten days, which suggests the Jan. 26th morning peak may have been an anomaly.

FortisBC's load duration curve in Figure 8: FortisBC Load Duration Curve for Top 100 Hours in 2009 also suggests that using a conservation rate for even a few hours per year could result in significant benefits. Figure 8 shows that peak loads were reached in 2009 during just a few hours of the year. For example, the top 10% (71 MW) of the peak load in 2009 occurred for about 40 hours. Similarly, the top 6% of the peak load (44 MW) in 2009 occurred for fewer than 6 hours.

Figure 8: FortisBC Load Duration Curve for Top 100 Hours in 2009

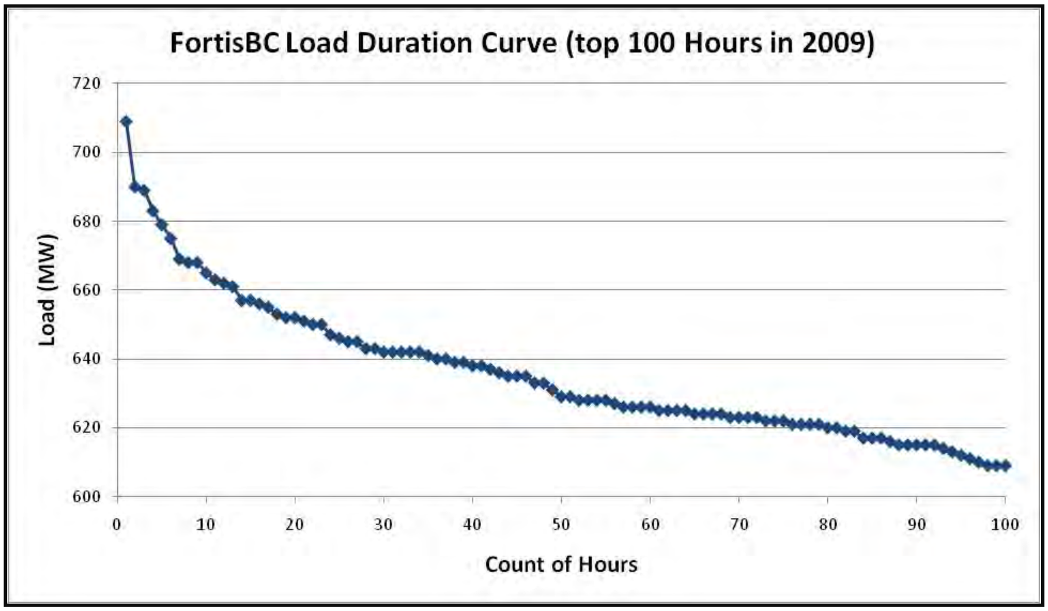


Table 15: Top 10 Hourly Loads in 2009 provides more detail on the time period for the top 10 peak hours in 2009, which all took place during the January and December winter months.

Table 15: Top 10 Hourly Loads in 2009

Date	Hour Ending	Load (MW)	% of 2009 Peak	Difference (MW)
26-Jan-09	9	709	100%	0
26-Jan-09	8	690	97%	19
14-Dec-09	18	689	97%	20
8-Dec-09	18	683	96%	26
14-Dec-09	17	679	96%	30
14-Dec-09	19	675	95%	34
10-Dec-09	18	669	94%	40
26-Jan-09	10	668	94%	41
8-Dec-09	19	668	94%	41
26-Jan-09	18	665	94%	44

Interactive Effects

The evidence indicates that savings increase and are more likely to persist if rates are combined with on-going information, customer feedback, and enabling technology. For example, the Hydro One pilot showed that TOU rates with IHD increased peak savings from 3.7% to 5.5% while energy savings increased from 3.3% to 7.6 %. The California SPP showed that customers with enabling technology (such as smart thermostats) reduced their on-peak usage by from 18% to 27%. The results suggest that:

- Utility communication and marketing is important to remind customers that they can manage their usage; and
- Coupling enabling technology with the rates will increase the peak energy and conservation impacts by roughly 50%.

The pilot programs and experience to date have not focused on the enhanced benefit between these conservation rate/LC programs and the utility's energy efficiency programs. Very few pilots have measured the benefits of market segmentation and targeting customers with the highest likelihood to reduce energy. One evaluation of Ameren's Power Smart Pricing (PSP) did examine the propensity of customers to participate in Ameren's CFL program. They found that PSP customers were five times more likely to participate in the CFL program (Ameren, 2008). Self selection bias may explain some portion of this increased participation, but it also appears that increased awareness of energy consumption enhances participation in other programs.

Program Impact

Energy and Capacity Savings

Based on the research discussed in previous sections of this report, NCI developed estimates of the savings FortisBC might expect to see from potential AMI future programs. Because of the range of results from the various studies reviewed and the uncertainties, conservative savings values were recommended. The recommended savings impacts by type of program are summarized in Table 16: Per Participant Savings for Possible AMI Future Programs.

Table 16: Per Participant Savings for Possible AMI Future Programs

Program Type		Peak	Energy	Source
Conservation Rates	TOU	11%	5.5%	BC Hydro CRI[8]
	CPP/CPR	10%	0	
	Inclining	1.8%	1.8%	BC Hydro CRI[9]
Pre-Pay		5.8%*	11.7%	Woodstock Hydro 2004[10]
Load Control		13.3%	0	FERC 2009
In-Home Displays		2.7%	5.4%	ACEEE 2010

* Assume that the peak period savings are half of the annual savings

Impacts with Supporting Technology

The supporting technology bundle is assumed to include an in-home display (IHD) and either a programmable, communicating thermostat (PCT) or up to 4 load control switches/smart appliances. The impact of the supporting technology was estimated to increase savings by 50% over the savings estimates summarized in Table 16: Per Participant Savings for Possible AMI Future Programs. This 50% increase in savings is consistent with the data and assumptions in the "*US National Demand Response Assessment*" (FERC 2009). This assumption is conservatively consistent with the results from multiple studies reviewed including:

- Hydro One found that households with TOU and IHDs showed more than twice the savings in both energy and demand compared to TOU participants without TOU.
- The ACEEE meta-analysis found that programs focused on peak load shifting provided an average energy savings of 3%, while those focused on both peak and energy have provided energy savings of 10%.

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[8] B,C, Hydro, 2010 "Conservation Rate Initiative, BC Hydro Website

[9] B.C, Hydro 2008, "2008 Residential Inclininy Block Application," February, 2008

[10] Average of range from Woodstock Hydro, 2004. "Pay-As-You-Go-Power: Treating Electricity as a Commodity," Ken Quesnelle (Vice-President), January 20, 2004

- Woodstock Hydro found that supporting technology increase savings from pre-pay meters from an average of 11.77% to 15% to 20%.
- Public Service Electric & Gas "myPower" pilot showed 50% higher peak savings for customers with supporting technology (18% vs. 12%) for their CPP/TOU rate.

Conservation Rates

TOU

We recommend using the BC Hydro CRI results as the impact from participating customers. BC Hydro is most similar to FortisBC in terms of climate, prices and demographics. As discussed below, these need to be adjusted for number of participation rates. We recommend assuming that 20% to 30% response rate is consistent with analyses that show that 20% to 30% provide most of the response to mandatory TOU programs, and make the voluntary programs (e.g. BC Hydro, Hydro One) consistent with the mandatory programs (Newmarket Hydro).

- The Newmarket program is the only program reviewed where there was no self-selection bias and results included multiple years. The evaluation results for this program for the very aware segment of customers are consistent with the observed responses for the BC Hydro CRI voluntary respondents;
- The ACEEE Meta-Analysis indicates that volunteers are approximately 5% of the customer population; and
- Several studies indicate that elasticity estimates should apply to the total bill. If the TOU rate is revenue neutral, then conservation effects should be minimal.

For peak demands, the most relevant TOU studies are the Newmarket and BC Hydro CRI programs: The Newmarket evaluation shows a peak demand savings for TOU rates of 2.8%. The BC Hydro CRI evaluation shows peak period reductions of 11.5% in year 1 and 11.1% in year 2. Since customers self-selected to participate in the BC Hydro study, it is reasonable to assume that they are more price responsive than the general population. The NewMarket results are consistent with the BC Hydro CRI results assuming an average effective participation of 25%, i.e. 25% of the customers placed on the TOU rate actually respond to the price signal. We recommend using the BC Hydro value rounded down to 11% as the response for the responsive customer. We recommend forecasting a range of 20% to 30% of customers as being responsive.

CPP and CPR

We recommend using the 10% savings for critical peak hours for CPP and CPR based on the preliminary results from the BC Hydro CRI year 2 participants in CPP. This 10% reduction during critical peak hours is in addition to the 11.1% reduction due to the TOU rates. The Woodstock CPP program showed an 11.9% reduction. We recommend using the slightly lower BC Hydro savings because of the proximate location, being more recent, and because it is implemented in addition to the TOU rates.

Energy savings from CPP and CPR are assumed to be negligible without supporting technology, due the very small number of critical peak hours. The energy savings with supporting technology is the 5.4% that can be attributed to the IHD.

Inclining Block Rates

The 1.8% savings for the inclining block rates is based on the BC Hydro estimates from its "2008 Residential Inclining Block Application" where they estimated conservation savings of 200-523 GWh from a customer eligible load of 17,108 GWh (BC Hydro, 2008a). The 6.3% impact with supporting technology assumes that half of the elasticity effect from the inclining block rate is captured in the 5.4% additional savings from supporting technology. Without TOU rates, we assume that inclining block rates will have negligible peak savings.

Pre-pay

We recommend using the 11.7% savings from pre-pay based on the Woodstock Hydro program results. This is consistent with the 12% savings observed in the Salt River Project (SRP) program. The impact of supporting technology (e.g. IHD) would be to increase by 50% to 17.5%. This 5.8% increase in conservation is consistent with the 5.4% impact of real-time consumption feedback reported in the ACEEE meta-analysis (ACEEE, 2010).

Neither the Woodstock nor SRP program provided data on peak demand savings. We conservatively assume that without supporting technology and TOU rates, there will be no peak period reductions.

Load Control

Load control peak savings of 13% is based on the FERC as demand response assessment. Load control entails installing the switches that are included in the supporting technologies. Thus, the supporting technology scenario has no change in impact.

We assume energy savings from pure load control programs are negligible, consistent with the evaluation results of multiple load control programs. Loads are typically controlled for less than 80 to 100 hours per year (less than 1% of the hours) and there is often some payback after the load control event. BC Hydro observed a less than 1% reduction in peak period consumption for the direct load control participants in its CRI program (LeClair, 2010).

In-Home Displays (IHD)

The IHD saving was forecasted to be 5.4% of annual energy use based on the ACEEE meta-analysis of 36 residential feedback pilots and studies conducted between 1995 and 2010. The peak demand savings were estimated to be half of the annual energy savings as a conservative assumption (this assumption was also applied to the pre-pay rates). The ACEEE meta-analysis found that many of the conservation actions employed focused on the non-space conditioning loads. Thus, one would expect the peak demand savings to be less than the annual energy savings. A portion of the annual energy can be expected to occur during peak periods. With supporting technology, the peak load impacts are assumed to be the same 20% reduction from the load control switches (i.e. the IHD provides no incremental demand reductions over the load control switches).

Participation Rates

Most of the pilots and programs reviewed were conducted with volunteers. Customers who volunteer to participate in the programs are more likely to respond to the price signals, incentives and information than other customers. In order to forecast the benefits from a system-wide roll-out of the programs, the per participant impacts need to be adjusted to reflect participation rates. In some instances, for example – TOU default rates, while all customers see the rates only a subset will actively respond to price signals. Reconciling the BC Hydro 11% peak savings for TOU rates with the 2.8% peak savings could imply that approximately 20% to 30% of customers actually respond to the price signals.

In order to estimate net energy and capacity benefits from future programs, participation forecasts are required. There are two radically different approaches to these future programs.

- ***Opt-In***—programs are offered as options and customer enrolls voluntarily.
- ***Opt-Out***—customers are assigned to the program. In some cases, they may choose not to participate. For example, a customer may refuse to have an IHD installed. In other cases, the customer may not pay any attention to the incentives or price signals such as for a TOU or a CPP default tariff program.

There is limited data on participation rates, in some cases, e.g. TOU programs, implied participation rates can be inferred by comparing savings from mandatory programs to voluntary programs[11], or by looking at the percentage of customers that provide savings.

The ACEEE meta-analysis used the following participation for real-time residential feedback programs:

- Opt-in: 3% to 8%
- Opt-out: 65% to 75%

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.

[11] Such comparisons can only be indicative because many factors, e.g. specifics of tariff design, weather, demographics, etc. could also drive the observed differences.

Recommended participation rate assumptions by program scenario are summarized in Table 17: AMI Future Program Participation Rate Assumptions. The TOU and CPP/CPR low opt-in assumption of 9% is based on the 13% participation rate from the Hydro One pilot times the 72% that expressed a desire to say on the TOU rates. The 20% and 30% rates for high opt-in and opt-out program scenarios are the 20% to 30% participation recommendations discussed in the *"TOU"* subsection above.

The inclining block rate savings are based on an elasticity estimate and implicitly applied to all eligible customers.

The pre-pay participation rates are based on the IHD participation rates for the opt-in program scenarios. It is assumed that neither pre-pay nor load control would be offered as an opt-out program. The load control participation rates are based on utility experience with load control programs.

The IHD participation rates are the same assumptions used by the ACEEE in their meta-analysis.

Table 17: AMI Future Program Participation Rate Assumptions

Program Type		Opt-In		Opt-Out	
		Low	High	Low	High
Conservation Rates	TOU	9%	20%	30%	60%
	CPP/CPR				
	Inclining	Not Applicable			
Pre-Pay		3%	8%	Not Applicable	
Load Control		5%	15%		
In-Home Displays		3%	8%	65%	75%

Program Benefits and Costs

Energy and Capacity Savings

The energy and capacity benefits from these future programs were forecasted for each program participation scenario for 2018. Year 2018 was selected for developing the forecasts based an assumed 2014 launch date and it would take approximately three years before the full participation rates are achieved. The forecasted capacity savings are summarized in Table 18: 2018 Capacity Savings (MW and % of Residential Load) and the forecasted energy savings are summarized in Table 19 2018 Energy Savings (MWh and % of Residential Sales).

Table 18: 2018 Capacity Savings (MW and % of Residential Load)

	Opt-In		Opt-Out	
	Low	High	Low	High
TOU	2.7	6.0	9.0	18.1
	0.89%	1.98%	2.97%	5.94%
TOU w Support	4.1	9.0	32.6	35.3
	1.34%	2.97%	10.74%	11.60%
CPR & CPP	2.5	5.5	8.2	16.4
	0.81%	1.80%	2.70%	5.40%
CPR & CPP w Support	-	-	31.4	32.8
	-	-	10.33%	10.79%
Incline Block	4.9			
	1.62%			
Pre-pay	0.5	1.3	Not Applicable	
	0.16%	0.42%		
Pre-pay w Support	0.7	1.9		
	0.23%	0.63%		
Load Control	1.8	5.5		
	0.60%	1.80%		
In-home displays	0.2	0.6	4.8	5.5
	0.07%	0.19%	1.58%	1.82%

Table 19: 2018 Energy Savings (MWh and % of Residential Sales)

	Opt-In		Opt-Out	
	Low	High	Low	High
TOU	6,762	15,028	22,541	45,083
	0.45%	0.99%	1.49%	2.97%
TOU w Support	10,144	22,541	59,632	78,690
	0.67%	1.49%	3.93%	5.18%
CPR & CPP	-	-	-	
	0.00%	0.00%	0.00%	
CPR & CPP w Support	-	-	47,951	55,329
	-	-	3.16%	3.65%
Incline Block	24,590			
	1.62%			
Pre-pay	4,795	12,787	Not Applicable	
	0.32%	0.84%		
Pre-pay w Support	7,193	19,181		
	0.47%	1.26%		
Load Control	-	-		
	-	-		
In-home displays	2,213	5,902	47,951	55,329
	0.15%	0.39%	3.16%	3.65%

The year 2018 capacity savings (also shown in Figure 9: Capacity Savings (MW) in 2018 by Program Scenario) range from a low of 200 kW for the low participation, opt-in scenario for IHDs to a high of 31 MW for the TOU with supporting technology for the opt-out scenario. The high energy savings for the TOU and CPP/CPR opt-out scenarios are driven largely by the supporting technologies. Not only do the supporting technologies enhance the savings for the participants in these rate programs, but they also result in savings from the non-participants in the conservation rate programs.

Figure 9: Capacity Savings (MW) in 2018 by Program Scenario

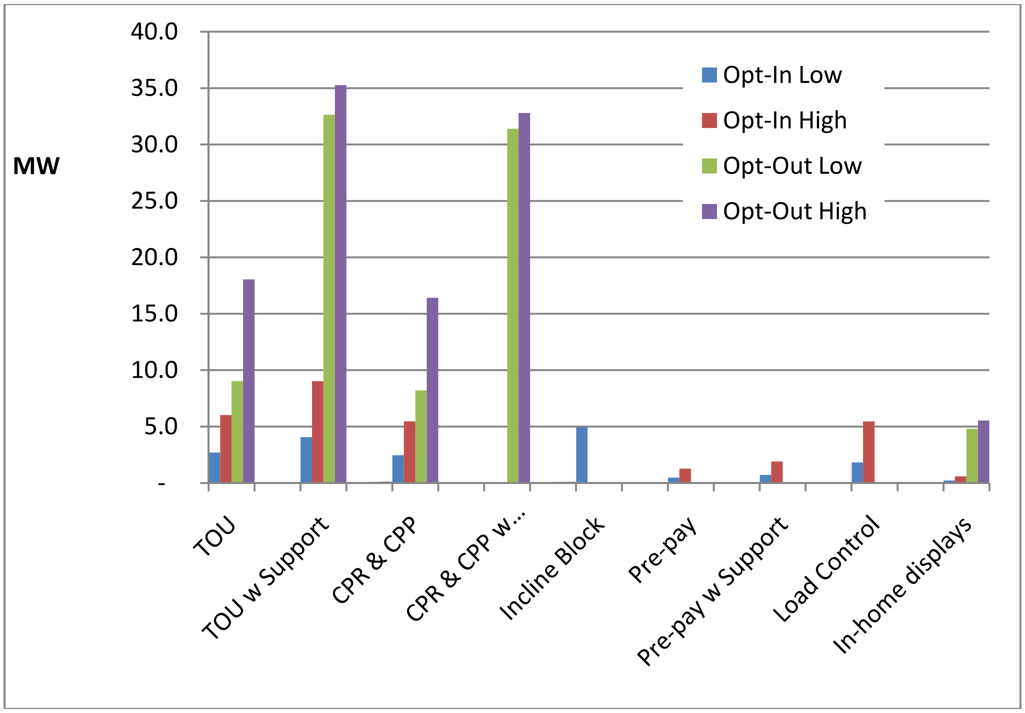
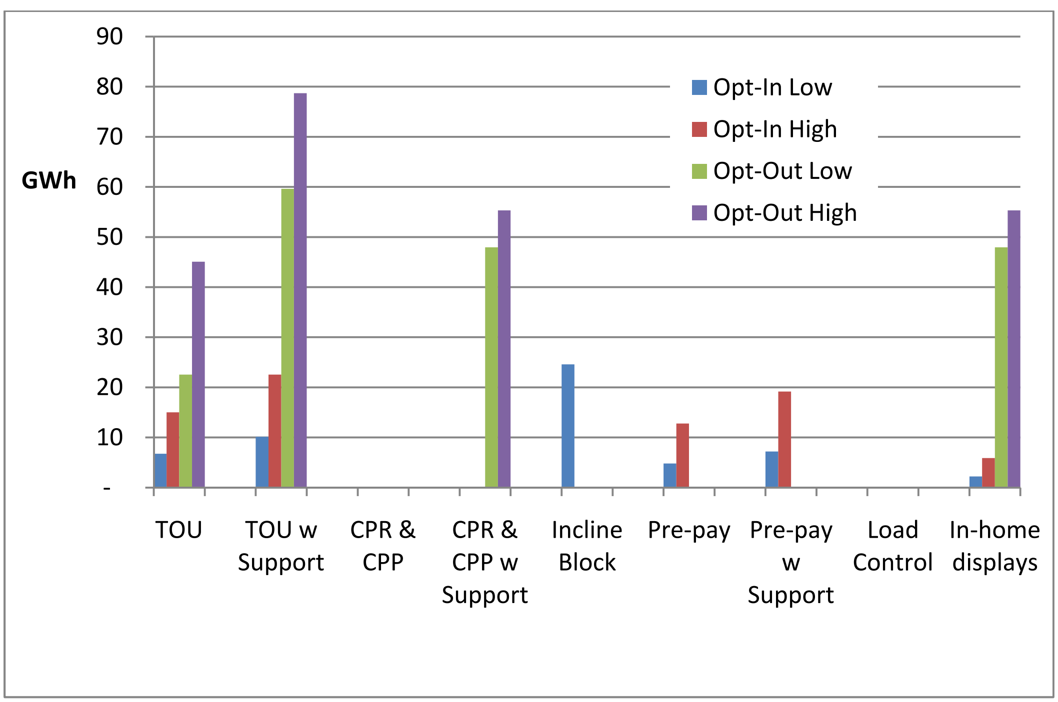


Figure 10: Energy Savings (GWh) in 2018 by Program Scenario



Assumptions

Key assumptions used in the calculations of the costs are summarized in Table 20: Key Assumptions and Table 21: FortisBC Forecast Data.

Table 20: Key Assumptions

Constants	Value	Units	Source
Program Start Year	2014	yr.	FortisBC Estimate
Present Value Year	2010	yr.	NCI Assumption
Residential Demand % of Peak Capacity	39%	Percentage	Residential average annual coincident peak demand from Cost of Service Analysis (FortisBC, 2009)
Residential Customers	95,502	Customers	FortisBC. "2009 Resource Plan", May 2009. P. 71
Persistence	90%		NCI Assumption
T&D Line Losses	9%	Percentage	FortisBC. "2008 Actual System Related Load Data", 2010.

Table 21: FortisBC Forecast Data

Year	Peak Load Forecast for All customers (MW)	Annual Energy Sales for Residential Customers (GWh)
2014	744	1,303
2015	754	1,324
2016	764	1,344
2017	773	1,365
2018	783	1,386
2019	793	1,407
2020	803	1,427
2021	813	1,447
2022	823	1,468
2023	833	1,488
2024	843	1,507
2025	853	1,527
2026	862	1,546
2027	872	1,564
2028	881	1,582
2029	891	1,600
2030	900	1,617
2031	909	1,634
2032	918	1,650
2033	927	1,665

Source: FortisBC. "Forecast Energy Sales by Class (GWh)" and "Peak Forecast (MW)" Microsoft Excel Document Received on January 14, 2010.

Conclusions and Recommendations

The evaluation of utility programs demonstrates that significant benefits can be realized through the implementation of AMI future programs functionality. Conservation reductions with supporting technology range with from of $395 to $1389 per customer for FortisBC. The analysis shows that:

- Inclining block rates provide the smallest benefits. Since FortisBC plans to roll-out TOU rates in 2014, and rate changes create customer confusion, there is little value to rolling out inclining block rates as an interim program.
- The research shows that on-going communication and marketing is essential for maintaining the behavioral savings. An on-going communication and marketing program (and the associated annual costs) need to be part of the program. The capacity and energy savings benefits and customer costs analysis included applicance on-going communication and marketing costs.
- The supporting technology (IHD) and appliance controllers produce substantial additional benefits regardless of the underlying rates and should be deployed as part of any program.
- TOU supplemented with supporting technologoes provides the greatest savings at the lowest costs per participating customer.

FortisBC should offer a default TOU program (conservative assumptions about the savings from TOU were used, reflective of a deafault program) coupled with supporting technology. Additional benefits can be realized by offering pre-pay and CPP/CPR options.

The utility interviews also identified a number of recommendations, summarized in

Table 22: Key Recommendations from Utility Interviews.

Table 22: Key Recommendations from Utility Interviews

Key Driver of Program Savings	Lessons Learned
Peaking Period	• If technologically possible, provide energy demand information at the customer appliance level in order to inform customers on which major appliances to adjust during peak periods, e.g. electric space heating. (Hydro One, 2010) • Provide residential customers with higher price signals during non-discretionary demand periods in the winter as customers tend to be less responsive to peak events during winter peak periods (morning and evening hours) when compared with summer peak afternoon hours (Avista, 2010)
Customer Persistence and Satisfaction	• Minimize customer activities required to operate and maintain IHDs (e.g. installation, programming updates, and replacing batteries) with automated and utility controlled technology where possible (Hydro One, 2010; Avista, 2010) • Implement price signals with enabling technologies (e.g. IHD) to incentivize ongoing customer participation (Avista, 2010). Without price signals, savings from IHD decay quickly (Avista, 2010)
Program Design	• For a voluntary program, involve local community partners and municipalities to encourage customer awareness and adoption (Ameren, 2010) • Design the program to be simple and implement a pricing structure that are clear to help customers understand the benefits of participating (BC Hydro, 2010) • Develop an implementation plan that allows time for customers to gradually adapt and gives priority to technologies that are compatible with future enhancements (PG&E) • Keep program informational materials concise and easy to understand to reduce customer questions and additional customer communication costs (PG&E)
Program Implementation	• Develop an implementation plan that allows time for customers to gradually adapt and gives priority to technologies that are compatible with future enhancements (PG&E) • Ensure meters operate and are configured correctly during rollout (BC Hydro)

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   This 2009 report prepared by the Federal Energy Regulatory Commission for Congress forecasts the potential for demand response in the U.S. and includes the following:

   a. Estimation of nationwide demand response potential in 5 and 10 year horizons on a State-by-State basis, including a methodology for updates on an annual basis;

   b. Estimation of how much of the potential can be achieved within those time horizons, accompanied by specific policy recommendations, including options for funding and/or incentives for the development of demand response;

   c. Identification of barriers to demand response programs offering flexible, non-discriminatory, and fairly compensatory terms for the services and benefits made available; and

   d. Recommendations for overcoming any barriers

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Attachment 1: Primary Research

NCI interviews five utilities in total and sent each a sample interview guide prior to the discussion. The interviews differed slightly depending on the knowledge and relvance of the questions for each utility. The detailed notes included in this section paraphrase the relevant content from the interviews.

Notes from Interviews

Sample Interview Guide

Background

Navigant Consulting, Inc. (NCI) is assisting FortisBC, an electric utility located in British Columbia, in an assessment of mass market conservation demand management functionality enabled by advanced metering infrastructure (AMI). To build on efforts from other utility deployments and pilot programs, we are interviewing utility experts with AMI program experience to gain an in-depth understanding of the lessons learned, customer education requirements, and benefits/costs associated with offering conservation demand management as part of an AMI program. Our assessment focuses on conservation demand management functionality including load control (e.g., demand response), in-home displays, and various pricing programs (e.g., innovative rates, conservation rates, and pre-paid metering).

Questions

1. *Can you briefly describe your background and experience working on your utility's AMI and conservation demand management related programs?*
2. *Please briefly describe the components of your AMI and conservation demand management programs. What pricing programs and/or rate structures are you offering? How effective are each and how difficult are they to implement? Which of the following features does your program include?*
    a. *Demand Response / Load Control; in-home displays; innovative rates (Time of Use [TOU] enabled by AMI, Critical Peak Pricing [CPP], Critical Peak Rebates [CPR], Incline Block with access to real time information, EPP with CPR); Pre-pay (EPP)*
3. *Do you have any results/benefits that you can share (i.e., % energy and capacity savings, elasticity associated with pricing differentials) associated with the features listed below? Do you have an estimate for the incremental costs typically associated with each (e.g., costs related to billing system changes and/or increased system bandwidth for real-time data)*
    a. *Load control devices (e.g. utility controlled demand response enabled by AMI)*
    b. *Innovative rates linked to AMI*
    c. *In-home displays of customer usage information/data*
4. *What types of customer education or communications activities were needed to support your AMI related conservation demand management and pricing program? How much did you spend on these activities (total cost, and/or cost/customer)? How much did you spend on customer service associated with the conservation demand management program, and what advice would you offer to minimize customer call volume?*
5. *What are some of the lessons learned from your AMI enabled conservation demand management program? What additional advice can you offer to a utility planning to deploy AMI systems with conservation demand management functionality?*

Ameren Interview Notes

Date	January 20, 2010
Organization	Ameren

1. Can you briefly describe your background and experience working on your utility's AMI program?

- *I have experience working on and guiding the implementation of both the Power Smart Pricing (PSP) program and our AMI deployment. Recently, I have been working as a liaison between our company and CNT Energy. CNT Energy is responsible for all the marketing and customer education associated with the PSP program. I have also worked on some regulatory projects dealing with billing issues and other projects.*

2. Can you describe the load control and pricing schemes of your pilot and AMI program?

- *Enhancing customer service was the main objective of Ameren's AMI program. Our AMI system provides real-time information to customers on energy prices and also uses a CellNet radio configuration that transmits data on our customers' energy usage. Our network currently uses one-way communication, but has the capability for two-way communication if we decide to implement it. Reducing costs and O&M associated with meter reads was a secondary benefit. On college campuses for example, there are often a significant number facilities that require meter reads towards the close of the school year, and our AMI system's ability to automate the meter reading process has significantly reduced the number of manual meter reads required.*
- *Ameren is just finishing our first phase of the smart meter deployment. The next phases will involve potentially expanding the AMI program to all customers and integrating AMI with the state of Illinois's goals for a smart grid.*
- *For the PSP pilot, a PriceLight (a small orb that glows different colors based on the current estimated price of electricity) was the only in-home display device we used. About 100 customers with the PriceLight were monitored and the data shows that these customers seemed to be more responsive to price changes. The PSP pilot also used real-time pricing (RTP). Illinois Public Act 94-0977 required that electric utilities which serve more than 100,000 customers must have RTP available to residential customers as a rate option.*
- *AMI customers were using the same real-time pricing (RTP) rates as the rest of Ameren's customers and as of June 2009 we switched to an hourly day-ahead pricing scheme. These day-ahead estimates of hourly prices don't exactly match RTP, but they are fairly close. We did not develop special rates for AMI as these meters were deployed to collect information primarily for billing purposes and cost saving.*
- *We spent roughly $1 million for our meter data management system, but I don't have much other cost information at this time.*

3. What types of customer education or communications activities were needed to support your AMI related conservation demand management and pricing program? How much did you spend on these activities?

- *Several on-line tools have been developed for computer users to monitor energy prices while they're logged onto the Internet. These include our PSP website which displays the current cost of energy, Google and Vista gadgets that display prices graphically, and an application that displays the current price on the computer web browser toolbar. Day-ahead phone call notifications were used to alert customers of peak events.*

- *I don't have any of this cost data for AMI, but the PSP program marketing and customer education costs are equivalent to what we paid CNT Energy we outsourced all of these responsibilities to them. Other costs of the Power Smart Pricing program consist of the incremental cost of metering to collect hourly usage data, additional Ameren Illinois Utilities' expenses for software and data processing systems, and the program administrator and evaluation contracts.*

4. Do you have any results/benefits that you can share (i.e., % energy and capacity savings, elasticity associated with pricing differentials) associated with the PSP program?

- *Since Power Smart Pricing launched in early 2007, participants have saved an average of 17% compared with what they would have paid on the standard fixed rate (based on billing results from May 2007 through September 2009). Average annualized customer savings for 2008 (which account for the growing participation level across the year) were $92.65 or 7.7% (this does not include additional savings associated with the conservation effect).*
- *High Price Alert Days, the PriceLight, weekends and the year were all statistically significant factors that effected elasticity:*
    - a. *Customers did pay attention to High Price Alerts and increased their price response on those days*
    - b. *Customers with PriceLights showed an even greater response to price changes, and this effect shows up across all days throughout the summer season*
    - c. *On average, customers showed additional price response on weekends compared to weekdays*
- *Survey responses from these customers show high percentages of satisfaction with the program, with 71 percent of customers reporting that they find participating in PSP "quick and easy."*

5. What are some of the lessons learned from your AMI enabled conservation demand management and PSP pilot programs?

- *Interference on the radio communication network has been a problem and required additional estimates for the energy consumption of hourly billed customers whose signal was interrupted. Sometimes this interference even requires us to send an employee into the field to verify consumption estimate.*
- *Setting realistic expectations for customers and involving local community partners and municipalities help improve customer acceptance and satisfaction. For example, we clearly articulated to our customers that we would reduce meter reads rather than eliminate meter reads entirely. Also, we developed informational material that local news organizations could broadcast to explain the meter exchange process.*
- *Start communicating early in the deployment with and helping transition employees whose jobs may be at risk with the technology deployment.*
- *Establish payment for vendors to correspond with verification of accurate meter reading and full system functionality rather than just meter installations.*

Avista Interview Notes

Date of Interview	February 5th, 2010
Organization	Avista Utilities

1. Please describe the components of your demand response pilot program.
   - *Over the past two years our demand response pilot program tested the effectiveness of smart thermostats and direct control unit (DCU) switches for customer appliances. The pilot involved over 70 residential customers with roughly 50 programmable thermostats and about another 50 load control switches used on customer appliances (e.g. water heaters, compressors, heat pumps, and AC units). These appliances were chosen based on their compatibility with our equipment.*
   - *Our main goals involved testing customer acceptance and cost effectiveness.*
   - *This was a voluntary program that allowed customers to opt out but only a few with morning water heater demand chose to opt out. The events were called on weekdays during the winter and summer peak periods. Customers were notified by phone one day in advance of a peak event.*
   - *We used a one-way paging system with five minute interval data for the devices.*
   - *The report on this project will be submitted to the Idaho Public Utilities Commission on March 1st, 2010.*

2. Can you describe the customer acceptance of the program and technology?
   - *Customers tended to be very enthusiastic about the smart thermostats and energy management capability at the start of the pilot, but after a few months the novelty for customers seemed to wear-off and participation dropped. Battery failures in some of our devices were also partly to blame for lower participation and some dissatisfied customers.*
   - *Most customers found the program favorable and early adopters of the technology in particular seemed very happy with the program.*
   - *The turnover in homes with customers that had signed-up for the program was challenging as customers that moved into a house with a smart thermostat installed by a previous resident rarely chose to participate in the program. This left us with stranded assets since thermostats were already installed. The new customers probably would have been more likely to participate if Avista used additional incentives such as a dynamic rate.*
   - *For the smart thermostats we initially mailed information to about 3,000 customers of whom 300 responded and ~50 were randomly selected to receive a thermostat for the pilot.*
   - *For the DCU we had about 130 people that originally qualified for the program, but many dropped-off due to the delay between the initial notification and the technology implementation.*

3. Did you test any dynamic rates during the program?
   - *No, we only used the traditional rate for our program.*
   - *The lack of dynamic pricing meant customers had less incentive to participate during peak events and reduce their load with the smart thermostats. I anticipate participation and savings would have been higher if we used dynamic rates instead of the traditional rate.*

4. Can you provide us with a breakdown of the program costs?
   - *This entire pilot program cost US$123,000 for 2 years which included customer incentives, equipment costs, roughly US$1,000/month hosting fee for the vendors, and US$2,000 for marketing through an advertisement agency.*
   - *Avista paid customers with a DCU about $10/peak month for participating during peak events. Avista provided no cash incentives to use the smart thermostats, but these customers did receive a free thermostat.*

5. Do you have estimates of program savings during winter?
   - *We did not have sufficient data to measure the average energy reduction, but we estimate savings are consistent with other pilots of this nature. We originally thought the meters would provide us with these estimates, but this was not the case. For DCU we used industry standards to estimate savings by device of 0.33kW for water heaters, 1.5kW for electric heaters, and 1kW for AC units.*
   - *Many of our customers traveled during the winter and summer peak periods which also made it difficult to estimate savings.*
   - *Customers tended to be less responsive to peak periods during the winter when compared with the summer.*
   - *Given the high overhead and administrative costs required to deploy a small number of devices for this pilot, Avista's preliminary analysis suggests the program is not cost effective at this scale.*

6. What are some additional lessons learned from your conservation demand management program?
   - *Don't begin marketing for the deployment until contractors are trained and ready. After the initial marketing phase of our program the technology deployment was delayed and many customers lost interest in participating during this delay period.*
   - *Implementing price signals (e.g. dynamic rates) with the smart thermostats would have likely improved ongoing customer participation and savings.*

BC Hydro Interview Notes

Date of Interview	January 18th, 2010
Organization	BC Hydro

1. Can you briefly describe your background and experience as it relates to conservation demand management and your utility's AMI program?
   a. *I work in the Conservation Rates department of the PowerSmart Group at BC Hydro where I focus on time-of-use (TOU) related to AMI. I began working at BC Hydro as part of the Conservation Research Initiative, which was a two year pilot, conducted between October 2006 and October 2008. The pilot is finished and the report will likely be released sometime in late February or March 2010.*

2. What type of load control and pricing schemes did you use during the pilot?
   a. *Key components of the pilot were supplied by three separate vendors and included smart meter replacements for roughly 2,000 customers and a few different network topologies. We used several rate options including TOU, critical peak pricing (~100 customers), critical peak rebate, and varying off-peak structures. Customers participated on a voluntary basis, but did not choose their tariff. They also had the option to opt-out of a CPP event on a per event basis, but there was only one record of a customer doing this during one winter CPP event.*
   b. *The pricing differential for TOU between peak and off-peak ranged from 2-1 and 6-1.*
   c. *There was also a load control 45 households with electric heating. The load control units operated with a separate network.*

3. What were the incremental costs and saving for each feature?
   a. *We may be able to reverse engineer load control costs, but TOU will likely be too difficult. There are valuable lessons to be learned from a 2,000 customer pilot, but the cost data from the programs were not meant to model full-scale deployment. Also, the direct costs of the program may be outdated.*
   b. *On-peak savings from TOU were around 11.5%*
   c. *We also saw higher levels of overall conservation than expected even though the program was more focused on peak reduction*

4. Did your pilot include in-home displays?
   a. *At the start of the pilot, we began installing in-home displays (IHD) for 250 households. We used Blue Line Innovations PowerCost Monitors, but since the technology was in its early development stage back in 2006, they had several technical issues and a problem communicating to the meter across residential property. To resolve this issue, we had to replace about 2/3 of the IHDs with newer models after the first year. The monitors also had several levels of customer communication. The basic communication included a*

welcome pack explaining the customer's tariff and recommendations for shifting behavior. Enhanced communication provided additional information on TOU rates and community benchmarks.

5. How do you plan to go forward with your AMI program?
   - *This pilot was designed to provide us with a customer view and there are a number of lessons learned that will inform future smart metering work. There are also a number of other utility programs worth looking at with larger and more relevant data points to the customer population.*

   - *The implementation of TOU will likely be very different. We will likely implement a blend of CPP and TOU, but we still need to do the rate design before we make any decisions.*

6. Do you have any results/benefits that you can share on elasticity?
   - *Elasticity is difficult to estimate since we didn't have enough of the controls in place to separate experimental adjustments from other factors. For example, many of our customers made the decision to participate not based on the economic incentives, but rather the idea that they were making a socially responsible decision by reducing energy usage. While the customers had a lot of support and education, they often did not have a clear price signal that influenced their decision.*

7. What types of customer education or communications activities are needed to support your AMI related conservation demand management and pricing program? How much did you spend on these activities (total cost, and/or cost/customer)
   - *We provided a considerable amount of customer education. We also had an annual event for participating customers where we summarized results and customers shared recommendations for shifting load. This program required a lot of customer support and service, so we also developed a separate phone and email line for customers.*

8. What are some of the programmatic insights or lessons learned from your AMI enabled conservation demand management program? What additional advice can you offer to a utility planning to deploy AMI systems with conservation demand management functionality?
   a. *It is very important to effectively communicate with customers.*
   b. *While customer response to load control and CPP was very positive, the process of implementing load control for winter peaking utilities still needs some work to make it practical on a larger scale. Our load control installations were a significant challenge as some customer homes required re-wiring and dry-wall patching. Also, the cost of a licensed electrician to install these devices for each customer is significant.*
   c. *When implementing alternative pricing schemes, try to choose a design that is clear and easy for customers to understand. We used a fairly complicated TOU model which was a challenge for customers to understand as they had previously been on a flat base rate. We decided to increase peak rates, but kept off-peak rates the same as the base rate rather than lowering them, so many customers didn't think they were saving money. To reassure customer savings we agreed to give them a bill guarantee that would compensate them if they did not save money compared to the previous year's charges. This bill guarantee*

came in the form of a rebate on the customer's bill. Roughly 2/3 of the customers saved money during both years, and 1/3 needed the bill guarantee.

d. *The study we are drafting contains additional lessons learned relative to future technology implementation pilots such as how to establish a micro AMI environment and tips for meter replacements. For example, it is critical to notify customers in advance when you are going to disrupt their electricity to replace a meter.*

e. *You can refer to the public applications and tariff regulatory filing to see the way the pricing was implemented and organized. The 1141 customers (rates for people in Lower Mainland and St. John) used these TOU rates from November to February.*

Hydro One Interview Notes

Date of Interview	January 20, 2010
Organization	Hydro One

1. Can you briefly describe your background and experience working on your utility's AMI program?
   - *I work at Hydro One and have experience working on the in-home display (IHD) and time-of-use (TOU) programs where I dealt with marketing and implementation related issues.*

2. Please briefly describe the objectives of your AMI program.
   - *Our regulator has mandated that we install smart meters for all our customers by the end of 2010 and offer TOU rates by the end of 2011.*

3. What costs are associated with IHDs and billing rate changes such as TOU or CPP? Do you have any results that you can share on these programs?
   - *At the start of the IHD deployment, we paid roughly $150 per IHD device which included hardware, marketing and shipping, but hardware costs have since decreased. We outsourced shipping and marketing to a third party while most customers self-installed the devices on a voluntary basis.*
   - *The IHD installations on average reduced energy by 6.5%; when IHD was combined with TOU the savings were slightly higher at 7.6% (4.3% from IHD and 3.3% from TOU).*
   - *We don't have much detail on the costs of billing rate changes as we typically track costs on a full deployment basis.*

4. What types of customer education or communications activities were needed to support your AMI related conservation demand management and pricing program? How much did you spend on these activities?

    - *The pilots tried to minimize the amount of customer education and marketing to isolate the impact of just the technology. The TOU pilot for example tested customer response to purely to price information rather than conservation recommendations.*
    - *For the deployment, we spent $25- $50 per customer on education and marketing which included customer*
    - *calls and informational instructions mailed with the device.*

5. What are some of the lessons learned from your AMI enabled conservation demand management program? What additional advice can you offer to a utility planning to deploy AMI systems with conservation demand management functionality?
    - *For the first IHD pilot, separating out the feedback from the electric heating load and the rest of the load may have helped encourage conservation. Many of the houses in the 500 customer pilot with electric space heating were less responsive to real time feedback. For example, the IHD reduced load by 1.2% in these houses compared to the 6.7% average reduction from IHDs.*
    - *Real-time feedback of energy consumption is effective in promoting conservation even without real-time pricing*
    - *Based on results of the Time-of-Use Pricing Pilot, 76% of pilot participants under the Regulated Price Plan (RPP) TOU rates paid a lower electricity bill as a result of load-shifting compared to the regular RPP rates. Savings attributable to conservation would be incremental. Customers who were better off gained on average about $23 during the pilot (about $6 per month), while customers who were worse off on average lost about $7 (less than $2 per month).*
    - *IHDs that can be remotely updated by the utility or AMI system are often more effective in promoting conservation as customers rarely program these devices on their own (e.g. programming updates to TOU periods). We would make this a priority feature for future deployments so we could implement Critical Peak Pricing or other conservation rates if we choose to.*
    - *IHD technology powered from the house circuit rather batteries tends to be more reliable as we had a problem with the batteries of our earlier models*
    - *IHDs that require a licensed electrician to install tend to be more expensive and potentially risky for homeowners to install themselves*
    - *Of the 30,000 IHDs installed only 29% are still in use and 15% were never installed or used by customers. To improve participation we recommend that future programs eliminate the need for customer installation and/or provide incentives for customers to install and use the technology. Offering cash incentives for customers to install and use the IHD device or charging customers more for the device may improve ongoing participation. Even when we charged the customer $10 for shipping, there was still very little incentive for customers to install them. I do not recommend giving the device to customers for free.*

PG&E Interview Notes

Date	January, 15th 2010
Organization	PG&E

1. Can you briefly describe your background and experience working on your utility's AMI program?
   - *I work in the smart energy web group at PG&E and help explore innovative customer products related to energy efficiency, demand response, and behavioral changes. I also do work on PG&E's home area network (HAN) strategy, which we plan to launch in the next year and will provide customers with access to usage and additional demand response programs.*
   - *I have limited experience on the Ancillary Services and Automated Demand Response Pilots.*

2. Please briefly describe the components of your AMI program. How effective are each and how difficult are they to implement?
   - *We currently offer a SmartRate pricing scheme, which shifts peak demand by providing voluntary critical peak pricing for our smart meter customers. Customers receive a discounted rate except for non-critical peak periods and then pay more during critical peak periods. There is a relatively small adoption rate in the hundreds of thousands.*
   - *We also offer a voluntary time of use (TOU) rate for some customers with PV systems, but less than a hundred thousand customers have adopted this program. We have plans to enroll all commercial customers in either the SmartRate program (default option) or the TOU pricing scheme (alternative to SmartRate).*
   - *SmartAC is our direct load control program for the mass market including residential customers. We contract out to a 3rd party who installs a device that can receive a signal to reduce the demand of the AC system. I don't have specific data on this program.*

3. How much did you spend on customer education and communications activities?
   - *I don't have much information on the program costs for the SmartRate program.*

4. Do you have any results/benefits that you can share from your innovative rates, load control, or in-home displays?
   - *I don't have information for you on the costs and benefits per customer for the SmartRate program.*
   - *PG&E does not have much experience with in-home displays, but we have future plans to support in-home displays with our AMI program*

NAVIGANT

5. What are some of the lessons learned from your AMI enabled conservation demand management program? What advice would you offer to minimize customer call volume?
   - *Having a thoughtful and well-paced roadmap or implementation plan which allows time for customers to gradually adapt to changes and gives priority to technology that is compatible with future enhancements will help any utility's smart grid program. This is a huge paradigm shift for customers, so it is important not to overload them with changes at the beginning.*
   - *One key recommendation I have to reduce customer call volume would be to keep the program simple. For example, dynamic pricing can be confusing and difficult for customers to reverse engineer so implementing a pricing structure that is straightforward and clear, will help customers to understand the benefit proposition. Keeping the message, numbers, and implementation simple will likely be a more successful program than a rate structure that has optimized rates.*
   - *Additionally, too much information can also be confusing for customers as well as third party contractors that assist customers. Our customers always seem to have questions on what we send them, so sending less material could help reduce questions.*

Attachment 2: Utility Research Table

Table 23: Detailed Utility Research Table

Utility	Location	Program/Pilot	Source(s)
Ameren	Illinois	Power Smart Pricing (PSP) program	Summit Blue Consulting, "Power Smart Pricing 2008 Annual Report," March 31 2009. Voytas, Rick, "AmerenUE Critical Peak Pricing Pilot", presented at U.S. Demand Response Research Center Conference, Berkeley, CA., June 2006 CNT Energy and Summit Blue, "Residential Real-Time Pricing Program Achieves Savings for Utility and Customers", Draft Paper, November 2009.
Ameren	Illinois	Smart Meter Deployment	Ameren, 2010. Personal communication. January 2010. Ameren, 2006. "Automated Meter Reading." Ameren Services. Web. 18 Sept. 2010. <http://www.ameren.com/Residential/ADC_AMR.asp>.
Avista	Washington and Idaho	Demand Response Pilot	Avista, 2010. Personal communication. February 2010. Avista, 2009. "2009 Electric Integrated Resource Plan," Avista Utilities, August 2009.
Baltimore Gas and Electric	Maryland	Residential Smart Meter Pricing Program	The Brattle Group, "BGE's Smart Energy Pricing Pilot Summer 2008 Impact Evaluation." Prepared for BG&E, April 2009.
BC Hydro	British Columbia	Conservation Research Initiative	BC Hydro, "2009 Electricity Conservation Report", November 2009. BC Hydro, 2010. Personal communication. January 2010. BC Hydro, 2009. "Conservation Research Initiative." BC Hydro. Web. 18 January 2010.
BC Hydro & Newfoundland Power	British Columbia, Newfoundland & Labrador	BC Hydro and Newfoundland Power Pilot	CEATI, 2008. "Real-Time Feedback and Residential Electricity Consumption", CEATI International Inc.
Commonwealth Edison	Illinois	The Community Energy Cooperative's Energy-Smart Pricing Plan (ESPP)	Summit Blue Consulting, "Evaluation fo the 2006 Energy-Smart Pricing Plan - Final Report", 2007.
Connecticut Light & Power	Connecticut	Plan-it Wise Energy Pilot Program	The Brattle Group, "CL&P's Plan-it Wise Program Summer 2009 Impact Evaluation", November 2009.
Green Mountain Power	Vermont	AMI Pilot	Green Mountain Power, "2007 Sustainability Report," Oct. 26, 2007.
Hydro One	Ontario	IHD Program Deployment	Hydro One, 2010. Personal communication. January 2010.
Hydro One	Ontario	Time-of-Use Pricing/IHD Pilot Project	Hydro One, "Time-of-Use Pricing Pilot Project Results", EB-2007-0086, May 2008. Hydro One, "The Impact of Real-Time Feedback on Residential Electricity Consumption:

			The Hydro One Pilot", March 2006.
Hydro Ottawa	Ontario	Ontario Energy Board Smart Price Pilot	Ontario Energy Board, "Ontario Energy Board Smart Price Pilot Final Report," Toronto, Ontario, July 2007.
Idaho Power	Idaho	Idaho Residential Pilot Program	Idaho Power, "Analysis of the Residential Time-of-Day and Energy Watch Pilot Programs: Final Report." December 2006.
Newmarket Hydro	Ontario	Newmarket Hydro Time-of-Use Pricing Pilot	Navigant Consulting, Inc. 2008. "Evaluation of Time-Of-Use Pricing Pilot," Presented to Newmarket Hydro Ltd. March 2008.
PG&E	California	Smart Meter and Voluntary SmartRate Program	Charles River Associates,"Impact Evaluation of the California Statewide Pricing Pilot", 2005. PG&E, 2010. Personal communication. January 2010. Bode, Josh. "How Well do Pricing Pilot Impacts Predict Actual Program Impacts?", Freeman Sullivan & Co. June 2009 EEI, 2008. Appendix C: The California Statewide Pricing Pilot Summary. January, 2008.
PG&E	California	Smart AC Ancillary Services Pilot	Rocky Mountain Institute,"Automated Demand Response System Pilot: Final Report", March 2006.
PG&E	California	Automated Demand Response System Pilot (ADRS)	Freeman, Sullivan & Co.,"2009 Pacific Gas and Electric Company SmartAC Ancillary Services Pilot", December 2009.
Public Service Electric & Gas	New Jersey	PSE&G Residential Pilot Program; MyPower Sense and MyPower Connection	PSE&G and Summit Blue Consulting, "Final Report for the Mypower Pricing Segments Evaluation," Newark N.J., Decemeber 2007. PSE&G and Summit Blue Consulting, "Residential Time-of-Use with Critical Peak Pricing Pilot Program: Comparing Customer Response between Educate-Only and Technology Assisted Pilot Segments." 2007.
Puget Sound Energy	Washington	TOU Program	Faruqui, Ahmad and Stephen S. George, "Demise of PSE's TOU Program Imparts Lessons," Electric Light & Power, Vol. 81.01:14-15,2003.
Salt River Project	Arizona	SRP M-Power Pre-pay Program	SRP, 2009. "SRP 2009 Annual Sustainability Report Summary."
Woodstock	Ontario	Pay-As-You-Go (Pre-pay)	Woodstock Hydro. "Pay- As-You-Go-Power: Treating Electricity as a Commodity", Ken Quesnelle (Vice- President). January 20, 2004
Xcel Energy	Colorado	Xcel Experimental Residential Price Response Pilot Program	Energy Insights, Inc."Xcel Enery TOU Pilot Final Impact Report", March 2008.; Energy Insights, Inc."Experimental Residential Price Response Pilot Program March 2008 Update to the 2007 Final Report", March 2008.

NAVIGANT

Appendix C-2

PCS Utilidata Conservation Voltage Regulation Optimization Report

PCS UTILIDATA	Doc #: 3230-082911-001	Revision #: 0	Page i of iii
	File: Fortis BC CVR_VVO Report Rev 0.docx		Date: 29 August 2011
FortisBC CVR_VVO Report	Originator: T. Wilson	Review: J. Wilson R. Decker	Acknowledgement: M. Sidiropoulos

Conservation Voltage Regulation_Volt/VAR Optimization Report For FortisBC

Originator: ______________________ 29 August 2011
Tom Wilson, CTO/Founder, PCS UtiliData — Date

Reviewed by: ______________________ 29 August 2011
Jeremy Wilson, Director of Technical Sales, PCS UtiliData — Date

Approved by: ______________________ 29 August 2011
Ron Decker, CEO, PCS UtiliData — Date

Acknowledged by: ______________________ ______________
Michael Sidiropoulos, Senior Planning Engineer, FortisBC — Date

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Conservation Voltage Regulation and Volt/VAR Cost Benefit Report FortisBC

1. Executive Summary

An estimate of the various methods of implementing Conservation Voltage Regulation/Reduction (CVR) indicates that FortisBC could conserve 50,072 MWh (or more) per year in their service territory with a value of $104.30 per MWh (or $5,223,460 per year) by installing and operating a Smart Grid Volt/VAR Optimization (VVO) system on their entire electric distribution system. Lesser savings may be obtained using other CVR implementation methods or by installing VVO partially throughout their distribution system. `Table 7 in Section 5 shows a detailed summary of the expected benefits and the estimated costs of the different CVR implementation methods. This analysis is based on: Data and other information provided by FortisBC; historical (CVR) data from other utilities' CVR projects; and, a review of CVR literature and the author's actual CVR project experience.

The analysis of the amount of energy that could be conserved included only energy that is provided on FortisBC owned and operated circuits. It did not include energy sold wholesale to the municipalities of Kelowna, Summerland, Penticton, Grand Forks or Nelson, although there is significant potential for additional energy conservation with these municipal customers.

Three alternatives for implementing CVR were considered: Smart Grid Volt/VAR Optimization (VVO), Line Drop Compensation (LDC) and Simple Set point Reduction (SPR). While all three implementation methods of CVR yield significant energy savings, VVO based CVR yields the most kWh savings, the most benefits to FortisBC customers, the highest Net Present Value and also system wide operational benefits to FortisBC not provided by implementing CVR with LDC or SPR.

Detailed discussion of the methodology of the analysis, assumptions used in estimating savings and costs and the differing methodologies for implementing CVR are included in the report and its appendices.

2. FortisBC Distribution System Description

FortisBC is a wholly owned subsidiary company of Fortis Inc. FortisBC is an integrated energy provider focused on providing natural gas, electricity, propane and alternative energy solutions to approximately 1,100,000 customers in more than 135 British Columbia communities. While it provides natural gas service throughout B.C., it provides electrical service to approximately 111,500 customers in the south central part of the province including Kelowna, Osoyoos, Trail, Castlegar, Princeton and Rossland. It also services approximately 48,500 customers through the wholesale supply of power to municipal distributors in the communities of Summerland, Penticton, Kelowna, Grand Forks and Nelson. In 2010 FortisBC had a peak electricity demand of 707 MW.

Most of FortisBC's transmission-to-distribution voltage level transformers are three phase transformers with on-load tap changers for distribution voltage level regulation. Their distribution system includes eighteen very long feeders (over 75km) with the longest being 203.79 km. Several distribution feeders have one or more mid-line regulator banks.

In 2010 the total energy generated including total system technical losses, distribution system non-technical losses and billed energy was 3,562,480,180 kWh. The total for direct served customers (not including wholesale) including all associated losses was 2,528,525,640 kWh. (This kWh value is the denominator for computing percentages of energy savings.)

For the purposes of this report the FortisBC service territory is considered to be three separate regions: North Okanagan, South Okanagan and Kootenay_Boundary.

2.1 North Okanagan Region

The North Okanagan Region roughly includes the service area on the east side of Lake Okanagan from Winfield north of Kelowna to just east of Penticton at the south end of the lake.

The overall billed energy plus losses (less wholesale billed) in the region in 2010 was 1,065,676,751 kWh.

There are fourteen (14) substations and terminals with seventeen (17) transformers and sixty-seven (67) distribution voltage level feeders in the region serving energy to both direct customers and wholesale municipalities at distribution voltage levels.

2.2 South Okanagan

The South Okanagan Region roughly includes the service area on the west side of Lake Okanagan from Summerland south and the east side of the lake from Naramata south to Osoyoos and west to Princeton.

The overall billed energy plus losses (less wholesale billed) in the region in 2010 was 527,093,831 kWh.

There are sixteen (16) substations with twenty (20) transformers or transformer banks and thirty-six (36) distribution voltage level feeders in the region serving energy to both direct customers and wholesale municipalities at distribution voltage levels.

2.3 Kootenay and Boundary

The Kootenay and Boundary Regions roughly include the service area from Rock Creek on Provincial Highway 3, following the highway to Creston in the east. It includes the area surrounding Kootenay Lake from Kaslo south and the south end of Slocan Lake. It includes the area along the Columbia River from Castlegar to Trail and along the Kootenay River from Nelson to Castlegar.

The overall billed energy including losses (less wholesale billed) in the region in 2010 was 935,755,059 kWh.

There are twenty-five (25) substations with twenty-nine (29) transformers and fifty-nine (59) distribution voltage level feeders in the region serving energy to both direct customers and wholesale municipalities at distribution voltage levels.

3. CVR Implementation Methodologies

3.1 Set Point Reduction of Substation Bus Voltage (SPR) Based CVR

Energy use and demand can be reduced by setting regulator or LTC voltage set points to lower levels, either locally in the substation or using SCADA. This reduces overall average voltages by some amount and will have the effect of reducing overall energy consumption and demand. While this approach is much less costly than VVO or LDC based CVR it has several disadvantages

While both LDC and VVO based CVR are implemented to reduce overall average distribution voltages to reduce demand and energy usage, these systems are designed to make sure that voltage levels do not go below minimum standard levels (See Appendix B - Distribution Voltage Standards). The current Fortis BC voltage set-points were selected to be conservative, reducing that possibility of low voltages as much as possible. Simply lowering voltage set-points and averages poses the likely possibility of providing customers with lower than acceptable voltages.

Even though a simple lowering of voltage set points appears easy to do, it will require that the same studies and modeling that would be required for implementing LDC based CVR to determine the new set points. In addition to the potential low voltage issues and the equivalent labor required, there is no way to measure or verify any energy conservation or demand reduction without adding additional instrumentation to the system.

Because of these disadvantages, most utilities implementing CVR do not used this method (the author knows of none).

3.2 Line Drop Compensation Based CVR

Until the advent of "smart grid" VVO systems, utilities implementing CVR typically used Line Drop Compensation (LDC).

Almost all regulator controllers and on-load tap-changer transformer (LTC) controllers in use today have the ability to implement LDC. When implementing LDC the controllers use an internal "model" to represent the physical characteristics of a distribution feeder (or feeders) fed by the same substation bus. The "model" consists of two (2) settings that can be entered or adjusted in the controller. Those two (2) settings are the X setting and the R setting. Those settings represent the impedance of the feeder or system of feeders being fed by the regulator or LTC. Based upon the current or load, the voltage set-point at the regulator or LTC output (or bus) is computed so that a point distant in the system is held at a constant voltage. The controller then adjusts tap position to hold the output voltage at the set point.

When using LDC to implement CVR, the voltage set-point is selected so that customer delivery voltages at "electrically" distant points of the feeder or system of feeders is in the low end of CAN standard voltages without going below minimum acceptable levels.

In order to implement LDC, the distribution system is modeled and is reduced to two (2) variables – X and R. Two main factors influence the determination of the proper X and R values:

1. The circuit physical variables of the feeder must be entered correctly for the model to provide accurate results. Most distribution feeders are very complex making this effort non-trivial. Often lumped element assumptions are made to ease this effort.

2. Load models must be entered. The ZIP model is normally used. The ZIP model is an excellent tool for static system planning and circuit design, however because it is static, it is prone to error when being used as a dynamic load model. Loads are highly dependent on stochastic customer behavior with average and random components, temperatures and other dynamic factors.

The values of X and R are entered into the LTC or regulator controller. The controller uses current (I) and the X and R values to calculate the voltage drop to the end-of-the-line. Bus voltage is then controlled to the set point plus the calculated voltage drop.

LDC implementation of CVR protects remote points on the distribution line from going below CAN minimums (if the underlying model is correct and X & R values are computed and entered correctly). LDC capability is built into most regulator and LTC controllers. Additionally initial costs are lower than smart grid VVO type solution and are usually on the order of 25% of the initial costs of a VVO based CVR implementation, assuming no distribution line upgrades are required.

LDC CVR implementations have several disadvantages when compared with smart grid VVO based CVR:

1. They require the distribution system model and the X & R settings be reviewed periodically usually on an annual basis or more frequently if significant feeder load or configuration changes have been made. This effort can be engineer and technician labor intensive validating models, and verifying or changes settings to all LTC regulator controls in the field.
2. LDC does not coordinate with mid-line regulators and switched capacitors or is extremely difficult if not impossible to do so.
3. Normally the target set point needs to be set high enough to allow for potential model errors. This reduces the demand reduction and energy conservation effect of the CVR.
4. No additional visibility is provided over the distribution system.
5. Measurement and Verification requires extra data acquisition equipment and labor.
6. LDC based CVR is not capable of automatically reconfiguring to adapt to distribution feeder topology changes.
7. The X and R model is fixed while the actual distribution system and load is constantly and dynamically changing.

3.3 Smart Grid VVO Based CVR

With the advent of “smart grid” initiatives the term volt/var optimization (VVO) has come into common use. VVO is the operation of a distribution system with automatic coordinated operation of voltage regulation devices and switched capacitor banks with the goal of minimizing lagging kVARs and controlling distribution voltage levels to some “optimum” point to reach a utility’s operational goal. The goal can vary from utility to utility and can include reduction of peak demand, implementation of CVR or even in some cases to increase load. However in the opinion of many industry experts and the author, the real benefit of VVO lies in Conservation Voltage Regulation (CVR) – the act of reducing voltage on the distribution system to make utilization devices more efficient and reduce line losses.

There are essentially two significantly different types of smart grid VVO, each with the potential for implementing CVR. GIS or static model based VVO behavioral based VVO.

3.3.1 GIS or static model based VVO

Geographical Information System (GIS) based VVO uses computerized GIS models of the physical distribution systems which are kept up to date on an automatic or frequent (at least daily) manual basis. State estimation is run on periodic basis, typically every 2 to 15 minutes using the GIS model and a load model (often the ZIP model) with additional inputs measured in the field such as current, kW, kVAR, voltages, etc. The system computes optimum system voltage set points and capacitor switch positions for “current” conditions and then issues capacitor switching commands and downloads set points to LTC or regulator controllers. At that point the algorithms residing within the LTC or regulator controls make tap change decisions in the same manner as they do had conventionally prior to VVO.

GIS VVO based CVR has several advantages over LDC based CVR implantation:

1. Coordinated voltage and capacitor control.
2. Different objectives can be specified such as:
   (1) Conservation Voltage Regulation
   (2) Reducing losses

(3) Optimizing revenue,
(4) Emergency demand reduction (or increase)
(5) peak demand reduction only

3. It is automated and does not require operator resetting controller set points
4. VVO enables potentially tighter voltage control than LDC or SPR based CVR
5. Capable of automatic reconfiguration with circuit topology changes
6. Even with higher initial cost, overall economic benefits are usually higher than LDC economic benefits.

A disadvantage of a GIS VVO system is that it requires significant compute power which means it would be required to be centrally located to hold the costs down. According to many industry experts, this will significantly impact the scalability of these solutions for large distribution areas. GIS VVO systems also require constant attention and updating of GIS model. If model is not up to date, control will not be optimum at best and may need to be shut down to prevent inappropriate control action [18]. They require the underlying load model assumptions to be the correct although is rarely the case as the ZIP model is usually used to estimate load reactions to voltage changes and the incorrect model assumptions cause non-optimal control actions and set points to be issued.

The GIS VVO system depends on the standard LTC or regulator controller algorithms (based on set point, bandwidth and time out of band) for final voltage control and if the local settings in the LTC or regulator control are mis-set the benefit of VVO could be lost with no indication that this was the case. GIS VVO could be looked at as essentially an automated yet rather complex set point controller for LTC or regulator controller.

3.3.2 Behavioral based VVO

Behavioral based VVO uses actual “real time” field measurements and live observed data including remote voltage and VAR data to determine tap changer and capacitor switch control actions (rather than GIS and load models). They require less compute power and can be located at individual substations or they can serve several substations from a central location.

Behavioral VVO systems make no assumptions of load properties, but rely on measurements to determine control actions. They do not use a GIS model; and therefore to not have the requirements for frequent model updating and they are not prone to the ZIP model weaknesses. Because they are using actual field data they allow tighter voltage control than LDC or manual CVR and generally tighter voltage control than GIS based VVO.

Successful behavioral based VVO systems use digital signal processing to extract additional distribution system behavior information from field data observations and signals. Appropriate use of this extracted information, coupled with direct element control often reduces the number of tap operations compared to other types of VVO.

In general the costs of behavioral based VVO are comparable with GIS model based VVO costs and similarly will likely have much better economic benefits than LDC based CVR.

Behavioral based VVO systems require strategic placement of end-of-line voltage monitoring devices. In cases were feeder configuration changes are required they may require additional end-of-line voltage monitors.

4. Methodology of Analysis

The steps involved in this analysis were:

1. Necessary data was collected
2. Where actual data was unavailable assumptions were made to fill in data gaps. The assumptions were reviewed by FortisBC personnel.
3. The potential average voltage reductions for each feeder for VVO based CVR, LDC based CVR and SPR based CVR were determined. The average voltage reductions were based on the feeders and system as is with no feeder infrastructure modifications.
4. CVR factors were estimated to use for each feeder
5. Potential energy conservation was then computed for each feeder for all three CVR implementation methods.
6. Cost estimates for the three different CVR implementations were made.
7. Finally the results are summarize and reported.

4.1 Data Supplied by FortisBC

The following information and data was received from FortisBC personnel:

1. Electronic PDF copies of FortisBC substations
2. Google Earth place points showing FortisBC substation locations
3. Excel formatted spreadsheet showing:
    a. Regions
    b. Substation names and numbers
    c. Transformer names
    d. Substation seasonal peak loads for 2010 summer and 2011 winter
    e. Rated voltages and capacity of transformers
    f. Measured 2010 annual energy use
    g. Type of regulation available
    h. Feeders and feeder seasonal peak loads
    i. Number of feeder located regulators and capacitor banks
    j. Feeder length
    k. On peak and off peak voltage drops
    l. Presence of any unique loads (e.g. airport or hospital)
    m. Percent urban or rural customers on the feeder
    n. Regional percentage load by type – residential, commercial, industrial
    o. Regional percentage of residential and commercial with electric heat, gas heat, heat pump or air conditioning and electric or gas hot water.
4. Excel formatted spreadsheet showing:
    a. 2010 billed kWh usage by month, region and rate type
    b. 2010 loss estimates
5. Excell formatted spreadsheet showing
    a. 2010 billed average daily kWh usage by feeder and rate type

The author visited FortisBC in Kelowna on July 19, 2011 and met with Michael Sidiropoulos, Betsy Matamoros and Blaine Whiteside. Seven (7) voltage loggers were left (on loan to FortisBC) to be used to spot check voltage on various feeders. FortisBC personnel placed and removed the loggers obtaining spot checks at ten (10) different times and/or locations. See Appendix E – Voltage Logger Charts.

The author also maintained telephone and email communication with both Michael Sidiropoulos and Betsy Matamoros to obtain information and/or clarification as needed.

4.2 Assumptions

The following assumptions were made in approaching the analysis. These assumptions were reviewed by FortisBC personnel for reasonability and in some cases were provided by them.

1. No infrastructure improvements are assumed for either the energy conservation numbers or the cost estimates[1].
2. Station OLTC and regulator set points are set at 123.5 V on a 120 V basis.
3. Station OLTC and regulator bandwidths are symmetrically set at 3 V on a 120 volt basis symmetrical, 1.5 V above set point and 1.5 V below set point.
4. Substation Load Factor (LF) and Feeder LF are the same.
5. For substations that do not have data for a station LF or feeder LF the LF is assumed to be an average of the area substation LFs that are available.
6. LF is computed as: LF = average annual kW/Peak kW and annual kWh = average kW * 8760 hrs/year.
7. Total system losses including transmission energy losses = 8.8% of total energy produced. (See the author's comments on loss estimates in Section 6.1)
8. Distribution energy losses = 6.3% of total energy on a distribution feeder. Distribution energy losses are all losses downstream of the substation transformer. (See the author's comments on loss estimates in Section 6.1)
9. Non-technical losses are assumed to be included in the distribution losses.
10. All LTC and regulator steps are 5/8% therefore 1 step = 0.75V
11. Rural feeders will be assumed to have 80% residential and 20% commercial load division to account for pumping etc., barns, rural stores.
12. 112 V is the minimum acceptable service entrance voltage. (See Appendix B - Distribution Voltage Standards.)
13. Allowance for peak load distribution transformer and service entrance voltage drop – 3V
14. For purposes of estimating voltage reductions the assumption was made that during a 24 hour day there were 12 on-peak hours and 12 off-peak hours in the daily load cycle.

4.3 Average Voltage Reduction Estimates

As a first step in estimating average voltage reduction potential for each feeder, FortisBC performed feeder studies using Cyme Power Engineering modeling software. For each feeder they determined the maximum voltage drop on both a three phase section of the feeder and on a single phase feeder lateral. These maximum voltage drops were provided for both on-peak periods and off-peak (35% of full load) load periods.

The voltage reduction estimates obtained using the following procedures for each feeder can be found in the accompanying Excel Workbook, Analysis workbook for Fortis BC Rev0.xlsx

4.3.1 Computing average voltage reduction

Because energy conservation is occurring 24 hours per day with CVR daily average voltage reductions prior to implementation should be used when estimating potential energy conservation with VVO and

[1] The author's company has installed VVO systems without infrastructure improvements since 2003. In general energy conservation is available without improvements, however there have been some instances where the visibility of the VVO system has shown where improvements could be made that would enhance the conservation obtained.

LDC based CVR. When implementing CVR with SPR the voltage drop at peak should be used in determining potential voltage reduction.

The following are the variables used in computing average voltage reduction available:

$\Delta V_{VVO}\%$ = Daily average percent voltage reduction with CVR (this is the value to be estimated). The percentage is computed using a 120 volt base.

V_{bus} = OLTC voltage setpoint prior to implementation of CVR = 123.5 volts

V_{dp} = Maximum modeled voltage drop on-peak either single phase or three phase (provided from model)

V_{eolp} = On-peak end of line voltage prior to CVR implementation

H_p = Hours on-peak ($H_p + H_o = 24$)

V_{do} = Maximum modeled voltage drop off-peak either single phase or three phase (provided from model)

H_o = Hours off-peak ($H_p + H_o = 24$)

V_{eolo} = Off-peak end of line voltage prior to CVR implementation

V_{end} = Minimum VVO allowable primary end of line voltage set point

V_s = Allowance for voltage drop in distribution transformer and secondary conductors to service entrance = 3 volts

V_{se} = Minimum Normal Operating Condition service entrance voltage = 112 volts

V_{step} = OLTC or regulator step size = 0.75 volts

V_a = VVO regulating allowance [2] = 0.5 volts

V_{LDC} = Minimum LDC based CVR end of line set point = Vend + 2.0 volts (See Section 3.2 Line Drop Compensation Based CVR)

V_{SPR} = Voltage reduction available with SPR based CVR

4.3.1.1 VVO based CVR voltage reduction

To estimate $\Delta V\%$ for a feeder with VVO based CVR –

V_{end} is first computed:

$$V_{end} = (V_{se} + V_s + V_{step} + V_a) \text{ volts}$$

$$V_{end} = (112 + 3 + 0.75 + 0.5) \text{ volts}$$

$$V_{end} = 116.5 \text{ volts}$$

On-peak end of line voltage, V_{eolp}, and off-peak end of line voltage, V_{eolo}, are estimated:

$$V_{eolp} = V_{bus} - V_{dp}$$

[2] When determining a set point to use for controlling the voltage at the end of a distribution line when using behavior based VVO the minimum allowable setpoint is based on the size of the regulator or OLTC step plus an allowance V_a for the VVO regulating algorithms to operate, usually 0.5 volts

$V_{eolo} = V_{bus} - V_{do}$

Finally the average voltage reduction $\Delta V_{VVO}\%$ can be estimated:

$$\Delta V_{VVO}\% = \{[(V_{eolp} - V_{end}) * H_p] + [(V_{eolo} - V_{end}) * H_o]\} / 24 / 120 \text{ volts}$$

4.3.1.2 LDC based CVR voltage reduction

The procedure to estimate $\Delta V_{LDC}\%$ for a feeder with LDC based CVR –

V_{LDC} is first computed:

$$V_{LDC} = (V_{se} + V_s + V_{step} + V_a + 2) \text{ volts}$$

$$V_{end} = (112 + 3 + 0.75 + 0.5 + 2) \text{ volts}$$

$$V_{end} = 118.5 \text{ volts}$$

On-peak end of line voltage V_{eolp}, off-peak end of line voltage V_{eolo}, are estimated:

$$V_{eolp} = V_{bus} - V_{dp}$$

$$V_{eolo} = V_{bus} - V_{do}$$

Finally the average voltage reduction $\Delta V_{LDC}\%$ can be estimated:

$$\Delta V_{LDC}\% = \{[(V_{eolp} - V_{LDC}) * H_p] + [(V_{eolo} - V_{LDC}) * H_o]\} / 24 / 120 \text{ volts}$$

4.3.2 SPR based CVR voltage reduction

The maximum voltage reduction $\Delta V_{SPR}\%$ available on a feeder with SPR based CVR is the reduction available on-on peak.

$$\Delta V_{SPR}\% = (V_{LDC} + V_{dp}) / 120 \text{ volts}$$

4.4 Conservation Voltage Regulation Factor (CVR_f) Estimates

Estimates of demand reduction and conservation on a feeder depend upon available voltage reduction and the Conservation Voltage Regulation Factor (CVR_f).

4.4.1 CVR Factor

Conservation Voltage Regulation Factor (CVR_f) is a measure of energy conservation when voltage optimization is implemented.

$$CVR_f = \Delta E\% / \Delta V\%$$

where $\Delta E\%$ is the percent of energy reduced and $\Delta V\%$ is the percent voltage reduction.

CVR factors are often erroneously thought to be constant; however they are not constant and vary considerably depending on types of loads connected to the grid and the voltage level at the particular location on the distribution feeder where they are connected. While CVR factors are not constant, the mean (average) values of verified CVR_f can be used in estimating and forecasting energy conservation.

4.4.2 CVR Factor Estimates

Experience with actual CVR installations leads to the conclusion that overall feeder CVR Factors are highly dependent on customer type, ie. residential, commercial or industrial on a feeder and the type of space heating and hot water heating in use by those customers. For example, regions with significant amounts of baseboard electric heat and electric hot water tend to have lower CVR Factors. Regions that have high penetrations of gas heat or heat pumps and high penetration of air conditioning tend to have higher CVR Factors.

Absent an actual measured and verified CVR Factor for each individual feeder based upon actual CVR operation, conservative estimates of CVR Factors must be used. The CVR Factors, shown in Table 1 – Selected CVR Factors, were selected to provide conservative energy conservation estimates:

Conservative CVR Factors for SPR and LDC based implementations of CVR	
Customer type	CVR_f in per unit
Residential	0.70
Commercial	0.60
Industrial	0.40
Conservative CVR Factors for VVO based implementations of CVR	
Residential	0.95
Commercial	0.70
Industrial	0.50
Likely CVR Factors for VVO based implementations of CVR	
Residential	1.10
Commercial	0.75
Industrial	0.55

Table 1 – Selected CVR Factors

4.4.3 CVR Factor Selection Commentary

The value of CVR factors has been, and remains to be, a subject of controversy. There are essentially three different sources from which CVR Factor information could be, and has been, obtained for analysis in this report:

1. The first is from literature that discusses past CVR projects (mostly using LDC based CVR) at varying utilities (several references t this literature can be found in Appendix R – References).
2. The second is from laboratory test data in which individual appliances and utilization equipment has been tested for energy usage versus voltage level. One can compute CVR Factors from the data using the formula given in Section 4.4.1. The seminal source for laboratory test data is the 1981 EPRI report [4] referenced in Appendix R – References. The Pacific Northwest National Laboratories is also conducting laboratory tests [17][19].

3. The third is from actual experience measured values using a measure and verification protocol such as Protocol #1[3] (See Appendix D – Measurement and Verification) [12][13].

Since the approval of Measurement and Verification "Protocol #1 for Automated CVR" [12][13] (see Appendix D – Measurement and Verification) was approved in 2004 the protocol has been used on 70 distribution feeders in the U. S. and in Canada. The CVR Factors obtained from using Protocol #1 and laboratory test results tend generally to be higher than CVR Factors that are found in some of the early literature discussing CVR projects. (The author is not sure of the cause of this but expects statistics that have been used and the assumptions of underlying models are the cause of these differences. In the past it has been common to use standard statistical approaches which assume Gaussian data distribution and averaging all the data not taking into account the period nature of load patterns. For a more in depth discussion on the statistics that should be used and models, refer to Appendix D – Measurement and Verification).

To assure conservative estimations of energy conservation, the author has elected to use CVR Factors which are generally in agreement with the earlier literature for SPR and LDC based CVR. The conservative CVR Factors for VVO have been selected to be lower than those CVR Factors that have been found using Protocol #1 and the likely VVO CVR factors have been selected to be in line with the CVR Factors that are found when using Protocol #1.

4.5 Energy Conservation Estimates

Estimated conservation, ΔE, in kWh on any particular feeder is calculated as:

> Feeder ΔE = ΔV% * [(%Residential load * CVR_f for residential0 + (%Commercial load * CVR_f for commercial) + (%Industrial load * CVR_f for industrial)] * estimated total 2010 kWh on feeder.

FortisBC provided general estimates for customer load types on feeders based upon region. (In some cases where an adjustment appeared obvious to the author a modification to load type %s was made.)

Where ΔV% on one or more feeders fed by an LTC or station regulator bank is 0% or less no energy conservation was estimated for that or any feeder fed by that LTC or station regulator. In case of SPR based CVR no conservation was estimated if ΔV% on one or more feeders was less than 1%.

4.6 Cost estimates

Cost estimates for VVO implementation of CVR were based on the standard estimating procedures used by the author's company in preparing customer proposals and estimates for AdaptiVolt™ VVO technology (See Appendix C – VVO System Cost Estimates). The estimates are based on an architecture of three (3) separate VVO systems in the North Okanagan Region serving ten (10) substations with sixteen (16) transformers and thirty-eight (38) feeders; (3) separate VVO systems in the Kootenay_Boundary Region serving sixteen (16) substations with (15) transformers and forty (40) feeders; two (2) VVO systems in the South Okanagan Region serving eight (8) substations with eight (8) transformers and eighteen (18) feeders.

No costs are included for infrastructure improvement. Both the energy conservation estimates and the cost estimates assume that no feeder or infrastructure modifications are made as part of the projects. In

[3] Battelle Northwest recently used procedures in line with the procedures used in Protocol #1 to evaluate 15 VVO feeders for American Electric Power in Ohio. The results of these evaluations tend to be on the same order as the results obtained on the 70 feeders that have been evaluated using Protocol#1.

other words, no line regulators or switched capacitors are added, and no line reconductoring or load balancing is done.

The cost estimates include:

1. Engineering costs and expenses for both FortisBC and the VVO vendor;
2. Project management costs for both Fortis BC and the VVO vendor;
3. VVO hardware and software including voltage sensing equipment with potential transformers and communication devices compatible with the projected AMI communication system;
4. New LTC and regulator controllers for all LTCs and regulators
5. Start-up and commissioning service and expenses
6. Training and
7. Measurement and Verification on all circuits.

The costs assume that the fiber optic back-bone will be used for inter-substation communications and from the VVO system to the substations. They also assume an in-place AMI communications system that can be leveraged for a VVO application.

Costs estimates for the LDC system were estimated to be 30% of the cost of the VVO based CVR. Costs for SPR based CVR were estimated at 50% of the cost of LDC based CVR.

4.6.1 Cost Estimate Classification

Based upon the AACE International Cost Estimate Classification System [15] the VVO Vendor cost section of the VVO estimates should be considered a Class 2 estimates and the FortisBC cost sections should be considered Class 3 estimates. The LDC and SPR cost estimates should be considered as Class 4 estimates.

5. Summary

Table 2 - FortisBC CVR Benefit/Cost Table below shows the summary of estimated energy conservation in kWh, estimated energy conservation as a percentage of the total direct billed energy less wholesale including losses and the $ value of the estimated conservation. The table also shows the estimated cost of each type of implementation. The information is broken down by type of CVR implementation and by region. It also shows the system totals.

FortisBC CVR Benefit/Cost Table										
Region and Type of CVR Implementation	Conservative with LDC and SPR			Conservative w/VVO CVR			Possible with VVO CVR			Estimated Cost
	kWh/yr	%	$ Value/yr	kWh/yr	%	$ Value/yr	kWh/yr	%	$ Value/yr	$
NOK Fdrs with VVO based CVR				23,918,617	2.24%	$2,495,190	26,974,388	2.53%	$2,813,968	$3,168,254
NOK Fdrs with LDC based CVR	8,217,833	0.77%	$857,284							$950,476
NOK Fdrs with Bus Set Point Reduction based CVR	2,490,731	0.23%	$259,833							$475,238
SOK Fdrs with VVO based CVR				7,443,862	1.41%	$776,544	8,430,909	1.60%	$879,512	$1,593,218
SOK Fdrs with LDC based CVR	2,953,008	0.56%	$308,058							$477,965
SOK Fdrs with Bus Set Point Reduction based CVR	470,275	0.09%	$49,059							$238,983
BND_KT Fdrs with VVO based CVR				18,709,035	2.00%	$1,951,727	21,134,112	2.26%	$2,204,711	$4,130,379
BND_KT Fdrs with LDC based CVR	8,357,874	0.89%	$871,893							$1,239,114
BND_KT Fdrs with Bus Set Point Reduction based CVR	4,014,227	0.43%	$418,764							$619,557
System Total VVO CVR				50,071,515	1.98%	$5,223,460	56,539,408	2.24%	$5,898,191	$8,891,851
System Total LDC	19,528,716	0.77%	$2,037,236							$2,667,555
System Total with Bus Set Point Reduction	6,975,233	0.28%	$727,656							$1,333,778
$ Value analysis using	$ 104.32	per MWh (firm, inclusive of capacity)				From Mark Warner				

Table 2 - FortisBC CVR Benefit/Cost Table

6. Author's Comments, Conclusions and Recommendations

6.1 Conservative Estimates

The author has taken steps to assure that all estimates of both energy conservation potential and costs are conservative, that is, energy conservation is not overstated and costs are not understated.

As an added measure to assure conservative estimates of energy conservation, voltage loggers were temporarily placed inside a few customer facilities by FortisBC personnel. The charts of the logger data are shown in Appendix E – Voltage Logger Charts. These charts show that the potential voltage reduction estimates are realistic and achievable using VVO.

6.2 System Loss Assumption Recommendation and Comments

The author recommends that FortisBC reevaluate the distribution loss and system loss assumptions. FortisBC assumes that distribution losses average 6.3% and that overall system losses including the transmission system are 8.8% based on generated and incoming kWh. (See Section 4.2.) These percentages include all technical losses (conductor I^2R losses and transformer no load and load losses) and non-technical losses (theft, etc.) This recommendation is based on two factors which leads the author to believe that the 6.3% assumption may be understating losses on the FortisBC distribution system.

The first factor is subjective and qualitative rather than quantitative and objective. FortisBC has several very long feeders and also serves some very sparsely populated areas. Technical losses have a strong correlation to customer and load density. Urban/suburban areas with high customer density and high relative load density tend to have much lower distribution losses (in the order of 3% to 4.5 % while rural customer densities and load densities have much higher losses. BC Hydro's stated losses as a percentage of generated and incoming kWh is 9.1% as compared to the FortisBC loss percentage of 8.8%[4]. BC Hydro does have long feeders and low customer and load density areas, but they also serve the BC Lower Mainland with its areas of very high customer and load densities. BC Hydro also utilizes much higher voltages for their transmission lines which also reduces losses. While the author does not have actual hard data on the comparisons of customer and load densities for FortisBC and BC Hydro, it is reasonable to expect that BC Hydro's average customer and load densities are higher than FortisBC's average customer and load densities. It that is true, the FortisBC total loss percentages should be higher than BC Hydro's loss percentages.

The second factor is objective and quantitative. Data used during the analysis of CVR based conservation indicates that distribution losses are higher than assumed. An average of 11.2% distribution losses was found at 11 substations which is much higher than the assumed 6.3% distribution loss

Some of the data provided by FortisBC personnel to be used in analyzing the CVR conservation potential included 2010 total kWh data from power monitors in 36 of the 55 distribution substations and terminals with distribution. They also provided the 2010 billed data including the daily average kWh billed per feeder. The data was used to verify that energy conservation estimates using feeder annual kWh based upon the assumptions outlined in Section 4.2 were conservative so as not to overstate the potential for CVR based energy conservation.

In an attempt to better understand the percentage of losses (which will also be reduced when CVR is implemented) on the distribution feeders the daily billed kWh average of all the feeders in a substation

[4] Per Michael Sidiropoulos of FortisBC

was totaled and then multiplied by 365. The presumption is that the station monitored 2010 kWh less total billed kWh on all feeders in that substation should be the kWh losses, both technical losses and non-technical losses on the distribution feeders. (Only 28 stations had both metered data and billed data that would allow this computation.)

In doing this loss analysis the computed results fell into three categories. The first category include those values which fall within what an electric utility may expect as normal loss percentages i.e those that show losses to be between 4% and 15% of the total annual kWh metered at the substation (11 fell into this category and the average distribution loss percentage for those was 11.2%). The second category included results that were higher than could reasonably be expected and were likely caused by lack of all the data required for the computation (8 fell into this category). The third category were those values which showed negative values, a case which is physically impossible and were also likely caused by lack of all the data required for the computation (9 fell into this category).

6.3 Distribution Feeder Infrastructure Improvements

For the purposes of this report it was assumed that no distribution infrastructure improvements would be made, both for the energy conservation obtained and for cost estimating purposes. The author's company has installed many VVO based CVR implementations at utilities in Canada and the United States [16]. In all cases significant energy conservation benefits were obtained with no initial infrastructure improvements.

However, in several cases the data and system visibility provided by the VVO system's enabled the utilities' engineers to enhance the conservation and demand reduction significantly with only relatively minor modifications, such as moving capacitor banks and better balanced loads. There have also been cases where the data and system visibility showed previously unknown required maintenance issues which when addressed improved the conservation and demand reduction.

There are several substations or LTC transformers that were not included in the VVO energy conservation estimates because one of several feeders had insufficient voltage reduction availability. (DG Bell, RG Anderson, Pine Street Hedley, Princeton and Coffee Creek are among these stations). In the author's opinion some feeder infrastructure improvement may be economically justified for implementation of CVR after a VVO system is in place.

6.4 Other Fortis VVO Opportunities

FortisBC serves the communities of Summerland, Penticton, Kelowna, Grand Forks and Nelson; however, no energy conservation based on their loads was included in this evaluation. The total wholesale 2010 billed kWh was 2,323,012,537 kWh. The potential conservation available for these communities, using the same assumptions and percentages as for the FortisBC direct customer conservation, is approximately 46,015 MWh, almost equivalent to the savings estimated in the analysis.

The author recommends that Fortis BC consider some means of including this large potential conservation opportunity at some time.

Appendix A - Conservation Voltage Regulation (Reduction)

Conservation Voltage Regulation (CVR) is the operation of the distribution system such that feeder voltages are maintained at as low a level possible while maintaining customer service entrance voltage levels within Normal Operating Conditions. (See Appendix B - Distribution Voltage Standards.)

This section introduces the concept of CVR, intuitively exposes the physical basis for its efficacy, and briefly describes some of the important practical considerations. It is intended for the audience not acquainted with the concept. For the reader interested in a thorough critique of CVR, there are numerous technically detailed examinations of CVR available, a few of which are referenced in this document. The technical papers on CVR include topics such as quantitative assessment of the CVR effect in consumer devices, application of CVR for distribution efficiency, estimation of the effectiveness of CVR systems from utility metering data, and related topics.

The root idea of CVR in electricity delivery systems is that a reduction in delivered voltage results in a reduction of delivered power (demand) and in most cases, delivered energy (time integral of demand). This effect has been observed over a narrow range of delivered voltage well within the bounds established by both ANSI and CSA standards [3][2]. The physical basis for this observation is, in the broadest terms, twofold:

(1) Most classes of utilization devices operated by utility customers (e.g. fluorescent lamp ballasts, incandescent lamps, induction motors in a variety of applications, linear and switching power converters) manifest a peak in efficiency when excited at an input voltage below the nameplate voltage;

(2) Electrical transmission and distribution system transormers exhibit reduced losses when excited at voltages below the rated nominal voltage.

Discussion of the physical mechanisms for this behavior is beyond the scope of this report; however, references quantifying the relevant phenomena are cited.

CVR History in North America

Electric utilities have long made temporary distribution voltage reductions in emergencies to reduce demand in the short term.

In 1980s electric utilities began studying the effect of voltage reduction on energy usage on distribution feeders. In 1981 Electric Power Research Institute (EPRI) commissioned the University of Texas at Arlington to test and study the effects of reduced voltage on the efficiency of important power system loads [4]. That study included such utilization devices as television sets, microwave ovens, motors, heat pumps, air conditioners, distribution transformers, resistance heating devices as well as others. Also in 1982 the Environmental Defense Fund (EDF) published an article discussing the efficacy of CVR as an energy conservation method [5].

In 1985 the Northwest Power Planning Council (now the Northwest Power and Conservation Council, NWPCC) mentioned CVR and called for assessment of loss reduction through reduced voltage . In 1987 Bonneville Power Administration (BPA).commissioned Pacific Northwest National Laboratories to assess CVR applicable in the BPA service area [6]. The assessment concluded that CVR was an effective energy conservation measure and that that potential conservation available was up to 270 average MW or 2.37×10^6 MWh/year.

In 1988-90 Snohomish Public Utility District in Washington State conducted a pilot study of CVR on 12 distribution feeders. The results of the study confirmed significant energy conservation on those feeders [7]. (Snohomish PUD has since implemented CVR at all of its distribution system substations.)

In 1990 BC Hydro launched a program which included load to voltage dependency (aka CVR) studies at a substation on Vancouver Island. The tests showed a significant reduction on both load (kW) and reactive power (kVAR) [8]. (BC Hydro has since implemented CVR at 5 additional major substations and is currently in the process of applying CVR to at least 100 of their major substations in the next few years.)

With the California Energy Crisis in 2000-01 interest in CVR as a long term conservation and demand reduction measure gained impetus. In 2002, the author's company fielded its first automated CVR system projects at Inland Power and Light Company. That project showed significant energy conservation and demand reduction along with significant kVAR reduction [1].

In 2004 the Northwest Energy Efficiency Alliance (NEEA) began a major study on the effects of CVR. Known as the NEEA Distribution Efficiency Initiative (DEI) Study, several Pacific Northwest utilities undertook CVR projects utilizing several different methods of accomplishing CVR. That study showed significant energy conservation available by implementing CVR. Additionally it showed very significant kVAR reduction when CVR is implemented. The final report was issued in December, 2007 [9].

In 2005 Hydro Quebec implemented a CVR pilot project to study the effect of controlled voltage reduction [10] (more recently they have received federal funding from Ottawa to implement "smart grid" based CVR in a pilot project in Boucherville, QC). They have estimated that 2 TWh of energy can be saved annually and are in the planning process to obtain those savings.)

In 2009 the NWPCC identified over 400 average MW (aMW) of conservation available using CVR or voltage optimization in its "6th Northwest Power Plan" [11].

With the advent of "smart grid" initiatives the term Volt/VAR optimization (VVO, a.k.a. CVVC – Coordinated Volt/VAR Control and IVVC – Integrated Volt/VAR Control) has come into common use. VVO is the operation of a distribution system with automatic coordinated operation of voltage regulation devices and switched capacitor banks with the goal of minimizing lagging kVAR's and controlling distribution voltage levels to some "optimum" point to reach a utilities optimal goal. The goal can vary from utility to utility and can be to reduce peak demand, implement CVR or even in some cases to increase load.

Appendix B - Distribution Voltage Standards

The Canadian Standards Association (CSA) has established limits for distribution voltages in its standard *CAN3-C235-83*, ***Preferred Voltage Levels for AC Systems, 0 to 50,000 V***, *Electric Power Transmission and Distribution (Reaffirmed 2000)*. Table 3 below shows the various allowable voltage levels for different points on the system various system conditions.

In general the serving electric utility will use the values in the "At Service Entrances" portion of the table as a guide for operating and for design of the distribution system.

Recommended Voltage Variation Limits for Circuits up to 1000 V								
From CAN-2-C235-83, Preferred Voltage Levels for AC Systems, 0 to 50000 V (Reaffirmed 2000)								
Nominal System Voltages	At Utilization Points				At Service Entrances			
	Extreme Operating Conditions				Extreme Operating Conditions			
		Normal Operating Conditions				Normal Operating Conditions		
Single-Phase	13.33%	10.00%		5.83%	-11.67%	-8.33%	4.17%	5.83%
120/240	104/208	108/216	125/250	127/254	106/212	110/220	125/250	127/254
240	208	216	250	254	212	220	250	254
480	416	432	500	508	424	440	500	508
600	520	540	625	635	530	550	625	635
Three Phase,	*	*			*	*		
4-Conductor	-10.00%	-8.33%	4.17%	5.83%	-8.33%	-6.67%	4.17%	5.83%
120/208Y	108/187	110/190	125/216	127/220	110/190	112/194	125/216	127/220
240/416Y	216/374	220/380	250/432	254/440	220/380	224/388	250/432	254/440
277/480Y	240/416	250/432	288/500	293/508	245/424	254/440	288/500	293/508
347/600Y	300/520	312/540	360/625	367/635	306/530	318/550	360/625	367/635
Three Phase,								
3-Conductor	-13.33%	-10.00%	4.17%	5.83%	-11.67%	-8.33%	4.17%	5.83%
240	208	216	250	254	212	220	250	254
480	416	432	500	508	424	440	500	508
600	520	540	625	635	530	550	625	635
* - Indicates that the Volt % below nominal for Three Phase 4-Conductor vary depending upon nominal.								

Table 3 - Voltage Variation Limits

Explanations of terms

- Nominal voltage is the voltage by which a system is designated.
- Normal Operating Conditions - Where voltages lie within the indicated limits under this heading no improvement or corrective action is required.
- Extreme Operating Conditions - Where voltages lie outside the indicated limits for normal operating conditions but within the indicated extreme limits, <u>improvement or corrective action should be taken on a planned and programmed basis</u> but not necessarily as an emergency. Where voltages lie outside the indicated limits for extreme operating conditions, <u>improvement or corrective action should be taken on an emergency basis.</u>

CVR Voltage Levels

In determing the permissable level of voltages for the CVR operating regimes the Service Entrance voltages during Normal Operating Condigions are normally used. When dealing with CVR it is common to refer to voltages on a 120 volts basis voltage. Note that there are two 120 volt service entrance nominal system voltages, single phase 120/240 volts with a normal low of 110 volts and three phase Y 120/208volts with a normal low of 112. A conservative approach to designing a CVR implementation dictates that 112 volts, the higher of the two be used as the minimum service entrance voltage for design.

Appendix C – VVO System Cost Estimates

The cost estimates for the VVO systems as discussed in Section 4.6 and the summarized estimated costs shown Table 2in in Section 5 are given in more detail in Table 4, Table 5 and Table 6.

NOK VVO Estimates			
VVO Vendor Supplied			
Qty	Unit	Description	Estimated Cost
1	lt	Preliminary infrastructure engineering survey, field verification and scoping.	$ 75,000
		Infrastructure Survey Expenses	
3	ea	VVO Core Unit w communications components	$ 2,153,254
38	ea	Line Voltage Monitor w RF components	
114	ea	Potential Transformers	
13	ea	LTC Controllers	
16	ea	Voltage Regulator Controls	
6	ea	Mid-Line Regulator Interface units w RF components	
16	ea	Substation Meters	
1	lot	Project management and installation coordination	
		Start-up and Commissioning	
		Start-up Expenses	
		Training	
		Measurement and Verification	
FortisBC supplied or contracted estimates			
1	lot	Field Monitoring and Interface installation	$ 940,000
		VVO Core Unit Installation	
		Installation within substations	
		Fortis Project Management and Engineering	
	Total NOK Project Estimate		$ 3,168,254

Table 4 - NOK VVO Estimate

SOK VVO Estimates			
VVO Vendor Supplied			
Qty	Unit	Description	Estimated Cost
1	lt	Preliminary infrastructure engineering survey, field verification and scoping.	$ 50,000
		Infrastructure Survey Expenses	
2	ea	VVO Core Unit w communications components	$ 1,520,586
18	ea	Line Voltage Monitor w RF components	
54	ea	Potential Transformers	
9	ea	LTC Controllers	
27	ea	Voltage Regulator Controls	
11	ea	Mid-Line Regulator Interface units w RF components	
8	ea	Substation Meters	
1	lot	Project management and installation coordination	
		Start-up and Commissioning	
		Start-up Expenses	
		Training	
		Measurement and Verification	
FortisBC supplied or contracted estimates			
1	lot	Field Monitoring and Interface installation	$ 635,000
		VVO Core Unit Installation	
		Installation within substations	
		Fortis Project Management and Engineering	
	Total SOK Project Estimate		$ 2,205,586

Table 5 - SOK VVO Estimate

BND_KT VVO Estimates			
VVO Vendor Supplied			
Qty	Unit	Description	Estimated Cost
1	lt	Preliminary infrastructure engineering survey, field verification and scoping.	$ 50,000
		Infrastructure Survey Expenses	
2	ea	VVO Core Unit w communications components	$ 1,520,586
18	ea	Line Voltage Monitor w RF components	
54	ea	Potential Transformers	
9	ea	LTC Controllers	
27	ea	Voltage Regulator Controls	
11	ea	Mid-Line Regulator Interface units w RF components	
8	ea	Substation Meters	
1	lot	Project management and installation coordination	
		Start-up and Commissioning	
		Start-up Expenses	
		Training	
		Measurement and Verification	
FortisBC supplied or contracted estimates			
1	lot	Field Monitoring and Interface installation	$ 635,000
		VVO Core Unit Installation	
		Installation within substations	
		Fortis Project Management and Engineering	
	Total NOK Project Estimate		$ 2,205,586

Table 6 - BND_KT VVO Estimate

Appendix D – Measurement and Verification

In 2004 the Northwest Regional Technical Forum (RTF,) a subsidiary of the NWPCC approved the Measurement and Verification (M&V) protocol *"Protocol #1 for Automated CVR"* (Protocol #1) and BPA subsequently approved it to use for determining obtained conservation results for which they will compensate utilities and other customers [12][13]. The author's company developed Protocol #1 in close collaboration and cooperation with BPA. The Washington State University Department of Electrical Engineering reviewed the engineering analysis and the use of time series analysis and the Statistics Department at the University of Waterloo in Ontario reviewed the robust statistical methods and analysis. Protocol #1 meets the U. S. Department of Energy's energy conservation measurement and verification guidelines [14].

Protocol #1 has been used by the Ontario Power Authority (OPA) to determine the energy conservation levels for VVO projects in the province. Tennessee Valley Authority (TVA) as well as American Electric Power (AEP) has also used it to determine energy conservation and demand reduction. Dr. Kevin Schneider of Pacific Northwest National Laboratories has used very similar procedures to those used in Protocol #1 in evaluating demand reduction and energy conservation levels of VVO systems.

Underlying model

For any statistical analysis to be valid, the underlying model must be as close to actual reality as possible. The model underlying Protocol #1 assumes that there is a linear model for energy consumption with a linear dependence on delivered voltage, there is an asymmetric linear dependence on ambient temperature and there is stochastic[5] customer behavior with average and random components. The raw data graphed in Figs 1 and 2 support these model assumptions. Other factors such as micro-climates and solar flux are not yet included in the model.

Protocol #1 Methodology

Protocol #1 uses a set testing period with the automated CVR engaged on alternate days. In verifying energy savings the protocol attempts to eliminate other factors that affect demand such as climate variation, mainly temperature, consumer behavior and other special exceptions.

A combination of time series analysis and robust statistical methods are used to verify energy savings and estimate future savings on each feeder. All the pertinent data is broken into time ensembles for comparison, i.e. data from one time one day is compared only with the data from the same time period on the alternate day. Additionally different types of days are compared with the same type of day, i.e. winter weekends are compared with winter weekends and summer weekdays are compared to summer weekdays.

The methodology of Protocol #1 compares demand on a uniform basis by comparing data from alternate days and as closely as possible demand is based on the same environment. It exploits prior knowledge of the demand processes such as daily periodicity, utilization device efficiency vs. voltage and customer demand behavior. It also applies results only within the bounds of observations.

[5] A stochastic process is one whose behavior is non-deterministic, in that a system's subsequent state is determined both by the process's predictable actions and by a random element.

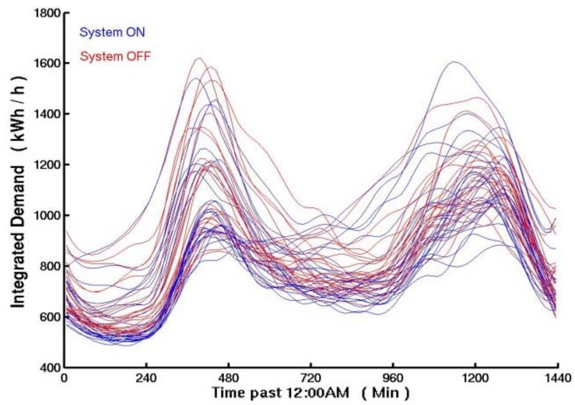

Fig. 1 Inland Halfmoon substation Feeder 3 Demand Profile Ensemble

Fig. 1 shows the aggregated daily demand profiles for the year of testing. It is clear that there are similar daily demand profiles but the exact shape and magnitude vary from day to day.

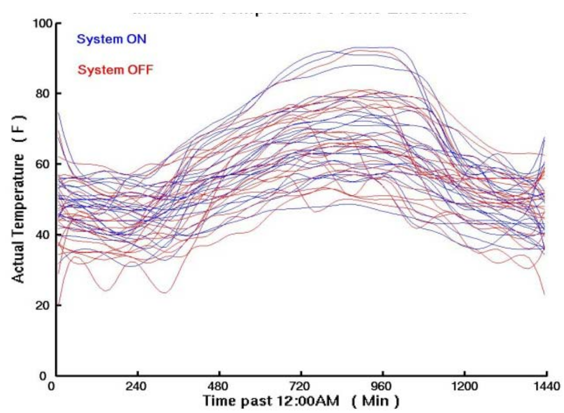

Fig. 2 Halfmoon substation temperature profile ensemble

Fig. 2 shows the aggregated daily temperature profiles for the year of testing. They also have similar profiles but the exact shape and magnitude vary from day to day.

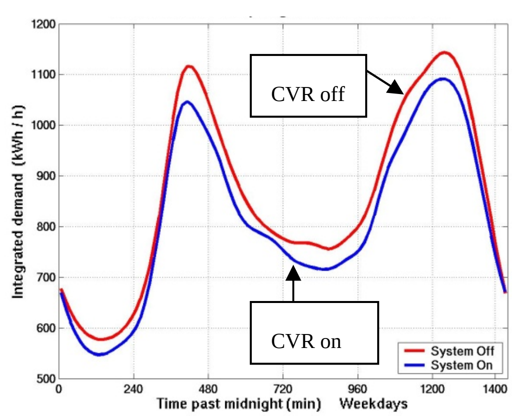

Fig 3 Halfmoon Feeder 3 Demand profile, Spring/Autumn weekdays

Fig. 3 shows the temperature compensated demand results for Spring and Autumn weekdays.

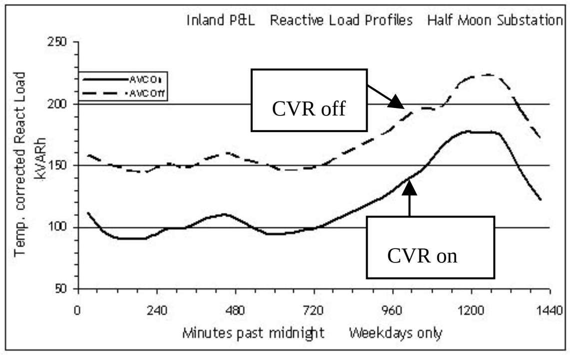

Fig. 4 Halfmoon Feeder 3 reactive demand profile May - September 2003

Fig 4 shows the Feeder 3 reactive demand results for May through September. The analysis of the collected data showed an even greater percentage reduction in reactive power than in real power reduction[6]. Based upon this finding all of the reactive demand data collected during testing of automated CVR systems has been analyzed and the Conservation VAR Reduction Factor ($CVRQ_f$)[7] determined.

Forecasts

The data shown in Figs. 1 and 2 are part of the data which was used to both develop the protocol and to prove the efficacy of the protocol. Prior to final approval the RTF required that data from one year be used to forecast the results for the next year. To do this, winter 2002/03 data from Halfmoon Feeders 1 and 3 were used to calculate Conservation Voltage Regulation Factor (CVR_f)[8] coefficients for each of the feeders. Then those coefficients were used to forecast savings which were then compared with actual savings during January 2004. Table 7 shows the results of that exercise.

Feeder	Computed CVR_f using Winter 2002/03 data	Forecasted January 2004 results	Actual January 2004 results
Feeder 1	0.953	539kWh/day	518 kWh/day
Feeder 3	0.914	787 kWh/day	691 kWh/day

Table 7 Results of Halfmoon forecasting exercise.

Benefits of the time series analysis and robust statistical methods

The methods used in this protocol present significant benefits over other methods of determining the effects of implementing CVR. They eliminate the need for a temporal model of the demand profile. They allow the analyst full control over the use of correlation structures. They facilitate identification of parameters for measured variables. There are no constraints on regression methods or models and no

[6] The author believes that this was the first time that reactive power reduction was observed and documented with CVR applied. He also believes that this aspect of CVR holds a great deal of promise as a transmission system resource in mitigating transmission voltage instability events.

[7] $CVRQ_f$ = % reactive power demand reduction/% voltage reduction

[8] CVR_f = % energy saved/% voltage reduction

implied constraints on probability density or random data. Estimates of demand profiles require no extrapolation and therefore conservation estimates are bounded by observations. Finally these methods allow the estimation of CVR performance with limited measurements and test periods.

Appendix E – Voltage Logger Charts

North Okanagan Feeders

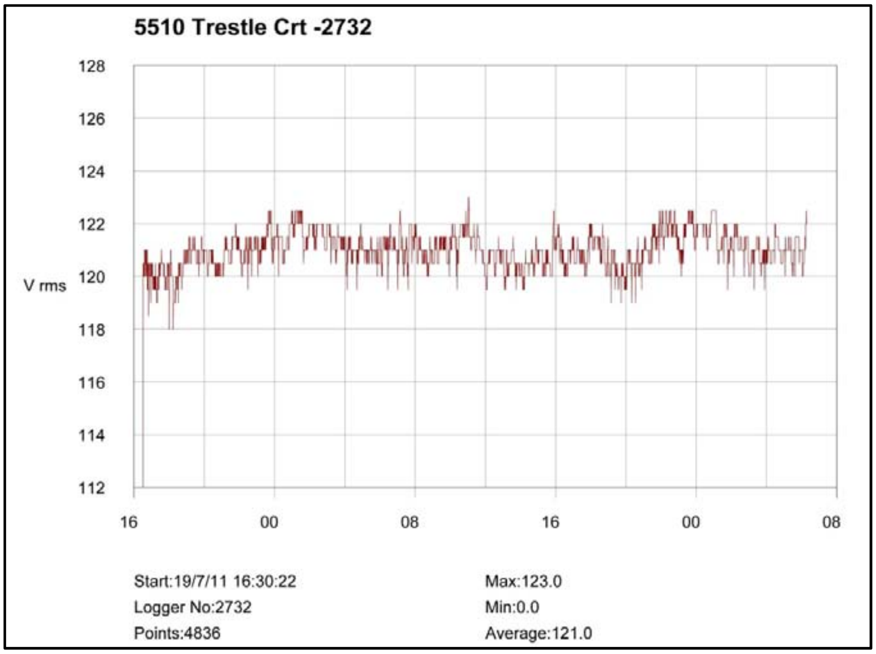

Figure 5 - DG Bell, Feeder 2

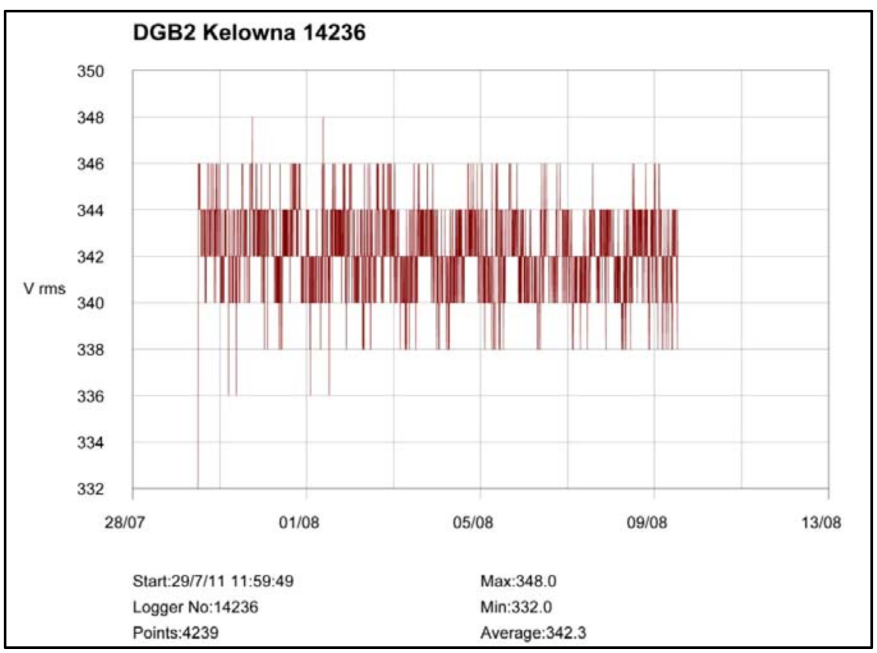

Figure 6 - DG Bell, Feeder 2, 600V 3Ø

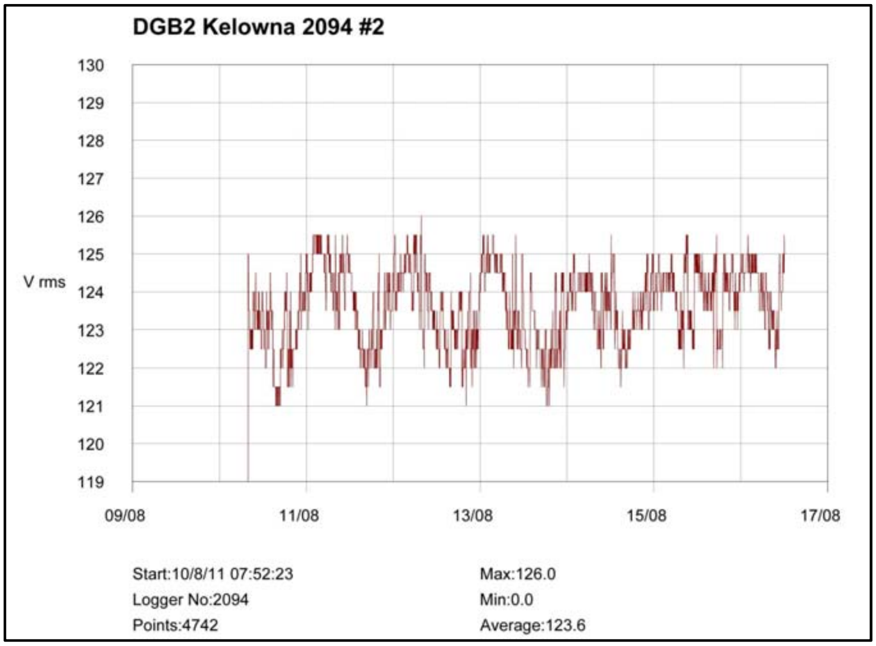

Figure 8 - DG Bell, Feeder 2

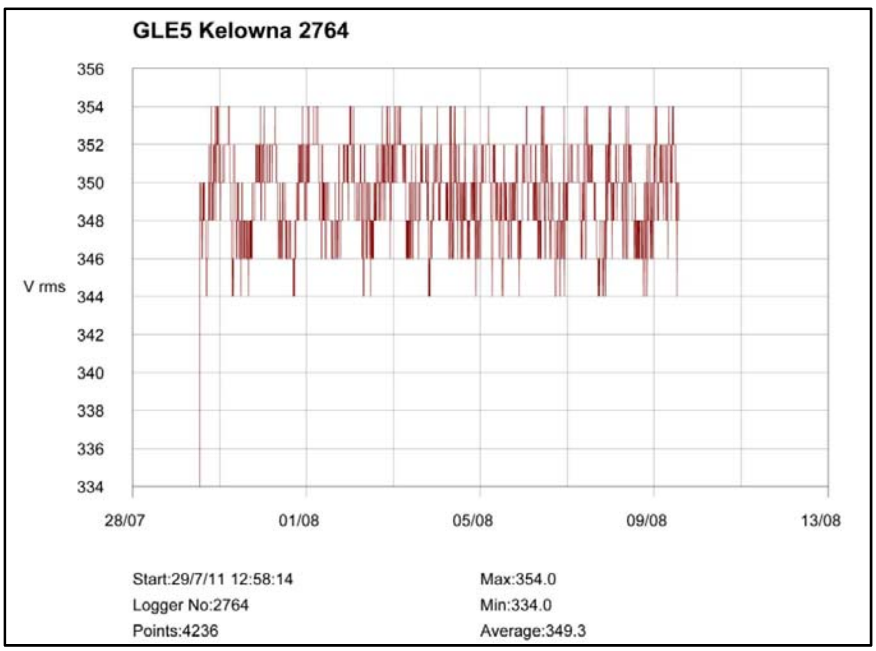

Figure 7 - Glenmore, Feeder 5, 600V 3Ø

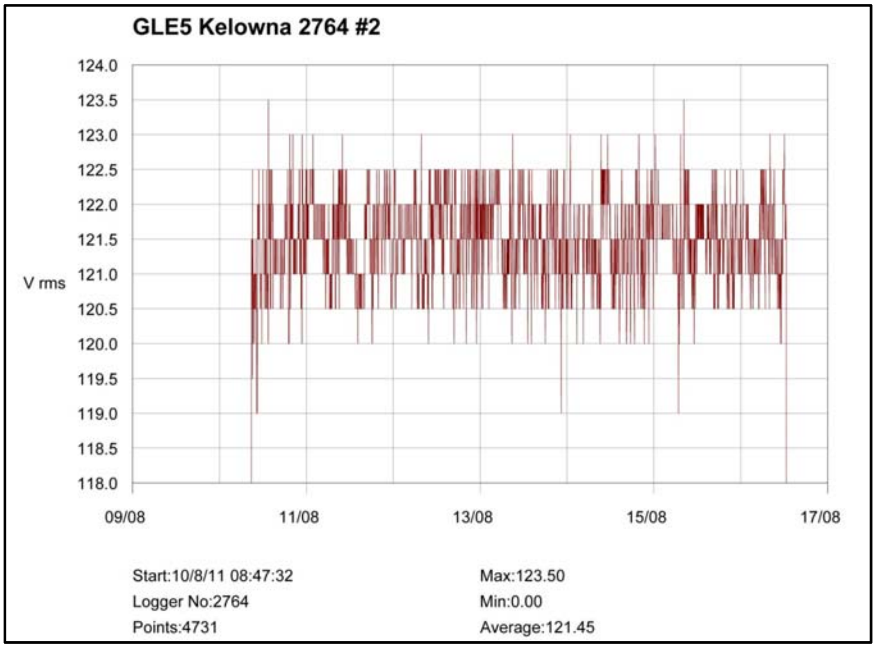

Figure 10 - Glenmore, Feeder 5

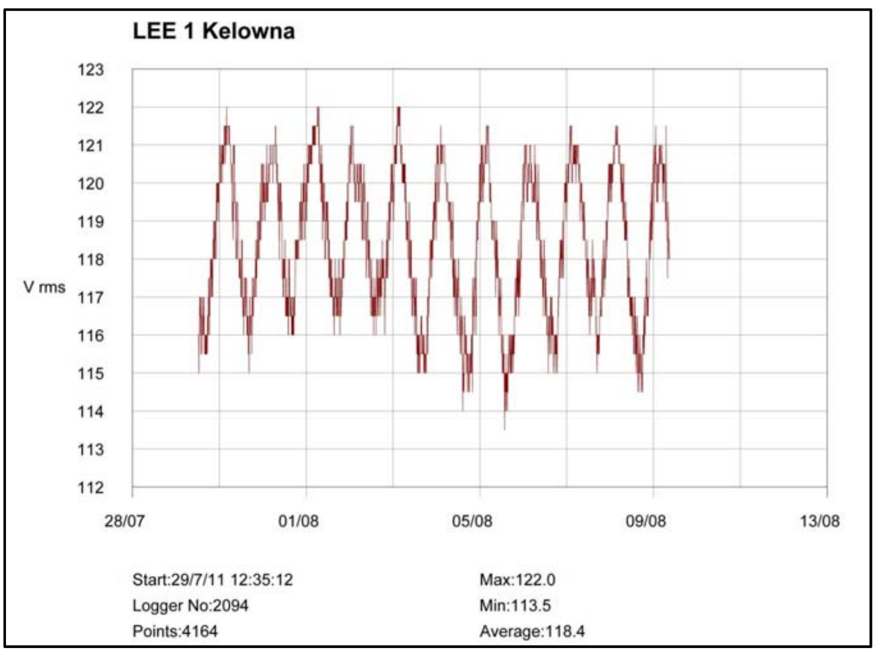

Figure 9 - Lee Terminal, Feeder 1

South Okanagan Feeders

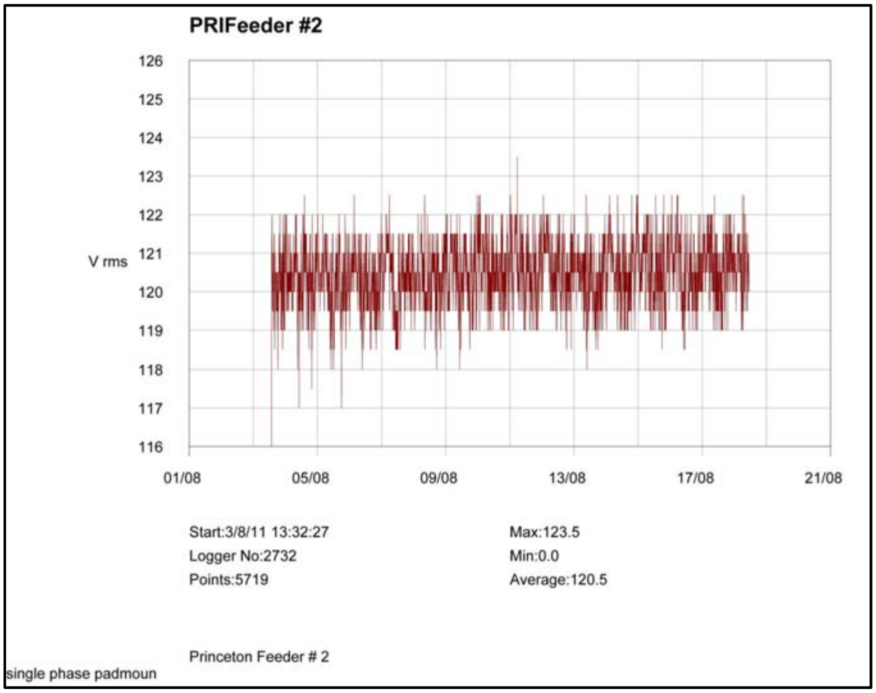

Figure 11 - Princeton, Feeder 2

Boundary_Kootenay Feeders

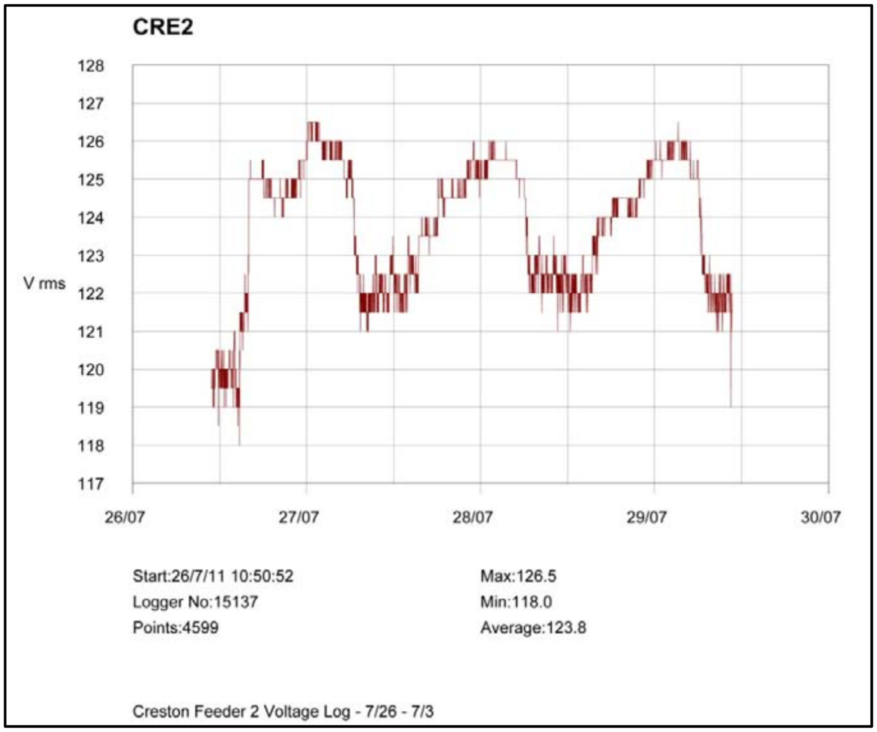

Figure 12 - Creston, Feeder 2

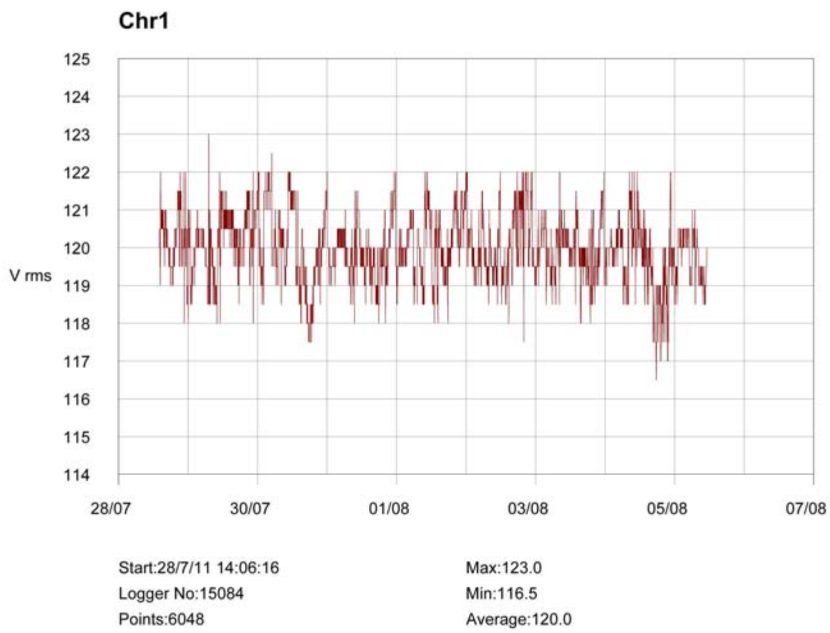

Figure 13 - Christina, Feeder 1

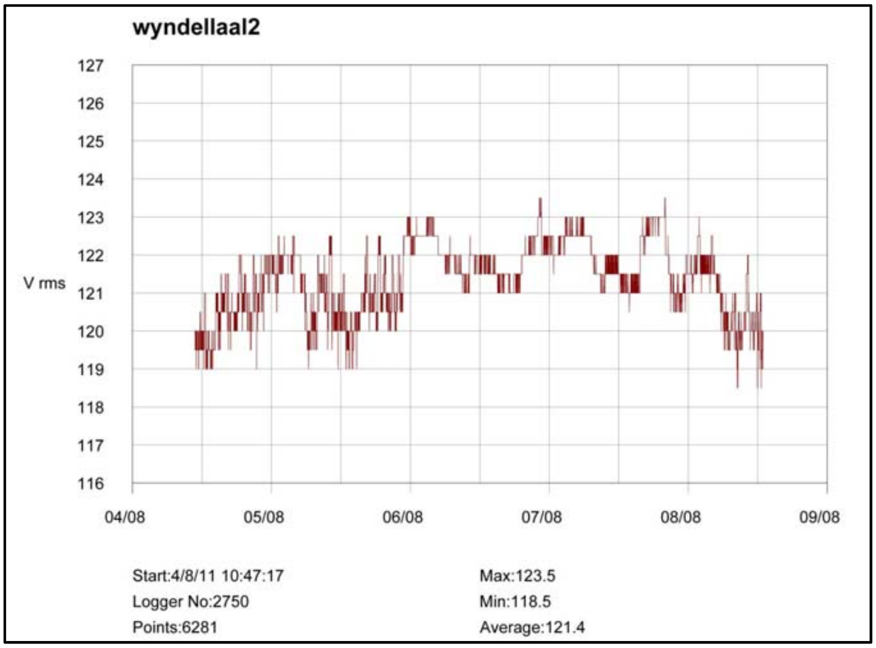

Figure 14 - Lambert, Feeder 2

Appendix F – About the Author

Tom Wilson (IEEE - M' 1972, SM' 1985) is a native of Spokane, Washington. After serving in the US Navy as an Electricians Mate, he earned his BSEE from Washington State University in 1971. While working as a Substation Operations Engineer at Pacific Gas and Electric Company, he attended the University of Santa Clara studying MSEE courses. In 1982 he earned his MBA from Gonzaga University. He worked as an Electrical Engineer for Kaiser Aluminum and Chemical Corporation and as an Industrial Control Application Engineer for Reliance Electric. He has also served as a District Engineering Manager for Rockwell Automation and as a Drive Service Center Manager for Omron Electronics.

He is the founder of PCS UtiliData, a Smart Grid solutions provider, specializing in automated Volt/Var Optimization for utilities and industrial facilities to reduce demand and increase energy efficiency. After serving as its president for 24 years he now serves as it CTO and Founder. He holds patents in the U. S. and in Canada for automated voltage control and is a licensed Registered Professional Engineer in both Illinois and Missouri.

A founding member of the Control Systems Integrators Association he has led the company in winning several national and regional awards including the first national CSIA "Charlie Bergman" award, the Rockwell Automation "Circle of Excellence" award" and the IEEE Region VI "Small Business of the Year" award.

He has served on the Western Power Delivery Automation Conference Program Committee (WPDAC) sponsored by Washington State University and also on the Western Energy Institute (WEI) Service Company Committee.

Wilson has been active in the IEEE serving with the Spokane Section in several offices including Section Chair and IAS Chair. During his tenure as IAS Chapter Chair the Spokane Chapter was awarded the Outstanding Small Joint Chapter Award by the IAS. He currently serves on the PES DA Working Group Volt/Var Task Force.

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Appendix C-3

BC Hydro Smart Meter Press Release

Appendix C-3

Press Release

January 18, 2011

BC Hydro Smart Metering Program to provide major benefits to customers

Enhanced system safety, reliability and more

VANCOUVER – As part of BC Hydro's ongoing effort to keep customers informed and engaged in the opportunities offered by smart meters, the utility released Tuesday the Smart Metering and Infrastructure Business Case.

The Smart Metering Business Case [PDF, 1 Mb] details how the program delivers over $500 million in net benefits over the next 20 years. Net benefits mean lower rates for customers in the long-term, reducing them below what they would otherwise be in the absence of BC Hydro's investment in the program.

The document includes comprehensive details about the program's customer and financial benefits, including the modernization of B.C.'s electricity system, improved safety and reliability, reduced electricity theft, and the ability to provide customers with new tools to manage their energy use and ultimately save money.

"The system is the backbone of our economy and smart meters are essential to keeping our system affordable, safe and reliable," said Minister of Energy Steve Thomson. "With smart meters, BC Hydro customers will receive better service and new tools to manage their own energy use. The financial benefits are clear, BC Hydro's business case details how the program pays for itself by making our system more efficient and reducing electricity theft, which currently costs ratepayers up to $100 million a year."

The Smart Metering Program involves replacing existing customer meters with smart meters starting later this summer and upgrading the technology and telecommunications infrastructure that BC Hydro uses to manage the electricity system in a reliable, safe and cost-effective manner.

Major program benefits include:

- Improved safety and reliability;
- Enhanced customer service;
- Reduced electricity theft;
- Improved operational efficiency and reduced wasted electricity;
- Greater customer choice and control; and
- Modernization of B.C.'s electricity system.

"Keeping our customers up-to-date with the latest information about the Smart Metering Program is a top priority for us as we prepare to install the meters later this year," said Bev Van Ruyven, BC Hydro Deputy CEO and Executive Vice President. "As B.C. continues to grow, so has our need for more electricity and a modernized, safe and reliable grid to supply power to our customers.

"The Smart Metering Program is a key component of our commitment to replace and upgrade aging facilities and systems across the province as we take steps to plan for future generations and keep rates as low as possible."

Smart meter deployment across the province will include a number of elements. First, customers will begin to receive notification early this year that meters are coming to their community and information about what they can expect. Meter deployment will begin in mid 2011 and conclude at the end of 2012.

For most customers, installation will be simple and will only take a matter of minutes. Then, in mid-2012, customers will receive information about in-home feedback options that will provide them with the ability to monitor their energy use in near-real-time and make adjustments to save money.

Appendix C-3

A backgrounder including the top 10 questions asked about smart meters follows. For more information, see the Smart Metering and Infrastructure section of bchydro.com.

Related links, information and media resources:

- Smart metering essential to modernizing BC Hydro's grid
- News release with images, video and audio clips
- Smart Metering and Infrastructure Business Case [PDF, 550 Kb]
- Media Contact info
- Backgrounder: Top 10 Questions on Smart Meters

About BC Hydro:

Fifty years ago, British Columbians turned to BC Hydro to build the clean electricity system they count on to power BC's economy, create jobs in every region, and keep the lights on. Now BC Hydro is building again for the next 50 years. B.C. continues to grow and so has the need for more electricity. That's why BC Hydro is building, renewing, and encouraging conservation to meet today's needs and those of future generations, and today's announcement of the smart metering business case is an example of this. In 2011 BC Hydro is celebrating 50 years of providing power for British Columbians, and inviting them to help prepare for the next 50 years.

For further information, contact:

BC Hydro Media Relations
Direct: 604 928 6468

BACKGROUNDER

Top 10 Questions on Smart Meters

1. **Why do we need smart meters?**
The Smart Metering Program will make our electricity system safer, more reliable, it will improve customer service, reduce electricity theft, and it will create the foundation for a modernized electricity grid that can accommodate new technologies. It's also important to note that existing electro-mechanical meters are nearly obsolete and will not be manufactured much longer.

2. **Will my rates go up because of smart meters?**
No, the project will pay for itself and in fact delivers over $500 million in benefits over 20 years. These benefits mean lower rates for customers, reducing them below what they would otherwise be in the absence of BC Hydro's investment in the program.

3. **Are you introducing time of use rates?**
BC Hydro will maintain the existing rate structure throughout the meter installation period. The business case for the smart metering program includes only voluntary time-of-use rates in the estimate of the program's benefits. BC Hydro is in the early stages of considering rate structures that will offer incentives for customers to use less electricity. Any proposal for new rate structures will have to be reviewed and approved by the independent BC Utilities Commission.

4. **Will customers have to save energy for the Smart Metering Program to work?**
No, more than 80 per cent of the benefits from the program will be delivered through operational efficiencies within BC Hydro such as theft reduction and meter reading optimization. That means customers don't have to take action for the program to pay for itself.

5. **How long will it take to install a smart meter at my house?**
Installation takes only a few minutes and most customers will not need to be home when the exchange occurs.

6. **When will I get my smart meter?**
Installation will begin this summer and customers will receive advance notification that BC Hydro will be exchanging their existing meter with a smart meter.

7. **Doesn't BC Hydro already know when the power is off?**
No, BC Hydro is not aware of power outages for residential customers and small businesses until customers call to inform us that their power is out. Smart meters will pinpoint problems quickly and automatically which will help get the power back on faster and safer.

8. **Will BC Hydro be able to tell when I'm home and what I'm doing?**
No, BC Hydro will only be getting aggregated hourly data which informs us how much electricity was used. More specific information about household use is limited to the "home area network" used by customers who choose in-home display devices. All of this data is protected by extensive security and privacy provisions in the infrastructure including the use of data encryption similar to that used by online banking systems.

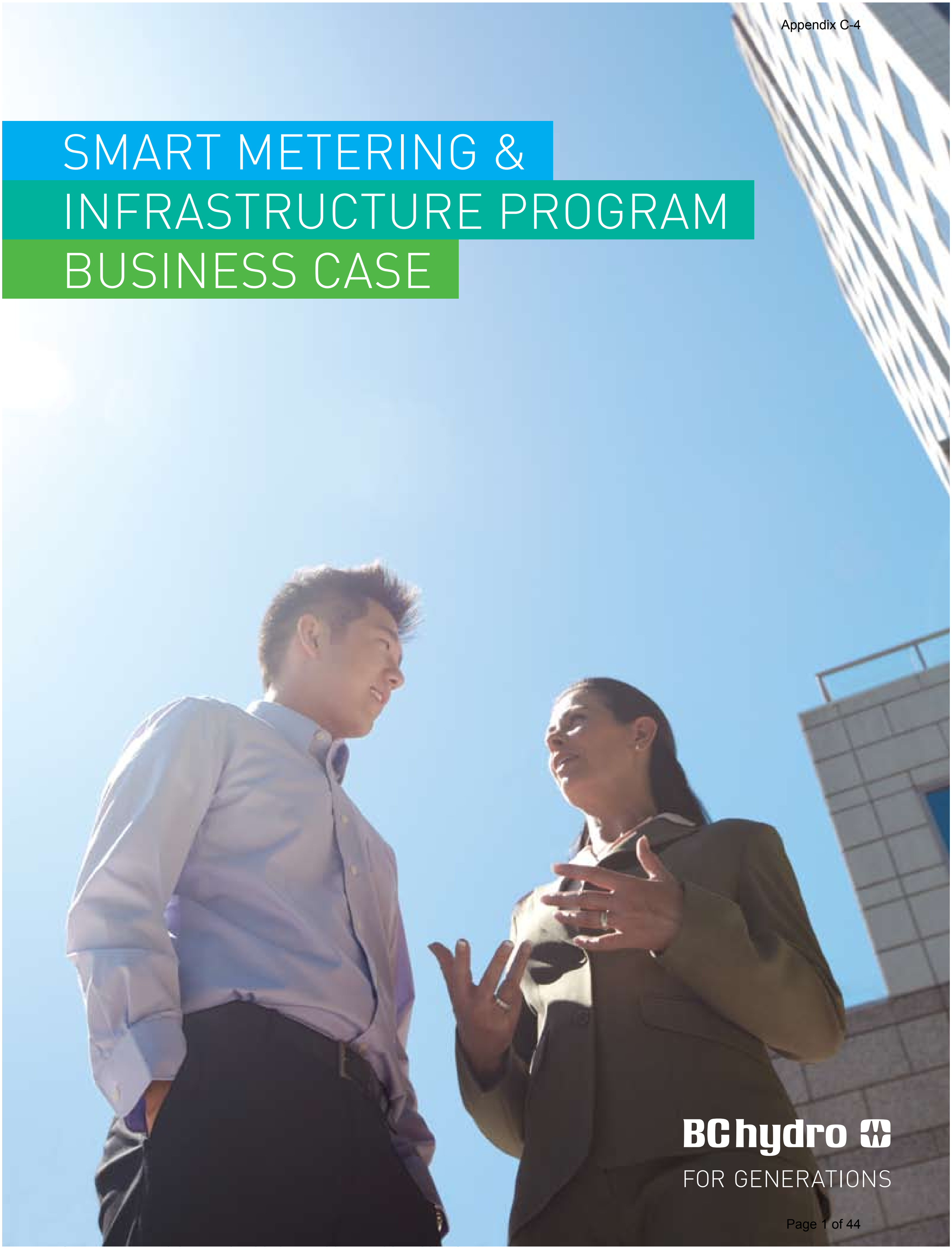
9. I**s the radio frequency emitted by smart meters safe?**
Yes, smart meters emit less radio frequency than a baby monitor.

10. **What have you learned from the experiences of other jurisdictions?**
We have benefited by learning from the implementation experience of other utilities. Examples include using proven meter technology, maintaining existing rate structures through the installation period and dedicating more resources to ensuring customers are informed throughout the process.

Appendix C-4

BC Hydro Smart Meter Business Case

SMART METERING & INFRASTRUCTURE PROGRAM BUSINESS CASE



BC hydro

FOR GENERATIONS

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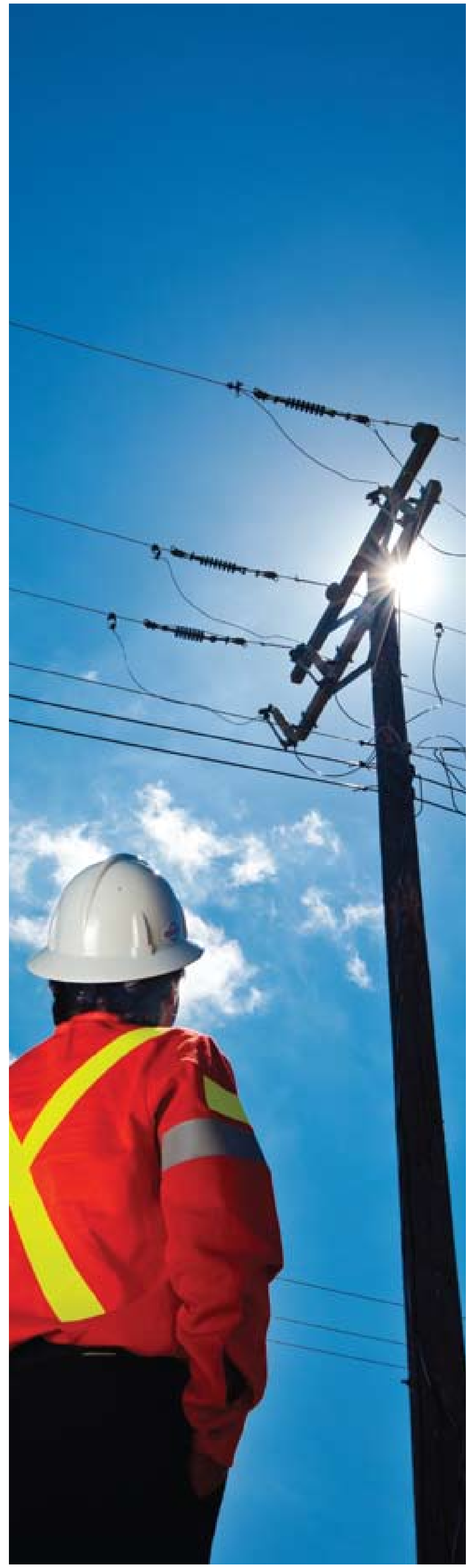


EXECUTIVE SUMMARY

In 2011, BC Hydro will begin implementation of the Smart Metering Program. The Smart Metering Program will pay for itself through reduced theft of electricity, energy savings, and operating efficiencies.

BC Hydro's Smart Metering Program is an important foundational step in the modernization of BC Hydro's electricity system. The program involves replacing existing customer meters, now becoming obsolete, with a comprehensive smart metering system. This system includes the technology and telecommunications infrastructure needed for BC Hydro to continue to manage the electricity system in a reliable, safe and cost-effective manner.

Substantial Benefits to Customers

The Smart Metering Program will:

- **Improve safety and reliability** through faster and precise outage notification and a reduction in the damage caused by illegal electricity diversions.
- **Enhance customer service** by reporting electricity use more accurately, eliminating estimated bills, simplifying the process of opening and closing an account when moving, and reducing the need for onsite visits by field crews.
- **Reduce electricity theft** that currently amounts to approximately $100 million a year in lost revenue—costs that are borne by all legitimate BC Hydro customers.
- **Improve operational efficiency and reduce wasted electricity** through voltage optimization. Lower operating costs are passed on to all customers in rates.
- **Support greater customer choice and control** by offering optional in-home feedback tools that provide direct and timely information to customers about their electricity consumption.
- **Help modernize British Columbia's electricity system** by replacing nearly obsolete meters, and creating the foundation for supporting new uses of electricity such as electric vehicles, customer generation and microgrids.

Implementation to be Prudent and On Budget

Smart meter installation will be on time and on budget. Installation of smart meters will begin in 2011 and **will be complete by the end of 2012** with other elements of the program implemented through 2014.

Security, privacy and safety features in smart metering infrastructure will include encryption of data similar to that used by online banking systems, and mandatory criteria was included in all procurement processes to ensure only proven technologies were considered.

BC Hydro will **maintain existing rate structures** throughout the meter installation process. Any new rate structures will be subject to public consultation and review by the independent British Columbia Utilities Commission.

The BC Utilities Commission will review the prudency of BC Hydro's decisions and actions in relation to the implementation of the program.

Benefits for BC Hydro Customers Exceed Costs

The Smart Metering Program business case shows that the benefits exceed the cost by $520 million in today's dollars. These benefits are attributed to four primary areas including:

- **Operating Efficiencies—**More efficient use of distribution assets and streamlining of business processes, reducing operating and future capital expenses;
- **Energy Savings—**Lower electricity use through improved system control, operational efficiencies and providing customers with new options to better manage their electricity consumption;

- **Revenue Protection—**Includes both recovery of revenue (e.g. back-billing) and prevention of future potential revenue loss (e.g. reduced theft); and
- **Capacity Savings—**Lower electricity use at certain key periods, which reduces peak demand and capacity constraints.

Almost 80 per cent of the quantified benefits delivered through the Smart Metering Program result from BC Hydro activities. If customers take advantage of the conservation tools to be implemented by the Smart Metering Program, the overall benefits increase significantly.

Positive Net Present Value

The Smart Metering Program business case has a net present value (NPV) of $520 million through F2033. The NPV remains positive even if all costs are incurred but only the BC Hydro operational efficiencies are realized. The NPV also remains positive if all benefits are achieved at the low end of the estimated benefit range.

The following table summarizes the key financial components of the Smart Metering Program business case, resulting in the positive NPV of $520 million.

BUSINESS CASE SUMMARY IN NOMINAL AND PRESENT VALUE

Business Case Summary	Nominal Value ($M)	Present Value ($M)
Gross Benefits attributable to Smart Metering Program, less costs related to the achievement of individual benefits	$4,658	$1,629
Less: Ongoing operating and maintenance expenses and incremental asset replacement capital	(745)	(330)
Less: Smart Metering Program Costs	(930)	(779)
Total Net Value for the period F2006 to F2033	**$2,983**	**$520**

Rate Analysis

Net benefits will flow into lower rates for customers, reducing them below what they would otherwise be in the absence of BC Hydro's investment in the program.

KEY TIMELINE FOR CUSTOMERS

Stage	Timeframe	Key Activities
Program Information	**Underway and throughout the program**	Customers have access—through the BC Hydro website, bill inserts, and community events—to information about the Smart Metering Program, the smart metering system that will be installed, how it works, and other topics of customer interest. Customers can share their feedback, concerns, and interest directly through calling, email, community events, and customer research.
Installation of Smart Meters	**Mid 2011 through 2012**	Customers receive information packages before smart meters are installed in their community[1].
In-home Feedback Tools	**2012 through 2014**	Customers receive information highlighting new options available to support their energy conservation efforts. Customers receive a rebate for a basic in-home display device that can be redeemed at select stores. Customers will have access to information about their electricity use, up to the previous day, through a secure Power Smart website.

[1] Smart meter installation will begin simultaneously in communities throughout the province.

INTRODUCTION

BC Hydro was created 50 years ago to plan, build and deliver a clean, reliable supply of electricity to homes and businesses throughout our growing province. Investments in dams, generating stations and transmission and distribution networks ensured a stable supply of electricity for generations of British Columbians that followed.

Thanks to this visionary planning and investment, BC Hydro has been reliably meeting our province's growing energy needs for the last 50 years. However, vitally important elements of our electricity system infrastructure are reaching an age when significant investment is required to keep our system reliable.

At the same time that our electricity system is aging, demand for power is growing. The latest forecasts show demand for electricity in British Columbia growing by as much as 40 per cent over the next 20 years. That's the equivalent of adding five more cities the size of Vancouver to our system.

The Need for Smart Metering

Home electronics, consumer products, and manufacturing automation are just a few examples of how technology has advanced, leading to more electricity use than ever before.

Customers are using more technology than ever before.

The electricity system that supplies the energy to support this demand hasn't kept pace. For example, meters—the devices that measure how much electricity customers are using—have not fundamentally changed since the 1950s. In fact, the electro-mechanical meter is becoming obsolete and will soon no longer be manufactured.

Today, BC Hydro's meters provide a one-way flow of information (from the customer to the utility) that is very basic and not timely. For example, residential and commercial customers might be surprised to learn that BC Hydro does not know of outages until, and unless, customers call to tell us the power is out.

The electricity system must be updated to ensure that BC Hydro can continue to provide customers with safe and reliable electricity.

Modernizing British Columbia's electricity system will also ensure that advances in technology can be accommodated. Without new investment in technology and systems the 20th century electricity system will be unable to support 21st century innovations such as solar panels, electric vehicles and increased customer service options.

Utilities around the world are upgrading their electricity systems and adopting smart meters to enhance customer service, improve reliability and make their operations more efficient. By 2015, 250 million smart meters will be installed worldwide[2].

In short, investing in smart metering infrastructure is as important as renewing and reinvesting in our dams and generating facilities.

Over the next three years, BC Hydro will be investing $2 billion per year to build and renew dams, generating facilities, and transmission and distribution networks to ensure a safe and reliable supply of power continues to flow to B.C.'s homes and businesses. A key component of this investment is the Smart Metering Program.

WHAT IS THE SMART METERING PROGRAM?

Smart meters are part of an integrated program that will pay for itself through reduced theft of electricity, energy savings, and operational efficiencies. This means that over the long term the Smart Metering Program will reduce customer rates below what they would otherwise be in the absence of BC Hydro's investment in the program.

BC Hydro's Smart Metering Program is an important foundational step in the modernization of BC Hydro's electricity system. It involves replacing existing customer meters with smart meters and upgrading the technology and telecommunications infrastructure that allows BC Hydro to manage the electricity system in a reliable, safe and cost-effective manner.

The program consists of:

- Smart meters are digital meters that allow two-way communications between a customer's meter and BC Hydro through a secure connection that captures the amount of electricity consumed and when. For more information about smart meter safety, security, and privacy, see Appendix 1.
- Optional in-home feedback tools to provide up-to-date energy consumption and price information directly to residential and commercial customers providing them with more choices to actively manage their electricity use.
- Systems and infrastructure to reduce electricity theft that will help to create safer communities and mitigate rate impacts borne by legitimate customers .
- Advanced telecommunications infrastructure to allow BC Hydro to more accurately measure the actual flow of electricity through the system and support advanced electricity system management and customer applications.
- Information technology systems to integrate meter reading data into BC Hydro's customer billing, load forecasting and outage management systems.

The broad scope of the Smart Metering Program is described further in Appendix 2.

Smart meter installation will begin in 2011 and will be complete by the end of 2012. Customers will be notified in advance when the meter exchange will take place in their community. While customers do not need to be home for the meter exchange, they do need to ensure technicians have access to their current meter. There will be a brief service interruption during the meter exchange, which takes only minutes. Once smart meters are installed, customers will have the option of adopting in-home feedback tools. For example:

- Customers can choose to take advantage of incentives to purchase an in-home display device that provides near real-time information about their energy use; and
- All customers will have access to a secure website that provides prior day consumption data and other tools to analyze electricity use.

Your new smart meter will replace the existing meter on the outside of your home or in your meter bank if you live in a multi-dwelling unit. If you choose an optional in-home display, the smart meter can send real-time consumption and price information directly to you.

[2] Pike Research, November 2009

BENEFITS

BC Hydro's Smart Metering Program delivers substantial benefits to customers. Specifically, the program will:

- Improve safety and reliability;
- Enhance customer service;
- Reduce electricity theft;
- Improve operational efficiency and reduce wasted electricity;
- Support greater customer choice and control; and
- Help modernize British Columbia's electricity system.

Power line technician during a Campbell River snowstorm.

Improve Safety and Reliability

Keeping customers' power on requires BC Hydro to dispatch crews day and night, under all types of weather conditions to search for, assess, and repair faults on the electricity system. The current metering infrastructure does not provide any residential customer outage information to BC Hydro. In fact, BC Hydro is not aware of outages until customers call in to inform us that the power is out.

Due to this lack of detailed and specific outage information, field crews engage in significant travel to identify the location and cause of an outage, increasing personal risk as well as delaying restoration times. During storm season, the outages are frequently at multiple locations and the risk is even higher due to the need to drive and fly under adverse conditions.

In addition, theft of electricity is occurring in increasingly dangerous ways, posing major safety risks to the general public, first responders and BC Hydro employees through the threat of fire and electrocution. For example, in Surrey, approximately 50 per cent of marijuana growing operations inspected by the fire department involved diversion of electricity from BC Hydro distribution lines. Theft also causes strain on the distribution infrastructure resulting in an estimated 100 premature transformer failures a year.

Smart meters will decrease illegal electricity diversion (shown here), keeping neighbourhoods safe from fires like the one that destroyed this house.

Photo credit: Vancouver Fire and Rescue Services and Vancouver Police Department

The Smart Metering Program will deploy new technologies, better analysis and notification tools, and automated decision-making that will result in improved public and employee safety and shorter outage restoration times. Benefits include:

- **Faster outage notification—**Real-time outage notification provided automatically by smart meters will serve to pinpoint problems quickly and specifically, reducing the amount of travel required under adverse conditions and accelerating the restoration process.
- **Reliable restoration notification—**Allowing field crews to quickly confirm the outage has been addressed instead of driving along the electricity lines to look for secondary outage problems.
- **Reduced risk and fewer outages from electricity diversions—**By helping identify potential electricity diversions in a more consistent and automated way, the Smart Metering Program will reduce safety risks and customer outages that are caused by premature transformer failures.

Enhance Customer Service

Smart meters capture more accurate and detailed electricity use information, which will result in enhanced customer service including:

Call centre agents will have more accurate information available to address customer questions related to their bills, electricity use, or opportunities for energy savings.

- **More accurate meter readings—**Anomalies in reported electricity use can be reconciled quickly and accurately with the use of hourly meter data rather than bi-monthly meter reads or estimated bills.
- **Elimination of estimated billing—**With smart meters in place, customer bills will be generated from actual electricity use, not from estimated readings based on profiles.
- **More streamlined moving procedures—**With automated meter reads available on request, customers can receive an accurate, up-to-date final bill and will no longer have to deal with transferring bill amounts when they move into or move out of a home or business.
- **Better informed customer service representatives—**BC Hydro call centre employees will have substantially more accurate information available to address customer questions related to their bills, electricity use, or opportunities for energy savings.
- **Increased privacy and convenience—**Customers will no longer need to provide meter readers with regular access.
- **Reduced onsite visits—**Automated meter reading, automated connection services, and more information available for problem solving, will reduce the need for BC Hydro to send crews to customer homes and businesses resulting in direct savings that will be passed on to customers.

Reduce Electricity Theft

Legitimate customers bear the cost of electricity theft, which has grown significantly from approximately 500 GWh in 2006 to an estimate of at least 850 GWh today—that's enough power to supply 77,000 homes for a year and amounts to approximately $100 million a year in energy cost.

Although BC Hydro has identified over 2,600 electricity thefts over the past five years, identifying and confirming theft is a time-consuming, inefficient and expensive manual process. While BC Hydro cannot reasonably expect to eliminate all electricity theft, augmenting the current manual process with new technology will substantially reduce current levels of theft by:

Electricity theft results in higher rates for legitimate customers.

- **Theft detection—**New distribution system meters (different from those to be installed at customer homes or businesses) located at key points on BC Hydro's system will measure electricity supplied to specific areas. Combined with software tools to enable electricity balancing analysis, distribution system meters will help BC Hydro identify electricity theft more accurately and address it more quickly.
- **Tamper detection—**Smart meters have a tamper detection feature that automatically notifies BC Hydro if they have been removed from the wall or otherwise manipulated.

Reducing electricity theft delivers tangible financial benefits through increased revenue, revenue recovery (e.g. back-billing), and reduced cost of energy.

Improve Operational Efficiency and Reduce Wasted Electricity

Currently, BC Hydro transmits more electricity than needed by customers to ensure there is acceptable power quality delivered to every customer. Reducing wasted electricity benefits all customers through lower operating costs.

The amount of excess energy required can be substantially reduced with better monitoring and control over the distribution system including:

- **Voltage optimization—**Use voltage information collected from smart meters to make existing electricity control devices (voltage regulators, capacitor banks, and transformers) along the distribution system more efficient. Simply put, less electricity will be required to be transmitted to maintain expected power quality, resulting in less electricity having to be generated or purchased, which in turn, lowers costs.
- **Efficiencies in meter reading, meter sampling, distribution system maintenance, outage management, and load research—**Will significantly reduce operating costs.

Support Greater Customer Choice and Control

Today, customers have few tools to manage their electricity use because the current meters do not capture enough information. Without specific and timely information, it is difficult for customers to take advantage of new service options or make informed decisions to actively manage electricity in their own circumstances.

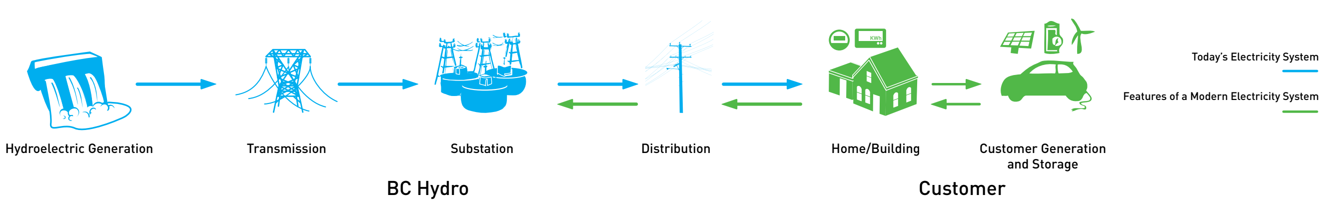
Research has shown that electricity is typically not something customers regularly think about, and that increasing customer awareness by enabling them to view their own consumption in a timely manner can achieve electricity savings of up to 15 per cent. See Appendix 3 for more information related to research.

More information and control will help customers to save money—and help to achieve BC Hydro's goal of meeting two-thirds of incremental electricity demand through conservation by 2020.

Optional in-home feedback tools will provide customers with more choices and control.

The Smart Metering Program will enable customers to have greater choice and control of their energy use through:

- **Optional in-home feedback tools—**BC Hydro will provide incentives for customers to adopt market available in-home displays, programmable thermostats, and energy management software products.
- **Power Smart website—**Customers will also have the option of accessing their own secure consumption information through BC Hydro's expanded Power Smart website.
- **Rate Options—**Smart meters capture information that will enable BC Hydro to design new rate structures that encourage conservation during peak periods, such as voluntary time-of-use. The design of these rates will involve consultation with customers and will be subject to review and approval by the BC Utilities Commission.



Help Modernize BC Hydro's Electricity System

BC Hydro's electricity system, including the current base of electromechanical meters, has changed very little over the past 50 years. These older style meters are becoming obsolete, as meter vendors switch to producing smart meters.

Upgrading to a smart metering system is a key foundational step in modernizing BC Hydro's overall electricity system. Additional measurement points throughout the electricity system combined with the ability to measure electricity to and from a customer site will enable:

- **Support for new customer applications—**Advanced telecommunications infrastructure will support advanced electricity system functions and emerging applications like customer generation and microgrids.
- **Support for large-scale clean energy initiatives—**Implementation of smart metering and network operations functions will help BC Hydro to manage new uses for the electricity system such as electric vehicles, electrification of public transportation, community-based generation, and integration of renewable fuel sources. For example, with a more modern electricity system, customers who invest in solar panels, or other clean sources of electricity, could sell excess power back to BC Hydro, or draw electricity from their electric vehicles during a power outage.

With a more modern electricity system, customers who invest in solar panels, or other clean sources of electricity, could sell excess power back to BC Hydro.

FINANCIAL ANALYSIS

The Smart Metering Program business case, originally developed beginning in 2006, was most recently updated in December 2010 and reflects updated benefit assumptions as well as increased cost certainty as a result of the procurement activity during 2010. This section summarizes the benefits, costs, and net present value included in the business case.

Quantified Benefits

The Smart Metering Program business case includes approximately $1.6 billion in quantified benefits (present value), to be realized over 20 years. These benefits are attributed to four primary areas including:

- **Operational Efficiencies—**More efficient use of distribution assets and streamlining of business processes, thereby reducing operational and future capital expenses;
- **Energy Savings—**Lower electricity use through improved distribution system control, efficiencies and reduced consumption by customers;
- **Revenue Protection—**Includes both recovery of revenue and prevention of future potential revenue loss through reduced theft; and
- **Capacity Savings—**Lower electricity use at certain key periods, which reduces peak demand and capacity constraints.

Almost 80 per cent of the quantified benefits delivered through the Smart Metering Program result from operational efficiencies within BC Hydro. If customers take advantage of the conservation tools offered through the program, the overall benefits increase significantly. Additional information regarding each specific benefit stream, including key assumptions, is provided in Appendix 4.

In addition to the quantified benefits, the Smart Metering Program will deliver numerous other benefits that have not been quantified in this business case or cannot be monetized. A summary of these additional benefits can be found in Appendix 5.

The operational savings delivered by the Smart Metering Program will benefit all BC Hydro customers. As a publically-owned cost-recovery utility, all benefits realized by BC Hydro are passed on to customers and will be reflected in rates. In addition, customers will not be billed separately for the cost of the new smart meters.

TABLE 1: PROGRAM BENEFITS AS OF DECEMBER 2010—IN PRESENT VALUE

Type of Benefit	Description	Expected Benefit ($ Million)	Sensitivity Range[3] ($ Million)
Operational Efficiencies, Avoided Capital	Meter Reading Automation	$222	$182–$247
	Meter Sampling	$61	$56–$66
	Remote Re-connect Automation	$47	$42–$52
	Distribution Asset Optimization	$15	$12–$25
	Outage Management Efficiencies	$10	$5–$15
	Continuous Optimization and Load Research	$6	$2–$10
	Call Center & Billing	($2)	($4)–$0
Energy Savings	Voltage Optimization—Commercial Customer Sites	$108	$48–$148
	Voltage Optimization—Distribution System	$100	$85–$150
Revenue Protection	Theft Detection	$732	$632–$832
Derived from BC Hydro Operational Efficiencies (~80%)		**$1,299**	**$1,060–$1,545**
Capacity Savings	Voluntary Time-of-use Rates	$110	$30–$250
Energy Savings	Conservation Tools (in-home feedback tools)	$220	$170–$270
Increased Customer Conservation (~20%)		**$330**	**$200–$520**
Total Quantified Benefits		**$1,629**	**$1,260–$2,065**

Benefits Realization

The Smart Metering Program is a large and complex project designed to deliver significant benefits from across several business groups at BC Hydro. The benefits described in this business case pay for the investment in the program. BC Hydro is implementing a formal benefit realization framework, base-lined with the benefit streams identified in this business case, to ensure accountability and transparency in the measurement and reporting of the benefits over time.

[3] Sensitivity ranges identified for each benefit bracket the probable benefit outcomes. The ranges are based on an assessment of the upside and downside in variability associated with the key drivers behind each benefit.

TABLE 2: SMART METERING PROGRAM BUDGET

$ millions

Initiation Phase (Completed F2007)			**1.4**
Identification Phase (Completed F2008)			**8.9**
Definition Phase (Completed F2011)			**38.8**
Implementation Phase (F2011–F2014)			
Smart Metering System			
	Architecture and Design	8.6	
	Assets: Smart Meters, Telecommunications, Software	256.0	
	Deployment Activities	126.5	
Sub-Total: Smart Metering System			**391.1**
Solution Integration (Information Technology)			
	Architecture and Design	3.2	
	Assets: Meter Data Management System and Other Applications	7.9	
	Implementation Activities	49.8	
Sub-Total: Solution Integration (Information Technology)			**60.9**
Theft Detection			
	Architecture and Design	2.6	
	Assets: Distribution System Meters, Application Software	62.7	
	Deployment Activities	45.2	
Sub-Total: Theft Detection			**110.5**
Conservation Tools			
	Architecture and Design	2.4	
	Assets: In-Home Displays, Website, Software Supporting Rates	18.4	
	Rebate Program	42.0	
Sub-Total: Conservation Tools			**62.8**
Grid Modernization Infrastructure Upgrades			
	Architecture and Design	1.9	
	Assets: Advanced Telecom Devices and Applications	33.0	
	Deployment Activities	19.3	
Sub-Total: Grid Modernization Infrastructure Upgrades			**54.2**
Program Delivery Activities			
	Project Management and Controls	22.2	
	Safety, Security, Privacy Governance	1.1	
	Finance and Regulatory	2.4	
	Customer Research, Engagement and Outreach	8.6	
	Contract Management	2.7	
Sub-Total: Program Delivery Activities			**37.0**
Sub-Total: Implementation Phase			**716.5**
Interest During Construction			**14.4**
Contingency			**60.0**
Sub-Total			**840.0**
Reserve Subject to Board Control			**90.0**
Total: Program Authorized Amount			**930.0**

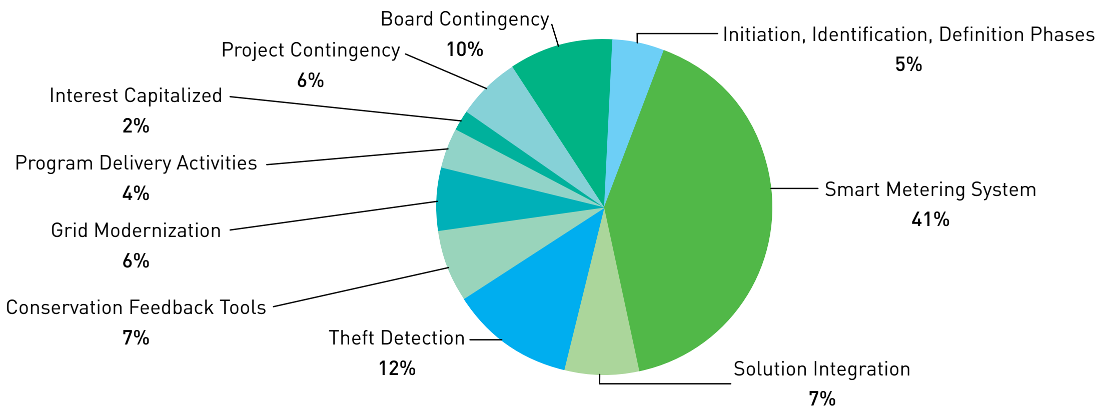


FIGURE 1: BUDGET COMPONENTS BY PERCENTAGE WITH SPECIFIC FOCUS ON THE IMPLEMENTATION PHASE

Program Costs

The total Authorized Amount for the Smart Metering Program is $930 million (nominal value) including contingency. The budget was developed using BC Hydro's standard project planning methodology, and is organized into four major phases (see Glossary for definition of phases):

- **Initiation Phase—**Completed in F2007
- **Identification Phase—**Completed in F2008
- **Definition Phase—**Completed in F2011
- **Implementation Phase—**Scheduled to be fully completed in F2014, with the installation of customer meters on track for the December 2012 date as legislated by the Province of British Columbia.

Net Present Value

The Smart Metering Program business case shows a net present value (NPV) of $520 million through F2033. The NPV remains positive even if all costs are incurred and only the BC Hydro operational efficiencies are realized. The NPV also remains positive if all benefits are achieved at the low end of the estimated benefit range. A more detailed discussion of the business case analysis can be found in Appendix 6.

The positive NPV of the Smart Metering Program will benefit all BC Hydro customers. These net benefits will flow, over time, into lower rates for customers, reducing them below what they would otherwise be in the absence of BC Hydro's investment in the program. See Appendix 7 for a discussion of the Smart Metering Program rate analysis.

RISKS

BC Hydro has put in place a Risk Management process to identify, assess, and mitigate risks that could significantly impact the Smart Metering Program. Appendix 8 provides a summary of the key risks and mitigation strategies. The procurement process employed by the program has also played a significant role in mitigating technology, cost, and schedule risk. More information about how BC Hydro has managed risk through procurement can be found in Appendix 9.

LESSONS LEARNED FROM OTHER JURISDICTIONS

BC Hydro has also managed risk through learning from others. By adopting smart meters after learning from the experience of other utilities, BC Hydro has the advantage of knowing what factors contribute to successful implementation and benefit realization. Some of these key learnings are included in Table 3.

TABLE 3: SUMMARY OF LESSONS LEARNED FROM OTHER JURISDICTIONS

Program Element	Experience of other utilities	Our approach
Technology	Some utilities were adopters of early smart metering technology which had limited capabilities and ultimately had to be replaced.	BC Hydro is taking advantage of the fact that metering technology has stabilized, and technology standards are now more open, robust and secure. BC Hydro is actively involved in numerous industry standards and policy groups as outlined in Appendix 10. BC Hydro has also included mandatory criteria in procurement packages to ensure only proven and scalable technology would be considered.
Meter Accuracy	In some jurisdictions, questions were raised about meter accuracy. Ultimately, it was determined that events such as heat waves occurring at the same time as meter installation were the main factors in perceived inaccuracies. Testing has confirmed smart meters are more accurate than electro-mechanical meters.	BC Hydro is governed by the testing requirements established by Measurement Canada, a federal agency. The installed base of meters in Canada has a very high degree of accuracy due to regular random testing.
Rates	Several utilities have chosen to implement time-of-use rates at the same time as smart meter installation, resulting in higher bills for customers.	BC Hydro will maintain existing rate structures at the same time as meter installation. BC Hydro will engage customers in the design of any new rate structures and any new or modified rates will be subject to review and approval by the BC Utilities Commission.
Customer Choice and Support	Some utilities provided few in-home feedback options and provided limited transactional information through their call centre, not offering customers adequate meter installation information or support for conservation efforts.	BC Hydro will offer incentives for customers to adopt conservation tools such as in-home displays that will provide near real-time feedback, and a secure web page that provides next day consumption data, with tools to help analyze patterns. Trained call centre agents will be available to answer specific customer questions during the meter installation period, and to provide advice on how to maximize conservation savings through the use of new in-home feedback tools when they become available.
Security and Privacy	In some cases, privacy and security considerations were implemented as an afterthought.	Privacy, security and safety features were key evaluation criteria in all procurement processes related to the Smart Metering Program. Privacy-by-Design and Security-by-Design processes are used for all design, development, and implementation activities. BC Hydro also has active and ongoing involvement with industry standards and policy groups, including those focused on security, privacy and safety standards.

KEY TIMELINE FOR CUSTOMERS

A key lesson learned from other smart meter initiatives is the importance of communication with customers. Accordingly, BC Hydro has developed a proactive approach to ensure open and frequent customer engagement. The following table provides highlights from the Smart Metering Program's customer engagement approach.

TABLE 4: KEY TIMELINE FOR CUSTOMERS

Stage	Timeframe	Key Activities
Program Information	**Underway and throughout the program**	Customers have access—through the BC Hydro website, bill inserts, and community events—to information about the Smart Metering Program, the smart metering system that will be installed, how it works, and other topics of customer interest. Customers can share their feedback, concerns, and interest directly through calling, email, community events, and customer research.
Installation of Smart Meters	**Mid 2011 through 2012**	Customers receive information packages before smart meters are installed in their community[4].
In-home Feedback Tools	**2012 through 2014**	Customers receive information highlighting new options available to support their energy conservation efforts. Customers receive a rebate for a basic in-home display device that can be redeemed at select stores. Customers will have access to information about their electricity use, up to the previous day, through a secure Power Smart website.

[4] Smart meter installation will begin simultaneously in communities throughout the province.

APPENDIX 1: SMART METER SECURITY, PRIVACY AND SAFETY

Security, privacy and safety have been considered key priorities throughout the development of the Smart Metering Program. The program redefines many of the existing business processes—and introduces new ones—requiring that security, privacy and safety are embedded in each and every aspect. The basic principles of Security-by-Design, Privacy-by-Design and Safety-by-Design have been incorporated throughout the planning of the program. Each of these disciplines are also intrinsically linked; for example, ensuring a security objective is achieved also enhances safety and privacy.

Procurement

Security, privacy and safety requirements are included throughout all of the Smart Metering Program Requests for Proposals (RFPs). Examples of specific requirements include:

- Ensuring vendors are provided with all BC Hydro safety standards and Smart Metering Program security and privacy specifications.
- BC Hydro's Safety-by-Design Practice referenced as a specification. Examples include the metering system specifications explicitly referencing:
    - Applicable American National Standards Institute (ANSI) and Institute of Electrical and Electronics Engineers (IEEE) safety standards; and
    - Generation Project and Service Delivery Practices: Safety-by-Design.
- In RFPs, proponents are required to describe their safety programs and how they propose to comply with BC Hydro safety principles.
- Vendors are required to document, in detail, how their solutions to smart metering security standards demonstrate security best practices.
- Security penetration testing is a mandatory deliverable before implementation of each component of the solution.
- Field Operations Safety and Work Methods staff members participated in vendor evaluation sessions where worker safety practices were thoroughly reviewed. This involvement will continue for future procurements associated with smart metering field devices and related work methods.
- Enhanced meter safety and security design criteria was included in the metering system RFP.

Security in the Smart Meter and Smart Metering System

There are a number of security and safety features within the smart meters themselves, including:

- Use of the end-to-end 128-bit Advanced Encryption Standard (AES) algorithm, which is the same as typical online banking systems;
- Use of an asymmetric key algorithm, which ensures the smart meter cannot read any information it generates once that information has been encrypted. This also means that a specific smart meter can not access or read any data generated by another smart meter; and
- Limited historical data is stored on the smart meters mitigating any exposure of a customer's private data. Additionally, BC Hydro has privacy requirements in place to ensure that employees protect the privacy of customers in accordance with the *Freedom of Information and Protection of Privacy Act*.

There are also security and safety features inherent in the smart metering system:

- Home Area Network (HAN) components, such as in-home display devices, utilize a secure communication system that works only for the local network (i.e. the specific home). Nearby in-home display devices will not be able to access information from another device.

- The smart metering deployment architecture is designed to use different access keys for each localized area to ensure the overall system remains secure—essentially, the smart metering system is broken up into many isolated units. Gaining access to one isolated unit does not provide access to the whole. In other words, devices with a localized area key do not have access to the entire network and no one device is capable of accessing the entire electricity system.
- When a customer moves to a home with an existing smart meter, BC Hydro will ensure that all current in-home device connections are cleared so that usage information from the previous home owner stays private.
- Field tools, used to configure smart meters when remote configuration is not possible, are managed through a secure isolated network. Access to field tools will be limited to necessary staff members using unique passwords. Field tools also carry limited customer meter data and will be purged after each use.

Smart Meter Privacy

- The Smart Metering Program has been focused on privacy concerns since its inception. BC Hydro's Freedom of Information Coordination Office (FOICO) has been central in the discussion of privacy-related issues and participated in all aspects of the requirements and RFP phases of the project.
- In addition to FOICO, resources with expertise in privacy are assigned to the Smart Metering Program to assess and ensure that privacy requirements are met through the life of the program.
- A Privacy Impact Assessment (PIA) is completed for the entire Smart Metering Program, each individual release, and specific security or privacy sensitive components. In all, more than thirty PIAs are anticipated and each PIA will require FOICO sign-off to ensure privacy requirements are effectively managed throughout the program.
- Security and privacy frameworks are being developed for each release of the program to ensure that BC Hydro standards for security and privacy meet or exceed compliance requirements and future expectations.

Smart Meters and Radio Frequency Safety

Smart meters will use radio frequency to communicate data to and from BC Hydro. The health effects of the frequencies employed have been thoroughly investigated by BC Hydro. In addition, many reputable health authorities such as the World Health Organization and Health Canada have conducted thorough reviews of all the different types of studies and research on electromagnetic fields and health. These health authorities have examined the scientific weight-of-evidence and have determined that when all of the epidemiological and experimental studies are considered together, the consensus is that there is no cause-effect relationship between exposure to electromagnetic fields and human health.

Specific to radio frequency exposure to the public, proposed Field Area Network devices must be certified by Industry Canada and in compliance with Health Canada's Limits of Exposure to Radio Frequency Electromagnetic Energy in the Frequency Range from 3 kHz to 300 GHz [Safety Code 6]. BC Hydro will continue to monitor research related to radio frequency. General information and resources related to electromagnetic fields can be found on BC Hydro's website at:
bchydro.com/safety/electric_magnetic_fields/magnetic_fields_and_health.html.

BC Hydro will collaborate with customers who are concerned about radio frequency with the objective of identifying solutions that can be mutually supported.

There are three key factors that contribute to radio frequency safety: duration of the signal, signal strength and distance from the signal.

1. **Signal Duration**
   While the period during which a smart meter transmits data back to BC Hydro will vary depending on the specific metering system used, transmission is expected to last for only a few minutes per day.

2. **Signal Strength**
The signal strength emitted by a smart meter is considerably less than visible light and exposure common to everyday living, such as laptops, cell phones and handheld radios. For example, if you are standing adjacent to the smart meter and it is transmitting continually for those few minutes, exposure is between 60 times and 600 times below the acceptable level identified in Safety Code 6.

3. **Distance from the Signal**
Smart meters will be located in the same place as the existing meter on the outside of a customer's home, or in a meter bank in multi dwelling units such as town homes, condominiums or apartment buildings.

Standing 3 metres (10 feet) away from the meter while it is transmitting, exposure drops to 60,000 times to 600,000 times below the Safety Code 6 acceptable level. Excluding the built in safety factor in Health Canada's Safety Code 6, standing adjacent to a smart meter device, the radio frequency radiation is 60 times less than the Safety Code 6 acceptable level. This is assuming the smart meter device is transmitting 100 per cent of the time, which it does not.

Some customers have expressed concerns about the potential effect of radio frequencies on their unique personal health condition. Individuals who have concerns or questions are invited to contact us at **smartmeters@bchydro.com**.

The following table compares the radio frequency generated by items common to everyday life.

DEVICE RELATIVE POWER DENSITY IN MICROWATTS PER SQUARE CENTIMETRE (μW/cm²)

Distance from the Signal	Signal Strength
FM radio or TV broadcast station signal	0.005 microwatts
Smart meter device at 3 metres (10 feet)	**0.01 microwatts***
Cyber cafe (Wi-Fi)	10–20 microwatts
Laptop computer	10–20 microwatts
Cell phone held up to head	30–10,000 microwatts
Hand-held radio at head	500–42,000 microwatts
Microwave oven, 5 cm (2 inches) from door	5,000 microwatts
Summer sunlight at earth's surface	100,000 microwatts

*Adjacent to meter <10 microwatts

Design and Operation of Equipment

BC Hydro's Safety-by-Design practice addresses the design and operation of new and existing equipment throughout the system including:

- Safe placement of equipment in energized locations (e.g. collectors requiring a power source);
- Safe operation of equipment (e.g. vehicles used for deployment); and
- Designing new components (e.g. integration of distribution system meters) from a safety perspective.

An important component of the Smart Metering Program since 2008 has been the engagement of other utilities and research bodies throughout North America (e.g. Pacific Gas & Electric) to understand their safety challenges and experiences. BC Hydro is an active member of several industry groups where the focus is safety, security, and privacy standards.

BC Hydro has anticipated a possible risk of violence related to electricity theft from drug operations during the installation of smart meters. Measures to protect both employees and the public include:

- The establishment of a police coordination program;
- The development of policies to ensure employees do not engage in unsafe situations; and
- Violence risk assessment training for all installation technicians.

Internal Procedures

Internal procedures have been reviewed from a safety, security and privacy perspective. An outcome of this review is the development of enhanced and new training programs to reinforce safety awareness and safe work practices. Examples include:

- A Safety-by-Design Project Hazard Matrix will be implemented for all planned technologies and the physical placement of meters, telecommunications components and system meters.
- Standards design work is underway with the Distribution Engineering Standards department for the safe and secure placement of telecommunications components.
- Meter installer training programs will be reviewed by the BC Hydro Work Methods department and scrutinized for compliance with safe work practices.
- Mandatory safety requirements and qualifications for meter installation proponents include compliance with WorkSafeBC and the *Safety Standards Act*, with a specific focus on vehicle safety, and provision for safety audits of the installation work.
- Project team members are trained in, and will adhere to, applicable BC Hydro safe work practices in our field and laboratory environments.

Industry Standards Development

BC Hydro is participating in the National Electric Energy Testing Research and Applications Center (NEETRAC), testing and developing meter service connect/disconnect standards with respect to performance and safety. As part of BC Hydro's metering system procurement process vendors must provide formal documentation related to their compliance with the testing requirements and acceptance criteria of NEETRAC. Further, BC Hydro is working as a member of an American National Standards Institute committee on advancing service connect/disconnect standards. BC Hydro's commitment to service switch safety will enhance the safety of both customers and workers.

APPENDIX 2: PROGRAM SCOPE

For the past four years, BC Hydro has been defining the scope and approach for the Smart Metering Program. Key activities include:

- Developing a detailed set of specific functional, operational and technical requirements captured in a set of comprehensive use cases described later in this section.
- Actively participating in technology and industry standards groups focused on smart metering and the emerging smart grid sectors to ensure BC Hydro business needs are captured in industry standards.
- Monitoring the progress and results from utilities who were early implementers of smart metering projects—including Pacific Gas & Electric, Southern California Edison, San Diego Gas & Electric, Duke Power, ENEL (Italy), and in Ontario—Hydro One, Toronto Hydro—and incorporating their "lessons learned" into BC Hydro's project planning.
- Tracking the market evolution of metering technologies, software products, and in-home energy management offerings to ensure BC Hydro's solution choices are based on proven, secure technologies.

The activities listed above resulted in the final Smart Metering Program scope which includes the following six major components. Each will be managed and implemented as part of a single, integrated program:

Smart Metering System—Captures and communicates consumption data and meter events, such as outages, to both the customer and BC Hydro;

Solution Integration—Designs, develops, and implements the software components, business processes, and ongoing support structures required to enable smart metering capabilities;

Theft Detection—Enables BC Hydro to better localize sources of electricity diversion;

Conservation Tools—Provide information enabling customers to make informed and timely decisions in relation to their electricity consumption;

Grid Modernization Infrastructure Upgrades—Provide the smart meter operations centre, and advanced technology and telecommunications infrastructure, to help improve the reliability and security of the electricity system; and

Program Delivery Activities—Provide the overall project management activities and responsibilities designed to ensure a quality implementation of each solution component included in the program scope.

Following is a more detailed description of each scope component.

Smart Metering System

Included as part of the Smart Metering System[5] are:

- **Smart Meters—**Digital meters—capable of two-way communications—with the ability to measure the incoming and outgoing flow of electricity from a specific location such as a customer's home or business. The two-way communication capability enables smart meters to provide use data to both customers and BC Hydro—in different formats. When paired with an in-home display, the smart meter can send real-time consumption and price information directly to the customer. Real-time customer use information will be transmitted through the Home Area Network directly to the customer and will not be available to BC Hydro. Smart meters will capture and store use on an hourly basis and transmit the data back to BC Hydro, through the Field Area Network and Wide Area Network, during short intervals (couple of minutes) at prescheduled times during the day.
- **Metering Telecommunications—**Consisting of two parts—the Field Area Network (localized to meters in the field) and the Wide Area Network connections (enterprise wide focus)—this communications infrastructure provides the physical devices required to enable two-way transmission of data between smart meters and BC Hydro. There are several different ways this field-based communications infrastructure can be implemented, depending on the metering system selected.
- **Automated Data Collection System—**This software application is designed to aggregate meter usage and event data from smart meters and manage the Field Area Network communications infrastructure. This software is provided by the metering system vendor.

[5] BC Hydro is currently in an active procurement process to select the Metering System vendor.

Solution Integration

In addition to the overall smart metering system, the Smart Metering Program is responsible for the business environment that supports smart metering including implementation of new business software applications, changes to existing information systems, enhanced data warehouse and analytics capabilities, and all of the business transformation activities that will help BC Hydro adapt to the new technologies and systems. Specific elements of scope include:

- **Meter Data Management System—**A software application that stores, validates, edits and analyses meter reading data prior to releasing it for integration into other BC Hydro operational systems such as customer billing, load forecasting and outage management.
- **Interfaces and Integration—**This systems integration work involves modifying existing applications to handle the enhanced automated meter reading information, and building interfaces between new and existing enterprise applications to support BC Hydro's end-to-end business processes.
- **Business Transformation—**The major elements of business transformation work involve development of new and modified business processes, design of organizational and job changes, rollout of training and knowledge management programs, employee engagement to facilitate cultural change, and effective transition to business operations for ongoing work.

Theft Detection

BC Hydro currently does not have the measurement devices and analytical tools to quickly and accurately identify where theft of electricity is occurring. A comprehensive theft detection solution, based on electricity balancing analysis, will be implemented as part of the program. Scope elements include:

- **Distribution System Meters—**New meters (different from those to be installed at customer homes or businesses) will be installed at key points on BC Hydro's system to measure electricity supplied to localized areas.
- **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 and smart meters.

Conservation Tools

Smart meters will enable customers to take advantage of new tools to save energy and money. These include:

- **In-home Display—**Customers will have the choice of whether or not they wish to acquire in-home display devices. BC Hydro will provide financial incentives to enable customers to acquire a basic market available in-home display device from their local retailer. In-home displays will be enabled through the Home Area Network, a communication channel between the smart meter and the customer's home or business. This secure channel, an attribute of the smart metering system, enables customers to view their consumption either on a real-time or accumulated basis, represented in both cost and kilowatt-hours.
- **Power Smart Website—**BC Hydro's existing secure Power Smart website will be expanded to include new interactive and informative applications—based on the hourly data captured from smart meters—designed to help customers better understand and model their energy use. Today, residential customer meters are read every two months, which provides little practical information for customers to determine which, if any, conservation actions they should pursue.
- **Rate Options—**The smart metering system infrastructure will enable BC Hydro to design new rate structures that encourage conservation during peak periods. While the implementation of new rates is enabled by the Wide Area Network, Field Area Network and web interface, the design and implementation of new rate structures is a separate initiative. Key functional and data requirements to support rate options will be enabled by the new smart metering system and the Meter Data Management System. The design of these rate options will involve consultation with customers and key stakeholders, and will be subject to full review and approval by the BC Utilities Commission.

Grid Modernization Infrastructure Upgrades

This program scope element involves two key components; the specific requirements of each will depend on the metering technology selected:

- **Advanced Telecommunications Infrastructure—**Involves the design and installation of additional secure and reliable Wide Area Network telecommunications infrastructure to support advanced electricity system functions and emerging customer applications like customer generation and microgrids.
- **Advanced Operational Support—**Involves the implementation of a smart metering and network operations function to support real-time operations of the metering system. This support function will likely be implemented as an extension of BC Hydro's distribution operations centre so that all real-time system and telecommunications operations can be managed seamlessly and efficiently.

Program Delivery Activities

Included in the scope of the Smart Metering Program are the overall program delivery activities and services which ensure all of the technical aspects of the project are successfully implemented, and accepted by BC Hydro's customers and stakeholders. These activities include:

- **Project Management and Controls—**Includes the personnel and support tools to manage and report on the overall delivery of all aspects of the Smart Metering Program, including scope, schedule, budget, quality, issues resolution, environment management, and transition to operations.
- **Security, Privacy and Safety—**This independent team ensures appropriate governance and compliance for all the physical security, cyber security, data privacy, and employee, vendor and contractor safety aspects of the program. Security, privacy and safety have been fundamental drivers of the program.
- **Finance & Regulatory—**This team provides financial oversight and regulatory support to the project team.
- **Customer Research, Engagement and Outreach—**Includes the resources required to support the Smart Metering Program with respect to research, community engagement, customer communications, employee engagement, and media.
- **Contract Management—**Includes the personnel and processes required to manage procurement and tendering activities, as well as manage contractual commitments and any contract issues that may emerge.

Use Cases

Use cases provide a starting point to inform the scope of complex, cross functional projects, and define the subsequent procurement requirements. Use case methodology is an industry-leading approach to matching functional needs to the appropriate technology and systems.

BC Hydro examined use cases from other utilities across North America involved in smart metering systems. From there the approach was expanded to create 17 individual use cases based on BC Hydro's unique business needs and context. For example, BC Hydro's requirements included enhanced customer service options and theft detection. The inclusion of these requirements improved program benefits and contributed to a stronger business case.

Organized into four main categories the use cases include: Customer Service, Distribution System Optimization, Home Area Network and in-home feedback, and network and meter management. Based on business scenarios the use cases capture the current and long-term (over 20 years) functional, operational and technical requirements for BC Hydro.

Category	Use Cases	Description
Customer Service	Customer Contact Collect Interval Data Remote Connect or Disconnect Pre-pay Services Bill an Account	These use cases describe the functional requirements and business processes required to achieve enhanced customer services through improved communications, more accurate account billing, automated meter data collection, remote connect and disconnect services, and new service offerings such as pre-paid options. Customer Service Representatives will be better equipped to handle all customer requests regarding account enquiries, billing and payments, as well as help customers to monitor and adjust their energy consumption.
Distribution System Optimization	Extending or Reconfiguring the Distribution System Analyzing Meter Data for Load Research, Planning and Rates Detection of Tampering or Theft Distribution System Optimization and Automation Outage Detection and Restoration Customer Generation	These use cases describe the functional requirements, business processes, and operational aspects required to optimize the distribution system with respect to implementation of a new smart metering system. This includes the impact on BC Hydro's network design and engineering processes to incorporate new features and capabilities. Current and historical data captured through the Meter Data Management System includes accumulated energy consumption, demand profiles, aggregated time-of-use information, voltage information, and metering events (e.g. tamper flags). This more detailed and timely information supports several distribution system business processes including outage detection and analysis, theft identification and mitigation, and customer generation.
Home Area Network	Home Area Networks Providing Demand Side Management Capabilities Plug-in Hybrid Vehicles	These use cases describe the functional and technical requirements, and the business processes required to enable a Home Area Network using new smart meters and various in-home feedback tools. This may include providing pro-active notifications to customers if they choose, and the ability to accommodate electric vehicles on the distribution network. As customers, especially industrial and commercial customers, become more interested in direct load control, they can use demand response capabilities included in the Smart Metering Program to configure, manage, monitor and settle various load programs.
Network and Meter Management	Meter Lifecycle Management Management and Recovery of the System Installation and Configuration of the System	These use cases describe the requirements to configure, manage, recover and maintain the various metering units within the product lifecycle. A typical life cycle of a smart meter is described, including the installation, replacement, and remote troubleshooting methods involved. Described within these use cases is the initial installation and configuration of the smart metering system including meter procurement, quality assurance testing, logistics and installation.

APPENDIX 3: RESEARCH

In addition to applying lessons learned from other utilities, BC Hydro has reviewed research findings, conducted customer research, and field tested theft detection devices to assist in shaping the delivery of the Smart Metering Program. Key results are included below.

Research on Energy Conservation Effectiveness of In-home Feedback

BC Hydro has estimated that customers who use in-home feedback tools will realize an average 4 per cent energy savings. This estimate is considered to be conservative, based on various research findings, as outlined below.

Research in relation to the effectiveness of in-home feedback tools includes both academic research related to behaviour change and actual pilots and trials that have been conducted worldwide. This research has informed the savings assumption above, as well as the overall approach BC Hydro will be taking related to in-home feedback. Key research findings have found that saving from direct and indirect feedback can range from 3–15 per cent and 0–10 per cent respectively[6].

Specific industry initiatives have also provided a point of reference for potential energy conservation for the Smart Metering Program. For example, customer energy conservation has been reported as follows:

- Pacific Gas & Electric states an average 6.5 per cent reduction in energy use when using an in-home display[7],
- Southern California Edison reports a 6.5 per cent reduction in energy use when using Home Area Network devices and a 2 per cent reduction in energy when using historical online feedback[8], and
- Commonwealth Edison reported a 2 per cent reduction in energy use when customers subscribed to monthly online reports[9].

Research on Customer Participation for In-home Feedback

Customer participation will depend on several factors, including the cost of in-home feedback tools, their overall appeal and simplicity of use, the marketing campaign that supports their distribution, and their effectiveness in helping customers save electricity. Also reported in Southern California Edison and Pacific Gas & Electric's application filing to the California Public Utilities Commission were their assumptions on participation. Southern California Edison assumes a 10 per cent penetration with 1 per cent growth per year for their online web pages while Pacific Gas & Electric assumes a 21 per cent penetration by 2030 for customer-purchased in-home displays.

BC Hydro qualitative focus group research, conducted with customers and employees, found there was strong interest in electricity feedback mechanisms. Based on focus groups completed in 2010, customers were optimistic that increased awareness via in-home feedback tools will help them conserve energy and save money. In general, most participants expressed interest in the program. In addition, it was found that 83 per cent of BC Hydro customers have at least one computer and 86 per cent had internet connectivity at home[10]. Given these statistics, the potential use of a secure online feedback website should be widespread.

Conservation Research Initiative

Important feedback was also derived from the Conservation Research Initiative, a program launched by BC Hydro in 2006. The goal of the Conservation Research Initiative was to examine how individual British Columbians could make a difference and help meet the growing demand for electricity in BC by conserving electricity in their homes.

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[6] The Effectiveness Of Feedback On Energy Consumption; Sarah Darby, Environmental Change Institute, Oxford University, April 2006; Residential Electricity Use Feedback: A Research Synthesis and Economic Framework; EPRI (Electric Power Research Institute), February 2009; Impact Of Informational Feedback On Energy Consumption—A Survey Of The Experimental Evidence; Ahmad Faruqui, Sanem Sergici and Ahmed Sharif, May 2009

[7] Application filed to CPUC December 12, 2007 App No 07-12-009

[8] Application filed to CPUC July 31, 2007 App No 07-07-026

[8] Pilot findings: http://usweatherizing.com/blog/?p=923

[10] Residential Customers Needs Survey F10 (February 2010)

This study was conducted in more than 1,800 residential homes across six communities: Vancouver, Burnaby, North Vancouver, West Vancouver, Campbell River and Fort St. John. The study tested time-of-use rates and smart meters to help BC Hydro better understand how adjusting the price of electricity at different times of the day influences electricity use by residential customers.

The results of the Conservation Research Initiative are summarized below:

- Overall consumption was reduced by 7.6 per cent.
- Energy use during peak hours was reduced by 11.5 per cent.
- 63 per cent of participants saved money by conserving and shifting their consumption to off-peak hours.

Theft Detection Pilots

Since 2005, BC Hydro has implemented four theft detection pilots using distribution system meters to conduct energy inventory balances with customer smart meters. All of these pilots have successfully demonstrated that the energy inventory balance approach, conducted at either the primary or secondary voltage level, can readily identify localized areas of the electricity system where theft is occurring. In total these pilots, which are still operational, covered over 800 homes, and resulted in the identification and termination of 22 electricity thefts. Where thefts have been identified and shut down quickly, there has been little recurrence. Further details regarding the theft pilots can not be released for security reasons. These theft detection pilots identified key requirements for the design of a scalable solution including the following three major components in addition to the basic smart metering system: distribution system meters; theft analytics software; and new investigation techniques and processes.

APPENDIX 4: QUANTIFIED BENEFITS AND KEY ASSUMPTIONS

This section provides a summary of the key sensitivities and assumptions for each benefit stream included in the Smart Metering Program business case.

Benefit Description	Present Value (PV) Millions (M)	Key Business Case Assumptions	Sensitivity Millions (M)
Meter Reading Automation Accenture Business Services for Utilities currently provides manual meter reading services. BC Hydro supplies the infrastructure including vehicles, facilities, meter reading software and hand-held equipment. This benefit represents a reduction in manual meter reading services, supporting infrastructure, and green house gas emission costs, based on an assumed Field Area Network coverage for 95 per cent of customers.	**$222 M** Range is: $182 M–$247 M	A Field Area Network will provide communications infrastructure to at least 95 per cent of customers. Costs to read the remaining 5 per cent of customers are estimated at 3 times higher than current costs.	Each per cent point over 95 per cent coverage adds $6 M to the PV.
Meter Sampling BC Hydro has ongoing processes to ensure customer meters are maintained and operated within the accuracy requirements mandated by Measurement Canada. Each year, a statistical sample of meter groups is removed and tested for accuracy. If a sample group does not meet the accuracy standards, that entire group of meters is removed from service. An average of 40,000 meters are replaced annually under this program. Smart meters will eliminate the need to sample and test meters for some period of time.	**$61 M** Range is: $56 M–$66 M	This benefit results from reduced operating costs for sampling processes and reduced capital expenditures to replace failed meter groups over a planned seven-year period following installation of smart meters. Health of meters in service will be monitored during the seven year suspension of sampling. Estimate of 1 per cent of meters replaced annually, based on increased accuracy of electronic smart meters.	Each per cent change in the meter failure rate results in a $3.4 M change in PV.
Remote Re-connect Automation Today, meter reconnections and disconnections are completed onsite by a meter technician or power line technician. The remote on/off switch provided within smart meters enables all connection related services to be completed remotely, safely and securely. This benefit is due to reducing the need for manual connects/disconnects for non-payment, and the associated vehicle expenses.	**$47 M** Range is: $42 M–$52 M	BC Hydro's policies and procedures for when service can and will be disconnected are not changed for this business case. Remote on/off switch will be included in all meters where it is technically feasible.	Each percentage point over 95 per cent coverage adds $0.23 M to the PV.

Distribution Asset Optimization Capital expenditures related to growth of the distribution system—driven by load growth, reliability improvements, customer connections and station expansion—are approximately $500 M per year for the foreseeable future. Smart Metering Program benefits from improved availability of assets and system performance data and information results in conservative capital budget savings of 0.3 to 0.5 per cent per year following implementation of all Smart Metering Program assets.	**$15 M** Range is: $12 M–$25 M	Does not include any distribution asset optimization benefits resulting from theft detection and reduction. Only includes incremental benefits due to new distribution system meters and smart meters.	Each 0.1 per cent change in the distribution system capital budget impact related to smart metering results in a $4.7 M PV change.
Outage Management Efficiencies Today, BC Hydro is only made aware of customer (residential/commercial) outages when they call 1 888 POWERON. Smart meters will provide automated outage notification, specific outage location information, and confirm when power has been restored. Smart Metering Program related benefits include improved time to restore outages, reduced visits to false outages, more rapid identification and restoration of embedded outages, and improved customer satisfaction.	**$10 M** Range is: $5 M–$15 M	Includes outage management improvements from both trouble-based outages (e.g. single customer calls) and storm-based outages (i.e. wide-spread outages due to a specific event).	Due to the high variability of outages from year to year, this benefit is based on an average, over the term of the business case.
Continuous Optimization and Load Research BC Hydro's Continuous Optimization Program targets operational savings in the commercial sector. The program provides consulting services to help identify actions to reduce energy use in buildings. With smart meters, the program will no longer have to retrofit the existing meter and install additional hardware on the customer's site to capture interval meter reading data. Smart meters will provide Load Research with load profile information in a more timely and accurate form, avoiding capital and operational costs.	**$6 M** Range is: $2 M–$10 M	Estimated savings in meter upgrades of $1,800 per Continuous Optimization site, plus savings of additional hardware and installation costs of $2,980 per site. Estimated annual operational savings for Load Research of $290 K, plus one-time capital savings of $2.2 M.	A 10 per cent change in the number of customers in the Continuous Optimization Program results in a change of $0.2M PV.

Call Centre and Billing With smart meters, customer calls related to estimated bills and meter reading access arrangements will be substantially reduced. Also, call centre agents will have much more information available to help address questions regarding meter reads, billing, payments, and energy conservation. BC Hydro expects call volumes to increase as smart meters are being introduced and this cost has been factored in to the overall business case.	**($2) M** Range is: $(4) M–$0 M	Call volumes estimated based on inquiries related to current Power Smart programs. Approximately 48 per cent of billing errors will be eliminated.	A change of 48,000 calls results in a change of $1 M in PV. Every 5 per cent change in billing exceptions changes the PV by $0.5 M
Voltage Optimization Voltage optimization or Volt-VAR Optimization (VVO) technology helps reduce the amount of electricity that must be transmitted in order to ensure sufficient power quality at customer sites. Smart meters will enhance BC Hydro's existing VVO program by providing significantly more measurement points along the distribution network, thus helping to manage voltage more effectively. Smart metering helps deliver VVO benefits for both the Distribution system and Customers: **Customers—**Extend the VVO program to a Power Smart Program for eligible commercial customers. **Distribution—**Enhance the effectiveness of the VVO program and enable the extension of the program to additional substations.	$108 M Range is: $48 M–$148 M $100 M Range is: $85 M–$150 M	At least 2,000 commercial customer sites have use characteristics that would benefit from voltage optimization. Benefit is net of the Demand Side Management Program costs to incent customers to install equipment.	Each increase/ decrease of 10 per cent in GWh/yr in energy savings results in $14 M increase/decrease in PV. For each 100 increase/decrease in the number of customer sites included into the VVO program, the PV increases/ decreases by $11 M.

Theft Detection The theft detection solution includes distribution system metering, business analytics, and an upgraded topology model to quickly and accurately identify where theft is occurring. This increased automation will shift BC Hydro from a reliance on public-generated tips to system-generated tips regarding suspected theft. Smart meters also have automated tamper alarms to alert BC Hydro. Benefits result from energy and capacity savings, additional revenue through prevention of theft, and back-billing to recover cost of stolen energy and investigation costs.	**$732 M** Range is: $632 M–$832 M	Estimated consuption by marijuana growing operations is 1,300 GWh/yr through F2033 (paid and theft), of which theft increases from 500 GWh/yr in F2007 to 850 GWh/yr in F2012. Realization of theft benefits is estimated at an initial 75 per cent, declining to about 67 per cent by F2027. Theft detection requires analysis and in-field investigation; the business case includes an incremental operations and maintenance increase of $10 M, declining to $7 M by F2015. Total portion of theft attributed to meter tampering is 5 per cent, with the rest attributed to diversion directly from distribution lines. An average of 16 per cent of back-billing for theft is collectible.	An increase/ decrease of 10 per cent in the amount of theft reduction achieved results in an increase/ decrease of $86 M PV.
Voluntary Time-of-Use Rates Reducing peak period demand for electricity can reduce the amount of capacity BC Hydro needs in the system, thus potentially deferring the need to build more generation, transmission, and distribution assets. The more detailed use information captured by smart meters enables BC Hydro to investigate different rate options including time-of-use. BC Hydro is in the early stages of rate design and will soon begin engaging with customers and stakeholders to receive feedback on different types of rates. No decisions have been made yet regarding specific rate designs and any final rate designs will be subject to approval by the BC Utilities Commission.	**$110 M** Range is: $30 M–$250 M	The business case benefits assume new time-of-use rates would be voluntary. Customer enrolment in time-of-use rate programs is expected to start slowly and build through 2015 to 30 per cent. Benefits are net of costs to design and implement the new rate structures. Price elasticity is assumed at -0.10.	A change in the participation rate of 1 per cent change results in a $5.2 M change in PV. The business case benefits translate to a 10 per cent shift from on-peak to off-peak usage by participating residential customers, on average.

Conservation Tools (in-home feedback) Offering customers opportunities to monitor their electricity consumption in new ways can lead to increased awareness of energy consumption and therefore increased conservation behaviour. Customers will be offered two feedback options: 1. Near real-time feedback delivered via an optional in-home display device; and/or 2. Hourly data, provided within 24 hours, through the Power Smart website.	**$220 M** Range is: $170 M–$270 M	BC Hydro will offer a rebate program to encourage customers to choose a basic, market available in-home display. Customer take-up of in-home display is assumed at 30 per cent. Energy savings from in-home displays are 4 per cent with eight year persistence. Website-based energy savings are 2 per cent, with 15 per cent penetration of residential customers.	An increase/ decrease of 1 per cent in customer participation translates to approximately $1.2 M in PV.

APPENDIX 5: ADDITIONAL NON-QUANTIFIED BENEFITS

In addition to the quantified benefits identified in the business case, the Smart Metering Program will deliver numerous other benefits that have not been captured in the business case to date. The following table provides a summary of these additional benefits.

Type of Benefit	Additional Benefits
Operational Efficiencies, Cost Savings and Other Benefits	Additional uses of metering (unrelated to theft detection) in distribution planning and operations, asset management, etc. Reduction of line losses unrelated to theft detection (e.g. street lights). Facilitation of screening process required to assess the impact of Distributed Generation and electric vehicles during planning. Increased data will significantly improve the precision and quality of load profiles. Reduce staffing needs, related facility space and office equipment. Reduction in carbon offset payment for emissions for the BC Hydro fleet vehicles used by Accenture Business Services for Utilities. Improved overall system efficiency through better ability to optimize supply and demand levels throughout the day.
Safety, Privacy and Security	Reduced employee and contractor exposure to potential accidents and injury due to reduction of time spent in the field. Improved public safety due to the reduction in electricity theft. Customer security and privacy will increase as meter readers will no longer be required to enter customer property to read, disconnect or reconnect meters.
Improved Customer Service and Convenience	Customer service representatives will have the ability to check current meter readings directly from the meter while the customer is on the phone to validate meter functionality, address billing complaints, and confirm whether an outage is on the customer side of the meter. Customers will no longer be required to unlock gates, keep dogs inside, provide keys for access, etc. On-demand meter reading when customers move in or out of premises will avoid adjusted billings between tenants, simplifying transactions for customers. Customers will have the option of signing up for automated outage notification. Customers can choose to receive rate related information through an in-home display. Customers who use the in-home feedback tools, whether it is a secure web page or in-home display, and conserve energy will benefit from lower bills. Better ongoing information for customers and quicker response to power outage situations will enable commercial customers to make better decisions and reduce down-time costs. Customers will benefit from faster service re-connection. Commercial customers will be better able to optimize commercial building systems, saving energy and money.

Environment	Facilitates conservation and energy efficiency. System efficiencies and increased automation within BC Hydro's operations will deliver some greenhouse gas emission reductions. Support for the large scale integration of electric vehicles and electrification of the transportation system could deliver further green house gas emission reductions. Smart metering benefits will help to achieve the Province's target to reduce the projected demand increase by at least 66 per cent through conservation. Supports BC Hydro's ability to pursue all cost-effective Demand Side Management.
Socio-economic	Employment opportunities related to the installation of meters, and creation of more information-based jobs. Opportunities for local business to build on the system and create new products and services that support a green economy. Opportunities to build on the new smart metering infrastructure to create made-in-B.C. technology solutions that support a green economy. Smart meters are the first step in enabling the large scale accommodation of electric vehicles, customer self generation and microgrids that will help communities throughout British Columbia become more self sufficient. Enables significant energy savings that can be used for other economic purposes.

APPENDIX 6: BUSINESS CASE ANALYSIS

A business case documents the economic justification to support an investment decision, such as acquiring assets. Business cases are based on forecasts of incremental cash flows, both benefits and costs, over a time horizon that reflects the economic lives of the assets acquired. These cash flows are then discounted resulting in a net present value (NPV).

A business case does not include non-cash financial impacts, such as depreciation, amortization, or write downs of existing assets. These are accounting transactions, included in appropriate financial reports, and are not a factor in the economic rationale to make a business investment.

The Smart Metering Program business case model includes all the inputs and assumptions required to complete a comprehensive financial analysis of costs and benefits over a 20 year term following the installation of the meters (through F2033). The Smart Metering Program business case analysis reflects those cash flows that are incremental to cash flows without the program. For example, the business case model captures total annual cash flows for capital expenditures, avoided and deferred capital benefits, operating expenses and operating benefits. The NPV of the cash flows over the evaluation period is then calculated. A positive NPV supports the proposed investment decision.

The table below provides a summary of the key financial modeling assumptions used in the Smart Metering Program business case model:

KEY FINANCIAL MODELLING ASSUMPTIONS

Category	Assumption	Sensitivity
Discount Rate and Inflation Rate	The present value of all costs and benefits has been calculated using the nominal (i.e., with inflation) BC Hydro discount rate of 8 per cent[11] per year.	A variation of 0.25 per cent (+/-) in the discount rate changes the NPV in the business case by approximately $30 M.
Value of Energy	Value of energy is the BC Hydro reference energy price based on the 2009 Clean Call for Power. This price is $124 per MWh for F2010 and adjusted for inflation annually.	A 10 per cent change in the assumed value of energy results in a change in the NPV of about $85 M.
Value of Capacity	Value of capacity is an estimate for the avoided cost of building generation, transmission and distribution assets. The capacity reference price is updated as part of the integrated resource planning process. For capacity benefits associated with energy savings in this business case, the value of capacity is $88 per kilowatt-year (as set in F2009 and adjusted for inflation annually).	A 10 per cent change in the assumed value of the capacity results in a change in the NPV of about $28 M.

[11] BC Hydro's discount rate (Weighted Average Cost of Capital) for business cases is based on BC Hydro's deemed capital structure, the allowed rate of return on equity—both of which are approved by the British Columbia Utilities Commission—and the forecasted average cost of debt. The Weighted Average Cost of Capital for F2011 is presently set at 8 per cent, and includes a 2 per cent rate of inflation.

Amortization period	Amortization periods for smart metering assets acquired are based on the estimated economic life of each asset type, as follows: • Smart Meters: 20 years • Telecommunications (Field Area Network): 20 years • Telecommunications (Wide Area Network): 35 years • Distribution System Meters: 15 years • IT Hardware: 5 years • IT Software: 10 years	These amortization periods have no impact on the NPV of the business case. Assumed amortization periods do, however, affect customer rate impacts attributable to the Smart Metering Program.
Asset Refresh	Assets are typically replaced based on the estimated economic life of each asset type. Where the economic life of an asset falls within the timeframe of this business case, the asset refresh cost has been factored into the financial analysis.	No sensitivity analysis required.

Business Case Summary

The following table provides a summary of the overall business case, including the key financial components resulting in the positive net present value (NPV) of $520 million. For greater clarity—and because benefits have typically been discussed in terms of present value and costs in terms of nominal value—both nominal and present value figures are provided.

The ongoing operating and maintenance expenses for the Smart Metering Program include any incremental costs required to operate and maintain the new assets—such as meter maintenance, software application support, and telecommunications operations and maintenance.

The capital cost to replace Smart Metering Program assets during the period to F2033, based on the economic life of each asset type, has been included in the overall NPV. This capital cost is adjusted for the un-depreciated net book value of assets remaining in service at the end of F2033.

The following table provides a net present value (NPV) scenario analysis, beginning with the base case of $520 million. The NPV remains positive even if all the benefits are achieved at the low end of the estimated benefit range. Conversely, if all benefits are achieved at the high end of the range, the NPV increases to $956 million.

BUSINESS CASE SUMMARY IN NOMINAL AND PRESENT VALUE

Business Case Summary	Nominal Value ($M)	Present Value ($M)
Gross Benefits attributable to Smart Metering Program, less costs related to the achievement of individual benefits	$4,658	$1,629
Less: Ongoing operating and maintenance expenses and incremental asset replacement capital	(745)	(330)
Less: Smart Metering Program Costs	(930)	(779)
Total Net Value for the period F2006 to F2033	**$2,983**	**$520**

Development of the Business Case

The Smart Metering Program business case has been updated and revised several times since the program was first initiated in 2006. Throughout the business case development process, BC Hydro has engaged a number of third party experts, including PricewaterhouseCoopers (PwC) and Enspiria Solutions, to review and validate costs, benefits, approach and methodology. As a result of the continued evolution of the smart metering industry and related technologies, BC Hydro undertook a full refresh of the business case in 2010.

APPENDIX 7: RATE ANALYSIS

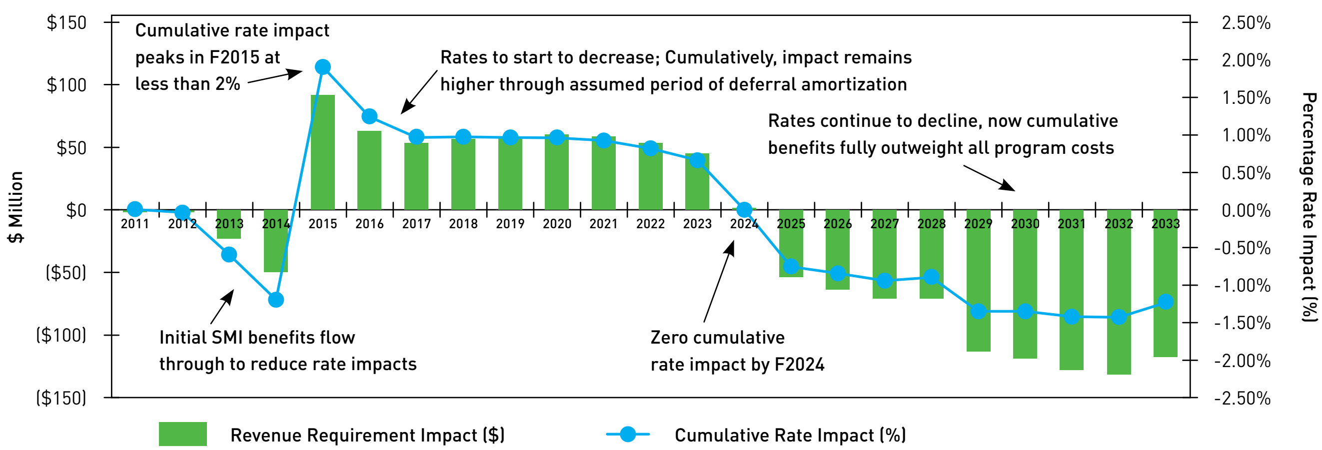
The Smart Metering Program pays for itself through reduced theft of electricity, energy savings, and operational efficiencies. Net benefits will flow to customers, reducing rates below what they would otherwise be in the absence of BC Hydro's investment in the program.

Similar to other capital projects, the Smart Metering Program has initial rate impacts which are reduced over time as the benefits accumulate. In order to better match the initial cost recovery to the timing of benefits realization, BC Hydro will seek BC Utilities Commission approval to "smooth" rate impacts.

The *Clean Energy Act* exempts the program from those sections of the *Utilities Commission Act* that specify BC Hydro's obligations to seek approvals from the BC Utilities Commission for capital projects. However, when BC Hydro seeks to recover Smart Metering Program expenditures in rates, the BC Utilities Commission will review the prudency of BC Hydro's decisions and actions in relation to the implementation of this program.

The estimated impact of the Smart Metering Program on BC Hydro's rates is based on the net cash flow benefits as presented in the business case, which are then incorporated into BC Hydro's regulatory accounting model to determine the incremental impact on BC Hydro's annual revenue requirements[12].

The graph below illustrates the projected rate impact of the Smart Metering Program over the term of the business case, before considering potential rate smoothing proposals. Specifically, the graph shows the annual impact of the program on BC Hydro's revenue requirements, as well as the cumulative rate impact which ultimately results in a sustained rate decrease of over 1.25 per cent (below what rates would otherwise be in the absence of the Smart Metering Program).



The green bars on the graph show the annual dollar impact (in millions) of the Smart Metering Program on BC Hydro's overall revenue requirement. The blue line on the graph illustrates the cumulative impact on rates over the term of the business case. To help manage current rate pressures, $75 million in benefits from the program will flow through to customers in F2012 through F2014—resulting in a cumulative rate decrease of just over 1 per cent by F2014.

Without the planned smoothing, in the first year following full implementation of the Smart Metering Program (F2015), there is an increase in BC Hydro's revenue requirement as the recovery of current—and previously deferred—costs starts. From F2016 through F2023, the additional revenue requirement due to the Smart Metering Program starts to drop.

[12] Revenue requirement refers to the total amount of money BC Hydro must collect from customers to pay all operating costs, energy costs, amortization, financing charges, and return on equity in a given year.

From F2024 on, the Smart Metering Program benefits reduce BC Hydro's annual revenue requirement, resulting in rates being reduced below what they would otherwise be without the program. Over the term of the business case, there is a total reduction in BC Hydro's revenue requirement of over $400 million.

This $400 million total reduction in BC Hydro's revenue requirement differs from the business case net present value of $520 million because the revenue requirement includes accounting impacts of non-cash transactions from a regulatory point of view. For example, the revenue requirement factors in the financial impacts due to timing of regulatory cost recovery and recovery of the un-depreciated sunk cost of existing meters—a non-cash item.

APPENDIX 8: KEY BUSINESS RISKS

SUMMARY OF KEY RISKS AND MITIGATION STRATEGIES

Risk	Description	Mitigation Strategies
Meter Supply Chain	Risk of the market's inability to meet meter supply chain requirements, and interdependencies with other vendors.	Procurement evaluation criteria considered the vendor's ability to meet the timeline. Incentive mechanisms are in place to align the related suppliers to deliver on time and on budget. Significant liquidated damages to be included in final contracts to ensure vendors meet their commitments.
Emerging Technology	Risk of technology continuing to evolve resulting in stranded assets.	All meter vendors under consideration in the procurement process have met minimum mandatory criteria which included having sizable deployments in other North American and European utilities, and based on proven technologies. Technology selection criteria were designed to meet current and expected future business needs. Procurement evaluation criteria included technology "future proofing" to ensure future business, technical and operational requirements were considered. Where technology risks may still exist, the successful vendor will be contractually committed to meeting BC Hydro's requirements by an agreed date. In addition, they will be required to provide full backward compatibility for selected products.
BC Hydro Resource Constraints	Significant resource constraints internally for telecommunications, field crews, and technology personnel—skills and head count—could impact the schedule.	The Smart Metering Program is a top corporate priority with broad executive oversight and commitment. Leverage meter and field contract labour market for peak resource requirements—including incentives for vendors to grow and create jobs in British Columbia.
Meter Deployment	Unable to complete meter deployment by the end of 2012.	Contract incentives are in place for solution integrator, meter system and meter deployment vendors to meet 2012 timeline. Use various strategies to deploy meters in multiple regions concurrently, including distributed warehouses.

Budget	Risk of exceeding project budget due to unforeseen costs or changes in scope.	Procurement approach designed to achieve cost certainty for at least 50 per cent of the project budget, including mechanisms like: • affordability ceilings • fixed price contracts • incentive mechanism shared with all vendors Rigorous control over scope elements implemented including: • formal change control process for any change in scope, timeline, or deliverables • project controls office in place to manage issues, risks, assumptions and changes Rigorous financial controls are being implemented including: • budget assigned to accountable managers and measured • financial performance tracking and forecasting tools
Safety/Security/ Customer Privacy	Risk of security or privacy breach impacting customers or system operations.	Safety, security and privacy were built into all procurement processes. Safety, security and privacy were built into end-to-end solution architecture and all business processes, which will be validated during solution acceptance testing. BC Hydro is an active participant in external standards setting groups, including committees focused on safety, security, and privacy. A dedicated smart metering safety, security and privacy office has been established. Formal penetration test plan including hiring external agencies to attempt to break into the system.
Customer Experience	Risk of limited customer awareness and public support of smart metering, and/or negative customer experience during meter deployment.	Customer research to discover baseline level of public awareness and to identify specific issues and concerns regarding meter deployment. Comprehensive Smart Metering Program communications plan developed and being implemented. Includes specific customer contact plans pre-, during, and post- meter deployment. Incorporating lessons learned from other utilities with respect to customer engagement.

APPENDIX 9: MANAGING RISK THROUGH PROCUREMENT

In 2008, BC Hydro initiated a procurement process for a single Solution Integration firm, which would in turn be responsible for selection and sub-contracting of the required technology components, meters, deployment services, and project implementation. Proposals submitted at that time were significantly over budget and did not achieve the risk transfer expected by BC Hydro.

In March 2010, BC Hydro decided to proceed with a "disaggregated" procurement approach to contract directly with proven industry vendors—ensuring BC Hydro retains direct control over the program while building business relationships that would extend over the economic life of the assets. Partnerships BC was engaged to provide expertise in structuring a comprehensive and open procurement process.

Specific project risk mitigation managed through procurement includes:

- **Minimum mandatory criteria:** a number of mandatory 'pass/fail' criteria were established to ensure only established, proven and scalable proponents are considered.
- **Affordability ceilings:** establishing the maximum value BC Hydro is prepared to pay for a product or service providing cost certainty.
- **Subject matter experts:** both internal and external subject matter experts have been involved to ensure a full understanding of proposed technologies.
- **Panel interviews:** because experienced professional resources are critical to the success of the project, panel interviews are conducted with key individuals proposed by vendors.
- **Fairness Advisor:** an independent and experienced Fairness Advisor participated in all procurement processes.
- **Due Diligence Committee:** a senior level independent advisory committee reviews procurement recommendations of the selection teams to ensure that the process was followed and the basis of recommendations is appropriately documented.

As of December 31, 2010, BC Hydro continues in active procurement or final contracting in four key procurement streams—Solutions Integrator, Metering System, Meter Data Management System and Meter Deployment Services. Announcements related to the successful proponents are expected in the near future.

APPENDIX 10: TECHNOLOGY AND INDUSTRY STANDARDS GROUPS

BC Hydro has been active with industry in North America for several years to understand and influence the technology and standards that will impact the success of the Smart Metering Program. This work has included participation on a number of committees and collaboration with various industry associations as outlined below:

Industry Association	Purpose	BC Hydro Participation and Value
Electric Power Research Institute (EPRI)	To advance innovation, research and utility solutions.	Active participation on power delivery programs including smart grid applications.
National Institute of Standards and Technology (NIST)	To advance industry standards. Currently working on priority action plans related to smart grid development.	BC Hydro is closely following the NIST guidelines and standards for security including NISTIR 7628 and Federal Information Processing Standards.
GridWise Alliance	To advance smart grid business and technology solutions, including policy and legislation.	Membership has provided direct access to the latest industry advancements.
National Electric Energy Testing Research and Applications Center (NEETRAC)	To test and validate industry solutions, particularly safety for metering services.	Involved in defining and testing the latest smart metering functionalities and applications.
Open Smart Grid (OpenSG)	Address delivery of utility smart grid and smart metering requirements and related key industry technology issues.	BC Hydro is actively involved in OpenSG efforts including smart grid security and applying best practices for protecting the smart metering network and smart grid.
Canadian Standards Association (CSA)	To certify the safety of electrical equipment.	Assist in the evaluation of new smart grid components to meet safety standards.
Canadian Electrical Association (CEA)	To represent the Canadian utility industry. Currently addressing metering standards and acceptance with Measurement Canada.	Committee work to support acceptance of future metering solutions.
Utilities Telecom Council (UTC)	To advance telecom solutions and set standards.	Participation to establish efficient smart grid communication solutions.
Canadian National Committee on Smart Grid Technology and Standards	To address appropriate standardization for smart grid in Canada.	Participation to guide Canadian standards in a global context.
Institute of Electrical and Electronics Engineers (IEEE)	To address international technology issues and set standards.	Participation on a variety of technical committees related directly to BC Hydro's program.
ZigBee Alliance	To develop open industry standards for low-power wireless communications.	Active participation in the "Smart Energy Profile" working group, which defines data communication standards for smart meters and in-home devices over a Home Area Network.
Health Canada	Responsible for helping Canadians maintain and improve their health, while respecting individual choices and circumstances.	Ensuring compliance with the protection of customers and workers related to electricity including electromagnetic fields (EMF).
SAP Lighthouse Council	To foster collaboration between SAP, major utilities and industry vendors to integrate Advanced Metering Infrastructure with utility Enterprise technology.	Exposure to leading practices that achieve integration of end-to-end processes between the meter and the backend systems, and to reduce a company's total cost of ownership for Advanced Metering Infrastructure.

GLOSSARY

Authorized Amount

Requested funding for a project inclusive of all contingencies and based on a fixed scope and in-service date.

British Columbia Utilities Commission (BC Utilities Commission)

An independent regulatory agency of the provincial government operating under and administering the *Utilities Commission Act*. The BC Utilities Commission's responsibility is the regulation of the energy utilities under its jurisdiction to ensure that the rates charged to utility customers for energy are fair, just and reasonable. The BC Utilities Commission is responsible for ensuring customers receive safe, reliable and non-discriminatory rates and shareholders receive a fair return.

Capacity

The maximum sustainable amount of energy that can be produced or carried at an instant. For example, a car engine's horsepower rating is its energy capacity.

Capital Refresh of Assets

The program assets are assumed to be replaced periodically based on the estimated economic life of each asset type.

Clean Energy Act

A long-term vision for BC to become a clean energy leader. This Act guides government, BC Hydro and the British Columbia Utilities Commission in advancing the province's ambitious sustainable energy vision.

Contingency

An amount provided in the estimate for a project having a fixed scope and in-service date to allow for potential costs which cannot be specifically identified at the time of estimate preparation but which experience shows will likely occur.

Customer Generation

Allows customers to generate power on a smaller-scale in order to provide an alternative to, or an enhancement of, the traditional electrical power system. It can take the form of solar panels, wind power, biomass, etc.

Definition Phase

Detailed investigation of the approved approach and preparation of a preliminary design, procurement, and Project Plan for Implementation Phase funding complete with business case. This phase also includes the securing of all key defining agreements.

Demand Side Management (DSM)

Actions that modify customer demand for electricity, helping to defer the need for new energy and capacity supply additions.

Direct Labour Cost

Labour cost without benefits or overhead loadings.

Distribution System

The portion of the power system that converts energy to the right voltage and delivers power to homes and businesses across the province.

Electrical Distribution System Optimization (EDSO)

Helps to reduce electricity usage and costs with no capital investment through matching voltage to equipment requirements.

Energy

How much is consumed (or produced) over a period of time.

Field Area Network

A secure two-way telecommunication network between customer meters, other end point devices, aggregation devices and network extenders.

Greenhouse Gas (GHG)

Gases that are thought to contribute to global climate change, or the "greenhouse effect," including carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O).

Grid Modernization

An automated, intelligent power delivery system that supports additional services and benefits to customers, the environment and the economy.

Gross Benefits

The value of benefits before the deduction of related costs.

Home Area Network (HAN)

A data communications system contained within a premise, such as a residence, that can connect devices (e.g. in-home display device) in the premise to the smart meter.

Identification Phase

Review of conceptual alternatives, evaluation of feasibility, review of alternatives, and delivery of a project plan for Definition Phase funding. This phase ends with a decision on whether or not to proceed to the next phase.

In-home Display

A device that can communicate with a smart meter to show how much energy is being consumed and at what cost.

In-home Feedback Tools

Different ways through which customers can receive feedback about the electricity they are consuming, and the cost of that electricity, in their home, business or other location. In-home feedback can include an in-home display and/or secure websites, home energy management systems etc. that provide information about energy consumption.

Implementation Phase

Includes detailed design, material and equipment procurement, construction, testing and commissioning into service. The phase ends with a Post-Expenditure Review and a Project Completion Report.

Initiation Phase

Establishment of an initial project team, research and benchmarking. This phase ends with a decision to proceed on whether or not to proceed to the next phase.

Interest During Construction (IDC)

When an asset is constructed, there is often a considerable period between the start of a project and its completion. Because the cost of an asset should include all costs incurred to prepare it for use, interest costs related to the construction are generally included in the cost of the asset that is capitalized.

Interval Data Recording (IDR)

A record of energy consumptions, with reading made at regular interval throughout the day, every day.

Measurement Canada

A federal agency responsible for ensuring the integrity and accuracy of measurement in the Canadian marketplace, including the accuracy of electricity meters.

Meter Data Management System

The software applications and infrastructure required to support the integration of data from the smart metering system into other BC Hydro systems. The data is made available to the utility for a variety of business functions such as billing, energy diversion detection and outage tracking.

Microgrids

Small networks of generating sources capable of operating independently from the electricity system. Microgrids can switch quickly between operating on and off the system, allowing communities to become more self-sufficient.

Net Benefits

The value of the benefits after the reduction of related costs.

Net Present Value (NPV)

The difference between the present value of benefits and the present value of costs (including capital, operating, maintenance and administration costs) for a given discount rate.

Nominal Growth/Price

Growth or price measured in current dollars at the time the goods are produced; change includes the amount of inflation.

Ongoing Operating Expenses

The incremental operating costs required to operate and maintain program assets, such as meter maintenance and telecommunications and software application operating costs.

Present Value

Today's discounted value of future receipts or expenditures.

Price Elasticity

The price responsiveness of consumption, expressed as the percentage change in quantity per a 1 per cent change in price. For example, an elasticity of -0.10 means that a 1 per cent increase in real price would lead to a 0.1 per cent decrease in consumption.

Project Costs

The authorized amount for the Smart Metering Program is $930 million (nominal), and this reflects the costs to put the program's assets required by regulation into operation.

Project Plan

A document that sets out a strategy and course of action for meeting the project objectives.

Revenue Requirement

A revenue requirement is the forecast cost of doing business for a period of time and must be approved by the British Columbia Utilities Commission. BC Hydro can collect its required revenue through tariffs—the rate charged to customers.

Regulatory Account

Deferred amounts related to the Smart Metering Program will be recorded in the Smart Metering Program Regulatory Account. BC Hydro's accounting policies allow for the deferral of amounts that under Canadian generally accepted accounting principles would otherwise be recorded as expenses or income in the current accounting period. The deferred amounts are either recovered or refunded through future rate adjustments.

Smart Grid

A smart grid delivers electricity from suppliers to consumers using digital communications to save energy, reduce costs and increase reliability and transparency. A smart grid is made possible by applying sensing, measurement and control devices with two-way communications, making it possible to dynamically respond to changes in system condition. A smart grid includes an intelligent monitoring system that keeps track of all electricity flowing in the system. It also has the capability of integrating clean, renewable electricity such as solar and wind.

Smart Meter

Smart meters provide two-way communication between the customer's meter and BC Hydro, capturing the amount of power that is consumed and when.

Smart Metering and Infrastructure Program

The Smart Metering and Infrastructure Program or Smart Metering Program plays a key role in modernizing BC Hydro's electricity system. It involves the introduction of new digital smart meters and the supporting infrastructure.

Supervisory Control and Data Acquisition (SCADA)

Computer systems used to send and collect supervisory controls and monitor data through power lines.

Volt-VAR Optimization (VVO)

Optimizes the energy delivery efficiency on distribution systems using real-time information, minimizing power loss.

Smart meters will allow BC Hydro to continue to manage the electricity system in a reliable, safe, and cost-effective manner.

Appendix C-5

Exponent Status of Research on RF Exposure and Health

Health Sciences Practice

Status of Research on Radiofrequency Exposure and Health in Relation to Advanced Metering Infrastructure

Status of Research on Radiofrequency Exposure and Health in Relation to Advanced Metering Infrastructure

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Contents

Limitations

At the request of FortisBC, Exponent prepared this summary report on the status of research related to radiofrequency 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.

1. Introduction

Radiofrequency energy (RF), also known as radio waves, refers to a range of frequencies in the electromagnetic spectrum. The electromagnetic spectrum includes fields in an array of frequencies measured in cycles per second (referred to as Hertz [Hz] and a corresponding range of wavelengths. Energy along the electromagnetic spectrum ranges from waves with low frequencies and long wavelengths (e.g., power-frequency EMF) to waves with high frequencies and short wavelengths (e.g., visible light, X-rays, gamma-rays). The RF range is at the lower end of the spectrum, lower than infrared rays, visible light, and ultraviolet light.[1] It is typically defined as between 3,000 Hz ($3x10^3$) and 300 billion Hz (3×10^{11}). RF energy includes frequencies used to operate various devices and technologies, including amplitude-modulated (AM) and frequency-modulated (FM) broadcast radio, television, mobile phones, cordless phones, garage door openers, baby monitors, wireless computer networks, security systems, radar, and microwave ovens.

RF signals have been used for familiar items like radio broadcasts for the past one hundred years, and even before that, for wireless telegraphy since the late 1890s. More recently, technological advancements have used very weak RF signals to operate cordless phones, baby monitors, wireless networks, and mobile phones. While research on RF energy has been conducted since the World War II era to support development of health-based exposure limits and standards, the recent proliferation of this technology has sparked additional research on RF fields, particularly in regard to mobile phones. Research on RF fields and health has increased in part because mobile phones are in widespread use, are used regularly, and are held next to the human body. In 2010 there were over 24 million mobile phones in use in Canada alone and about 5 billion throughout the world.

Although the main focus of this research has been on mobile phones, the widespread introduction of other devices that emit RF energy, such as advanced meters (also known as smart meters), also has raised questions about exposure and health. The main public questions

[1] While in engineering disciplines, RF and EMF are used synonymously, the common usage of EMF in epidemiologic studies primarily refers to electric and magnetic fields associated with the generation of electricity from power lines and all electric devices at 60 cycles per second (60 Hz).

that arise in regard to these devices are about cancer risk from long term exposures and symptoms from short term exposures. These areas are the focus of the overview of research in this report.

The purpose of this report is to assess the impact of recent research on the conclusions about adverse effects of relatively low levels of RF energy. This report begins with description of the methods scientists use to compile and evaluate research about the impact of an exposure on human health (Section 2). Section 3 discusses the nature of the health effects from high exposures to RF energy, the basis for the standards that have been set, and identifies the relevant standards to ensure the safe use of any device that uses RF energy. Section 4 discusses the reviews that have been conducted by scientific and health organizations. Section 5 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 2.

2. Evaluating Scientific Research

Health risk assessment approach

A health risk assessment is the scientific method used by scientists worldwide for determining whether or how an exposure in the environment, such as chemicals in the air, water, or food, or devices such as mobile phones or advanced meters, can affect human health. Health risk assessments include four general steps: hazard identification, dose response assessment, exposure assessment, and specific risk characterization.

In the first step, *hazard identification*, scientists identify and review all of the relevant scientific research studies of effects in humans and laboratory animals to determine the types of health problems that might result from exposure. The next step, *dose-response assessment*, is an evaluation of the data from the hazard identification to determine what intensity and duration of exposure causes adverse effects that have been identified. The dose response assessment is the basis for developing exposure limits and regulatory standards. Next, the *exposure assessment*, evaluates the amount and nature of human exposure from the agent being studied. The final step, *specific risk characterization*, compares the dose response pattern to the amount of the specific exposure being investigated to determine a level of risk for the exposed population. For some exposures, limits already have been developed from the data as a regulatory standard. In such cases, as for exposure to RF signals from advanced meters, the final step is to compare the specific exposure to the relevant standard.

Hazard identification

In a hazard identification, scientists search out and review all of the relevant scientific research studies to determine the types of health problems that an exposure could cause, regardless of the exposure. This process considers epidemiology studies of humans in their natural environment, experimental laboratory studies of humans or laboratory animals (*in vivo* studies), and laboratory studies of cells and tissues (*in vitro*) that may provide evidence for a mechanism—the way in which the exposure interacts with biological tissue. These three types of studies provide different but complementary information to determine how an exposure affects biological organisms. Only human and animal studies of RF exposure are considered in this report because they provide more direct information on human health than *in vitro* studies.

Dose-response assessment

The second step in the risk assessment process is to determine how responses to the exposure relate to the level of exposure. Almost anything in our environment can produce adverse effects if the exposure is high enough, including water and some vitamins, so the goal is to find the level below which adverse effects do not occur.

In a dose-response assessment, scientists evaluate the scientific research to estimate the amount of exposure (dose) that is likely to result in a particular health effect in humans. This is important because many things that might impact human health only do so after a certain amount of exposure has occurred. A simple summary of the dose–response principle is that for chemicals or physical agents that could affect biological function, 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. Then, exposures at lower levels are used to identify exposure levels that do 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 causality.

The concept of dose-response is a familiar part of our daily life. We know, for example, that the application of sunscreen lowers an individual’s exposure to sunlight, thus reducing the risk of sunburn. Another example is that a 6 percent solution of sodium hypochlorite, commonly known as bleach, carries a warning label that this substance is hazardous, dangerous, and corrosive. But, a similar highly-diluted solution 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.

Exposure assessment

The third step of the process 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.[2]

Specific health risk characterization

The information developed in the hazard identification, dose-response assessment, exposure assessment is used to reach a conclusion and characterize the specific health risk, if one exists.

Types of studies considered in a health risk assessment

The risk assessment process includes evaluating the methods used in conducting each individual study included in the hazard identification, analyzing the results,, and weighing the evidence, giving more weight to studies of better, more reliable designs, i.e., a weight-of-evidence review. This process is designed to ensure that all relevant studies are considered regardless of their conclusions or support for any particular hypothesis. During the weight-of-evidence review, scientists look for replication of results by different researchers or other laboratories to form conclusions about causality, because no single study is capable of assessing causality independently.

Epidemiology studies

One aspect of epidemiology research provides descriptive statistics on the population, such as birth rates and mortality rates, to help characterize health and disease in the population. These data are collected by public health organizations such as Health Canada to show trends over time or differences among places. Examples include data that show changes in heart disease deaths over time, variations in infant mortality rates among cities, or cancer occurrence in Canada overall and comparisons among provinces. These data are often compared to actions in the population that might affect cancer, such as comparing rates of lung cancer or heart disease over time to the changing rates of cigarette smoking.

Epidemiologists also study people in their natural environment in relation to individual exposure. These studies are often described as observational rather than experimental, although observational studies can include elements of experimental studies, for example studies of RF

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2 The exposure assessment for Advanced Metering Infrastructure's smart meters can be found in Appendix A.

often include interventions, such as turning sources of RF on or off at various times during the study. Each of the three main types of epidemiologic study design—cohort, case-control, and cross-sectional—have been used to obtain information on RF and health. In a cohort study, a group of people are observed over a long period to determine whether diseases develop in relation to exposures at various levels. This type of epidemiology study typically provides the most relevant and reliable information, particularly for conditions that develop over years, but it is often cost-prohibitive and time-consuming because it requires that a large number of people be followed over a long period. Cohort studies are often undertaken in occupational environments, because of the large population, relatively high exposures, and availability of records on individual workers.

To obtain information more readily, epidemiologists frequently use case-control studies. This type of study compares the exposure of people who have been diagnosed with a particular disease (i.e., the cases) to a similar group of people who do not have the disease (i.e., controls). The objective is to assess whether the cases have had a higher exposure level or more frequent exposure than the controls, or *vice versa*. One main challenge of a case-control study is to enroll a control group that is, to the greatest extent possible, similar to the case group on all factors but the presence of disease. If this condition is met and a difference is found in the exposure level between the two groups, the investigators can have some confidence that the difference is not being caused by some other factor. Another challenge of case control studies is that they are retrospective in nature (i.e., the study starts after onset of disease so *past* history of exposure must be evaluated).

Cross sectional studies look at the exposure and the outcome in a specific population in the same time period. Cross sectional studies are used to study acute outcomes, that is, diseases or conditions that occur in a short time period after an exposure such as a toxic chemical leak or spill, or an ongoing exposure such as emissions from traffic or industry sources of a possible air pollutant. Acute effects typically occur from relatively high exposures, and chronic effects, such as cancer, are typically linked to long term exposures at low levels. In the study of RF exposure, cross sectional designs have been used to study short term effects such as changes in sleep patterns, or non-specific symptoms such as headache, fatigue, nausea, or dizziness.[3]

The results of epidemiology studies are expressed as a statistical association, either an odds ratio (OR) in case control studies or risk ratio (RR) in cohort studies. These ratios are a quantitative measure of how an exposure and disease vary together. The strength of an association addresses the question—does this disease occur more often in people with the exposure of concern compared to people who are unexposed? A positive association (i.e., an OR or RR greater than 1.0) indicates that the answer may be yes, but numbers close to 1.0 indicate a weak link, and higher numbers a stronger link. While this information from an epidemiology study may provide an indication as to the factors involved in health and disease, neither a statistical association nor a correlation between any two things is a direct indication of cause and effect, because each study is only a sample of the population, random chance can affect results, and no single study is perfect.

The validity of a study depends upon the quality of the data, which depends upon the methods used to collect and analyze the information from which the results were calculated. To evaluate the results of any type of study, whether an epidemiologic study or laboratory research, it is crucial to assess the way the study was designed and conducted, the number of participants, the accuracy of the exposure assessment, and the statistical methods of analysis. This is particularly necessary in epidemiology studies to determine whether an association is a result of systematic error (bias) in selection of participants, misclassification of exposures, secondary effects by other variables such as the presence of other exposures or pre-existing conditions (confounding), or random variation (chance). Even if a statistical association from a single study is deemed valid, further scrutiny is warranted to determine if the statistical association indicates a cause and effect relationship.

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[3] Non-specific symptoms refer to self-reported conditions that are not directly linked to a specific disease.

Experimental studies

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 studies of the effects of planned exposures on human volunteers (usually short-term studies), whole animals (usually long-term studies, i.e., *in vivo* studies), and isolated cells and tissues (i.e., *in vitro* studies). Human and animal studies of RF exposure are considered in this report.

Specific methods are used to reduce subjectivity and avoid systematic error, or bias, in scientific experiments (NRC, 1997). These include the random assignment of subjects to control or comparison groups, the unbiased collection of information (e.g., researchers are not aware of the exposure, also termed “blind” to the exposure), and the need for replication of results in different studies, at various different laboratories, and across species, all of which strengthen the evidence. In addition, each study should contain enough participants or animals to overcome random variation. These factors serve as guidance for weighing the evidence from studies to reach a decision about cause and effect. The more firmly these criteria are met by the studies, the more convincing the evidence.

Studies in which laboratory animals receive high exposures in a controlled environment provide an important basis for evaluating the safety of environmental, chemical, and drug exposures. These approaches are used widely by health agencies to assess risks to humans from medicines, chemicals, and physical agents, because studies in laboratory animals such as rats and mice have been found to be reasonable indictors of adverse effects in humans (Health Canada, 1994; WHO, 1994; IARC, 2002 preamble; 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 critically sensitive periods be conducted to assess potential toxicity to humans (Health Canada, 1994). Furthermore, the position of the United States Environmental Protection Agency (EPA) 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).

3. Basis for Exposure Limits and Regulatory Standards

If the health risk assessment process indicates that there might be potential health hazard from higher exposures to a substance or physical agent, a government agency or technical organization is likely to promulgate a standard. A health standard is developed from the hazard identification and dose response assessment of the risk assessment process described above. A health agency or scientific organization typically evaluates three types of studies (epidemiology, *in vivo*, and *in vitro*) during the risk assessment. Most organizations identify experts in the many relevant disciplines that perform research on the topic of interest to evaluate the research. The scientists that developed Health Canada's Safety Code 6 (Limits of Human Exposure to Radiofrequency Electromagnetic Energy in the Frequency Range from 3 kHz to 300 GHz) used the risk assessment approach to evaluate all research related to RF exposure and health (Health Canada, 2009).[4]

The objective of any standard, whether it is regulating drinking water, air quality, or food safety, is to keep exposure below the lowest level at which any established potentially adverse effect is known to occur. The approach scientists use to develop health-based standards is to set the exposure many times below the level at which research suggests that an effect could occur. This conservative approach helps to compensate for unrecognized limitations in the research and exposure assessment, and to afford additional protection to all members of the population. The number used to lower the exposure limit below the lowest known effect level has been referred to as a 'safety factor'.

As with most environmental exposures, few studies of RF exposure include children and other sensitive persons. Several methods are used to develop protection for these populations. One approach is to incorporate information about the mechanism by which the agent affects the human body and ascertain whether children or the elderly would react differently because of biological characteristics. Another is to conduct experimental studies of animals at varying stages of development to determine potential sensitivities of the young and the old. Finally, scientists recommend exposure limits that are comfortably *below* levels known to produce

[4] http://www.hc-sc.gc.ca/ewh-semt/pubs/radiation/radio_guide-lignes_direct-eng.php

effects. This incorporates the basic scientific concept of dose response, which refers to the principle that the probability of an effect occurring, or the severity of an effect, increases with the dose, or amount of exposure.

Basis for the standard for radiofrequency exposure

The RF standards are called 'safety standards' because they address issues of human health and safety, and they prescribe exposure limits for a level in the environment presumed harmless. An exposure limit is the amount of exposure to RF at a specified frequency or a range of frequencies that should not be exceeded in order to protect human health with an adequate margin of safety.[5]

These exposure limits are based on the risk assessment process, those established scientific and technical methods for reviewing biological and health research. The RF standard in Canada, for example, uses a 50-fold reduction factor below an effect level reported in research studies to arrive at an exposure limit for all members of the general public (Health Canada 2009, p.9).

Known adverse health effects can be caused by high exposures to RF. The effect that would occur first, given sufficient exposure, is that of raising the body temperature. This is the basis of the applicable public exposure limit. Small changes in whole body temperature are actually not an adverse effect if they represent a change similar to daily changes to which our bodies routinely adapt (Erdreich and Klauenberg, 2001; IEEE, 2005). Health Canada's safety code and those of other organizations set exposure limits to ensure that the warming of tissues is restricted. The goal of the standard is to limit such warming of tissues, since even modest warming of the body can be distracting, and should be limited in a working environment. At higher levels of exposure, more serious adverse effects could occur, including effects similar to hyperthermia and local cell damage. Therefore the exposure limits in the RF standards are set below the level at which even minor effects from tissue heating might occur (FCC/OET Bulletin 56, 1999; IEEE, 2005; ICNIRP, 20009, Health Canada, 2009).

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5 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 standards.

Relevant standard in Canada

The regulatory standard in Canada to ensure public safety is the responsibility of Industry Canada, which has selected the human exposure limits developed by Health Canada, Safety Code 6 (Health Canada, 2009). These guidelines, first developed in 1979, are the product of ongoing review of published scientific studies, reviews, and research conducted by Health Canada. The website of Health Canada notes "This code is periodically revised to reflect new knowledge in the scientific literature. The current version of this code reflects the scientific literature published up to August 2009 and replaces the previous version published in 1999."[6]

[6] http://www.hc-sc.gc.ca/ewh-semt/pubs/radiation/radio_guide-lignes_direct-eng.php

4. Expert Reviews of Radiofrequency Fields and Health

Many organizations such as the International Commission on Non-Ionising Radiation Protection (ICNIRP), the Health Council of the Netherlands (HCN), the Scientific Committee on Emerging and Newly Identified Health Risks (SCENIHR), the Swedish Radiation Safety Authority (SSM), and Health Canada have reviewed the research and have independently supported the derivation of exposure limits on the basis of tissue heating, or developed a set of exposure limits for RF energy in various frequency ranges (ICNIRP, 2009; HCN, 2009; SCENIHR, 2009; SSM, 2009; Health Canada, 2009). These organizations have reviewed all of the available research through 2009 and have not concluded that RF exposure below the exposure limits developed by ICNIRP, which are similar to those of Health Canada, causes any type of cancer, other chronic disease, adverse physiologic changes, or symptoms that affect well-being.

Some studies have reported effects occurring with RF exposures below the level that raises body temperature, often called *non-thermal* effects. Non-thermal effects or low level effects refer to effects that occur at levels not believed to cause tissue heating. These studies have been reviewed by scientific and regulatory agencies, which have not accepted this data as reliable because the observed biological effects attributed to non-thermal levels were not consistent or reproducible, are not supported by any plausible biological explanation as to how they could occur, and in some studies the biological effects reported are not known to be linked to adverse effects on health (IEEE, 2005; ICNIRP, 2009; HCN, 2009; NRPB, 2004; SCENIHR, 2009; SSM, 2009, 2010).

The International Agency for Research on Cancer

In May 2011, a Working Group of scientists with expertise in various areas related to RF was convened to review the evidence for RF exposure and cancer for the IARC.[7] The IARC utilizes a standard preamble in their documents, which describes the risk assessment method and how they assess the weight of the evidence, and provides a categorization of the standard ratings

[7] 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/).

used, so that the terminology of conclusions is consistent across exposure sources (IARC, 2002 preamble). IARC relies heavily on epidemiology studies in humans and laboratory evidence of animal carcinogenicity, and considers *in vitro* studies to provide information on how the exposure might affect a change in health status.

The Working Group concluded that there was "limited evidence" in epidemiology studies, based on positive associations between use of wireless phones and a type of brain cancer. They also rated experimental studies of animals for carcinogenicity of RF exposure as "limited evidence." Data is rated "limited evidence" in epidemiology studies if a positive association between an exposure and cancer is found, although factors such as chance, bias, and confounding cannot be ruled out with reasonable confidence. Following the methods in their preamble, the rating "limited evidence" caused the IARC to include RF exposure in their Category 2B "possible carcinogen."[8] The IARC's categories err on the side of caution; only 1 out of 927 substances has been classified as "probably not a carcinogen." The vast majority of substances are classified as "possible carcinogens" or "not classifiable," leaving 107 "known carcinogens" and 58 "probable carcinogens." The category "possibly carcinogenic to humans" denotes exposures for which there is limited evidence of carcinogenicity in epidemiology studies and less than sufficient evidence of carcinogenicity in studies of experimental animals and include such things as occupation as a firefighter, pickled vegetables, and coffee. Moreover, the IARC statement was based on the review of studies involving mobile phones and RF exposure, which is a much greater than the exposure from advanced meters. The IARC report, however, does not comment on the level of exposure.

The Swedish Radiation Safety Authority

In their latest annual review (SSM, 2010), the Swedish Radiation Safety Authority's Independent Expert Group on Electromagnetic Fields considered studies published in 2010, including several that were available ahead of print as e-publications in 2010 and were published in 2011. They reviewed the Interphone data on brain tumors, and identified recall

[8] Category 1 is a "known carcinogen," Category 2A is a "probable carcinogen," and Category 3 is "not classifiable."

bias and participation bias as possible sources of systematic error, conclusions also reached by the Interphone Study Group (Interphone, 2010).

The SSM's "update on key issues" noted the following overall conclusion regarding the Interphone study:

> This year has seen the publication of the long awaited Interphone study looking at brain tumour risk in mobile phone users. However, 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. 260).

In addition, the SSM distinguishes potential risk by short-term users from the risk from long-term use:

> … the INTERPHONE study could not finally resolve whether use of mobile phone causes brain tumours. At least, a short term risk can be excluded with a high degree of certainty, but uncertainty still remains regarding very intensive and long-term use (SSM, 2010, p. 260).

And, they concluded the following regarding low level RF exposure from base stations and transmitters:

> 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.

Typical RF levels of advanced meters are not higher than these sources of low levels of exposure (Appendix A, Figure 1).

The International Commission on Non-Ionizing Radiation Protection

In 2009, the ICNIRP published the results of their comprehensive review of RF research that they conducted to update their 1998 exposure limits (ICNIRP, 1998, 2009a). The report, "*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)*" was prepared by 14 scientists from 10 different countries who are members of ICNIRP. As a result of this review, which include and evaluation of studies on symptoms, 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, 2009a, p 261).

5. Current Research on Radiofrequency Fields

This section provides a summary of research published after the most recent comprehensive reviews were completed (ICNIRP, 2009; HCN, 2009; SCENIHR, 2009; SSM, 2009; Health Canada, 2009). The purpose of this update is to assess the impact of these recent studies on the conclusions about adverse effects of relatively low levels of RF energy on such outcomes as cancer and non-specific symptoms, in comparison to the conclusions expressed by the recent weight of evidence comprehensive reviews, above. It focuses on recent epidemiology and *in vivo* studies of higher quality, regardless of direction of the results, and notes in general the limitations of weaker studies. For example, studies that are too small in size (i.e., too few people or laboratory animals), have not provided adequate controls, or use proxies or less reliable measures of individual exposure assessment, provide little useful information to evaluate the safety of RF exposures.

These studies examine both near-field exposures (i.e., those close to the body, such as mobile phones and other handsets) and far-field exposures (i.e., from sources further from the body such as radio and TV transmitters, base stations, and wireless local area network [LAN] access points).[9] Exposures from advanced meters will be far field under typical use.

Studies of cancer

Epidemiology studies and long term studies in animals provide the most direct information about the effect of RF exposure on cancer development. Studies on cancer and RF energy have been conducted since the 1970s; however, as use of mobile phones increased recently, many additional studies have been undertaken. These include both epidemiologic studies of users of mobile phones and exposures to mobile phone base stations, and laboratory studies of long term exposures to laboratory animals, including exposures to the head. In addition, since mobile phone use has become widespread, epidemiologists have examined the time trends in tumors of the exposure areas, including brain cancer. While studies of RF at any frequency are generally

[9] Near field and far field are not defined solely by physical distance, but by distance in relation to the wavelength and the antenna geometry. The distance to far field is typically close to the size of the wavelength.

relevant to the development of RF exposure limits and standards, frequencies used in mobile phones are more similar to those of used by advanced meters than those from AM radio transmission or radar, although the intensity (strength) of advanced meter exposures under foreseeable use is lower than that of mobile phones.

Epidemiology studies

Currently the greatest source of individual exposure to RF radiation for most people is use of a mobile phone, which has been a major component of contemporary scientific research about RF exposure and health. Other sources, including cordless phones, WiFi and mobile phone base stations, are weaker contributors to individual exposure. Cordless phone typically operate at far lower power levels than mobile phones, because they have a base unit connected to the telephone wiring in a house and so they produce lower RF exposures. Radar, AM/FM radio transmitters, and TV broadcast transmitters are far more powerful than mobile phone base stations, but like all types of electromagnetic fields the strength diminishes rapidly with distance from the source. These environmental exposure sources pose difficulties for individual exposure assessment in epidemiological studies because people generally do not spend all their time in one location (i.e., at home), so a valid measurement of average exposure is difficult to determine.

The sections below are grouped by exposure source, and to some extent this mirrors the intensity of exposure. The lowest of the exposures described below is that from mobile phone base stations and AM radio antennas. Occupational studies focus on occupations with the potential for higher exposure to RF energy, like radar operators and workers at a mobile phone manufacturing facility. The highest exposures studied are likely to be those of users of mobile phones (a localized near-field exposure), for which a large set of studies and pooled analysis was recently completed. Given the dose-response nature of effects on human health, mobile phone exposures represent the highest dose scenario for people in the general population, and therefore, the greatest potential for detecting adverse response to RF exposure. Exposures higher than that of mobile phones exposures are possible in laboratory animals, described in the section on laboratory studies below.

Exposure from mobile phone base stations

The difficulty of accurately assessing human exposure from a single low level source such as a nearby base station is compounded by other sources of low level RF in the environment, including AM and FM radio transmitters, TV broadcast transmitters, and household wireless appliances. The number of cancer cases in local area populations is typically too small to support epidemiologic studies and account for cancer latency—for most cancers the duration or latency period between exposure and diagnosis is decades, not a few years.

Some researchers have evaluated reports that appear to be cancer clusters by combing all types of cancers as one disease. Combining various cancer types is not viewed as a useful method for finding causes because the term ‘cancer’ describes over 100 diseases that originate in different types of cells, occur at different rates, and have different causes (ACS, 2009). Two studies that assessed cancer rates in adults in the vicinity of mobile phone base stations use this method (Eger et al 2004; Wolf and Wolf, 2004).[10] No valid conclusion can be drawn from these two studies because of small numbers and other flaws in their methodology.

Epidemiologists can obtain more reliable data for assessing the effect of low level exposure by studying a larger group of people in a case-control design, and use better methods of estimating exposure than distance from a single base station. One of the few epidemiologic studies of cancer in children estimated exposure from all mobile phone base station antennas (masts) in the vicinity of the residence in mothers of 1,397 children, ages 0-4, diagnosed with cancer and 5,588 controls (Elliot et al., 2010). The researchers used three different methods to assess each mother’s exposure to RF; the average distance from all masts within 700 metres, the total RF power output of masts within 700 metres, and the modeled power density at the residence. There was no association between development of cancer in the child and any of these measures of the mother’s exposure to low-level RF.

Epidemiology studies of exposures to radio antennas that used sophisticated exposure measures and large number of participants are described below.

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[10] Neither of these was published in a journal indexed in Medline, i.e., they were not peer-reviewed.

Exposure from AM radio or TV transmitters

Research published in the peer-reviewed scientific literature addressed the risk of cancer, particularly leukemia, in adults or children from exposure to AM radio or TV transmitters. Exposures from these sources are quite low. The majority of this research through 2003 studied geographical correlations, a method described as an ecological design, which compares group cancer rates for geographic areas, but does not assess exposure of individuals (Hocking et al., 1996; Dolk et al., 1997a, 1997b; McKenzie et al., 1998; Cooper et al., 2001). The results are limited by the use of distance as a surrogate for RF exposure from the single source, and the assumption that all people in an area have the same exposure, and no other exposure.

Two more recent case control studies of exposure to RF from AM radio transmitters, one in South Korea and one in Germany, provide more reliable epidemiologic information than geographic correlation studies (Ha et al., 2007, 2008; Merzenich et al., 2008).[11] Each was a large study that addressed the association between exposures from AM radio transmitters and leukemia in children, and assessed RF exposure for each individual participant (cases and controls), using calculations based on physical characteristics of antennas and the location of the residence of each participant.

Exposure assessment was based on calculations designed to predict the individual's total RF exposure at the residence from all of the AM radio transmitters established the year before the leukemia was diagnosed. Each study provided some evidence of validation of the exposure assessment model by calculations, although this was better documented and more complete for the German study (Merzernich et al., 2008; Schmiedel et al., 2009). Although similar in design to the South Korea study, the study in West Germany had a stronger design on several factors. The calculation used for exposure assessment was validated and published (Schmiedel et al, 2009), controls were population based rather than clinic based, three controls were used for most cases, and exposure tended to be higher. Neither of these two large case-control studies reported elevated ORs, or any statistically significant associations with leukemia or leukemia subtypes (lymphocytic or myelocytic leukemia) in children, even those who had highest levels of total RF exposure (below 1 V/m) from AM radio station transmitters.

[11] Ha et al. (2008) provides a correction to the data on total RF exposure published in Ha et al., 2007.

Occupational exposure

Workers in environments such as military facilities, where exposure to radar is likely, may incur exposure over the limits expressed in the RF standards. In most of these studies, exposure was estimated mainly by using occupation or job title as a proxy for exposure. Earlier studies reported some statistical associations between proxy measures of exposure and mortality from leukemia, but sources of bias in the study design, and confounding from other concomitant exposures reduced the value of the results (Milham, 1985; Szmigielski, 1996). Morgan et al. (2000) found no associations with any type of cancer in adults who worked manufacturing mobile phones, and Groves et al. (2002), which studied cancer in United States Navy veterans of the Korean War, reported an association with leukemia in only one of three naval occupations presumed to have high RF exposure from radar. These studies have been evaluated in scientific reviews, which found no consistent or convincing evidence that RF exposure is a cause of leukemia or any other cancer (ICNIRP, 1998, 2009; Ahlbom et al., 2004; NRPB, 2004; IEEE, 2005).

Mobile phone exposure

Mobile phones transmit and receive RF signals and are tested before marketing to verify that they operate in compliance with national RF standards, which limits exposure to the area of the head where the phone is held. Near-field exposure from a mobile phone is nevertheless higher that other environmental sources, unless a hands free device is used.

Since mobile phone use has become widespread and research expanded to provide increased information, epidemiologists can examine time trends in rates of brain cancer in populations in which there is widespread use of the phones.

Two studies of mobile phone use were published recently, one of adults (Cooke et al., 2010) and one of children and adolescents (Aydin et al., 2011). Researchers in Great Britain studied leukemia in 806 adults, and found that cases did not have increased regular mobile phone use compared to the control population. There was no link or positive trend with increased duration of use or cumulative use time, or any subtype of leukemia (Cooke et al., 2010). In Europe, epidemiologists studied children and adolescents with brain tumors by assessing mobile phone use in 352 cases, age 7-19, from cancer centers in Denmark, Norway, Sweden, and Switzerland from 2004-2008 (Aydin et al., 2011). Results did not show a trend of increased brain tumor risk with amount of use, or a link with tumors in the brain areas near where the phone is held; the study does not support a cause-and-effect link.

The most comprehensive research in humans of mobile phone use is the large multi-site, multi-national project developed and coordinated by the IARC, referred to as the INTERPHONE study. INTERPHONE includes 13 case-control studies of adults conducted in the United Kingdom, several European and Scandinavian countries, Japan, Israel, Canada, New Zealand, and Australia that followed a similar design so that results could be combined (pooled) with reasonable confidence. The brain cancer types studied include gliomas, which are malignant tumors, and meningiomas, which are benign (INTERPHONE, 2010). The INTERPHONE Study Group also studied acoustic neuromas (benign tumors), the results of which were published in 2011.[12]

Among the studies from individual countries, or pooled over several of the countries, the measure of 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 users (Christensen et al, 2005; Hepworth et al, 2006; Lönn et al 2005, Schüz et al 2006; Schoemaker et al 2006). If interpreted at face value, this would imply a reduced risk of brain cancer with regular phone use, compared to never users.

The INTERPHONE Study Group report (2010) pooled data for all the sites; the overall risk estimate for the major type of brain cancer (glioma) was again below 1.0, 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.

To obtain thorough information, the researchers evaluated exposure in several ways: as regular users (an average of at least one call per week for more than 6 months) and non-users, duration of cell phone use, cumulative call time, and cumulative number of calls. The only positive

[12] 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.

association that appeared 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.

As in most reports of scientific investigations, the INTERPHONE investigators include a discussion of issues in the design and execution of their study that could impact its results and the interpretation of those results. The authors have included Appendices to explore the impact of known limitations, mainly recall error and selection for participation. Recall error, often called recall bias, is widely recognized as bias that results when cases are more likely to report an exposure in the past than controls and that recall of exposures in years past can be inaccurate (Cardis et al., 2011). Selection bias is caused when the methods for selection, or agreement to participate, leads to differences between the cases and controls that can affect results. These recognized uncertainties are examined in the report. The INTERPHONE study is the largest to date on mobile phone exposure and brain cancer, and reported limited evidence of an increase in cancer risk associated only with the group with the highest cumulative use of mobile phones although no evidence of dose-response pattern. 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 other epidemiologic studies published prior to the Interphone study had not reported that people with brain cancers had a history of more mobile phone use (Muscat et al, 2000, 2002; Inskip et al., 2001; Schüz et al., 2006). There is one exception to this consistency of results across studies: positive associations have been reported in pooled results of case control studies from Sweden (Hardell, 2006a, 2006b; Hardell et al., 2011). These pooled analyses included information on use of cordless phones, and reported a positive association with mobile phone use in subgroups of longer term use, or use on the same side of the head as the tumor (ipsilateral use). Hardell (2006a, 2006b) and Hardell et al. (2011) report positive associations for mobile phone use and brain cancer, which tended to be stronger with increased hours of use. These indications of dose-response, if consistent across valid studies, would be interpreted as support inferences of causality, however, limitations in the analyses have been raised.

The limitations of the authors' analyses in these three studies are the unclear definition of user (any use, with no minimum amount specified), the potential bias in data collection methods, variations across publications in the definition of case groups, unclear exposure definitions (mobile phone types, inclusion or exclusion of cordless phone use), and the selection of results from multiple overlapping studies. These decisions result in data that is not always sufficiently clear to allow the reader to unmistakably understand the analyses, and raise concerns on the validity of the results, as has been noted by reviewers (Ahlbom et al., 2009; Swerdlow et al., 2011).

Brain cancer rates over time

If the increased risks suggested by the INTERPHONE Study Group (2010, 2011) in the highest use group and the Hardell study data (Hardell, 2006a, 2006b; Hardell et al., 2011) were correct, we might expect to see some increase in annual rates of brain cancer, particularly 10 years after mobile use became widespread. The period of 10 years or more would allow for the development of tumors, and if causal, would show increases in brain cancer rates as more people had a longer period of exposure through mobile phone use. No increase in brain cancer rates over time was seen in the combined populations of Denmark, Norway, Sweden, and Finland from 1973 to 2003 (Deltour et al., 2009), or in Switzerland from 1969 to 2002 (Röösli et al., 2007). It is important to assess these trends in data extended to longer time periods—the most recent analyses examined trends in England from 1998 to 2007 (de Vocht et al., 2011) and in the United States from 1992 to 2006 (Inskip et al., 2010). These data also did not indicate that the occurrence of brain cancer has increased over the years since the use of mobile phones became increasingly widespread (the late 1980s and 1990s).

Laboratory studies in animals

The data on laboratory animals was reviewed by ICNIRP (2009) and most recently the IARC (Baan, 2011). 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 Federal Drug Administration in the United States has requested the National Toxicology Program[13] 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 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

Based on epidemiology studies of people who use mobile phones, which provided 'limited evidence of carcinogenicity,' [14] even at the relatively high exposures to RF energy from mobile phones, and the 'limited evidence of carcinogenicity' in laboratory animals, the IARC Working group ranked RF energy in the category "possibly carcinogenic to humans" (Group 2B). Other review groups have also evaluated these data, including IARC's animal bioassays and many, but not all, of the INTERPHONE studies, and have not concluded that RF energy is likely to cause cancer (ICNIRP, 2009; SSM, 2010).

[13] The National Toxicology Program is part of the United States Department of Health and Human Services.

[14] This category is used when studies report an association, but when chance, bias, or confounding cannot be ruled out with confidence.

The World Health Organization continues to refer to the exposure limits developed by ICNIRP and the IEEE, as 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).

Symptoms related to well-being

The primary focus for this section of the report is on the recent studies on low level far-field exposures and symptoms related to well being. Epidemiology studies and human experimental studies are suitable for evaluating whether exposure to relatively low levels RF energy can cause short term health effects. The scientific literature includes studies of both near-field (i.e., mobile phones) and far-field (i.e., wireless LANs, base stations, and advanced meters) exposures. Some studies include methods to assess whether people can perceive exposure to these low levels of RF.

Although a large number of relevant studies of symptoms have been conducted over the years, many have limitations such as a small number of study subjects, self-reported rather than objectively-measured exposure assessments, and use of exposure surrogates such as distance from a single source (Frei et al, 2010). The more reliable studies of humans are double-blind, which means that neither the participants nor the researcher is aware of the exposure status.[15]

The summary below includes a published systematic review and meta-analysis of existing research that the authors examined through March 2009, as well as recent epidemiology and laboratory studies published through June 2011. Recent studies were selected for inclusion by focusing on those that incorporated quality factors to increase validity, such as improved exposure assessment methods, field interventions, and large groups of participants.

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[15] Blinding is a means to control for human error or bias due to conscious or subconscious preconceived ideas in both participants and researchers.

Researchers from the Swiss Tropical and Public Health Institute and the University of Basel in Switzerland conducted a systematic review of the research, which is a method that requires identifying all relevant peer-reviewed published studies, documenting methods of the literature search, and specifying the criteria for exclusion or inclusion of studies (Röösli et al 2010). The inclusion criteria required that studies use objective measures of exposure and show a clear description of an acceptable method for selecting participants.

Using this process Röösli et al. identified 5 human laboratory trials (randomized double-blind studies) and 12 epidemiology and field intervention studies of diverse symptoms published from August 2007 through March 2009 (Röösli et al., 2010).[16] Each of these included headache or tension as an outcome, and in each study exposure assessment and selection procedures were judged to be adequate. The results did not provide evidence for an increase in health effects related to exposure. The authors reported that no single symptom or symptom pattern was consistently related to exposure. They also noted, "The cross-sectional epidemiological studies, however, 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 (p. 890)."

Röösli et al. had planned a meta-analysis of all the data (i.e., statistically combine the data across studies to increase the power of the data), but for most health measures the studies were not sufficiently similar in methods or endpoints to combine the data, with one exception; studies that tested the ability of people to detect or identify the presence or absence of an RF field. When results were combined in the meta-analysis for four randomized double-blind trials, the association did not indicate that individuals could differentiate the field exposure from the sham (the session in the same laboratory setting but without exposure). Detection was also no better than chance in the combined results of people who had reported that they were sensitive to fields.

Recent human studies of far-field exposures published after the systematic review described above have been primarily cross-sectional epidemiology studies.

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[16] 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.

Epidemiology studies of short-term effects such as headache, sleep disturbances, and fatigue have been conducted in the ordinary environment, where RF exposure levels are low, so the challenge in such studies is to estimate RF exposure. Knowledge about the existence of RF energy sources such as a base station facility is a source of reporting bias, particularly if a person holds the opinion that such exposures contribute to his or her symptoms. Recent epidemiology studies have improved exposure assessments by using personal dosimeters to measure RF levels (Heinrich et al., 2010; 2011), by using validated predictive mathematical models (Mohler et al., 2010), or by controlling field exposures, e.g., transmitter on or off, but unknown to participants (Danker-Hopfe, 2010).

Rather than rely on self-assessment of exposure, Heinrich et al (2010) used personal dosimeters for 24 hours for a large group of children (1,484) and adolescents (1,508). For technical reasons, only measurements taken when the children were awake were used. The dosimeters were placed on the upper arm and recorded exposures to RF from mobile phones, base stations, and cordless phones. Symptoms rated by the participants in the morning and evening included acute effects: headache, nervousness, dizziness, concentration problems, and fatigue. Although a few of the 24 associations calculated were slightly elevated, one for children and one for adolescents, the link was not confirmed in the 10 percent of participants who had high exposures. The authors concluded that the few associations reported were chance or random events.

In the same population and with the same exposure data, the participants were asked to report chronic symptoms over the last 6 months (Heinrich et al., 2011). The researchers collected data on several other factors that could affect the symptoms and confound the analysis, such as age, sex, education, worries about the environment, as well as patterns of mobile phone use. After adjusting for these other factors, the results did not support an association between the symptoms in children and adolescents and the low levels of RF exposure recorded during waking hours. (All exposures were on average less than 0.2 % of the ICNIRP exposure limit and the maximum was less than 1% of the limit.)

In a study of sleep quality, Mohler et al. (2010) used a validated predictive model to estimate exposure to far-field RF energy from various everyday sources. The participants, 1,375 randomly selected adults, provided self-assessments of sleep disturbances and daytime sleepiness. No associations with these subjective measures of sleep quality were observed, even in the 10 percent of participants most exposed.

Danker Hopfe et al. (2010) included objective measures of sleep quality in a field intervention study. By selecting participants from areas that had no mobile phone service (i.e., no base station antennas), and bringing in portable mobile base stations to provide an exposure, the exposure was controlled and participants were blinded to exposure status. A total of 397 residents were included. Sleep quality was assessed before the study, and over two different 5-day time periods during the study, one without an RF source (sham), and one when a base station source was brought in. Neither objective physiological measures of sleep (hours asleep, time to fall asleep, wake time) or subjective measures (self-assessment of sleep quality) were observed to be affected by RF exposure.

These studies have not provided evidence to alter the conclusions of review groups that exposure to low levels of RF energy does not lead to increased acute symptoms or adverse effects on sleep. The exposures in these studies were below the exposure limits specified in the standards such as Health Canada.

6. Conclusion

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.

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Appendix A

Technical Memorandum

Advanced Metering Infrastructure Exposure Assessment

Description of the advanced meter radio frequency signal

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. The second radio, called Zigbee, operates in the frequency range of 2,400 MHz to 2,484 MHz.[17] 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.

Exposure calculation formula

The low RF signal produced by the advanced meter and the expected distance of use greater than 20 centimetres (cm) exempts this device from a required RF exposure assessment based on Industry Canada guidelines.[18] For illustrative purposes, however, an exposure assessment is performed below.

The exposure calculation is based on the computation modeling recommended in Industry Canada RSS-102. The power density at a distance R from the transmitter, with input power P, antenna gain G, and duty cycle δ is equal to:

$$2.56\frac{PG}{4\pi R^2}\delta$$

The additional factor of 2.56 is used to adjust for signal reflections from the ground that may increase the exposure to levels above that calculated using the standard inverse-square law.[19]

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[17] FCC_RF_Exposure_Report_HW3.1_Meter.pdf

[18] Industry Canada RSS-102

[19] Federal Communications Commission Office of Engineering & Technology, OET Bulletin 65, "Evaluating Compliance with FCC Guidelines for Human Exposure to Radiofrequency Electromagnetic Fields," 1997

Exposure from a single advanced meter at 902 MHz to 928 MHz

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]

Based on this information, the expected exposure levels at a distance of 0.5 metres (m) from the front of the advanced meter are listed in Table 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

Even with a maximum supported duty cycle of 5%, at a distance of 0.5 m, the exposure to RF signals is over 100 times below the exposure limit set by Health Canada. Under typical use, at a distance of 0.5 m, the exposure is 1,000 times below this exposure limit.

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 $1/10^{th}$ 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.

This arrangement greatly reduces potential exposure of occupants within the residence.

[20] Duty cycles are based on "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. The 5% duty cycle is cited for a 30 minute period.

[21] The exposure limit increases with frequency and is equal to 0.62 mW/cm^2 at 928 MHz.

Exposure from a single advanced meter at 2400 MHz to 2484 MHz

In the 2,400 MHz to 2,484 MHz band, the radiated power of the Itron AMI7 meter (FCC ID SK9AMI7) is 65.01 mW for an antenna gain of 2.4. A duty cycle of 1% or lower is expected.

Based on this information, the following table specifies the expected exposure levels directly in front of the advanced meter at a distance of 0.5 m.

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

Thus, as shown in Table 2, the expected exposure is more than 7,500 times below the exposure limit set by Health Canada.

Analogous to the 900 MHz range, reflection and absorption from the metal enclosure and surrounding material environment greatly reduce exposure at the interior of the residence.

Exposure from multiple advanced meters

Since the signal strength from a advanced meter falls off greatly with distance and advanced meters are typically installed one per house, the additional exposure from other, more distant advanced meters is negligible. A advanced meter as close as 5 m adds only 1/100 of the exposure of the advanced meter at 0.5 m (and at 16 m, ~1/1,000 the exposure). At greater distances the contribution from another advanced meter is far less.

Moreover, most multiple-meter installations are located far from the residential areas, separated from such areas with external walls or floors. The fall off of the signal with distance combined with attenuation from construction materials will negate most, if not all, added exposure from multiple-meter communication.

Exposure from the supporting infrastructure

In addition to advanced meters at home, there is a small number of supporting infrastructure RF transmitters installed on the utility poles in the neighborhood above the level of the residences. Due to the distance of these transmitters from the residences, the typical exposure from these devices in the residence should not exceed the typical exposure from the advanced meter.[22]

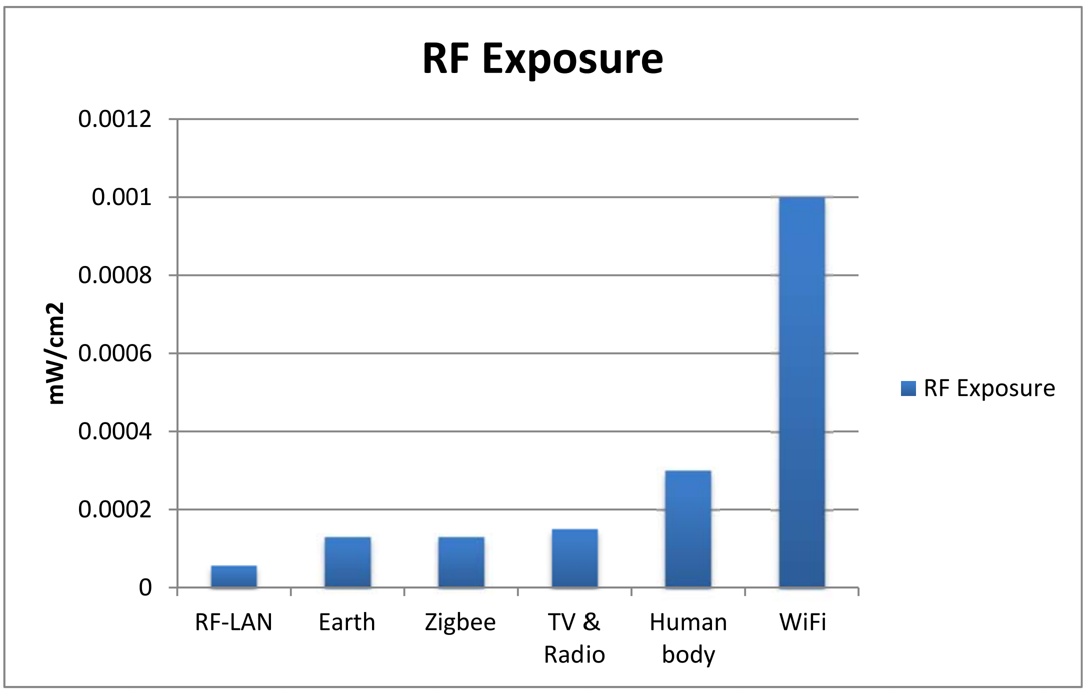

Figure 1. Comparison of RF exposure from RF-Lan and Zigbee signals to RF exposure from other sources under typical use. RF-LAN and Zigbee exposure is for an outside exposure at a distance of 0.5 meters. Exposure at larger distances or inside the residence is much smaller.

Outdoor RF-LAN exposure is calculated based on mean typical duty cycle at a distance of 0.5 m. Outdoor Zigbee exposure is calculated based on the maximum supported duty cycle of 1%. Indoor exposure at typical duty cycles will be much lower. Television and radio signals are part of the typical urban exposure to RF. The range of intensities is 0.000045-0.00015

[22] When used as part of the smart meter network.

mW/cm^2.[23] WiFi exposure is given for a 1 m distance. The range, depending on the installation, varies from 0.000000010-0.0010 mW/cm^2.[24] Exposure from the Earth and the human body in the frequency range of 3 kHz to 300 GHz (majority of this natural RF exposure is at the high end of the frequency range) can be found in Valberg et al. (2007) [25] and Swerdlow (2009).[26] For comparison, cell phone exposure based on a 1.8 minute call[27] is 0.95 mW/cm^2, and the exposure from a baby monitor is 0.019 mW/cm^2 at 20 cm distance.[28]

[23] PA Valberg, TE Van Deventer, and MH Repacholi, Workgroup report: base stations and wireless networks—radiofrequency (RF) exposures and health consequences. Environmental Health Perspectives: 115:416, 2007.

[24] KR Foster, Radiofrequency exposure from wireless LANS utilizing Wi-Fi technology. Health Phys 92:280-289, 2007.

[25] PA Valberg, TE Van Deventer, and MH Repacholi, Workgroup report: base stations and wireless networks—radiofrequency (RF) exposures and health consequences. Environmental Health Perspectives: 115:416, 2007.

[26] A. Swerdlow, "Exposure to high frequency electromagnetic fields, biological effects and health consequences (100 kHz-300 GHz)," 2009.

[27] In a 6 minute period.

[28] Based on PA Valberg, TE Van Deventer, and MH Repacholi, Workgroup report: base stations and wireless networks—radiofrequency (RF) exposures and health consequences. Environmental Health Perspectives: 115:416, 2007.

Limitations

At the request of FortisBC, Exponent conducted specific modeling and evaluations of components of the electrical environment of this project. This report summarizes work performed to date and presents the findings resulting from that work. In the analysis, we have relied on geometry, material data, usage conditions, specifications, and various other types of information provided by the client. We cannot verify the correctness of this input data, and rely on the client for the data's accuracy. Although Exponent has exercised usual and customary care in the conduct of this analysis, the responsibility for the design and operation of the project remains fully with the client.

The findings presented herein are made to a reasonable degree of engineering and 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.

Appendix D

Project and Alternates NPV Analyses

Revenue Requirements Analysis
Advanced Metering Infrastructure Project

AMI

Line No.		NPV @ 8.00%	0 Dec-12	1 Dec-13	2 Dec-14	3 Dec-15	4 Dec-16	5 Dec-17	6 Dec-18	7 Dec-19	8 Dec-20	9 Dec-21	10 Dec-22	11 Dec-23	12 Dec-24	13 Dec-25	14 Dec-26	15 Dec-27	16 Dec-28	17 Dec-29	18 Dec-30	19 Dec-31	20 Dec-32
	Summary																						
	Revenue Requirements																						
1	Operating Expense & Theft Reduction (Net)	**-54,556**	0	(383)	(574)	(1,919)	(4,796)	(5,663)	(6,424)	(6,699)	(7,124)	(7,426)	(6,868)	(7,125)	(7,257)	(7,399)	(8,127)	(8,359)	(8,949)	(9,375)	(9,665)	(9,889)	(10,204)
2	Depreciation Expense	**14,686**	-	-	3,989	4,449	1,272	1,183	1,142	990	918	836	780	780	749	743	727	749	777	793	1,167	2,907	2,911
3	Carrying Costs	**17,239**	-	-	956	2,384	2,689	2,541	2,365	2,177	2,037	1,911	1,843	1,798	1,750	1,713	1,688	1,686	1,677	1,642	1,590	1,471	1,286
4	Income Tax	**4,043**	-	4	827	161	(937)	(257)	(3)	217	397	550	658	754	840	916	988	1,045	1,104	1,160	1,205	1,229	1,231
5	Total Revenue Requirement for Project	**(18,589)**	0	(378)	5,198	5,075	(1,772)	(2,195)	(2,920)	(3,315)	(3,771)	(4,129)	(3,587)	(3,793)	(3,917)	(4,026)	(4,724)	(4,879)	(5,391)	(5,780)	(5,702)	(4,282)	(4,775)
6																							
7	Net Present Value of Revenue Requirements at	**6.0%**	**(24,717)**																				
8	Net Present Value of Revenue Requirements at	**8.0%**	**(18,589)**																				
9	Net Present Value of Revenue Requirements at	**10.0%**	**(13,959)**																				
10																							
11	**Rate Impact**																						
12	Forecast Revenue Requirements		287,441	310,378	327,609	365,860	383,868	390,778	397,812	404,972	412,262	419,682	427,237	434,927	442,756	450,725	458,838	467,097	475,505	484,064	492,777	501,647	510,677
13	Incremental Rate Impact		0.00%	(0.12%)	1.70%	(0.03%)	(1.78%)	(0.11%)	(0.18%)	(0.10%)	(0.11%)	(0.09%)	0.13%	(0.05%)	(0.03%)	(0.02%)	(0.15%)	(0.03%)	(0.11%)	(0.08%)	0.02%	0.28%	(0.10%)
14	Cumulative Incremental Rate Impact		0.00%	(0.12%)	1.58%	1.54%	(0.27%)	(0.38%)	(0.56%)	(0.65%)	(0.76%)	(0.85%)	(0.72%)	(0.77%)	(0.80%)	(0.82%)	(0.97%)	(1.00%)	(1.11%)	(1.19%)	(1.18%)	(0.90%)	(0.99%)
15																							
16	Cumulative Rate Impact of Entire Project		**(0.99%)**																				
17	Levelized Annual Rate Impact		**(0.05%)**																				
18	**Regulatory Assumptions**																						
19	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
20	Debt Component		60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
21	Equity Return		9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%
22	Debt Return		5.92%	5.82%	5.98%	5.93%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%
23	AFUDC		6.60%	6.60%	6.70%	6.60%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
24																							
25																							
26	**Capital Cost**																						
27	Project Capital		-	13,562	15,900	17,166	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Sustaining Capital:		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Meter Growth and Replacement		-	-	(183)	(169)	(243)	(144)	(361)	(128)	(15)	(37)	689	721	758	813	432	408	42	40	2	80	557
30	Handheld Replacement		-	-	(250)	-	-	-	-	(273)	-	-	-	-	(299)	-	-	-	-	(327)	-	-	-
31	Measurement Canada Compliance		-	(146)	(909)	(903)	(1,478)	(976)	(2,310)	(1,072)	(1,645)	(1,229)	(1,070)	(1,452)	(820)	(1,324)	(486)	(501)	(293)	(306)	(302)	(432)	(901)
32	IT Hardware, Licencing, and Support Costs		-	-	292	568	578	736	599	610	640	632	805	655	667	679	691	880	738	729	742	756	769
33	AFUDC		-	168	893	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Total Construction Cost in Year		-	13,584	15,743	16,662	(1,143)	(384)	(2,071)	(863)	(1,021)	(634)	425	(76)	305	168	638	786	486	135	442	403	425
35	Cumulative Construction Cost		-	13,584	29,327	45,989	44,846	44,462	42,391	41,527	40,507	39,873	40,298	40,221	40,526	40,694	41,332	42,118	42,604	42,740	43,182	43,585	44,011
36																							
37	Net Cost of Removal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Total Capital Cost in Year		-	13,584	15,743	16,662	(1,143)	(384)	(2,071)	(863)	(1,021)	(634)	425	(76)	305	168	638	786	486	135	442	403	425
39	Cumulative Capital Cost		-	13,584	29,327	45,989	44,846	44,462	42,391	41,527	40,507	39,873	40,298	40,221	40,526	40,694	41,332	42,118	42,604	42,740	43,182	43,585	44,011
40																							
41	Additions to Plant in Service		-	(552)	29,879	16,662	(1,143)	(384)	(2,071)	(863)	(1,021)	(634)	425	(76)	305	168	638	786	486	135	442	403	425
42	Cummulative Additions to Plant		-	(552)	29,327	45,989	44,846	44,462	42,391	41,527	40,507	39,873	40,298	40,221	40,526	40,694	41,332	42,118	42,604	42,740	43,182	43,585	44,011
43	CWIP		-	14,136	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44																							
45	**Operating Expenses**																						
46	New Operating Costs		-	-	875	1,529	1,556	1,591	1,620	1,611	1,636	1,662	1,688	1,715	1,742	1,769	1,798	1,826	1,855	1,885	1,915	1,946	1,977
47	Meter Reading		-	-	-	(998)	(2,544)	(2,713)	(2,757)	(2,803)	(2,983)	(3,032)	(3,082)	(3,274)	(3,329)	(3,384)	(3,589)	(3,649)	(3,710)	(3,929)	(3,991)	(4,058)	(4,292)
48	Remote Disconnect/Reconnect		-	-	(133)	(414)	(544)	(564)	(584)	(605)	(627)	(648)	(671)	(694)	(717)	(741)	(766)	(791)	(817)	(843)	(870)	(898)	(1,339)
49	Meter Exchanges		-	-	(349)	(331)	(408)	(310)	(531)	(302)	(187)	(212)	511	542	573	626	245	218	(151)	(155)	(193)	(116)	357
50	Contact Centre		-	-	20	7	(20)	(56)	(58)	(60)	(62)	(64)	(66)	(69)	(71)	(73)	(76)	(78)	(81)	(83)	(86)	(89)	(91)
51	**Theft Reduction**		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Theft Reduction		0	(383)	(987)	(1,711)	(2,835)	(3,611)	(4,114)	(4,540)	(4,901)	(5,131)	(5,248)	(5,346)	(5,455)	(5,596)	(5,739)	(5,885)	(6,046)	(6,249)	(6,440)	(6,675)	(6,815)
53	**Total Costs / (Savings)**		0	(383)	(574)	(1,919)	(4,796)	(5,663)	(6,424)	(6,699)	(7,124)	(7,426)	(6,868)	(7,125)	(7,257)	(7,399)	(8,127)	(8,359)	(8,949)	(9,375)	(9,665)	(9,889)	(10,204)
54																							
55																							
56																							

Revenue Requirements Analysis
Advanced Metering Infrastructure Project
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Line No.		NPV @ 8.00%	0 Dec-12	1 Dec-13	2 Dec-14	3 Dec-15	4 Dec-16	5 Dec-17	6 Dec-18	7 Dec-19	8 Dec-20	9 Dec-21	10 Dec-22	11 Dec-23	12 Dec-24	13 Dec-25	14 Dec-26	15 Dec-27	16 Dec-28	17 Dec-29	18 Dec-30	19 Dec-31	20 Dec-32
57																							
58	**Depreciation Expense**																						
59	Opening Cash Outlay		-	-	(16,598)	13,281	29,943	28,800	28,416	26,345	25,481	24,461	23,827	24,252	24,175	24,480	24,648	25,286	26,072	26,558	26,694	27,136	27,539
60	Additions in Year		-	(16,598)	29,879	16,662	(1,143)	(384)	(2,071)	(863)	(1,021)	(634)	425	(76)	305	168	638	786	486	135	442	403	425
61	Cumulative Total		-	(16,598)	13,281	29,943	28,800	28,416	26,345	25,481	24,461	23,827	24,252	24,175	24,480	24,648	25,286	26,072	26,558	26,694	27,136	27,539	27,965
62																							
63	Depreciation Expense on Incremental Capital		-	-	(1,112)	423	1,272	1,183	1,142	990	918	836	780	780	749	743	727	749	777	793	1,167	2,907	2,911
64	Write Off Existing Meters (Term)		-	-	4,564	4,026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	Status Quo Depreciation on Existing Meters		-	-	538	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	**Total Depreciation Expense**		-	-	3,989	4,449	1,272	1,183	1,142	990	918	836	780	780	749	743	727	749	777	793	1,167	2,907	2,911
67																							
68	**Net Book Value**																						
69	Gross Book Value New Capital		-	(552)	21,304	29,943	28,800	28,416	26,345	25,481	24,461	23,827	24,252	24,175	24,480	24,648	25,286	26,072	26,558	26,694	27,136	27,539	27,965
70	Accumulated Depreciation New Capital		-	-	4,571	7,607	6,335	5,152	4,010	3,021	2,102	1,266	487	(293)	(1,043)	(1,786)	(2,513)	(3,262)	(4,040)	(4,833)	(6,000)	(8,907)	(11,818)
71	Gross Book Value Existing Meters		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Accumulated Depreciation Existing Meters		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
73	Incremental Net Book Value		-	(552)	25,875	37,550	35,135	33,569	30,355	28,502	26,563	25,094	24,738	23,882	23,438	22,863	22,773	22,810	22,519	21,861	21,136	18,632	16,146
74					835																		
75	**Carrying Costs on Average NBV**																						
76	Return on Equity		-	-	501	1,256	1,439	1,360	1,266	1,165	1,090	1,023	987	963	937	917	904	903	898	879	851	787	689
77	Interest Expense		-	-	454	1,128	1,249	1,181	1,099	1,012	947	888	857	836	813	796	784	784	779	763	739	684	598
78																							
79	**Total Carrying Costs**		-	-	956	2,384	2,689	2,541	2,365	2,177	2,037	1,911	1,843	1,798	1,750	1,713	1,688	1,686	1,677	1,642	1,590	1,471	1,286
80																							
81																							
82	**Income Tax Expense**																						
83	Combined Income Tax Rate		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
84																							
85	**Income Tax on Equity Return**																						
86	Return on Equity		-	-	501	1,256	1,439	1,360	1,266	1,165	1,090	1,023	987	963	937	917	904	903	898	879	851	787	689
87	Gross up for revenue (Return / (1- tax rate)		-	-	669	1,674	1,919	1,814	1,688	1,554	1,454	1,364	1,316	1,284	1,249	1,222	1,205	1,203	1,197	1,172	1,135	1,050	918
88	Income tax on Equity Return		-	-	167	419	480	453	422	388	363	341	329	321	312	306	301	301	299	293	284	262	230
89																							
90	**Income Tax on Timing Differences**																						
91	Depreciation Expense		-	-	5,102	5,671	2,585	2,630	2,684	2,730	2,778	2,827	2,876	2,974	3,066	3,159	3,254	3,328	3,414	3,472	3,530	3,588	3,648
92	Less: Capitalized Overhead			-	(875)	(999)	(1,073)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
93	Less: Capital Cost Allowance		-	(13)	(2,248)	(5,444)	(5,762)	(4,761)	(3,957)	(3,245)	(2,677)	(2,201)	(1,889)	(1,675)	(1,481)	(1,326)	(1,192)	(1,096)	(999)	(872)	(765)	(689)	(644)
94	Total Timing Differences		-	13	1,979	(773)	(4,250)	(2,131)	(1,273)	(514)	101	626	988	1,300	1,585	1,833	2,061	2,232	2,415	2,600	2,764	2,900	3,004
95	Gross up for tax (Total Timing Differences/(1-tax rate))		-	18	2,639	(1,030)	(5,666)	(2,841)	(1,698)	(686)	135	835	1,317	1,733	2,113	2,443	2,748	2,976	3,220	3,466	3,686	3,866	4,005
96	Income tax on Timing Differences		-	4	660	(258)	(1,417)	(710)	(424)	(171)	34	209	329	433	528	611	687	744	805	867	921	967	1,001
97																							
98	**Total Income Tax**		-	4	827	161	(937)	(257)	(3)	217	397	550	658	754	840	916	988	1,045	1,104	1,160	1,205	1,229	1,231
99																							
100																							
101	**Capital Cost Allowance**																						
102	Opening Balance - UCC		-	-	(155)	25,709	35,927	27,950	22,805	16,777	12,669	8,972	6,137	4,673	2,922	1,746	587	33	(277)	(790)	(1,527)	(1,850)	(2,135)
103																							
104	Additions		-	-	29,879	16,662	(1,143)	(384)	(2,071)	(863)	(1,021)	(634)	425	(76)	305	168	638	786	486	135	442	403	425
105	Less: Capitalized Overhead		-	-	(875)	(999)	(1,073)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
106	Less: AFUDC		-	(168)	(893)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
107	Net Additions		-	(168)	28,111	15,663	(2,216)	(384)	(2,071)	(863)	(1,021)	(634)	425	(76)	305	168	638	786	486	135	442	403	425
108																							
109	CCA on Opening Balance		-	-	(24)	4,161	5,858	4,736	4,005	3,244	2,681	2,190	1,799	1,610	1,400	1,250	1,112	1,002	936	824	704	628	565
110	CCA on Capital Expenditures (1/2 yr rule)		-	(13)	2,272	1,283	(97)	24	(48)	1	(5)	11	90	64	81	77	81	95	62	48	61	60	79
111	Total CCA		-	(13)	2,248	5,444	5,762	4,761	3,957	3,245	2,677	2,201	1,889	1,675	1,481	1,326	1,192	1,096	999	872	765	689	644
112	Ending Balance UCC		-	(155)	25,709	35,927	27,950	22,805	16,777	12,669	8,972	6,137	4,673	2,922	1,746	587	33	(277)	(790)	(1,527)	(1,850)	(2,135)	(2,354)

Revenue Requirements Analysis
Advanced Metering Infrastructure Project

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Line No.		NPV @ 8.00%	0 Dec-12	1 Dec-13	2 Dec-14	3 Dec-15	4 Dec-16	5 Dec-17	6 Dec-18	7 Dec-19	8 Dec-20	9 Dec-21	10 Dec-22	11 Dec-23	12 Dec-24	13 Dec-25	14 Dec-26	15 Dec-27	16 Dec-28	17 Dec-29	18 Dec-30	19 Dec-31	20 Dec-32
	Summary																						
	Revenue Requirements																						
1	Operating Expense & Theft Reduction (Net)	**-15,232**	0	-	(229)	(1,627)	(1,727)	(1,814)	(2,061)	(1,860)	(1,907)	(1,963)	(1,271)	(1,414)	(1,418)	(1,400)	(1,968)	(2,034)	(2,444)	(2,647)	(2,729)	(2,698)	(2,438)
2	Depreciation Expense	**4,932**	-	-	3,989	3,783	211	90	17	(168)	(273)	(390)	(481)	(515)	(582)	(624)	(677)	(693)	(703)	(727)	(392)	1,307	1,271
3	Carrying Costs	**7,312**	-	-	474	1,165	1,250	1,137	997	847	745	659	635	634	632	642	668	717	760	780	786	726	603
4	Income Tax	**3,803**	-	(2)	1,194	594	(567)	(147)	22	169	289	390	455	515	571	621	672	711	756	799	835	850	846
5	Total Revenue Requirement for Project	**815**	0	(2)	5,429	3,915	(833)	(734)	(1,026)	(1,012)	(1,146)	(1,304)	(662)	(780)	(797)	(761)	(1,306)	(1,299)	(1,630)	(1,794)	(1,501)	185	281
6																							
7	Net Present Value of Revenue Requirements at	**6.0%**	**-317**																				
8	Net Present Value of Revenue Requirements at	**8.0%**	**815**																				
9	Net Present Value of Revenue Requirements at	**10.0%**	**1,650**																				
10																							
11	**Rate Impact**																						
12	Forecast Revenue Requirements		287,441	310,378	327,609	365,860	383,868	390,778	397,812	404,972	412,262	419,682	427,237	434,927	442,756	450,725	458,838	467,097	475,505	484,064	492,777	501,647	510,677
13	Incremental Rate Impact		0.00%	(0.00%)	1.66%	(0.41%)	(1.24%)	0.03%	(0.07%)	0.00%	(0.03%)	(0.04%)	0.15%	(0.03%)	(0.00%)	0.01%	(0.12%)	0.00%	(0.07%)	(0.03%)	0.06%	0.34%	0.02%
14	Cumulative Incremental Rate Impact		0.00%	(0.00%)	1.66%	1.24%	(0.02%)	0.01%	(0.06%)	(0.06%)	(0.09%)	(0.13%)	0.02%	(0.01%)	(0.01%)	(0.00%)	(0.12%)	(0.12%)	(0.19%)	(0.22%)	(0.16%)	0.17%	0.19%
15																							
16	Cumulative Rate Impact of Entire Project		**0.19%**																				
17	Levelized Annual Rate Impact		**0.01%**																				
18	**Regulatory Assumptions**																						
19	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
20	Debt Component		60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
21	Equity Return		9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%
22	Debt Return		5.92%	5.82%	5.98%	5.93%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%
23	AFUDC		6.60%	6.60%	6.70%	6.60%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
24																							
25																							
26	**Capital Cost**																						
27	Project Capital		-	6,807	10,739	10,188	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Sustaining Capital:		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Meter Growth and Replacement		-	-	(247)	(231)	(306)	(207)	(426)	(195)	(81)	(104)	621	652	687	741	361	335	(32)	(35)	(72)	5	480
30	Handheld Replacement		-	-	(250)	-	-	-	-	(273)	-	-	-	-	(299)	-	-	-	-	(327)	-	-	-
31	Measurement Canada Compliance		-	(146)	(909)	(903)	(1,478)	(976)	(2,310)	(1,072)	(1,645)	(1,229)	(1,070)	(1,452)	(820)	(1,324)	(486)	(501)	(293)	(306)	(302)	(432)	(901)
32	IT Hardware, Licencing, and Support Costs		-	-	30	35	36	184	37	38	39	39	201	41	41	42	43	220	45	45	46	47	48
33	AFUDC		-	84	452	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Total Construction Cost in Year		-	6,744	9,815	9,090	(1,748)	(999)	(2,698)	(1,502)	(1,687)	(1,294)	(247)	(759)	(391)	(540)	(82)	54	(281)	(623)	(329)	(380)	(373)
35	Cumulative Construction Cost		-	6,744	16,559	25,649	23,901	22,901	20,203	18,701	17,014	15,720	15,473	14,714	14,323	13,783	13,701	13,755	13,475	12,852	12,523	12,143	11,770
36																							
37	Net Cost of Removal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Total Capital Cost in Year		-	6,744	9,815	9,090	(1,748)	(999)	(2,698)	(1,502)	(1,687)	(1,294)	(247)	(759)	(391)	(540)	(82)	54	(281)	(623)	(329)	(380)	(373)
39	Cumulative Capital Cost		-	6,744	16,559	25,649	23,901	22,901	20,203	18,701	17,014	15,720	15,473	14,714	14,323	13,783	13,701	13,755	13,475	12,852	12,523	12,143	11,770
40																							
41	Additions to Plant in Service		-	(552)	17,112	9,090	(1,748)	(999)	(2,698)	(1,502)	(1,687)	(1,294)	(247)	(759)	(391)	(540)	(82)	54	(281)	(623)	(329)	(380)	(373)
42	Cummulative Additions to Plant		-	(552)	16,559	25,649	23,901	22,901	20,203	18,701	17,014	15,720	15,473	14,714	14,323	13,783	13,701	13,755	13,475	12,852	12,523	12,143	11,770
43	CWIP		-	7,297	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44																							
45	**Operating Expenses**																						
46	New Operating Costs		-	-	89	162	165	168	171	174	178	181	184	187	191	194	198	202	205	209	213	217	221
47	Meter Reading		-	-	-	(1,490)	(1,517)	(1,672)	(1,702)	(1,732)	(1,898)	(1,932)	(1,967)	(2,143)	(2,182)	(2,221)	(2,411)	(2,454)	(2,498)	(2,701)	(2,749)	(2,799)	(3,015)
48	Remote Disconnect/Reconnect		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Meter Exchanges		-	-	(349)	(331)	(408)	(310)	(531)	(302)	(187)	(212)	511	542	573	626	245	218	(151)	(155)	(193)	(116)	357
50	Contact Centre		-	-	32	33	34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	**Theft Reduction**		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Theft Reduction		0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	**Total Costs / (Savings)**		0	-	(229)	(1,627)	(1,727)	(1,814)	(2,061)	(1,860)	(1,907)	(1,963)	(1,271)	(1,414)	(1,418)	(1,400)	(1,968)	(2,034)	(2,444)	(2,647)	(2,729)	(2,698)	(2,438)
54																							
55																							
56																							

Revenue Requirements Analysis
Advanced Metering Infrastructure Project

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Line No.		NPV @ 8.00%	0 Dec-12	1 Dec-13	2 Dec-14	3 Dec-15	4 Dec-16	5 Dec-17	6 Dec-18	7 Dec-19	8 Dec-20	9 Dec-21	10 Dec-22	11 Dec-23	12 Dec-24	13 Dec-25	14 Dec-26	15 Dec-27	16 Dec-28	17 Dec-29	18 Dec-30	19 Dec-31	20 Dec-32
57																							
58	**Depreciation Expense**																						
59	Opening Cash Outlay		-	-	(16,598)	513	9,603	7,855	6,855	4,157	2,655	968	(326)	(573)	(1,332)	(1,723)	(2,263)	(2,345)	(2,291)	(2,571)	(3,194)	(3,523)	(3,903)
60	Additions in Year		-	(16,598)	17,112	9,090	(1,748)	(999)	(2,698)	(1,502)	(1,687)	(1,294)	(247)	(759)	(391)	(540)	(82)	54	(281)	(623)	(329)	(380)	(373)
61	Cumulative Total		-	(16,598)	513	9,603	7,855	6,855	4,157	2,655	968	(326)	(573)	(1,332)	(1,723)	(2,263)	(2,345)	(2,291)	(2,571)	(3,194)	(3,523)	(3,903)	(4,276)
62																							
63	Depreciation Expense on Incremental Capital		-	-	(1,112)	(243)	211	90	17	(168)	(273)	(390)	(481)	(515)	(582)	(624)	(677)	(693)	(703)	(727)	(392)	1,307	1,271
64	Write Off Existing Meters (Term)		-	-	4,564	4,026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	Less: Status Quo Depreciation on Existing Meters		-	-	538	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	**Total Depreciation Expense**		-	-	3,989	3,783	211	90	17	(168)	(273)	(390)	(481)	(515)	(582)	(624)	(677)	(693)	(703)	(727)	(392)	1,307	1,271
67																							
68	**Net Book Value**																						
69	Gross Book Value New Capital		-	(16,598)	513	9,603	7,855	6,855	4,157	2,655	968	(326)	(573)	(1,332)	(1,723)	(2,263)	(2,345)	(2,291)	(2,571)	(3,194)	(3,523)	(3,903)	(4,276)
70	Accumulated Depreciation New Capital		-	6,918	8,030	8,273	8,063	7,973	7,956	8,124	8,397	8,787	9,267	9,783	10,364	10,989	11,665	12,358	13,061	13,788	14,180	12,873	11,602
71	Gross Book Value Existing Meters		-	6,366	(2,178)	(10,336)	(11,035)	(10,999)	(12,426)	(12,463)	(12,565)	(12,147)	(11,510)	(11,141)	(10,304)	(9,535)	(7,807)	(6,076)	(4,067)	(2,362)	(682)	(737)	(1,190)
72	Accumulated Depreciation Existing Meters		-	(6,918)	(3,459)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
73	Incremental Net Book Value		-	9,128	23,309	28,213	26,952	25,827	24,539	23,243	21,930	20,608	20,205	19,592	18,946	18,261	17,128	16,143	14,556	12,956	11,339	9,706	8,517
74																							
75	**Carrying Costs on Average NBV**																						
76	Return on Equity		-	342	642	1,020	1,092	1,045	997	946	894	842	808	788	763	737	701	659	608	545	481	417	361
77	Interest Expense		-	(342)	(168)	145	158	92	(1)	(99)	(149)	(183)	(174)	(154)	(131)	(94)	(33)	58	153	235	305	309	242
78																							
79	**Total Carrying Costs**		-	643	1,224	1,937	2,041	1,952	1,863	1,767	1,671	1,573	1,510	1,472	1,426	1,376	1,309	1,231	1,136	1,018	899	778	674
80																							
81																							
82	**Income Tax Expense**																						
83	Combined Income Tax Rate		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
84																							
85	**Income Tax on Equity Return**																						
86	Return on Equity		-	228	511	885	951	900	843	782	729	679	652	638	622	606	586	567	541	502	461	407	348
87	Gross up for revenue (Return / (1- tax rate)		-	456	856	1,360	1,456	1,393	1,330	1,261	1,193	1,123	1,077	1,051	1,017	982	934	878	810	726	641	556	481
88	Income tax on Equity Return		-	114	214	340	364	348	332	315	298	281	269	263	254	246	234	220	203	182	160	139	120
89																							
90	**Income Tax on Timing Differences**																						
91	Depreciation Expense		-	-	5,167	5,184	1,823	1,950	2,113	2,273	2,381	2,473	2,539	2,660	2,769	2,869	2,938	2,954	2,975	2,974	2,976	2,971	2,988
92	Less: Capitalized Overhead			-	(378)	(493)	(337)	413	555	701	794	872	923	981	1,035	1,077	1,089	1,067	1,041	1,022	1,006	982	981
93	Less: Capital Cost Allowance		-	7	(1,303)	(3,103)	(3,156)	(2,449)	(1,842)	(1,285)	(855)	(494)	(282)	(147)	(16)	87	172	217	274	368	448	501	534
94	Total Timing Differences		-	(7)	3,290	1,049	(2,569)	(1,325)	(839)	(413)	(62)	235	410	552	684	802	932	1,037	1,166	1,298	1,412	1,507	1,560
95	Gross up for tax (Total Timing Differences/(1-tax rate))		-	(9)	4,357	1,319	(3,559)	(1,951)	(1,365)	(862)	(436)	(74)	137	299	453	591	759	908	1,092	1,277	1,436	1,573	1,645
96	Income tax on Timing Differences		-	(116)	980	254	(931)	(495)	(311)	(146)	(9)	109	186	252	316	376	438	491	553	617	674	711	725
97																							
98	**Total Income Tax**		-	112	1,303	670	(526)	(139)	(9)	100	189	262	304	337	367	393	423	447	476	501	519	532	531
99																							
100																							
101	**Capital Cost Allowance**																						
102	Opening Balance - UCC		-	-	(77)	14,814	20,068	14,427	10,841	6,115	3,095	288	(1,790)	(2,627)	(3,860)	(4,612)	(5,423)	(5,697)	(5,781)	(6,135)	(6,730)	(6,946)	(7,152)
103																							
104	Additions		-	-	17,112	9,090	(1,748)	(999)	(2,698)	(1,502)	(1,687)	(1,294)	(247)	(759)	(391)	(540)	(82)	54	(281)	(623)	(329)	(380)	(373)
105	Less: Capitalized Overhead		-	-	(443)	(673)	(637)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
106	Less: AFUDC		-	(84)	(452)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
107	Net Additions		-	(84)	16,217	8,417	(2,385)	(999)	(2,698)	(1,502)	(1,687)	(1,294)	(247)	(759)	(391)	(540)	(82)	54	(281)	(623)	(329)	(380)	(373)
108																							
109	CCA on Opening Balance		-	-	(12)	2,449	3,366	2,611	2,125	1,568	1,177	825	553	463	334	251	167	101	71	(16)	(113)	(172)	(224)
110	CCA on Capital Expenditures (1/2 yr rule)		-	(7)	1,337	714	(110)	(24)	(98)	(49)	(57)	(41)	37	11	26	21	24	37	2	(11)	0	(1)	17
111	Total CCA		-	(7)	1,325	3,163	3,256	2,587	2,027	1,519	1,120	785	590	474	361	272	191	138	73	(28)	(113)	(174)	(207)
112	Ending Balance UCC		-	(77)	14,814	20,068	14,427	10,841	6,115	3,095	288	(1,790)	(2,627)	(3,860)	(4,612)	(5,423)	(5,697)	(5,781)	(6,135)	(6,730)	(6,946)	(7,152)	(7,318)

Revenue Requirements Analysis
Advanced Metering Infrastructure Project

PLC

Line No.		NPV @ 8.00%	0 Dec-12	1 Dec-13	2 Dec-14	3 Dec-15	4 Dec-16	5 Dec-17	6 Dec-18	7 Dec-19	8 Dec-20	9 Dec-21	10 Dec-22	11 Dec-23	12 Dec-24	13 Dec-25	14 Dec-26	15 Dec-27	16 Dec-28	17 Dec-29	18 Dec-30	19 Dec-31	20 Dec-32
	Summary																						
	Revenue Requirements																						
1	Operating Expense & Theft Reduction (Net)	**-56,142**	0	(383)	(682)	(2,086)	(4,966)	(5,835)	(6,599)	(6,877)	(7,305)	(7,609)	(7,054)	(7,315)	(7,450)	(7,595)	(8,327)	(8,561)	(9,155)	(9,584)	(9,878)	(10,106)	(10,423)
2	Depreciation Expense	**22,207**	-	-	3,989	5,051	2,246	2,156	2,115	1,963	1,892	1,808	1,752	1,752	1,721	1,715	1,700	1,721	1,749	1,765	2,139	3,878	3,883
3	Carrying Costs	**24,664**	-	-	1,391	3,496	3,989	3,769	3,520	3,261	3,048	2,849	2,709	2,592	2,472	2,362	2,266	2,192	2,110	2,003	1,880	1,689	1,432
4	Income Tax	**4,302**	-	(5)	559	(326)	(1,283)	(340)	0	290	528	726	871	996	1,105	1,198	1,282	1,347	1,411	1,468	1,514	1,535	1,533
5	Total Revenue Requirement for Project	**(4,969)**	0	(388)	5,258	6,135	(14)	(249)	(963)	(1,362)	(1,837)	(2,226)	(1,722)	(1,974)	(2,151)	(2,319)	(3,080)	(3,302)	(3,885)	(4,347)	(4,345)	(3,003)	(3,575)
6																							
7	Net Present Value of Revenue Requirements at	**6.0%**	**(8,459)**																				
8	Net Present Value of Revenue Requirements at	**8.0%**	**(4,969)**																				
9	Net Present Value of Revenue Requirements at	**10.0%**	**(2,430)**																				
10																							
11	**Rate Impact**																						
12	Forecast Revenue Requirements		287,441	310,378	327,609	365,860	383,868	390,778	397,812	404,972	412,262	419,682	427,237	434,927	442,756	450,725	458,838	467,097	475,505	484,064	492,777	501,647	510,677
13	Incremental Rate Impact		0.00%	(0.13%)	1.72%	0.24%	(1.60%)	(0.06%)	(0.18%)	(0.10%)	(0.12%)	(0.09%)	0.12%	(0.06%)	(0.04%)	(0.04%)	(0.17%)	(0.05%)	(0.12%)	(0.10%)	0.00%	0.27%	(0.11%)
14	Cumulative Incremental Rate Impact		0.00%	(0.13%)	1.60%	1.84%	0.21%	0.15%	(0.03%)	(0.13%)	(0.25%)	(0.34%)	(0.22%)	(0.28%)	(0.32%)	(0.35%)	(0.52%)	(0.57%)	(0.69%)	(0.78%)	(0.78%)	(0.52%)	(0.63%)
15																							
16	Cumulative Rate Impact of Entire Project		**(0.63%)**																				
17	Levelized Annual Rate Impact		**(0.03%)**																				
18	**Regulatory Assumptions**																						
19	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
20	Debt Component		60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
21	Equity Return		9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%
22	Debt Return		5.92%	5.82%	5.98%	5.93%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%	5.73%
23	AFUDC		6.60%	6.60%	6.70%	6.60%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
24																							
25																							
26	**Capital Cost**																						
27	Project Capital		-	16,163	24,513	24,296	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Sustaining Capital:		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Meter Growth and Replacement		-	-	(183)	(169)	(243)	(144)	(361)	(128)	(15)	(37)	689	721	758	813	432	408	42	40	2	80	557
30	Handheld Replacement		-	-	(250)	-	-	-	-	(273)	-	-	-	-	(299)	-	-	-	-	(327)	-	-	-
31	Measurement Canada Compliance		-	(146)	(909)	(903)	(1,478)	(976)	(2,310)	(1,072)	(1,645)	(1,229)	(1,070)	(1,452)	(820)	(1,324)	(486)	(501)	(293)	(306)	(302)	(432)	(901)
32	IT Hardware, Licencing, and Support Costs		-	-	292	567	577	735	598	609	620	631	803	654	665	677	690	878	736	727	741	754	767
33	AFUDC		-	200	1,179	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Total Construction Cost in Year		-	16,216	24,643	23,792	(1,144)	(385)	(2,073)	(865)	(1,041)	(635)	423	(78)	304	166	636	785	484	134	440	402	423
35	Cumulative Construction Cost		-	16,216	40,858	64,650	63,506	63,120	61,048	60,183	59,142	58,507	58,930	58,852	59,156	59,322	59,958	60,743	61,227	61,361	61,801	62,203	62,626
36																							
37	Net Cost of Removal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Total Capital Cost in Year		-	16,216	24,643	23,792	(1,144)	(385)	(2,073)	(865)	(1,041)	(635)	423	(78)	304	166	636	785	484	134	440	402	423
39	Cumulative Capital Cost		-	16,216	40,858	64,650	63,506	63,120	61,048	60,183	59,142	58,507	58,930	58,852	59,156	59,322	59,958	60,743	61,227	61,361	61,801	62,203	62,626
40																							
41	Additions to Plant in Service		-	(552)	41,411	23,792	(1,144)	(385)	(2,073)	(865)	(1,041)	(635)	423	(78)	304	166	636	785	484	134	440	402	423
42	Cummulative Additions to Plant		-	(552)	40,858	64,650	63,506	63,120	61,048	60,183	59,142	58,507	58,930	58,852	59,156	59,322	59,958	60,743	61,227	61,361	61,801	62,203	62,626
43	CWIP		-	16,768	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44																							
45	**Operating Expenses**																						
46	New Operating Costs		-	-	768	1,362	1,387	1,419	1,445	1,433	1,455	1,478	1,501	1,525	1,549	1,573	1,598	1,624	1,649	1,676	1,702	1,730	1,757
47	Meter Reading		-	-	-	(998)	(2,544)	(2,713)	(2,757)	(2,803)	(2,983)	(3,032)	(3,082)	(3,274)	(3,329)	(3,384)	(3,589)	(3,649)	(3,710)	(3,929)	(3,991)	(4,058)	(4,292)
48	Remote Disconnect/Reconnect		-	-	(133)	(414)	(544)	(564)	(584)	(605)	(627)	(648)	(671)	(694)	(717)	(741)	(766)	(791)	(817)	(843)	(870)	(898)	(1,339)
49	Meter Exchanges		-	-	(349)	(331)	(408)	(310)	(531)	(302)	(187)	(212)	511	542	573	626	245	218	(151)	(155)	(193)	(116)	357
50	Contact Centre		-	-	20	7	(20)	(56)	(58)	(60)	(62)	(64)	(66)	(69)	(71)	(73)	(76)	(78)	(81)	(83)	(86)	(89)	(91)
51	**Theft Reduction**		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Theft Reduction		0	(383)	(987)	(1,711)	(2,835)	(3,611)	(4,114)	(4,540)	(4,901)	(5,131)	(5,248)	(5,346)	(5,455)	(5,596)	(5,739)	(5,885)	(6,046)	(6,249)	(6,440)	(6,675)	(6,815)
53	**Total Costs / (Savings)**		0	(383)	(682)	(2,086)	(4,966)	(5,835)	(6,599)	(6,877)	(7,305)	(7,609)	(7,054)	(7,315)	(7,450)	(7,595)	(8,327)	(8,561)	(9,155)	(9,584)	(9,878)	(10,106)	(10,423)
54																							
55																							
56																							

Revenue Requirements Analysis
Advanced Metering Infrastructure Project
PLC

Line No.		NPV @ 8.00%	0 Dec-12	1 Dec-13	2 Dec-14	3 Dec-15	4 Dec-16	5 Dec-17	6 Dec-18	7 Dec-19	8 Dec-20	9 Dec-21	10 Dec-22	11 Dec-23	12 Dec-24	13 Dec-25	14 Dec-26	15 Dec-27	16 Dec-28	17 Dec-29	18 Dec-30	19 Dec-31	20 Dec-32
57																							
58	**Depreciation Expense**																						
59	Opening Cash Outlay		-	-	(16,598)	24,812	48,604	47,460	47,074	45,002	44,137	43,096	42,461	42,884	42,806	43,110	43,276	43,912	44,697	45,181	45,315	45,755	46,157
60	Additions in Year		-	(16,598)	41,411	23,792	(1,144)	(385)	(2,073)	(865)	(1,041)	(635)	423	(78)	304	166	636	785	484	134	440	402	423
61	Cumulative Total		-	(16,598)	24,812	48,604	47,460	47,074	45,002	44,137	43,096	42,461	42,884	42,806	43,110	43,276	43,912	44,697	45,181	45,315	45,755	46,157	46,580
62																							
63	Depreciation Expense on Incremental Capital		-	-	(1,112)	1,025	2,246	2,156	2,115	1,963	1,892	1,808	1,752	1,752	1,721	1,715	1,700	1,721	1,749	1,765	2,139	3,878	3,883
64	Write Off Existing Meters (Term)		-	-	4,564	4,026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	Less: Status Quo Depreciation on Existing Meters		-	-	538	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	**Total Depreciation Expense**		-	-	3,989	5,051	2,246	2,156	2,115	1,963	1,892	1,808	1,752	1,752	1,721	1,715	1,700	1,721	1,749	1,765	2,139	3,878	3,883
67																							
68	**Net Book Value**																						
69	Gross Book Value New Capital		-	(16,598)	24,812	48,604	47,460	47,074	45,002	44,137	43,096	42,461	42,884	42,806	43,110	43,276	43,912	44,697	45,181	45,315	45,755	46,157	46,580
70	Accumulated Depreciation New Capital		-	6,918	8,030	7,006	4,760	2,603	488	(1,476)	(3,367)	(5,176)	(6,928)	(8,680)	(10,402)	(12,117)	(13,816)	(15,537)	(17,286)	(19,052)	(21,191)	(25,069)	(28,952)
71	Gross Book Value Existing Meters		-	6,366	(2,178)	(10,336)	(11,035)	(10,999)	(12,426)	(12,463)	(12,565)	(12,147)	(11,510)	(11,141)	(10,304)	(9,535)	(7,807)	(6,076)	(4,067)	(2,362)	(682)	(737)	(1,190)
72	Accumulated Depreciation Existing Meters		-	(6,918)	(3,459)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
73	Incremental Net Book Value		-	9,128	47,607	65,945	63,254	60,677	57,915	55,124	52,294	49,432	47,466	45,267	43,013	40,694	37,903	35,235	31,962	28,626	25,246	21,825	18,819
74																							
75	**Carrying Costs on Average NBV**																						
76	Return on Equity		-	342	1,123	2,248	2,558	2,454	2,348	2,238	2,127	2,014	1,919	1,836	1,748	1,657	1,556	1,448	1,331	1,200	1,067	932	805
77	Interest Expense		-	(342)	268	1,248	1,430	1,315	1,172	1,022	921	835	791	756	724	705	710	744	780	804	813	757	627
78																							
79	**Total Carrying Costs**		-	643	2,141	4,268	4,779	4,584	4,387	4,181	3,973	3,763	3,584	3,430	3,265	3,096	2,907	2,705	2,486	2,241	1,993	1,741	1,503
80																							
81																							
82	**Income Tax Expense**																						
83	Combined Income Tax Rate		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
84																							
85	**Income Tax on Equity Return**																						
86	Return on Equity		-	228	992	2,113	2,417	2,308	2,194	2,074	1,962	1,851	1,762	1,687	1,606	1,526	1,442	1,357	1,264	1,157	1,047	923	792
87	Gross up for revenue (Return / (1- tax rate)		-	456	1,498	2,998	3,411	3,272	3,131	2,984	2,836	2,686	2,558	2,448	2,331	2,210	2,075	1,931	1,774	1,600	1,422	1,243	1,073
88	Income tax on Equity Return		-	114	374	749	853	818	783	746	709	671	640	612	583	552	519	483	444	400	356	311	268
89																							
90	**Income Tax on Timing Differences**																						
91	Depreciation Expense		-	-	5,167	6,452	3,858	4,016	4,212	4,404	4,546	4,671	4,772	4,928	5,073	5,208	5,314	5,368	5,427	5,465	5,508	5,542	5,600
92	Less: Capitalized Overhead			-	(974)	(1,350)	(1,210)	413	555	701	794	872	923	981	1,035	1,077	1,089	1,067	1,041	1,022	1,006	982	981
93	Less: Capital Cost Allowance		-	16	(3,092)	(7,504)	(7,932)	(6,502)	(5,355)	(4,345)	(3,535)	(2,855)	(2,377)	(2,018)	(1,701)	(1,443)	(1,230)	(1,078)	(936)	(771)	(631)	(531)	(460)
94	Total Timing Differences		-	(16)	905	(2,940)	(6,184)	(3,311)	(2,253)	(1,342)	(578)	72	548	947	1,302	1,611	1,906	2,155	2,409	2,651	2,864	3,047	3,179
95	Gross up for tax (Total Timing Differences/(1-tax rate))		-	(21)	1,177	(4,000)	(8,379)	(4,599)	(3,251)	(2,101)	(1,123)	(291)	321	827	1,276	1,669	2,058	2,399	2,749	3,081	3,371	3,626	3,802
96	Income tax on Timing Differences		-	(119)	185	(1,076)	(2,136)	(1,157)	(782)	(456)	(181)	55	232	384	522	645	763	864	967	1,068	1,158	1,225	1,265
97																							
98	**Total Income Tax**		-	109	669	(251)	(1,242)	(332)	(30)	221	428	599	720	819	902	970	1,033	1,082	1,131	1,170	1,198	1,217	1,219
99																							
100																							
101	**Capital Cost Allowance**																						
102	Opening Balance - UCC		-	-	(184)	35,894	50,593	39,906	32,881	25,268	19,824	14,984	11,203	8,941	6,518	4,775	3,139	2,182	1,533	734	(244)	(770)	(1,227)
103																							
104	Additions		-	-	41,411	23,792	(1,144)	(385)	(2,073)	(865)	(1,041)	(635)	423	(78)	304	166	636	785	484	134	440	402	423
105	Less: Capitalized Overhead		-	-	(1,040)	(1,529)	(1,510)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
106	Less: AFUDC		-	(200)	(1,179)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
107	Net Additions		-	(200)	39,192	22,262	(2,655)	(385)	(2,073)	(865)	(1,041)	(635)	423	(78)	304	166	636	785	484	134	440	402	423
108																							
109	CCA on Opening Balance		-	-	(29)	5,762	8,163	6,615	5,589	4,578	3,806	3,135	2,595	2,281	1,965	1,726	1,513	1,340	1,221	1,063	906	798	707
110	CCA on Capital Expenditures (1/2 yr rule)		-	(16)	3,143	1,802	(131)	24	(48)	1	(6)	11	90	64	81	77	81	94	62	48	61	60	79
111	Total CCA		-	(16)	3,114	7,564	8,032	6,640	5,540	4,579	3,800	3,146	2,685	2,345	2,046	1,802	1,593	1,434	1,283	1,111	967	858	787
112	Ending Balance UCC		-	(184)	35,894	50,593	39,906	32,881	25,268	19,824	14,984	11,203	8,941	6,518	4,775	3,139	2,182	1,533	734	(244)	(770)	(1,227)	(1,590)

Appendix E-1

Illumina Supergroup Findings

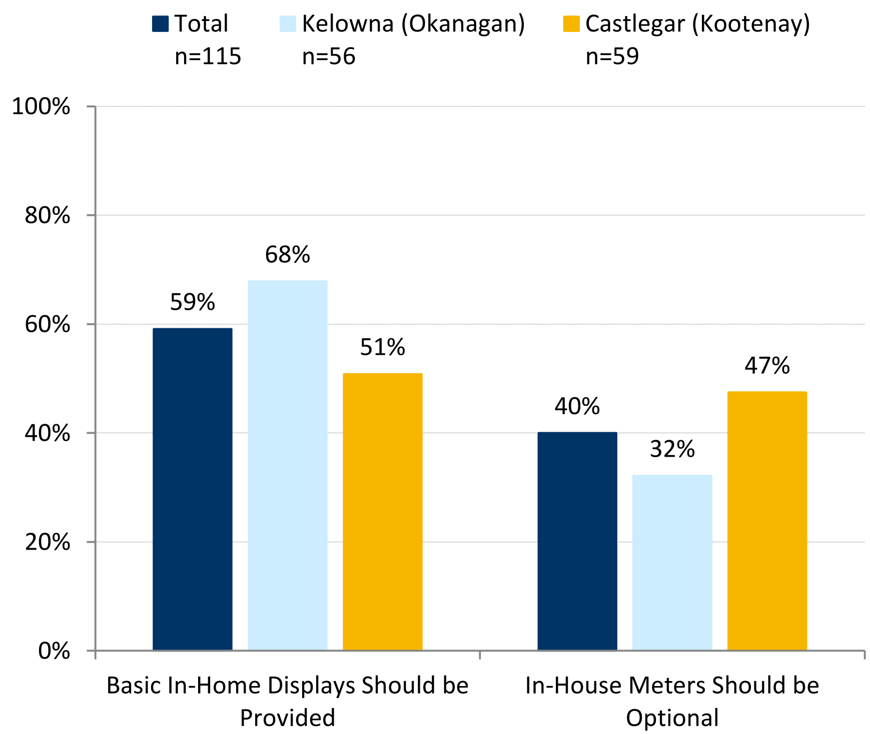
Advanced Metering Infrastructure (AMI)

The Advanced Metering Infrastructure (AMI) project involves replacing the current, manually read meters with advanced meters that can transmit meter reading data directly to FortisBC.

Advanced Metering Infrastructure (AMI)

Two-thirds of Okanagan residents would like in-house displays provided as part of the AMI project, while Kootenay residents are equally split between having in-house displays provided as part of the project or as an optional purchase.

Support for In-House Displays as Part of the AMI Project Versus an Optional Purchase



***Please note results may not round to 100% as "no answer" is not reported.**

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Advanced Metering Infrastructure (AMI)

Support for implementing in-house displays across the entire customer base relates to customer interest in education, information, and awareness of energy usage. 18% of people mention cost implications.

Reason for Preferred Option – Basic In-House Displays Should be Provided

Total Mentions	Total n=67	Kelowna (Okanagan) n=38	Castlegar (Kootenay) n=29
Smart Meters help to educate/inform customers/increases awareness of energy use	37%	37%	38%
Customers will be more responsible/mindful of their energy consumption/good for energy conservation	21%	32%	7%
Provide it free of charge/having to buy them would be a disincentive/a lot of people would not want to pay out of pocket for it	18%	13%	24%
Everyone should participate/would be more effective if everyone had one/if not everyone participates there would be no benefit	16%	26%	3%
Excellent idea/really like it/beneficial/I would want it	7%	5%	10%
Helps Fortis keep costs down/overall cost for Fortis would be cheaper/it benefits Fortis	7%	5%	10%
Other cost mentions (ie. Some cost increase can be justified, if everyone is included the cost per customer is lower, less cost if they are provided without a 3rd party, if I have to have it I would want to get the most for my rate increase)	6%	8%	3%
Facility of implementation/use	6%	11%	0%
The whole family could participate/the kids too/will also teach the kids	6%	11%	0%
No access to computer/not a big user of internet/some cannot operate a computer	4%	3%	7%
Cheaper for customers/more cost-effective for consumers/will save money on electric bill	3%	3%	3%
It is up to FortisBC to educate people about the value of the meters/people need to be	3%	5%	0%
Should be given the option/freedom of choice/people should have the option to refuse	3%	3%	3%
Accessing through website would be more cost-effective	1%	3%	0%
If people have it they will use it	1%	3%	0%
Internet is better/preferred/easily accessible	1%	3%	0%
Miscellaneous single mentions	15%	11%	21%

Indicates significant regional differences at a 95% confidence level

Freedom of choice, cost implications and a lack of engagement in monitoring personal energy usage are the primary reasons stated for preferring optional in-house displays.

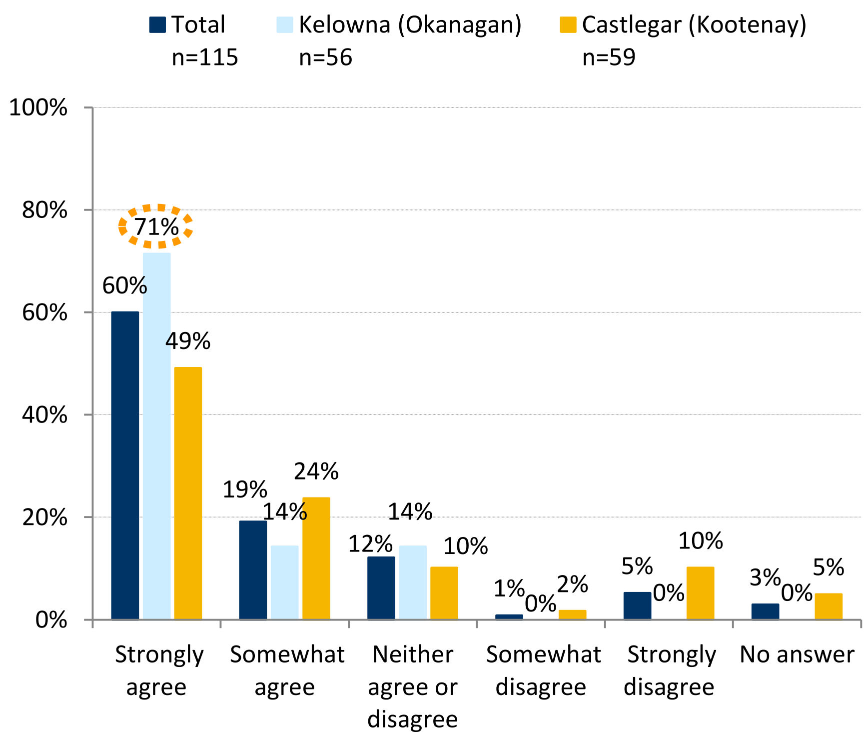
Reason for Preferred Option – In-House Displays Should be Optional

Total Mentions	Total n=41	Kelowna (Okanagan) n=15	Castlegar (Kootenay) n=26
Should be given the option/freedom of choice/people should have the option to refuse	27%	27%	27%
Provide it free of charge/having to buy them would be a disincentive/a lot of people would not want to pay out of pocket for it	20%	27%	15%
Not a critical issue/doesn't matter to me/wouldn't change my energy consumption/I can regulate my own energy use/it is already obvious when we use energy	17%	0%	27%
Internet is better/preferred/easily accessible	15%	27%	8%
People will get tired of looking at it/would just be a novelty at the beginning/would look at it initially and forget about it over time	10%	20%	4%
Cheaper for customers/more cost-effective for consumers/will save money on electric bill	7%	0%	12%
No access to computer/not a big user of internet/some cannot operate a computer	7%	20%	0%
Those who want it should pay for it	7%	13%	4%
Benefits don't outweigh the costs	5%	7%	4%
Don't want it/against them	5%	0%	8%
Excellent idea/really like it/beneficial/I would want it	5%	0%	8%
Expensive venture if no one uses it/it is money Fortis could have saved	5%	0%	8%
Internet is more comprehensive/better more usable information online	5%	7%	4%
Accessing through website would be more cost-effective	2%	7%	0%
Helps Fortis keep costs down/overall cost for Fortis would be cheaper/it benefits Fortis	2%	7%	0%
If people have it they will use it	2%	0%	4%
It is up to FortisBC to educate people about the value of the meters/people need to be educated about the program	2%	0%	4%
Smart Meters help to educate/inform customers/increases awareness of energy use	2%	0%	4%
Miscellaneous single mentions	2%	7%	0%

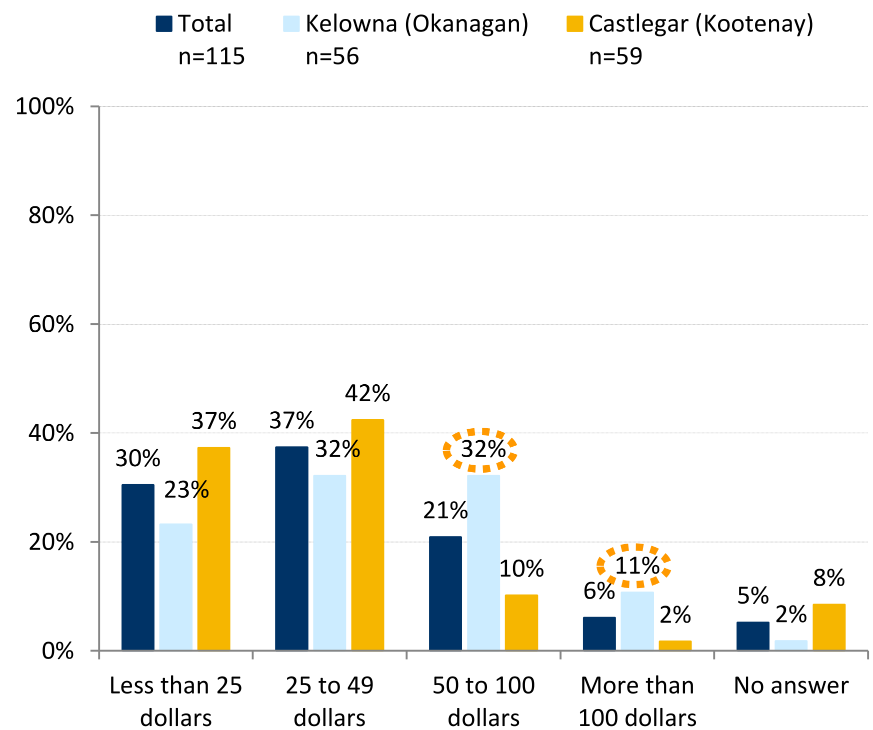
Advanced Metering Infrastructure (AMI)

If in-house displays were optional, customers would like to see an incentive program with these purchases. Most customers would pay up to 50 dollars for an in-house display.

Customer Support for an In-House Display Purchase Incentive Program (If an Optional Component of AMI)



Customer Price Point for Optional In-House Display

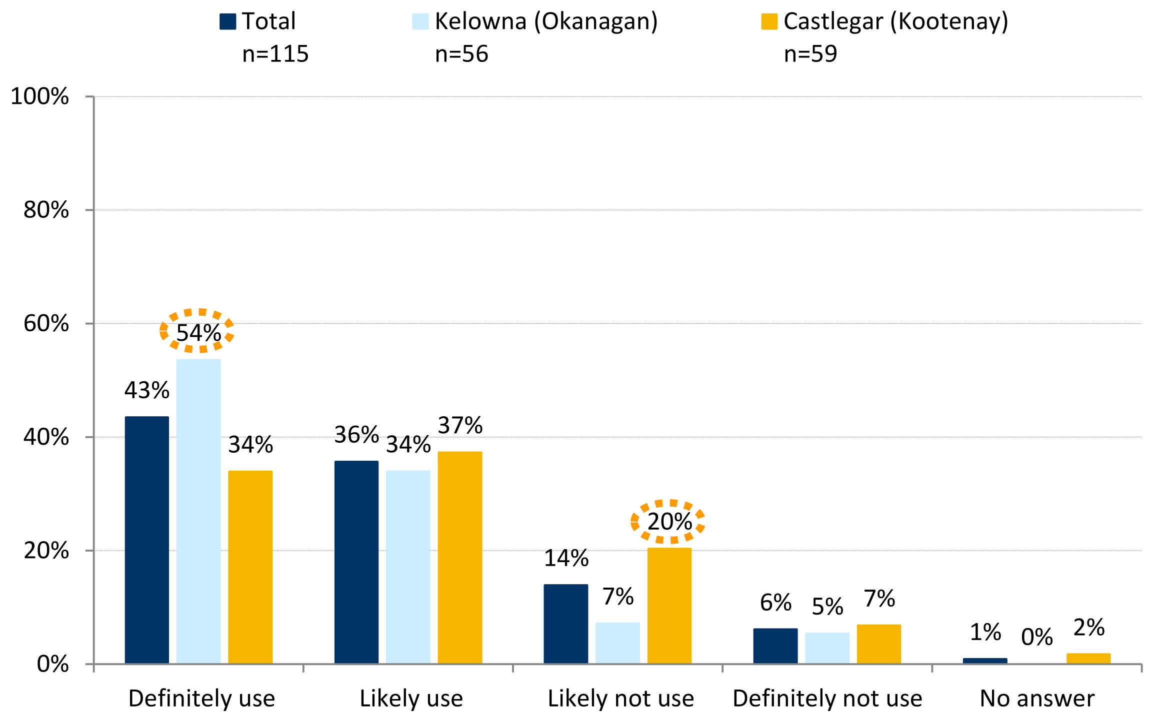


Indicates significant regional differences at a 95% confidence level

Advanced Metering Infrastructure (AMI)

When AMI is introduced, the majority of customers will use the FortisBC website provided for tracking their energy usage.

Likelihood that Customers Will Use a Secure Website to Track Energy Usage



Indicates significant regional differences at a 95% confidence level

The FortisBC website is a popular idea for customers so they can easily track usage or spot times of high usage. Issues with a website only approach is that some customers don't have access to a computer or are not computer literate.

Reasons Why a Secure Website Would or Would not be Used

Total Mentions	Total	Kelowna (Okanagan)	Castlegar (Kootenay)
Net: Would use (definitely/likely)	**n=89**	**n=48**	**n=41**
I am interested in my usage/tracking my usage/spotting my high usage times	30%	29%	32%
Would help with energy conservation/would use less/would help me make smart choices on power use/change the times of day I would use it	26%	33%	17%
Interested in where I can save money/helps me to manage the bill/it will keep the cost lower	16%	19%	12%
To become more informed/get more information/details	8%	10%	5%
Would only look at it periodically/not often/not on a regular basis	8%	8%	7%
Just to see/out of curiosity/interesting	7%	6%	7%
We use the internet extensively/always on the computer anyway/already pay bills online	6%	8%	2%
Prefer to use in-home display/home display meter would be enough	6%	4%	7%
Want to know the energy-draw of certain appliances/what it is costing me for each appliance	4%	4%	5%
Good/convenient access	4%	4%	5%
Other specific convenience mentions (ie. Can view information at my leisure, easy way, most efficient way, more flexible)	4%	8%	0%
Wonder how much this would cost/as long as there are no new charges for this	4%	2%	7%
Miscellaneous single mentions	8%	6%	10%
Net: Not use (likely not/definitely not)	**n=21**	**n=5**	**n=16**
Don't have access to a computer	19%	40%	13%
Not computer literate/don't know how to operate a computer very well	19%	0%	25%
Won't affect my power usage	14%	0%	19%
Don't like my personal information online	10%	0%	13%
Don't use the computer much/don't like using the computer	10%	0%	13%
Would help with energy conservation/would use less/would help me make smart choices on power use/change the times of day I would use it	10%	20%	6%
Wonder how much this would cost/as long as there are no new charges for this	5%	20%	0%
Don't have a lot of time to go online	5%	0%	6%
Prefer to use in-home display/home display meter would be enough	5%	20%	0%
Miscellaneous single mentions	10%	0%	13%

***Please note only mentions of 4% or greater are reported due to the wide variety of comments provided.**

Advanced Metering Infrastructure (AMI)

Positive support for the AMI program is a function of customer interest in energy usage or conservation (implied). Customers who are neutral about the program require additional information to make an informed choice. Cost remains a concern.

Comments About Advanced Metering or Smart Meter Programs

Total Mentions	Total n=93	Kelowna (Okanagan) n=49	Castlegar (Kootenay) n=44
Net: Positive	**46%**	**53%**	**39%**
Sounds good/fine/positive/I support it/the right direction/excellent project	33%	41%	25%
Will help people understand their usage/tool to keep people informed of their energy	9%	8%	9%
It is smart/smart investment/smart people use Smart Meters	3%	6%	0%
Will have a significant impact on usage/would reduce people's energy use	3%	2%	5%
More control over my power bill	2%	0%	5%
Would mean savings/savings in the long run	2%	2%	2%
Good idea to change the price depending on the peak period/there should be two prices for peak and non-peak times	3%	6%	0%
Net: Neutral	**27%**	**31%**	**23%**
Never heard of this before	11%	12%	9%
Would like more information/customers need to be enlightened and informed	9%	8%	9%
Good as long as it doesn't cost more/too much	3%	2%	5%
Puts the responsibility on the consumers	3%	6%	0%
A double-edged sword/good but have concerns	2%	2%	2%
Net: Negative	**15%**	**2%**	**30%**
Makes billing more expensive/concerned about increased costs/rates	8%	2%	14%
Not needed/should be optional/our usage wouldn't change/I am smarter than the meter	4%	0%	9%
They will charge us more during peak periods/worry about variable time-based rates	5%	0%	11%
Totally against it/they should be axed	2%	0%	5%
Miscellaneous single mentions	15%	18%	11%
Nothing	10%	10%	9%

Indicates significant regional differences at a 95% confidence level

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Customers would like to understand the additional costs of AMI before the program is introduced into their community.

Additional Information Desired About Advanced Metering Infrastructure

Total Mentions	Total n=83	Kelowna (Okanagan) n=43	Castlegar (Kootenay) n=40
Cost/associated costs/rates/what is the real cost to me?/how will it affect my bill?	35%	37%	33%
How this will benefit me/how it benefits consumers	8%	9%	8%
Do not change rates for high demand times/would like a guarantee that prices won't go up during peak usage times/do not raise rates	6%	2%	10%
How to use the information properly/how to understand what you are looking at/how to read the metering differences	5%	7%	3%
Installation schedule/implementation date/when we can get one	5%	7%	3%
Educate people in ways to save power/more information on conserving energy	4%	0%	8%
Have information meetings for the public/training/workshops	4%	2%	5%
How it works/operates	4%	5%	3%
More information (non-specific)	4%	5%	3%
More information on energy efficient appliances and devices/timer-based	4%	5%	3%
Pros and cons	4%	5%	3%
How accurate it will be/would living under hydro lines impact the digital readouts?	2%	2%	3%
How much time involved?/any downtime for changes to take place?	2%	5%	0%
Incentives to not use power during peak demand times	2%	5%	0%
The big picture advantage/how it will benefit the environment	2%	2%	3%
Miscellaneous single mentions	8%	9%	8%
Nothing	13%	12%	15%
Don't know/not stated	6%	5%	8%

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Appendix E-2

AMI Open House Feedback

FORTIS BC

Advanced Metering Infrastructure (AMI) Feedback

FortisBC will be filing an application with the British Columbia Utilities Commission for a new AMI program. This project proposes swapping existing electrical meters for new meters that allow a two-way information exchange. You may have also heard these called "smart meters".

Energy use information – hourly, daily or monthly data – will be available for customer viewing.

AMI feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
I would like FortisBC to provide customers with free in-home displays as part of the AMI project instead of interested customers purchasing their own in-home displays.	☐	☐	☐	☐	☑
I would like FortisBC to provide customers with access to a secure website to view their energy use information.	☐	☐	☐	☐	☑
Do you support conservation-based rate structures such as time-of-use rates?	☐	☐	☐	☐	☑

Are you willing to receive an ebill in place of a paper bill? ☐ Yes ☑ No

If you would like to receive an ebill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly. N/A	☐	☐	☐	☐	☐

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

HOW ~~IS~~ WILL THIS "AFFECT" EACH INDIVIDUAL + OUR ENVIROMENT HEALTH/WISE.

Before advanced metering is installed in my community, I'd like to know the following:

WOULD LIKE THE CUSTOMER VIEWS NOT JUST FORTIS BC'S VIEWS.

Additional comments regarding AMI:

Open house feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☐	☐	☐	☐	☑
The open house material presented to me tonight was a balanced perspective on the AMI.	☐	☐	☐	☐	☑

Please provide any questions or comments:

NOT WELL ORGANIZED IN TERMS OF INFORMATION TO THE GENERAL PUBLIC.

About you

Your feedback will be considered along with technical and financial inputs as FortisBC prepares the AMI for filing. Feedback collected at open houses and the web through feedback forms and via written comments will be summarized in the consultation report which will be provided to the British Columbia Utilities Commission during the regulatory review process.

Please indicate if your electricity account is (check all that apply):

☑ Residential ☐ Industrial ☐ Wholesale ☐ Commercial ☐ Irrigation ☐ Lighting

Did you attend an open house?

☑ Yes ☐ No

If yes, which location did you attend?

☐ Kelowna ☐ Princeton ☑ Osoyoos ☐ Creston ☐ Trail

How did you hear about the open house?

☑ Newspaper ☐ Radio ☑ Letter/email of invite ☐ From a friend or colleague ☐ Other (please specify): PAPER (NEWS.)

Your contact information (optional)

First name	Last name	Phone	Email
[redacted]	[redacted]	[redacted]	[redacted]

Address	City	Province	Postal code
[redacted]	[redacted]	[redacted]	[redacted]

Deadline for feedback forms or written comment is **July 15, 2011**. You can return written feedback forms or comments by:

email: FBCami@fortisbc.com or by **mail:** Attn: AMI Project Team
Suite 100 – 1975 Springfield Road
Kelowna, B.C., V1Y 7V7

3078 11/06

FORTIS BC

Advanced Metering Infrastructure (AMI) Feedback

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Energy use information – hourly, daily or monthly data – will be available for customer viewing.

AMI feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
I would like FortisBC to provide customers with free in-home displays as part of the AMI project instead of interested customers purchasing their own in-home displays.	☐	☑	☐	☐	☐
I would like FortisBC to provide customers with access to a secure website to view their energy use information.	☐	☑	☐	☐	☐
Do you support conservation-based rate structures such as time-of-use rates?	☐	☐	☐	☑	☐
Are you willing to receive an ebill in place of a paper bill? ☑ Yes ☐ No					
If you would like to receive an ebill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly.	☐	☐	☑	☐	☐

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

HEALTH PROBLEMS CONSERNS?

Before advanced metering is installed in my community, I'd like to know the following:

Additional comments regarding AMI:

Open house feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☐	☑	☐	☐	☐
The open house material presented to me tonight was a balanced perspective on the AMI.	☐	☐	☐	☑	☐

Please provide any questions or comments:

About you

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How did you hear about the open house?

☑ Newspaper ☐ Radio ☐ Letter/email of invite ☐ From a friend or colleague ☐ Other (please specify): ____________

Your contact information (optional)

First name	Last name	Phone	Email
[redacted]	[redacted]		[redacted]

Address	City	Province	Postal code
[redacted]	[redacted]	[redacted]	[redacted]

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Suite 100 – 1975 Springfield Road
Kelowna, B.C., V1Y 7V7

FORTIS BC™ [redacted]

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AMI feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
I would like FortisBC to provide customers with free in-home displays as part of the AMI project instead of interested customers purchasing their own in-home displays.	☐	☐	☐	☐	☑
I would like FortisBC to provide customers with access to a secure website to view their energy use information.	☐	☐	☐	☐	☑
Do you support conservation-based rate structures such as time-of-use rates?	☐	☐	☐	☐	☑

Are you willing to receive an ebill in place of a paper bill? ☐ Yes ☐ No — done already.

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
If you would like to receive an ebill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly.	☐	☐	☐	☑	☐

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

Due to health reasons, I will not have one in my home as I have an immune system disease!

Before advanced metering is installed in my community, I'd like to know the following:

That specific concerns in other countries such as U.S., Sweden, Denmark have been reviewed.

Additional comments regarding AMI:

Fortis needs to balance benefits from being more green to health disadvantages in presentation of information.

Open house feedback

The advertising of this meeting was extremely poor,

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better. – sketchy at best.	☐	☐	☐	☑	☐
The open house material presented to me tonight was a balanced perspective on the AMI.	☐	☐	☐	☐	☑

Please provide any questions or comments:

hence very poor attendance.

About you

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Please indicate if your electricity account is (check all that apply):

☑ Residential ☐ Industrial ☐ Wholesale ☐ Commercial ☐ Irrigation ☐ Lighting

Did you attend an open house? ☑ Yes ☐ No

If yes, which location did you attend? ☐ Kelowna ☐ Princeton ☑ Osoyoos ☐ Creston ☐ Trail

How did you hear about the open house?

☐ Newspaper ☐ Radio ☐ Letter/email of invite ☑ From a friend or colleague ☐ Other (please specify): ____________

Your contact information (optio[redacted]

[redacted]

Phone [redacted]

Em[redacted]

[redacted]

Deadline for feedback forms or written comment is **July 15, 2011**. You ca[redacted] forms or comments by:

email: FBCami@fortisbc.com or by **mail:** Attn: AMI Project Team
Suite 100 – 1975 Springfield Road
Kelowna, B.C., V1Y 7V7

Advanced Metering Infrastructure (AMI) Feedback

FORTIS BC™

FortisBC will be filing an application with the British Columbia Utilities Commission for a new AMI program. This project proposes swapping existing electrical meters for new meters that allow a two-way information exchange. You may have also heard these called "smart meters".

Energy use information – hourly, daily or monthly data – will be available for customer viewing.

AMI feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
I would like FortisBC to provide customers with free in-home displays as part of the AMI project instead of interested customers purchasing their own in-home displays.	☑	☐	☐	☐	☐
I would like FortisBC to provide customers with access to a secure website to view their energy use information.	☑	☐	☐	☐	☐
Do you support conservation-based rate structures such as time-of-use rates?	☑	☐	☐	☐	☐
Are you willing to receive an ebill in place of a paper bill? ☑ Yes ☐ No					
If you would like to receive an ebill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly.	☐	☑	☐	☐	☐

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

Before advanced metering is installed in my community, I'd like to know the following:

Additional comments regarding AMI:

Open house feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☑	☐	☐	☐	☐
The open house material presented to me tonight was a balanced perspective on the AMI.	☐	☑	☐	☐	☐

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Did you attend an open house?

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Your contact information (optional)

First nar [redacted] Last name [redacted]

[redacted] Cit [redacted]

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If you would like to receive an ebill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly.	☐	☐	☒	☐	☐

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

I would be comfortable with an AMI

Before advanced metering is installed in my community, I'd like to know the following:

An advanced statement of installation

Additional comments regarding AMI:

Open house feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☐	☒	☐	☐	☐
The open house material presented to me tonight was a balanced perspective on the AMI.	☐	☒	☐	☐	☐

Please provide any questions or comments:

It was a difficult meeting well managed.

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Email

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Do you support conservation-based rate structures such as time-of-use rates?	☐	☐	☐	☒	☐
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Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

Before advanced metering is installed in my community, I'd like to know the following:

Additional comments regarding AMI:

Open house feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☐	☒	☐	☐	☐
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I would like FortisBC to provide customers with access to a secure website to view their energy use information.	☐	☐	☐	☐	☒
Do you support conservation-based rate structures such as time-of-use rates?	☐	☐	☐	☐	☒

Are you willing to receive an ebill in place of a paper bill? ☐ Yes ☒ No

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
If you would like to receive an ebill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly.	☐	☐	☐	☐	☒

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

Radiation creates health problems.

Before advanced metering is installed in my community, I'd like to know the following:

Why they been promote here, while in other

Additional comments regarding AMI:

countrys had been prohibited.

Open house feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☐	☐	☐	☐	☒
The open house material presented to me tonight was a balanced perspective on the AMI.	☐	☐	☒	☐	☐

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About you

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How did you hear about the open house?

☐ Newspaper ☐ Radio ☐ Letter/email of invite ☒ From a friend or colleague ☐ Other (please specify): 2 Hrs before

Your contact information (optional)

[redacted] | Last name | Phone | [redacted]

C [redacted]

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3078 11/06

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	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
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I would like FortisBC to provide customers with access to a secure website to view their energy use information.	☐	☐	☐	☐	☒
Do you support conservation-based rate structures such as time-of-use rates?	☐	☐	☒	☐	☐
Are you willing to receive an ebill in place of a paper bill? ☐ Yes ☒ No					
If you would like to receive an ebill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly.	☐	☐	☐	☐	☐

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

It's just another potential for illness

Before advanced metering is installed in my community, I'd like to know the following:

I would like a choice to have a smart? meter in my home

Additional comments regarding AMI:

Open house feedback

Only 4 people showed up.

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☐	☐	☒	☐	☐
The open house material presented to me tonight was a balanced perspective on the AMI.	☐	☐	☐	☒	☐

Please provide any questions or comments:

How can it not be biased

About you

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Your contact information (optional)

First [redacted] Las[redacted] P[redacted] Email

Address [redacted] [redacted] Province [redacted] Postal code [redacted]

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AMI feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
I would like FortisBC to provide customers with free in-home displays as part of the AMI project instead of interested customers purchasing their own in-home displays.	☐	☐	☐	☐	☒
I would like FortisBC to provide customers with access to a secure website to view their energy use information.	☐	☐	☐	☐	☒
Do you support conservation-based rate structures such as time-of-use rates?	☐	☐	☐	☐	☒
Are you willing to receive an ebill in place of a paper bill? ☐ Yes ☒ No					
If you would like to receive an ebill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly.	☐	☐	☐	☐	☐

Are you wanting to lay off another employee

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

I am concerned about radiation effect.

Before advanced metering is installed in my community, I'd like to know the following:

Guarantee that there is no side effects of radiation:

Additional comments regarding AMI:

Encourage growops in our community. Good Deal!

Keep things the same.

Open house feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☐	☐	☐	☐	☒
The open house material presented to me tonight was a balanced perspective on the AMI.	☐	☐	☐	☐	☒

Please provide any questions or comments:

Why do you need to know more? The decision is already mandated to go ahead - just worried about themselves (Fortis). 50% we are expecting 50% rate increase this will cost us more!

About you

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AMI feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
I would like FortisBC to provide customers with free in-home displays as part of the AMI project instead of interested customers purchasing their own in-home displays.	☐	☐	☐	☑	☐
I would like FortisBC to provide customers with access to a secure website to view their energy use information.	☐	☑	☐	☐	☐
Do you support conservation-based rate structures such as time-of-use rates? undecided.	☐	☐	☐	☐	☐
Are you willing to receive an ebill in place of a paper bill? ☐ Yes ☑ No					
If you would like to receive an ebill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly.	☐	☐	☐	☐	☐

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

I haven't yet heard how it is working in other areas. Are we improving & progressing or are we using up techno stuff that other areas are scrapping.

Before advanced metering is installed in my community, I'd like to know the following:

time of use rates is a way to increase efficiency. For Fortis & ∴ (?) for Us.

Additional comments regarding AMI:

Over all - my concern would be total extra emissions in our communities.

Open house feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☑	☐	☐	☐	☐
The open house material presented to me tonight was a balanced perspective on the AMI.	☐	☑	☐	☐	☐

Please provide any questions or comments:

Seemed very balanced; #s re meter emissions somewhat misleading as "weighted info."

About you

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If yes, which location did you attend?
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Your contact information (optional)

[redacted] Last n[redacted] Pho[redacted] [redacted]
Cit[redacted] [redacted] [redacted]

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Do you support conservation-based rate structures such as time-of-use rates?	☐	☐	☐	☐	☑

Are you willing to receive an ebill in place of a paper bill? ☐ Yes ☑ No

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
If you would like to receive an ebill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly.	☐	☐	☐	☐	☐

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

DON'T WANT IT. HYPER SENSITIVE TO RADIATION

Before advanced metering is installed in my community, I'd like to know the following:

AMOUNT OF RADIATION EMITTED PEAKS (ACCUMULATED).

Additional comments regarding AMI:

WANT THE POWERLINE CARRIER OPTION ~~[illegible]~~ EXPLORED.

Open house feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☐	☐	☐	☐	☑
The open house material presented to me tonight was a balanced perspective on the AMI.	☐	☐	☐	☐	☑

Please provide any questions or comments:

WANT MORE INFO ON POWERLINE CARRIER.

About you

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Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

Sounds very usefull & efficient – Worth implementing.

Before advanced metering is installed in my community, I'd like to know the following:

Additional comments regarding AMI:

Let's get on with it! Very progressive.

Open house feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☒	☐	☐	☐	☐
The open house material presented to me tonight was a balanced perspective on the AMI.	☒	☐	☐	☐	☐

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Did you attend an open house? ☒ Yes ☐ No

If yes, which location did you attend? ☐ Kelowna ☐ Princeton ☐ Osoyoos ☐ Creston ☒ Trail

How did you hear about the open house?

☒ Newspaper ☐ Radio ☐ Letter/email of invite ☐ From a friend or colleague ☐ Other (please specify): ____________

Your contact information (optional)

First nam [redacted] Phone [redacted]

Address [redacted]

Deadline for feedback forms or written comment is **July 15, 2011**. You can return written feedback forms or comments by:

email: FBCami@fortisbc.com or by **mail:** Attn: AMI Project Team
Suite 100 – 1975 Springfield Road
Kelowna, B.C., V1Y 7V7

3078 11/06

Advanced Metering Infrastructure (AMI) Feedback

FORTIS BC

FortisBC will be filing an application with the British Columbia Utilities Commission for a new AMI program. This project proposes swapping existing electrical meters for new meters that allow a two-way information exchange. You may have also heard these called "smart meters".

Energy use information – hourly, daily or monthly data – will be available for customer viewing.

AMI feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
I would like FortisBC to provide customers with free in-home displays as part of the AMI project instead of interested customers purchasing their own in-home displays.	☐	☐	☐	☑	☐
I would like FortisBC to provide customers with access to a secure website to view their energy use information.	☑	☐	☐	☐	☐
Do you support conservation-based rate structures such as time-of-use rates?	☑	☐	☐	☐	☐

Are you willing to receive an ebill in place of a paper bill? ☑ Yes ☐ No

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
If you would like to receive an ebill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly.	☐	☐	☑	☐	☐

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

Sounds great to me.

Before advanced metering is installed in my community, I'd like to know the following:

Nothing - go ahead & do it.

Additional comments regarding AMI:

Open house feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☑	☐	☐	☐	☐
The open house material presented to me tonight was a balanced perspective on the AMI.	☐	☐	☑	☐	☐

Please provide any questions or comments:

About you

Your feedback will be considered along with technical and financial inputs as FortisBC prepares the AMI for filing. Feedback collected at open houses and the web through feedback forms and via written comments will be summarized in the consultation report which will be provided to the British Columbia Utilities Commission during the regulatory review process.

Please indicate if your electricity account is (check all that apply):
☑ Residential ☐ Industrial ☐ Wholesale ☐ Commercial ☐ Irrigation ☐ Lighting

Did you attend an open house?
☑ Yes ☐ No

If yes, which location did you attend?
☐ Kelowna ☐ Princeton ☐ Osoyoos ☐ Creston ☑ Trail

How did you hear about the open house?
☑ Newspaper ☐ Radio ☐ Letter/email of invite ☐ From a friend or colleague ☐ Other (please specify): ____________

Your contact information (optional)

First name [redacted] Last name [redacted] Phone [redacted] Email [redacted]

Address [redacted] City [redacted] Province [redacted] Postal code [redacted]

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Energy use information – hourly, daily or monthly data – will be available for customer viewing.

AMI feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
N/A I would like FortisBC to provide customers with free in-home displays as part of the AMI project instead of interested customers purchasing their own in-home displays.	☐	☐	☐	☐	☐
N/A I would like FortisBC to provide customers with access to a secure website to view their energy use information.	☐	☐	☐	☐	☐
Do you support conservation-based rate structures such as time-of-use rates? No	☐	☐	☐	☐	☐

Are you willing to receive an ebill in place of a paper bill? ☐ Yes ☒ No

If you would like to receive an ebill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly. No	☐	☐	☐	☐	☐

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

FORTIS SHOULD PURSUE PLC Meters

Before advanced metering is installed in my community, I'd like to know the following:

There is already too much RF in the air (Electro Smog)

Additional comments regarding AMI:

Why not be a leader industry? persue the least health damaging option PLC.

Open house feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☐	☐	☒	☐	☐
The open house material presented to me tonight was a balanced perspective on the AMI.	☒	☐	☐	☐	☐

Please provide any questions or comments:

You have failed to inform the public about proposal - You should have sent info re this with our bills -

About you

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☒ Residential ☐ Industrial ☐ Wholesale ☒ Commercial ☐ Irrigation ☐ Lighting

Did you attend an open house? ☒ Yes ☐ No

If yes, which location did you attend? ☐ Kelowna ☐ Princeton ☐ Osoyoos ☐ Creston ☒ Trail

How did you hear about the open house?

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Your contact information (optional)

Firs [redacted] L [redacted] Phone [redacted] Email

Ad [redacted] [redacted] Province [redacted] Postal code [redacted]

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Advanced Metering Infrastructure (AMI) Feedback

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Energy use information – hourly, daily or monthly data – will be available for customer viewing.

AMI feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
I would like FortisBC to provide customers with free in-home displays as part of the AMI project instead of interested customers purchasing their own in-home displays.	☐	☐	☐	☑	☐
I would like FortisBC to provide customers with access to a secure website to view their energy use information.	☐	☐	☐	☑	☐
Do you support conservation-based rate structures such as time-of-use rates?	☐	☑	☐	☐	☐
Are you willing to receive an ebill in place of a paper bill? ☐ Yes ☑ No					
If you would like to receive an ebill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly.	☐	☐	☐	☑	☐

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

THERE ARE SEVERAL ISSUES THAT I DO NOT AGREE THE SMART METERS WOULD BE OF BENEFIT.

Before advanced metering is installed in my community, I'd like to know the following:

HOW MUCH MORE WILL IT COST FAMILIES FOR POWER

HOW MANY METER READERS WILL LOSE THEIR JOBS.

Additional comments regarding AMI:

Open house feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☐	☑	☐	☐	☐
The open house material presented to me tonight was a balanced perspective on the AMI.	☐	☑	☐	☐	☐

Please provide any questions or comments:

About you

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Please indicate if your electricity account is (check all that apply):

☑ Residential ☐ Industrial ☐ Wholesale ☐ Commercial ☐ Irrigation ☐ Lighting

Did you attend an open house? ☑ Yes ☐ No

If yes, which location did you attend? ☐ Kelowna ☐ Princeton ☐ Osoyoos ☑ Creston ☐ Trail

How did you hear about the open house?

☑ Newspaper ☐ Radio ☐ Letter/email of invite ☐ From a friend or colleague ☐ Other (please specify): ______

Your contact information (optional)

First name	Last name	Phone	Email
[redacted]	[redacted]	[redacted]	

Address	City	Province	Postal code
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Energy use information – hourly, daily or monthly data – will be available for customer viewing.

AMI feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
I would like FortisBC to provide customers with free in-home displays as part of the AMI project instead of interested customers purchasing their own in-home displays.	☐	☐	☐	☐	☐
I would like FortisBC to provide customers with access to a secure website to view their energy use information.	☑	☐	☐	☐	☐
Do you support conservation-based rate structures such as time-of-use rates?	☑	☐	☐	☐	☐
Are you willing to receive an ebill in place of a paper bill? ☑ Yes ☐ No					
If you would like to receive an ebill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly.	☑	☐	☐	☐	☐

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

Well presented – hope the project gets approved

Before advanced metering is installed in my community, I'd like to know the following:

Additional comments regarding AMI:

Open house feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☑	☐	☐	☐	☐
The open house material presented to me tonight was a balanced perspective on the AMI.	☑	☐	☐	☐	☐

Please provide any questions or comments:

I initially knew very little about AMI program – came away well informed about it!

About you

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Did you attend an open house?
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Your contact information (optional)

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Do you support conservation-based rate structures such as time-of-use rates?	☐	☒	☐	☐	☐
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Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

Before advanced metering is installed in my community, I'd like to know the following:

Additional comments regarding AMI:

Open house feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☐	☒	☐	☐	☐
The open house material presented to me tonight was a balanced perspective on the AMI.	☐	☒	☐	☐	☐

Please provide any questions or comments:

About you

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Please indicate if your electricity account is (check all that apply):

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Did you attend an open house?

☒ Yes ☐ No

If yes, which location did you attend?

☐ Kelowna ☐ Princeton ☐ Osoyoos ☒ Creston ☐ Trail

How did you hear about the open house?

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Your contact information (optional)

First name	Last name	Phone	Email	
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	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
I would like FortisBC to provide customers with free in-home displays as part of the AMI project instead of interested customers purchasing their own in-home displays.	☐	☑	☐	☐	☐
I would like FortisBC to provide customers with access to a secure website to view their energy use information.	☑	☐	☐	☐	☐
Do you support conservation-based rate structures such as time-of-use rates?	☐	☐	☑	☐	☐
Are you willing to receive an ebill in place of a paper bill? ☐ Yes ☑ No					
If you would like to receive an ebill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly.	☐	☐	☐	☐	☑

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

Before advanced metering is installed in my community, I'd like to know the following:

Additional comments regarding AMI:

I AM IN FAVOUR OF SMART METER TECHNOLOGY

Open house feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☑	☐	☐	☐	☐
The open house material presented to me tonight was a balanced perspective on the AMI.	☐	☑	☐	☐	☐

Please provide any questions or comments:

About you

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Did you attend an open house?

☑ Yes ☐ No

If yes, which location did you attend?

☐ Kelowna ☐ Princeton ☐ Osoyoos ☑ Creston ☐ Trail

How did you hear about the open house?

☑ Newspaper ☐ Radio ☐ Letter/email of invite ☐ From a friend or colleague ☐ Other (please specify): ____________

Your contact information (optional)

Fi[redacted] Last name [redacted] Phone [redacted]

Ad[redacted]

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	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
I would like FortisBC to provide customers with free in-home displays as part of the AMI project instead of interested customers purchasing their own in-home displays.	☐	☐	☒	☐	☐
I would like FortisBC to provide customers with access to a secure website to view their energy use information.	☐	☐	☒	☐	☐
Do you support conservation-based rate structures such as time-of-use rates?	☐	☐	☒	☐	☐

Are you willing to receive an ebill in place of a paper bill? ☐ Yes ☒ No

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
If you would like to receive an ebill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly.	☐	☐	☒	☐	☐

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

Very afraid of health issues

Before advanced metering is installed in my community, I'd like to know the following:

Additional comments regarding AMI:

Open house feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☐	☒	☐	☐	☐
The open house material presented to me tonight was a balanced perspective on the AMI.	☐	☒	☐	☐	☐

Please provide any questions or comments:

About you

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☒ Residential ☐ Industrial ☐ Wholesale ☐ Commercial ☐ Irrigation ☐ Lighting

Did you attend an open house?
☒ Yes ☐ No

If yes, which location did you attend?
☒ Kelowna ☐ Princeton ☐ Osoyoos ☐ Creston ☐ Trail

How did you hear about the open house?
☐ Newspaper ☐ Radio ☐ Letter/email of invite ☐ From a friend or colleague ☐ Other (please specify): Poster

Your contact information (optional)

First na[redacted] Phone [redacted] Email [redacted]

[redacted] Province [redacted] Postal code [redacted]

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I would like FortisBC to provide customers with free in-home displays as part of the AMI project instead of interested customers purchasing their own in-home displays.	☐	☐	☐	☑	☐
I would like FortisBC to provide customers with access to a secure website to view their energy use information.	☐	☑	☐	☐	☐
Do you support conservation-based rate structures such as time-of-use rates?	☐	☐	☑	☐	☐

Are you willing to receive an eBill in place of a paper bill? ☐ Yes ☑ No

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
If you would like to receive an eBill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly.	☐	☐	☐	☑	☐

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

-If the system isn't Broke, don't Fix it.
-Meter man coming to the house gives a sense of Security

Before advanced metering is installed in my community, I'd like to know the following:

Additional comments regarding AMI:

About you

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Please indicate if your electricity account is (check all that apply):

☑ Residential ☐ Industrial ☐ Wholesale ☑ Commercial ☐ Irrigation ☐ Lighting

Did you attend an open house?

☐ Yes ☒ No

If yes, which location did you attend?

☐ Kelowna ☐ Princeton ☐ Osoyoos ☐ Creston ☐ Trail

How did you hear about the open house?

☐ Newspaper ☐ Radio ☐ Letter/email of invite ☐ From a friend or colleague ☐ Other (please specify): [redacted] Community Club

Your contact information (optional)

First name [redacted] Last name [redacted] Phone [redacted] Email [redacted]

[redacted] Province [redacted] Postal Code [redacted]

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AMI feedback

	Strongly agree	Agree	Neutral	Disagree	Str disa
I would like FortisBC to provide customers with free in-home displays as part of the AMI project instead of interested customers purchasing their own in-home displays.	☐	☐	☐	☐	[
I would like FortisBC to provide customers with access to a secure website to view their energy use information.	☐	☐	☐	☐	[
Do you support conservation-based rate structures such as time-of-use rates?	☐	☐	☐	☐	[
Are you willing to receive an ebill in place of a paper bill? ☐ Yes ☐ No					
If you would like to receive an ebill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly.	☐	☐	☐	☐	[

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

I strongly oppose the AMI meters. we lived near power lines in Cloverdale, B.C. my husband and I + friends got

Before advanced metering is installed in my community, I'd like to know the following:

cancer. my husband passed away 5 yrs ago. All Children born under power lines had learning problems at school. A W5

Additional comments regarding AMI: program on T.V. clarified many health problems, I have read of other who have these meters and have resulted in many health problems.

Open house feedback

only the electrion who was present helped me understand the health problem more clear

	Strongly agree	Agree	Neutral	Disagree	Str disa
The open house material presented to me tonight was useful and helped me understand the AMI better.	☐	☐	☐	☐	[
The open house material presented to me tonight was a balanced perspective on the AMI.	☐	☐	☐	☐	[

Please provide any questions or comments: I heard only what they felt was good about them, but none of the health problems people have experienced. Live near power lines, you will then understand why I object.

About you

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☒ Residential ☐ Industrial ☐ Wholesale ☐ Commercial ☐ Irrigation ☐ Lighting

Did you attend an open house?

☒ Yes ☐ No

If yes, which location did you attend?

☒ Kelowna ☐ Princeton ☐ Osoyoos ☐ Creston ☐ Trail

How did you hear about the open house?

☒ Newspaper ☐ Radio ☐ Letter/email of invite ☐ From a friend or colleague ☐ Other (please specify): ____

Your contact information (optional)

First name [redacted] Last name [redacted] Phone [redacted] Email [redacted]

Address [redacted] City [redacted]

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THIS IS PAGE ONE OF THREE
THE PAGE 2 + 3 GIVE MY REASONS FOR REFUSAL!

Appendix E-2

FORTIS BC

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	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
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I would like FortisBC to provide customers with access to a secure website to view their energy use information.	☐	☐	☐	☐	☒
Do you support conservation-based rate structures such as time-of-use rates?	☐	☐	☐	☐	☒

Are you willing to receive an ebill in place of a paper bill? ☐ Yes ☐ No

~~If you would like to receive an ebill, would you like more flexibility on how often you receive your electric eBill from FortisBC? Examples would be weekly, biweekly, monthly.~~ I WILL REFUSE AMI INSTALLATION!	☐	☐	☐	☐	☐

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:
WILL BE VERY COSTLY TO CUSTOMERS. IT IS A MAJOR INVASION OF PRIVACY. BC HYDRO AND FORTIS WOULD PROBABLY BE ILLEGAL IN DOING THIS

Before advanced metering is installed in my community, I'd like to know the following:
WHAT IS THE REAL PURPOSE OF DOING THIS PROJECT. THE REASONS GIVEN BY FORTIS ARE VERY WEAK AND ALSO NOT HONEST.

Additional comments regarding AMI: THE PURPOSE MUST BE MUCH STRONGER AND MAKE SENSE IN ORDER TO GO AHEAD WITH THIS. I WILL REFUSE INSTALLATION WHICH WILL BE MY PROBLEM AND YOURS!!

Open house feedback

	Strongly agree	Agree	Neutral	Disagree	Strongly disagree
The open house material presented to me tonight was useful and helped me understand the AMI better.	☐	☐	☐	☐	☒
The open house material presented to me tonight was a balanced perspective on the AMI.	☐	☐	☐	☐	☒

Please provide any questions or comments:
MANY QUESTIONS WERE NOT ANSWERED! "I DON'T KNOW" 99% OF THE PUBLIC WAS UNAWARE OF THESE MEETINGS AND ARE UNAWARE OF THE AMI PROJECT.

About you

Your feedback will be considered along with technical and financial inputs as FortisBC prepares the AMI for filing. Feedback collected at open houses and the web through feedback forms and via written comments will be summarized in the consultation report which will be provided to the British Columbia Utilities Commission during the regulatory review process.

Please indicate if your electricity account is (check all that apply):
☒ Residential ☐ Industrial ☐ Wholesale ☐ Commercial ☐ Irrigation ☐ Lighting

Did you attend an open house?
☒ Yes ☐ No

If yes, which location did you attend?
☐ Kelowna ☐ Princeton ☒ Osoyoos ☐ Creston ☒ Trail

How did you hear about the open house?
☐ Newspaper ☐ Radio ☐ Letter/email of invite ☒ From a friend or colleague ☐ Other (please specify): ______

Your contact information (optional)

First name [redacted] Last name [redacted] Phone [redacted] Email [redacted]
Address [redacted] City [redacted] Province [redacted] Postal code [redacted]

Deadline for feedback forms or written comment is **July 15, 2011**. You can return written feedback forms or comments by:

email: FBCami@fortisbc.com or by **mail:** Attn: AMI Project Team
Suite 100 – 1975 Springfield Road
Kelowna, B.C., V1Y 7V7

3078 11/06

MAILED JULY 15 THROUGH CANADA POST.

Appendix E-3

AMI Support Letters

FIRE CHIEFS' ASSOCIATION OF BC
#9 – 715 Barrera Road
Kelowna, BC V1W 3C9
Phone: 250-862-2388
Email: fcabc@shaw.ca

May 23, 2012

FortisBC Inc
Suite 100, 1975 Springfield Road
Kelowna, BC V1Y 7V7

Dear Sirs:

As President of the Fire Chiefs' Association of British Columbia, I am writing to lend my support to FortisBC's application for the Advanced Metering Infrastructure (AMI) or Smart Meter installation project.

Once fully operational Smart meters and the supporting infrastructure this system will allow the power supply to a home or business to be disconnected remotely during a fire. While waiting for a power line crew to arrive and disconnect at the utility pole, the utility can remotely de-energize at the meter, allowing for interim access inside the premises.

When installing the new meters, the utility will be checking and repairing faulty meter bases, which is a unique opportunity to identify and address meter base and related wiring issues, thus removing potential fire hazards that would have otherwise gone undetected.

Theft of electricity is occurring in increasingly dangerous ways. Tampering with the wires and other infrastructure on the grid creates a major safety risk to the general public, to us as first responders, and to the utility's employees. For example, in Surrey, approximately 50% of marijuana growing operations inspected by the fire department involved diversion of electricity from a utility's distribution lines.

Smart meter technology will make it much more difficult to steal electricity and will substantially reduce current levels of theft. Combined with other technology on the grid, the new meters will help to measure the flow of electricity throughout the grid and track it like a store's inventory system. This information will help the utility identify electricity theft that is occurring directly from the power lines more accurately and address it more quickly.

Yours truly,

Len W. Garis,
Fire Chief, City of Surrey,
President, FCABC

BC Sustainable Energy ASSOCIATION

5 - 4217 Glanford Avenue
Victoria, BC Canada V8Z 4B9
(250) 744-2720
info@bcsea.org

28 May 2012

To whom it may concern:

Re: FortisBC's Advanced Metering Infrastructure (AMI) project

The BC Sustainable Energy Association is pleased to support FortisBC's pending application to the BC Utilities Commission in regard to its Advanced Metering Infrastructure project.

BCSEA understands that advanced meters have the potential to improve the efficiency of the electricity grid, to enable conservation rate structures, to enable customers to understand their energy use better, and to provide other benefits. BCSEA supports cost-effective measures to increase the efficiency of energy use and delivery, and therefore we are keenly interested in the AMI project.

BCSEA also understands that FortisBC intends to support an open and transparent review of its AMI project, including addressing concerns customers may have about safety issues relating to the meters. We believe this would be in the public interest.

Regards,

Thomas Hackney
Director of Policy

GreenStep
250 862 8941
info@greenstep.ca
748 B Bernard Avenue
Kelowna, BC V1Y 6P5
www.greenstep.ca

May 24, 2012

FortisBC
1975 Springfield Rd.
Kelowna, BC
V1Y 7V7

Dear Mr. Weston,

Please accept this letter as confirmation of GreenStep's support for your Advanced Metering Infrastructure project. I have personally been closely following the progress of this technology in North America and am excited to learn that it will be coming to the FortisBC service area.

GreenStep works with businesses, organizations and home owners, on measuring and reducing their energy consumption and carbon footprint as part of an integrated sustainability strategy. The ability to do real time in-house monitoring has been proven to reduce energy consumption by 4% in homes. For our business clients who have established energy reduction targets of up to 50%, advanced metering technology will help them to monitor and measure progress towards their goals in a more meaningful way than simply looking at utility bills on a monthly basis. Our experience shows that when people can interact with their consumption related data, they are more motivated and achieve better results.

In addition, the significant reduction in transportation related emissions that will result from wireless data transmission will play an important role in reducing our region's greenhouse gas emissions.

GreenStep looks forward to receiving updates on the progress of this initiative and to the final implementation.

Sincerely,

Angela Reid

Angela Reid-Nagy
CEO, GreenStep Sustainability Coaching

climatesmart

May 30, 2012

Dear Mr. Warren,

I am writing today to express our support for FortisBC's application for Advanced Metering Infrastructure project to the BC Public Utilities Commission.

Climate Smart offers a comprehensive training program and software for small/medium enterprises (SMEs) to measure and profitably reduce their energy, transport, waste-related costs and greenhouse gas (GHG) emissions. We have worked in 25 communities with over 650 businesses representing over 47,000 employees. On average Climate Smart businesses are demonstrating a 5.8% reduction in emissions in their first year across energy, transport and waste. In our program we see that what gets measured gets managed.

We support the application for Advanced Metering Infrastructure:

- as a key pathway for scaling up the benefits of accessing actionable energy data. Actionable data drives behaviour and investment, reduces inefficiencies and costs and helps businesses and communities make progress on our energy conservation and emission reductions goals.
- to increase opportunities for wide-scale customer-owned distributed power generation and electric cars.

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.

In conclusion, I look forward to receiving updates from you on this project, and please contact me should you require any more assistance from our organization regarding FortisBC's Advanced Metering Infrastructure project.

Sincerely,

M. Elizabeth Sheehan

Elizabeth Sheehan

President, Climate Smart Businesses, Inc.

Appendix E-4

AMI First Nations Letters

FORTIS BC™

Bob Gibney
Senior Manager,
Corporate Services and
Aboriginal Affairs

FortisBC Inc.
Suite 100, 1975 Springfield Road
Kelowna, BC V1Y 7V7
(250) 469-8006
bob.gibney@fortisbc.com
www.fortisbc.com

July 4, 2011

Penticton Indian Band
Chief Johnathan Kruger
RR#2, Site 80, Comp 19
Penticton, BC
V2A 6J7

Dear Chief Kruger,

RE: FortisBC seeking public input on Advanced Metering Infrastructure for electricity customers.

In the past weeks FortisBC hosted a series of open house information sessions regarding the Company's proposal to deploy advanced meters for all customers. The open houses were well attended and customer input was most valuable. If you would like a copy of the presentation that was delivered at the open houses please go to www.fortisbc.com/ami.

FortisBC welcomes input from Penticton Indian Band regarding the project. I would like to extend an invitation for you to contact Ian Dyck, Advanced Metering Infrastructure, Project Manager with any questions or comments the Penticton Indian Band has. Ian can be reached at Ian.Dyck@fortisbc.com or 250.469.8130.

Sincerely,

Bob Gibney

FORTIS BC™

Bob Gibney
Senior Manager,
Corporate Services and
Aboriginal Affairs

FortisBC Inc.
Suite 100, 1975 Springfield Road
Kelowna, BC V1Y 7V7
(250) 469-8006
bob.gibney@fortisbc.com
www.fortisbc.com

July 4, 2011

Osoyoos Indian Band
Chief Clarence Louie
Site 25 Comp 1 RR#3
Oliver, BC
V0H 1T0

Dear Chief Louie,

RE: FortisBC seeking public input on Advanced Metering Infrastructure for electricity customers.

In the past weeks FortisBC hosted a series of open house information sessions regarding the Company's proposal to deploy advanced meters for all customers. The open houses were well attended and customer input was most valuable. If you would like a copy of the presentation that was delivered at the open houses please go to www.fortisbc.com/ami.

FortisBC welcomes input from Osoyoos Indian Band regarding the project. I would like to extend an invitation for you to contact Ian Dyck, Advanced Metering Infrastructure, Project Manager with any questions or comments the Osoyoos Indian Band has. Ian can be reached at Ian.Dyck@fortisbc.com or 250.469.8130.

Sincerely,

Bob Gibney

Blair Weston
Community & Aboriginal
Relations Manager

FortisBC Inc.

July 4, 2011

Lower Kootenay Indian Band
Chief Jason Louie
830 Simon Road
Creston, BC
V0B 1G2

Dear Chief Louie,

RE: FortisBC seeking public input on Advanced Metering Infrastructure for electricity customers.

In the past weeks FortisBC hosted a series of open house information sessions regarding the Company's proposal to deploy advanced meters for all customers. The open houses were well attended and customer input was most valuable. If you would like a copy of the presentation that was delivered at the open houses please go to www.fortisbc.com/ami.

FortisBC welcomes input from Lower Kootenay Indian Band regarding the project. I would like to extend an invitation for you to contact Ian Dyck, Advanced Metering Infrastructure, Project Manager with any questions or comments the Lower Kootenay Indian Band has. Ian can be reached at Ian.Dyck@fortisbc.com or 250.469.8130.

Sincerely,

Blair Weston

FORTIS BC™

Bob Gibney
Senior Manager,
Corporate Services and
Aboriginal Affairs

FortisBC Inc.
Suite 100, 1975 Springfield Road
Kelowna, BC V1Y 7V7
(250) 469-8006
bob.gibney@fortisbc.com
www.fortisbc.com

July 4, 2011

Upper Similkameen Indian Band
Chief Charlotte Mitchell
610 - 7th Avenue, PO Box 310
Keremeos, BC
V0X 1N0

Dear Chief Mitchell,

RE: FortisBC seeking public input on Advanced Metering Infrastructure for electricity customers.

In the past weeks FortisBC hosted a series of open house information sessions regarding the Company's proposal to deploy advanced meters for all customers. The open houses were well attended and customer input was most valuable. If you would like a copy of the presentation that was delivered at the open houses please go to www.fortisbc.com/ami.

FortisBC welcomes input from Upper Similkameen Indian Band regarding the project. I would like to extend an invitation for you to contact Ian Dyck, Advanced Metering Infrastructure, Project Manager with any questions or comments the Upper Similkameen Indian Band has. Ian can be reached at Ian.Dyck@fortisbc.com or 250.469.8130.

Sincerely,

Bob Gibney

Bob Gibney
Senior Manager,
Corporate Services and
Aboriginal Affairs

FortisBC Inc.
Suite 100, 1975 Springfield Road
Kelowna, BC V1Y 7V7
(250) 469-8006
bob.gibney@fortisbc.com
www.fortisbc.com

July 4, 2011

Lower Similkameen Indian Band
Chief Rob Edward
P.O. Box 100
Keremeos, BC
V0X 1N0

Dear Chief Edward,

RE: FortisBC seeking public input on Advanced Metering Infrastructure for electricity customers.

In the past weeks FortisBC hosted a series of open house information sessions regarding the Company's proposal to deploy advanced meters for all customers. The open houses were well attended and customer input was most valuable. If you would like a copy of the presentation that was delivered at the open houses please go to www.fortisbc.com/ami.

FortisBC welcomes input from Lower Similkameen Indian Band regarding the project. I would like to extend an invitation for you to contact Ian Dyck, Advanced Metering Infrastructure, Project Manager with any questions or comments the Lower Similkameen Indian Band has. Ian can be reached at Ian.Dyck@fortisbc.com or 250.469.8130.

Sincerely,

Bob Gibney

FORTIS BC™

Bob Gibney
Senior Manager,
Corporate Services and
Aboriginal Affairs

FortisBC Inc.
Suite 100, 1975 Springfield Road
Kelowna, BC V1Y 7V7
(250) 469-8006
bob.gibney@fortisbc.com
www.fortisbc.com

July 4, 2011

Okanagan Indian Band
Chief Byron Louis
12420 Westside Road
Vernon, BC
V1H 2A4

Dear Chief Louis,

RE: FortisBC seeking public input on Advanced Metering Infrastructure for electricity customers.

In the past weeks FortisBC hosted a series of open house information sessions regarding the Company's proposal to deploy advanced meters for all customers. The open houses were well attended and customer input was most valuable. If you would like a copy of the presentation that was delivered at the open houses please go to www.fortisbc.com/ami.

Although the number of FortisBC customers on Okanagan Indian Band is relatively small, FortisBC welcomes input from Okanagan Indian Band regarding the project. I would like to extend an invitation for you to contact Ian Dyck, Advanced Metering Infrastructure, Project Manager with any questions or comments the Okanagan Indian Band has. Ian can be reached at Ian.Dyck@fortisbc.com or 250.469.8130.

Sincerely,

Bob Gibney

Bob Gibney
Senior Manager,
Corporate Services and
Aboriginal Affairs

FortisBC Inc.
Suite 100, 1975 Springfield Road
Kelowna, BC V1Y 7V7
(250) 469-8006
bob.gibney@fortisbc.com
www.fortisbc.com

July 4, 2011

Okanagan Nation Alliance
Grand Chief Stewart Philip
3255C Shannon Lake Road
West Kelowna, BC
V4T 1V4

Dear Grand Chief Philip,

RE: FortisBC seeking public input on Advanced Metering Infrastructure for electricity customers.

In the past weeks FortisBC hosted a series of open house information sessions regarding the Company's proposal to deploy advanced meters for all customers. The open houses were well attended and customer input was most valuable. If you would like a copy of the presentation that was delivered at the open houses please go to www.fortisbc.com/ami.

FortisBC welcomes input from Okanagan Nation Alliance regarding the project. I would like to extend an invitation for you to contact Ian Dyck, Advanced Metering Infrastructure, Project Manager with any questions or comments the Okanagan Nation Alliance has. Ian can be reached at Ian.Dyck@fortisbc.com or 250.469.8130.

Sincerely,

Bob Gibney

Appendix F-1

AMI-SEC System Security Requirements

UCAIUG: AMI-SEC-ASAP

AMI System Security Requirements

V1.01

ASAP

12/17/2008

Executive Summary

This document provides the utility industry and vendors with a set of security requirements for Advanced Metering Infrastructure (AMI). These requirements are intended to be used in the procurement process, and represent a superset of requirements gathered from current cross-industry accepted security standards and best practice guidance documents.

This document provides substantial supporting information for the use of these requirements including scope, context, constraints, objectives, user characteristics, assumptions, and dependencies. This document also introduces the concept of requirements for security states and modes, with requirements delineated for security states.

These requirements are categorized into three areas: 1) Primary Security Services, 2) Supporting Security Services and 3) Assurance Services. The requirements will change over time corresponding with current security threats and countermeasures they represent. The AMI-SEC Task Force presents the current set as a benchmark, and the authors expect utilities and vendors to tailor the set to individual environments and deployments.

While these requirements are capable of standing on their own, this document is intended to be used in conjunction with other 2008 deliverables from the AMI-SEC Task Force, specifically the Risk Assessment, the Architectural Description, the Component Catalog (in development as of this writing), and the Implementation Guide (to be developed late 2008). This document also discusses the overall process for usage of this suite.

Acknowledgements

The AMI-SEC Task Force would like to acknowledge the work of the primary authors, contributing authors, editors, reviewers, and supporting organizations. Specifically, the Task Force would like to thank:

- The AMI Security Acceleration Project (ASAP)
  - The Architectural Team including resources from Consumers Energy, EnerNex Corporation, InGuardians, The Software Engineering Institute at Carnegie Mellon University, and Southern California Edison
  - Supporting organizations including The Electric Power Research Institute and The United States Department of Energy
  - Participating utilities, including American Electric Power, Austin Energy, BC Hydro, Consumers Energy, Duke Energy, Kansas City Power & Light, Oncor, Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison
- The utilities, vendors, consultants, national laboratories, higher education institutions, governmental entities, and other organizations that have actively contributed to and participated in the activities of the AMI-SEC Task Force

The AMI-SEC Task Force would also like to thank the Department of Homeland Security Cyber Security Division, National Institute of Standards and Technology Computer Security Division, North American Reliability Corporation and The Common Criteria for the works that they have produced that served as reference material for the AMI Systems Security Requirements document.

Authors

Bobby Brown
Brad Singletary
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Table of Figures

1. Introduction

As a key element in the evolution of the Smart Grid, the Advanced Metering Infrastructure (AMI) is the convergence of the power grid, the communications infrastructure, and the supporting information infrastructure. AMI security must exist in the real world with many interested parties and overlapping responsibilities. This document focuses on the security services that are important to secure the power grid, communications infrastructure and supporting information infrastructure.

1.1 Purpose

The purpose of the AMI Security Specification is to provide the utility industry along with supporting vendor communities and other stakeholders a set of security requirements that should be applied to AMI implementations to ensure the high level of information assurance, availability and security necessary to maintain a reliable system and consumer confidence. While this specification focuses on AMI, the security requirements contained in the document may be extended to other network-centric, Smart Grid solutions.

1.1.1 Strategic Importance

Utility companies of the future will deliver energy and information to customers through a “smart” energy supply chain created by the convergence of electric, communication and information technologies that are highly automated for responding to the changing environment, electricity demands and customer needs. The building blocks of this Smart Grid include AMI, advanced transmission and distribution automation, distributed generation, electric vehicle refueling infrastructure and renewable energy generation projects of today.

The emergence of this new class of Smart Grid systems holds tremendous promise and requires innovation and deployment of new technologies, processes and policies. Composed of many independent systems, the Smart Grid will evolve by integrating existing islands of automation to achieve value through the delivery of information to customers, grid operators, utility companies and other stakeholders. A reliable and secure Smart Grid holds the promise of enabling automated demand response, providing customers a myriad of options to manage their energy costs through technology enabled programs along with limiting outages with a self-healing resilient transmission and distribution network and other strategically important functions.

The challenge of providing both a reliable and secure AMI solution lies in the diversity of technologies, processes and approaches used to realize this vision. Managing change rising from the complexity of diverse solutions with an effective and efficient systems integration process will enable the AMI system. This requires a commitment to standards, best practices and a high degree of architectural discipline. This document specifies platform independent security requirements, services and guidance required to implement secure, resilient AMI solutions.

1.1.2 Problem Domain

As the utility industry’s capabilities increase to serve the needs of a rapidly growing information society, the breadth and sophistication of the threat environment these Smart Grid solutions operate in also increases. By bridging heterogeneous networks capable of exchanging information seamlessly across the AMI older proprietary and often manual methods of securing utility services will disappear as each is replaced by more open, automated and networked solutions. The benefits of this increased connectivity depends upon robust security services and implementations that are necessary to minimize disruption of vital services and provide increased reliability, manageability and survivability of the electric grid.

Recognizing the unique challenges of AMI enabled Smart Grid solutions is imperative to deploying a secure and reliable solution. Unique characteristics of AMI implementations that set them apart from other utility project include the following:

- AMI touches every consumer
- AMI is a command and control system
- AMI has millions of nodes
- AMI touches almost every enterprise system
- Many current AMI solutions are narrowband solutions

These network-centric characteristics, coupled with a lack of a composite set of cross industry AMI security requirements and implementation guidance, is the primary motivation for the development of this document. The problem domains needing to be addressed within AMI implementations are relatively new to the utility industry, however there is precedence for implementing large scale, network-centric solutions with high information assurance requirements. The defense, cable and telecommunication industries offer a number of examples of requirements, standards and best practices directly applicable to AMI implementations.

The challenge is to secure AMI in a holistic manner, noting that such an approach requires the buy-in of many stakeholders. Stakeholders can be viewed in three groups:

- Stakeholders within the enterprise who have an interest in generating value from technology investments:
  - Those who make investment decisions
  - Those who decide about requirements
  - Those who use technology services
- Internal and external stakeholders who provide technology services:
  - Those who manage the technology organization and processes
  - Those who develop capabilities
  - Those who operate the services
- Internal and external stakeholders who have a control/risk responsibility:
  - Those with security, privacy and/or risk responsibilities
  - Those performing compliance functions
  - Those requiring or providing assurance services

To meet the requirements of the stakeholder community, a security framework for AMI technology governance and control should:

- Provide a business focus to enable alignment between business and technology objectives
- Establish a process orientation to define the scope and extent of coverage, with a defined structure enabling easy navigation of content
- Be generally acceptable by being consistent with accepted technology good practices and standards and independent of specific technologies

- Supply a common language with a set of terms and definitions that are generally understandable by all stakeholders
- Help meet regulatory requirements by being consistent with generally accepted corporate governance standards (e.g., Committee of Sponsoring Organizations of the Treadway Commission) and technology controls expected by regulators and external auditors.

As such, this document provides security requirements for the purposes of procurement, design input, validation and certification. It is not the intent of this document to describe AMI architecture. The satisfaction of requirements identified in this document implies a need for coherent architecture, policies, procedures, etc… none of which is prescribed in this document.

AMI security involves a system of systems approach in design and operations, and therefore security responsibility must extend to stakeholders and parties outside and in addition to the electric utility. While security requirements for the broader AMI may or may not be within the scope of a single utility's responsibility, imposing the requirements upon cooperating interconnecting systems and the corresponding capabilities will meet or support some aspects of AMI security objectives. Moreover, interdependencies among the power grid, the communications infrastructure, and the information infrastructure pose a particularly serious challenge to the design of a secure and survivable AMI.

1.1.3 Intended Audience

The intended audience for this document includes utility companies seeking AMI implementation and policy guidance; vendors seeking product design requirements and input; policy makers seeking to understand the requirements of reliable and secure AMI solutions; and any reader who wishes to find information related to AMI security requirements. While this document is intended for use by security professionals, solution architects and product designers, much of the document is written for a broader audience seeking to understand AMI security challenges, requirements and potential solutions. Lastly, this specification may provide a foundation for security requirements in the procurement and implementation of AMI solutions.

This document is intended to be a living specification to be updated as the industry evolves, with a focus on AMI security functionality. As such, one of the benefits of this document is to create a baseline document for the utility industry that provides AMI security requirements and identifies gaps between current requirements and capabilities available in the market. Ideally, the AMI security specification will be referenced and reused throughout the utility industry, providing a common set of semantics for enabling the development and implementation of robust, reliable AMI solutions.

1.1. Scope

AMI Security is simply defined as those means and measures concerned with securing an AMI system. For the purpose of this document, the definition of AMI is:

> *The communications hardware and software and associated system and data management software that creates a network between advanced meters and utility business systems and which allows collection and distribution of information to customers and other parties such as competitive retail providers, in addition to*

providing it to the utility itself. AMI is further defined as: 1) The hardware and software residing in, on, or closest to the customer premise for which the utility or its legal proxies are primarily responsible for proper operation; and 2) The hardware and software owned and operated by the utility or its legal proxies which has as its primary purpose the facilitation of Advanced Metering.

This document presents security requirements for AMI systems. This document does not address business functional or other non-security related requirements.

A further understanding of the scope requires an understanding of the utility business systems and associated functionality. Section 2.1 of this document discusses Utility Business Systems and services. In general, this specification is a tool that can be applied broadly as defined above and to peripheral systems using AMI communication services. Each individual utility should decide the boundary distinction. The boundary definition and document applicability includes system security maturity of the associated connecting system, organizational responsibility and procurement scope.

The AMI-SEC Task Force considered HAN use cases in the development of this document and it is reasonable to assume utility edge application requirements can be applied to HAN applications (e.g., requirements applied to utility applications can also be applied to consumer applications). Imposing requirements on the HAN requires additional considerations associated with control and ownership that are outside the scope of this document.

1.2. Document Overview

This section describes how this document relates to the Architectural Description, Risk Assessment, Component Catalog and Implementation Guide.

The path that a particular utility follows through these documents (Risk Assessment, System Security Requirements, Architectural Description, Component Catalog and Implementation Guide) depends upon the level of resources the utility chooses to put toward the effort. In the drawing below, this level of resources tracks the "Entry Points" on the right side of the drawing. For the descriptions below (Figure 1), the utility will define Architectural Elements, i.e., hardware and software.

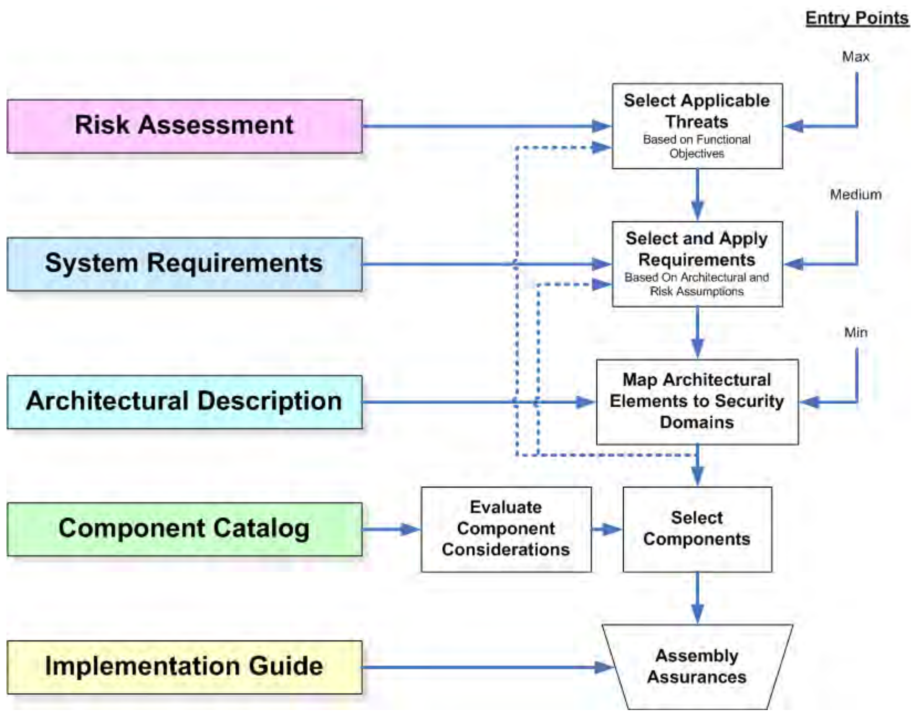

Figure 1 – Deliverables Process Flow

Maximum Level of Resources. For a utility with the ability to apply the maximum level of resources, the process to take is the following:

Step 1 The utility will tailor the AMI-SEC Risk Assessment to their particular environment, constraints, and risk acceptance limits.

Step 2 The utility selects which requirements apply to their potential solution architecture by combing through the AMI-SEC System Security Requirements document and assigning priority to the requirements they need in order to adequately mitigate risks.

Step 3 The utility maps the significant Architectural Elements of potential solutions against the defined Security Domains and places selected and prioritized requirements on Architectural Elements according to the elements' placement within the Security Domains.

Medium Level of Resources. For a utility with a moderate ("medium") level of resources, the process to undertake is the following:

Step 1 The utility will review the System Security Requirements document and select which requirements apply to their potential solution architecture.

Step 2 The utility maps the significant Architectural Elements of potential solutions against the defined Security Domains.

Step 3 The utility accepts the AMI-SEC Risk Assessment without any modification or customization, but bears the responsibility for combing through the AMI-SEC System Security Requirements document

Step 4 The utility assigns priority to the requirements they need to adequately mitigate risks.

Step 5 Once the utility has selected and prioritized requirements, the requirements are placed on Architectural Elements according to the elements' placement within the Security Domains.

Minimum Level of Resources. For a utility looking to utilize the minimal level of resources, the process to undertake is the following:

Step 1 The utility will review the Architectural Description document and map the significant Architectural Elements of potential solutions against the defined Security Domains.

Step 2 The utility accepts the AMI-SEC Risk Assessment without any modification or customization.

Step 3 The utility accepts the AMI-SEC System Security Requirements as a whole without selecting any particular subset as applicable to their environment.

Step 4 Requirements are placed on Architectural Elements according to the elements' placement within the Security Domains. In this scenario, the utility pushes the entire set of requirements on to the vendor. The onus lies with the vendor to push back and indicate where requirements are applicable and where they are not.

1.3. Definitions, acronyms, and abbreviations

Rather than produce an exhaustive list of AMI and security terms, links have been provided to well known, extensively used definitions, acronyms and abbreviations. Other terminology is addressed as encountered throughout this document.

Resource	Location
SmartGridipedia	http://www.smartgridipedia.org
NIST IR 7298 - Glossary of Key Information Security Terms	http://csrc.nist.gov/publications/nistir/NISTIR-7298_Glossary_Key_Infor_Security_Terms.pdf
International Electrotechnical Commission 62351-2 Security Terms	http://std.iec.ch/terms/terms.nsf/ByPub?OpenView&Count=-1&RestrictToCategory=IEC%2062351-2
Electropedia	http://www.electropedia.org/

Table 1 - Terminology References

1.4. References

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2. General system description

2.1. Use Cases

AMI Use Cases have been organized into five different categories consistent with the primary value streams they support. These five categories/value streams are:

- Billing

- Customer
- Distribution System
- Installation
- System

Reference 2.A - Business Functions as Stakeholders in AMI Systems provides additional extensions to the use cases presented here, as well as describing business functions and scenarios.

2.1.1. Billing

There are four primary use cases in the Billing category.

1. Multiple Clients Read Demand and Energy Data Automatically from Customer Premises
2. Utility remotely limits usage and/or connects and disconnects customer
3. Utility detects tampering or theft at customer site
4. Contract Meter Reading (or Meter Reading for other Utilities)

1 and 4 are directly related to the electronic capture and processing of time-based energy and demand data from customer meters to support the core Billing process of the electric utility (1) or, on a contract basis, for a gas or water utility (4) . The other Billing Use Cases explore other functionality that can be leveraged from having installed AMI meters in the field. Use case 2 explores utilization of the remote connect/disconnect functionality of AMI meters. Use case 3 considers how AMI meters and the data they capture can be leveraged to support the detection of energy theft.

Business value in the Billing area is created in several different ways. By automating the collection of time-based energy usage and demand, the utility is able to significantly transform the process for collecting energy and demand information to support the billing process. The traditional process for collecting meter data (manually recording meter dial settings on a monthly basis) is replaced by a fully automated, electronic capture process. Because the energy data is captured in intervals of time (typically 15 minute intervals), AMI systems enable time-based rates. Time-based billing rates vary throughout the day, reflecting changes in the balance between energy supply and demand. Although the primary implementers of AMI have been electric utilities, the potential exists for the infrastructure to be leveraged to capture gas and water meter data as well – either for the host utility if they deliver those commodities or for another utility (on a contract basis).

Other business value accrues from functionality that the AMI meters can provide. AMI meters typically are outfitted with remote connect and remote disconnect capability. This allows the utility to initiate or terminate service remotely, without having to send a field technician. This functionality supports the routine Move-In/Move-Out processes as well as the credit/collections processes. Disconnects for non-payment (and subsequent reconnects) can be accomplished remotely rather than requiring on on-site presence. AMI meters also come with functionality that can help utilities identify potential meter tampering or energy theft/diversion.

Finally, AMI provides a wealth of data that various entities within the utility to use to create additional business value. These areas include the following:

- Distribution system design – granular data on actual customer energy usage can be utilized for more optimal design of distribution system components
- Distribution planning – the utility has a wealth of usage and demand data by circuit that can be analyzed to better target investments in new distribution facilities to meet growth in demand
- Distribution operations and maintenance – the Distribution organization has a wealth of data for improved state estimation, contingency planning, and asset management
- Marketing – AMI data can be analyzed to develop energy services/products to meet customer needs

The following table summarizes the major business processes supported by the Billing Use Cases and the key areas of business value that they enable.

Use Case 1: Auto-Capture Customer Energy and Demand Data		
Major Processes Supported	**Business Value**	**Security Concerns**
• Read Meters • Validate Meter Reads • Generate Customer Bills	• Eliminate meter reader labor cost and meter reading infrastructure cost • Increase billing accuracy • Enable time-based rates • Enable improved o Distribution system design o Distribution planning o Distribution operations and maintenance o Marketing	Confidentiality (privacy) of customer data Integrity of meter data Availability of meter data (for remote read)
Use Case 2: Remote Connect/Disconnect		
Major Processes Supported	**Business Value**	**Security Concerns**
• Establish service • Terminate service • Manage credit/collection	• Reduce field service truck rolls o Labor o Transportation • Reduce bad debt • Reduce energy losses	Integrity of signal (correct message and location) Confidentiality (privacy) of signal Availability of connect/disconnect service
Use Case 3: Tamper Detection		
Major Processes Supported	**Business Value**	**Security Concerns**
• Protect revenue; reduce energy theft	• Reduce lost revenue	Integrity of tamper indication Availability of tamper indication Confidentiality (privacy) of location data
Use Case 4: Meter Reading for Other Utilities		
Major Processes Supported	**Business Value**	**Security Concerns**
• Read gas/water meters	• Eliminate meter reader labor cost and meter reading	Confidentiality (privacy) of customer data

• Read gas/water meters (other utilities) • Transfer meter reading data to other utility	infrastructure cost • Create additional source of revenue • Leverage AMI investment	Integrity of meter data Availability of meter data (for remote read) Availability of meter data to contracting utility through B2B infrastructure

Table 2 – Billing Use Cases

2.1.2. Customer

Four Use Cases have also been defined under the category of Customer:

1. Customer reduces their usage in response to pricing or voluntary load reduction events
2. Customer has access to recent energy usage and cost at their site
3. Customer prepays for electric services
4. External clients use the AMI to interact with devices at customer site

Use Case 1 explores how the AMI system, working together with customers, can create mutually-beneficial programs to manage energy demand/consumption. Use Case 2 is related to 1 in that it describes ways that customers can access information about their energy costs and consumption, and how they can receive messaging from the utility informing the customer of an upcoming peak energy event, requiring/requesting customer load reductions. Customer Use Case 4 is directly related to the previous use cases as well in that it describes how a customer's energy cost/consumption data can be shared with a third party energy service provider to outsource the customer's energy consumption. Use Case 3 describes how AMI functionality can be leveraged to enable customer pre-payment for energy.

The primary business value in the Customer Use Cases comes from an enhanced ability to manage peak load on the distribution network. By communicating pricing signals and upcoming peak load events to customers, customers can modify their energy consumption behavior to reduce their energy costs. The utility benefits by reducing the potential for outages resulting from overload of the system and deferring new capital investments to provide increased capacity.

Another source of business value unique to Use Case 3 (Customer Prepayment) accrues to the utility through reduction in bad debt and improved cash flow.

The following table summarizes the major business processes supported by the Customer Use Cases and the key areas of business value that they enable.

Use Case 1: Demand Response / Load Reduction		
Major Processes Supported	**Business Value**	**Security Concerns**
• Manage Energy Demand/Consumption	• Reduce peak load o Defer new construction o Green benefits o Reduce outages	Confidentiality (access control) of customer equipment Integrity of control messaging and message information Availability of customer devices
Use Case 2: Customer Access to Energy Data		
Major Processes Supported	**Business Value**	**Security Concerns**
• Provide Energy	• Customer energy awareness	Confidentiality (access control)

Information to Customers and Third Parties	• Reduce peak load	of customer equipment via price signals and messages Integrity of control messaging and message information Availability of customer devices
Use Case 3: Customer Prepayment		
Major Processes Supported	**Business Value**	**Security Concerns**
• Collect Revenue from Energy Sales	• Reduce bad debt • Improve cash flow • Improve customer convenience/satisfaction	Confidentiality (privacy) of customer data and payments Integrity of control messaging and message information containing prepayment data Availability of customer payment data and usage balances
Use Case 4: Third Party Energy Management		
Major Processes Supported	**Business Value**	**Security Concerns**
• Manage Energy Demand/Consumption	• Reduce peak load • Customer satisfaction	Confidentiality (privacy) of customer data Integrity of usage data, rate information Availability of usage data, rate information

Table 3 - Customer Use Cases

2.1.3. Distribution System

Four Use Cases have been defined for the Distribution System category:

1. Distribution Operations curtails customer load for grid management
2. Distribution Engineering or Operations optimize network based on data collected by the AMI system
3. Customer Provides Distributed Generation
4. Distribution Operator locates Outage Using AMI Data and Restores Service

Distribution System Use Case 1 is similar to Customer Use Case 1. Both use cases describe the process to send signals to customers for the purpose of reducing load on the system, typically during a system peak. Customer Use Case 1 describes demand response events that the customer can voluntarily participate in using a price signal or a load control signal that the customer may ignore. Distribution System Use Case 1 describes demand response events that are non-voluntary using load control signals or meter disconnection commands. Distribution Use Case 2 explores how data gathered by the AMI system can be utilized (either online or offline) to improve power quality and the overall performance of the distribution network. Distribution Use Case 3 describes how the AMI system can interface with distributed generation (small, customer-owned generation) to improve network operations and reduce off-system energy purchases. Use Case 4 investigates how the AMI system can be leveraged to support the identification of outages on the system and to facilitate the restoration of power following an outage.

The primary areas of business value in the Distribution System Use Cases are related to improving network operations. Optimizing network operations can result in reduced energy losses, reduced outage frequency, and increased customer satisfaction (improved power quality). In addition, Use Case 4 explicitly describes processes to reduce outage duration and, therefore, customer satisfaction.

The following table summarizes the major business processes supported by the Distribution System Use Cases and the key areas of business value that they enable.

Use Case 1: Emergency Demand Response		
Major Processes Supported	**Business Value**	**Security Concerns**

• Manage Energy Demand/Consumption	• Reduce peak load
	  o Defer new construction
	  o Reduce outages
		Confidentiality (access control) of customer equipment (including remote service switch and HAN devices)
		Integrity of control messaging and message information
		Availability of customer devices

Use Case 2: Distribution Network Optimization		
Major Processes Supported	**Business Value**	**Security Concerns**
• Manage Power Quality • Optimize Distribution Network • Manage Outages	• Customer satisfaction • Reduce energy losses • Improve outage performance	Integrity of system data Availability of system data Confidentiality of system data
Use Case 3: Distributed Generation		
Major Processes Supported	**Business Value**	**Security Concerns**
• Optimize Distribution Network • Manage/Dispatch Distributed Resources	• Network Optimization • Reduced Off-System Energy Purchases	Integrity of system data Availability of system data Confidentiality of system data
Use Case 4: Outage Location and Restoration		
Major Processes Supported	**Business Value**	**Security Concerns**
• Manage outages	• Reduced outage duration • Customer satisfaction	Availability of system data Integrity of system data Confidentiality of system data

Table 4 - Distribution Use Cases

2.1.4. Installation

Three Use Cases have been defined for the Installation category:

1. Utility installs, provisions, and configures the AMI system
2. Utility Manages End-to-End Lifecycle of the Meter System
3. Utility upgrades AMI to address future requirements.

Use Case 1 describes the process for deploying an AMI system, including the initial deployment plan, the forecasting and procurement process, logistical support, and field installation/testing/configuration. Use Case 2 focuses on managing the AMI system components through their life cycle, including maintenance and asset retirement. Use Case 3 explores future upgrades to the AMI system functionality and performance with particular attention to future deployment and integration of customer Home Area Network (HAN).

The key areas of business value in the Installation Use Cases include optimization of deployment costs and schedule for AMI system implementation, minimizing AMI operations and maintenance costs, maintaining billing accuracy, minimizing risk, and accommodating future growth and development within the AMI infrastructure.

The following table summarizes the major business processes supported by the Distribution System Use Cases and the key areas of business value that they enable.

Use Case 1: AMI System Deployment		
Major Processes Supported	**Business Value**	**Security Concerns**
• Deploy AMI system	• Optimize deployment costs/schedule	Integrity of system data for registration Availability of system data supporting deployment and registration Confidentiality of system data
Use Case 2: AMI System Maintenance		
Major Processes Supported	**Business Value**	**Security Concerns**
• Maintain AMI system	• Minimize AMI O&M costs • Maintain billing accuracy	Integrity of system data for remote diagnostics Availability of system data supporting maintenance and work orders Confidentiality of system data
Use Case 3: AMI System Upgrade		
Major Processes Supported	**Business Value**	**Security Concerns**
• Upgrade/enhance AMI system functionality/performance • Deploy/support customer HAN	• Minimize risk • Accommodate growth and future functionality	Integrity of system data for registration of new devices and remote firmware upgrades Availability of system data supporting deployment and remote upgrades Confidentiality of system data and customer data

Table 5 - Installation Use Cases

2.1.5. System

The final Use Case category is System. Only one Use Case has been defined for this category:

1. AMI system recovers after outage, communications or equipment failure.

System Use Case 1 explores how the AMI system responds and recovers to individual component failures, communications failures, and broader outages/disasters. The primary business value in this use case comes from maintaining AMI system integrity through unplanned equipment failures or distribution system outages.

Use Case 1: AMI System Recovery		
Major Processes Supported	**Business Value**	**Security Concerns**
• Recover from AMI component and telecommunications failures • Recover from major area outages/disasters	• Maintain system integrity	Integrity of system data Availability of system data Confidentiality of system data

Table 6 - AMI System Use Cases

2.2. System Context

AMI is the convergence of the power grid, the communications infrastructure, and the supporting information infrastructure. However, AMI security must exist in the real world with many stakeholders, other interested parties and overlapping responsibilities.

Consider an individual system that is part of an AMI solution to be made up of: 1) Software; 2) Hardware; 3) People and; 4) Information. Now, consider the entire AMI solution to be made up of a collection of various systems, each made up of software, hardware, workers and information – a system of systems. Systems-of-Systems are hierarchical in nature, that is, they naturally break down into parts.

The value of a logical decomposition comes from its ability to view a complex system at multiple levels of abstraction (decomposition) while maintaining forward and reverse traceability through the different levels of decomposition. Logical decomposition is can also be mapped to physical decomposition to correlate the model elements. The security domain model shown below (Figure 2) was developed to boundary the complexity of specifying the security required to implement a robust, secure AMI solution as well as serve as a tool to guide utilities in applying the security requirements in this document to their AMI implementation.

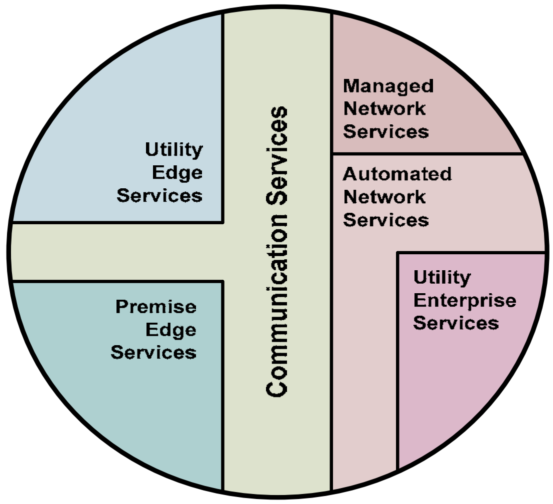

Figure 2 – AMI Security Domain Model

The following “services” are a description of each of the six security domains shown in the model above.

Security Domain	Description
Utility Edge Services	All field services applications including monitoring, measurement and control controlled by the Utility
Premise Edge Services	All field services applications including monitoring, measurement and control controlled by the Customer (Customer has control to delegate to third party)
Communications Services	are applications that relay, route, and field aggregation, field communication aggregation, field communication management information
Management Services	attended support services for automated and communication services (includes device management)
Automated Services	unattended collection, transmission of data and performs the necessary translation, transformation, response, and data staging
Business Services	core business applications (includes asset management)

Table 7 - AMI Security Domain Descriptions

Each utility’s AMI implementation will vary based on the specific technologies selected, the policies of the utility company and the deployment environment. The application of the security requirements should guide the AMI system’s capabilities.

Advanced Metering Infrastructure system use can be mapped across applicable security domains based on the collection of capabilities that enable use of the AMI. Security requirements in this document shall map to specific security domains based on the location of an enabling capability that enables a particular use for the AMI system. For any particular use of the AMI system, in the context of the enabling capability, the security requirements for that domain should be applied.

For example: If the use of the AMI system is “Remote Service Switch Operation” to support a customer “move-in” or “move-out” event then the analysis of which security requirements would apply for this use would be to map sequence of capabilities to domains.
(Note: there are a number of intermediate steps related to account updates, customer verification, policy enforcements and validations as well as error conditions not shown in this example.)

Process step	Enabling Capabilities (components)	Security Domain
Triggering event – Move-out request received from customer for a particular time and date	Request received via call center or via web (IVR or Company Website)	Utility Enterprise Services
Switch operation scheduled and validated	Customers Information System (CIS) or Meter Data Management Systems (MDMS)	Utility Enterprise Services
Command messages generated at scheduled time	CIS or MDMS	Utility Enterprise Services
Command received by head-end system	Network Management System (aka DCA or head-end)	Automated Network Services
Grid protection module validates command against rules (i.e. how many total service switch commands are pending in the next 10 min.)	Network Management System	Automated Network Services
Command transmitted to Meter	Network Management System	Automated Network Services
Command routed to the customer’s meter	Wide-Area Network, Neighborhood Area Network (aka LAN)	Communication Services
Command received by meter	Meter	Utility Edge Services
Service Switch “opened”	Meter	Utility Edge Services
Acknowledgement message created	Meter	Utility Edge Services
Acknowledgement message transmitted	Wide-Area Network, Neighborhood Area Network (aka LAN)	Communications Services
Acknowledgement message	Network Management System	Automated Network Services

received		
Account status updated	CIS and or MDMS	Utility Enterprise Services

Table 8 - Mapping of AMI Security Domain Services to Utility Processes

It should be noted that this specification and the method of mapping security requirements to specific domains based on use is lifecycle agnostic. Meaning, some uses of the system (i.e. key placement in devices) may happen prior to the commencement of operations.

2.3. System Constraints

A number of system constraints need to be taken into account when satisfying security requirements found in this document. The requirements described do not prescribe which of a range of solutions (e.g., the use of narrow- or wide-band communications technologies) is most appropriate in a given setting. Such a decision is typically based on making prudent trade-offs among a collection of competing concerns, such as the following

- Other business or non-functional requirements
    - Performance (e.g., response time)
    - Usability (e.g., complexity of interactions for users)
    - Upgradability (e.g., ease of component replacement)
    - Adaptability (e.g., ease of reconfiguration for use in other applications)
    - Effectiveness (e.g., information relevant and pertinent to the business process as well as being delivered in a timely, correct, consistent and usable manner)
    - Efficiency (e.g., the provision of information through the most productive and economical use of resources)
    - Confidentiality (e.g., protection of sensitive information from unauthorized disclosure)
    - Integrity (e.g., accuracy, completeness and validity of information in accordance with business values and expectations)
    - Availability (e.g., information being available when required by the business process)
    - Compliance – (e.g., complying with the laws, regulations and contractual arrangements)
    - Reliability (e.g., the provision of appropriate information for management to operate the entity and exercise its fiduciary and governance responsibilities)

It is important to consider system constraints when developing applying security requirements. The requirements themselves do not take into account the trade-offs involved with design phase of AMI. Therefore, satisfying these requirements should not be done in isolation from the design.

- Constraints
    - Computational (e.g., available computing power in remote devices)
    - Networking (e.g., bandwidth, throughput, or latency)
    - Storage (e.g., required capacity for firmware or audit logs)
    - Power (e.g., available power in remote devices)

- Personnel (e.g., impact on time spend on average maintenance)
- Financial (e.g., cost of bulk devices)
- Temporal (e.g., rate case limitations)
- Technology
- Availability
- Maturity
- Integration / Interoperability (e.g., legacy systems)
- Lifecycle
- Interconnectedness of infrastructure
- Applications (e.g., the automated user systems and manual procedures that process the information)
- Information (e.g., the data, in all their forms, input, processed and output by the information systems in whatever form is used by the business)
- Infrastructure (e.g., the technology and facilities i.e., hardware, operating systems, database management systems, networking, multimedia, and the environment that houses and supports them, that enable the processing of the applications.)
- People (e.g., the personnel required to plan, organize, acquire, implement, deliver, support, monitor and evaluate the information systems and services. They may be internal, outsourced or contracted as required.)
- Time
- Financial
- Technical
- Operational
- Cultural
- Ethical
- Environmental
- Legal
- Ease of Use

- Regulatory requirements
  - Scope / sphere of influence
  - Acceptance vs. transference

2.4. Security States and Modes

This section discusses the states and modes that may apply to the system as a whole and/or the component level. A component may be a sub-system or individual element of the system. Security modes and states are considered in the evaluation of security requirements because they pose special circumstances for which the requirements may change. Evaluating these special circumstances is important because in any given state or mode the risk of a system or sub-system component may increase or decrease, thus needing supplemental requirement treatment (less or more).

Definitions of terms:

- State – a temporal condition of a system or component; implies a “snapshot”.
  - Typically within a time-based consideration
  - Sometimes overlap

- Mode – describes operational intent (implies action taken).

2.4.1. System States

The term s*tate* for the purposes of this document implies a snapshot of the system. The goal is to identify the state as they relate to security.

The System State Flow Diagram (Figure 3) assists in understanding the transition between states and the direction in which changes in state are allowed to occur. The System State Flow Diagram is used in defining the AMI system transitions. It is important to understand and control state flow in order to prevent an undesired, inadvertent system state. Transition of states for security components should be defined and understood with respect to defining requirements. The Sanitation State is also a shown as a path where high assurance is required.

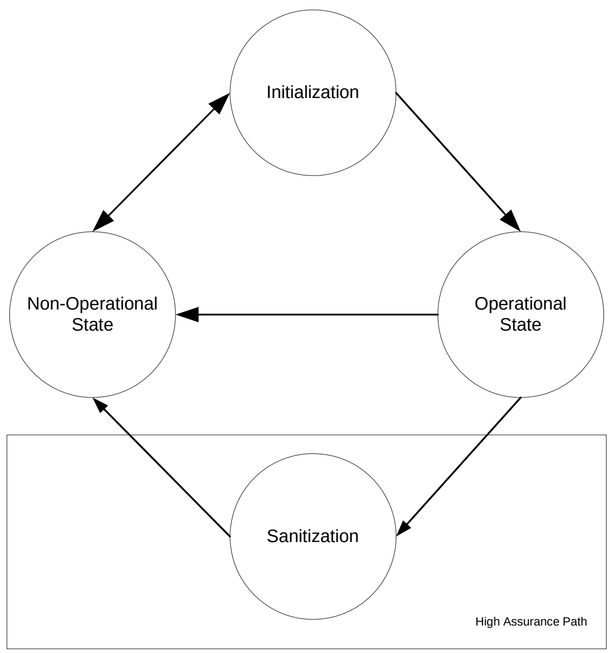

Figure 3 - Example of a System State Flow Diagram

System State	Description
Operational	Includes all functionality supportive of on-going operations (set by policy)
Non-operational	Not performing functionality indicative of on-going operations
Initialization	Used to configure system prior to operation
Sanitization	Removal and/or storing of information representative or residual of any running condition (e.g., sensitive data)

Table 9 - System States

2.4.1.1. System State Security Requirements

State.1 Activities allowed during non-operational state shall be limited to system activities needed to enter initialization. (Excludes interactions w/stakeholders, execution of business functions, etc.)

State.2 Activities allowed during initialization state shall be limited to system activities needed to enter operations. (Excludes interactions w/stakeholders, execution of business functions, etc.)

State.3 Activities allowed during initialization state shall include management functions necessary for element configuration.

State.4 Activities allowed during the initialization state shall include policy establishment (i.e., creation and configuration).

State.5 Activities allowed during the initialization state shall include security domain establishment.

State.6 A system shall transition into the operational state only upon completion of the critical initialization activities.

State.7 An operational system shall perform only those activities conformant to policy.

State.8 A system shall be capable of operating in a degraded mode while in an operational state. In this mode, "degraded" refers to a system that has non-operational or impaired components/elements. While services may be denied to some components/elements in the degraded mode, critical functions and security features of the system are still in force for the remaining components/elements.

State.9 A system shall transition into the non-operational state upon detection of a critical failure.

State.10 Supporting activities pertaining to the health of the system (e.g., diagnostics, maintenance, training, etc.) shall only be allowed during the operational state. Support activities may be performed in other system states, however they will be performed by systems external to the SUD.

2.4.2. System Modes

At the highest level, a system or component can be placed into a "normal" or "limited" mode of operation. At a minimum, modes should be taken into consideration during Protection Profile development. In a Protection Profile, criteria for entering and exiting each mode should be defined (pay close attention to risk associated with transition between modes – i.e., target mode must be defined before leaving current mode). For a more granular analysis, one may consider the following refinement examples:

- On-Line/Off-Line – system or element is accessible (or non-accessible) from a communication point of view
- Lock – certain functions are not accessible / intentionally disabled
- Maintenance – configuring / patching
- Diagnostics – monitoring for purposes of problem resolution (i.e., debugging)
- Commissioning/Decommissioning – initialization/establishment of functionality or service (decommissioning is reverse)
- Learning – acquiring new parameters and/or functionality for purposes of optimization
- Training – utilizing system functions for purposes of familiarization and simulation. (“Real” outputs are not engaged.)
- Sleep/Power saving – certain functions are temporarily disabled or degraded for decreased energy consumption.
- Special/Emergency – configurations based on criticality of function and preferential and/or prioritized treatment of certain operations. (Example needed, i.e., impending natural disaster.)

2.5. Security Objectives

As currently envisioned, Smart Grid services promise unprecedented levels of automation, situational awareness, and fine-grained control of the generation, transmission, distribution and use of electric power. If fully realized, such services should significantly increase the effectiveness, efficiency and reliability of the electric power system providing lower operating costs associated with many of today's labor-intensive tasks and would provide the incentives and technical capability for customers to automatically manage their usage patterns. Customers would specify demand-response usage policies based on pricing signals from the market or would permit direct supplier control of end-user load (automatically shedding load to reduce peak demand or mitigate emergency situations). In conjunction with end-user control, demand response would make the most efficient use of available generating capacity, while supporting conservation and environmental efforts.

Smart Grid services typically require complex distributed applications (some with near real-time constraints), communication over highly-networked information infrastructures, that include a broad range of Internet technologies. For the vision of the Smart Grid to be realized, system security must be maintained at a consistently high levels of assurance. Security concerns must be addressed from the outset of any Systems Development Life Cycle (SDLC) activity throughout every systems engineering, including architecture, acquisition, implementation, integration, deployment, operations, maintenance, and decommissioning. Security solutions must be comprehensive or *holistic* in nature (obligatory clichés: you’re only as strong as your weakest line” and "the devil is in the details") and capable of evolving in response to changes in the threat or technological environment.

The Smart Grid's primary (cyber) security objectives are as follows:

- Protect all Smart Grid services from malicious attack[1] and unintended adverse cyber and physical events that threaten the mission of the service (i.e., *security events*).
    - Ensure that sufficient information about a security events are available when and where needed to support the decision making necessary to protect (or minimize the disruption to) the mission of the affected Smart Grid service. This includes the collection and delivery of the real-time data needed for situational awareness as well as the collection and protection of forensics data needed for post-mortem analysis to improve the security and survivability of the system in the face of future security events.
    - Ensure the integrity, availability, and (where appropriate) the confidentiality of the information regarding security services, survivability services and mechanisms used to protect the Smart Grid services. These security and survivability services and mechanisms shall not provide an attack vector or incorrectly respond to malicious or benign stimuli in a manner that would create or worsen a security event.
- Prevent security incidents associated with a Smart Grid service from contributing to or complicating the safety and protection of personnel, stakeholders, stakeholder services and the electrical system.
    - Do not allow any Smart Grid service or its associated technology (e.g., communications networks and gateways) to be used as a stepping stone or conduit for attacks (or amplifying the effects of attacks) on other Smart Grid services, end users, external service providers (e.g., cell phone networks, ISPs), or any other interconnected entity.
    - Smart Grid services shall not amplify the adverse effects of any accident, natural disaster, or human error.
- Provide sufficient evidence to support the assurance of justifiable confidence (i.e., trust) in the integrity, confidentiality, and availability of Smart Grid services. (For example, provide evidence to support public trust in the accuracy of billing statements, the safety and reliability of electricity services, and the fairness of energy markets.)

Smart Grid security involves a system of systems approach in engineering design and operations, which requires that security responsibility be extend beyond the Smart Grid. While security requirements for the broader Smart Grid may or may not be within the scope of a single utility's responsibility, imposing the requirements through agreements and/or regulatory mandates upon cooperating interconnecting systems and corresponding capabilities will meet and/or support some aspects of the Smart Grid security objectives. Moreover, interdependencies among the power grid, the communications infrastructure, and the information infrastructure pose a particularly serious challenge to the design of a secure and survivable Smart Grid.

As an example, AMI system security must protect the missions of all AMI business functions and must not be allowed to be used as a conduit for attacking some method of control of the grid. This does not imply that AMI security architects are solely responsible for ensuring this, but rather that responsibility must be assigned for a systems of systems perspective wherein potential AMI impacts on the larger grid are analyzed, anticipated, and defended against in some portion of the overall system of systems (SoS) architecture and implementation.

Here are a few examples of what the Smart Grid security objectives are meant to prevent:

[1] Includes cyber and physical attacks, such as attempts to physically tamper with a meter, and disruption of the supporting communications infrastructure.

- Reputational Loss - Attacks or accidents that destroy trust in Smart Grid services, including their technical and economic integrity
- Business Attack - Theft of money or services or falsifying business records
- Gaming the system - Ability to collect, delay, modify, or delete information to gain an unfair competitive advantage (e.g., in energy markets)
- Safety - Attack on safety of the grid, its personnel or users
- Assets - Damaging physical assets of the grid or assets of its users
- Short-term Denial or Disruption of Service
- Long-term Denial or Disruption of Service (including significant physical damage to the grid)
- Privacy violations
- Hijacking control of neighbor's equipment
- Physical and logical tampering
- Subverting situational awareness so that operators take fatal actions that disrupt the system
- Cause automated system to waste resources on false alarms.
- Hijacking services
- Using Smart Grid services or the supported communication mechanisms to attack end users residential or industrial networks (e.g., allowing end-users to compromise other end-users' networked systems.)

2.5.1. Holistic Security

The magnitude of the challenge posed by melding the complexity of the power grid with open, distributed, highly networked technologies, crossing multiple organizational and administrative boundaries, in the presence of intelligent adversaries, is such that traditional security approaches alone are insufficient to meet them.

The primary concern is with protecting the business missions embodied in each of the Smart Grid services individually and collectively, not merely in enforcing security requirements or protecting IT components. *Survivability* is the capability of a system to fulfill its mission in a timely manner despite attack, accident or subsystem failure. Survivability is a blend of security and business risk management that builds upon traditional security approach by adding domain-specific strategies and tactics to create a holistic perspective. The characteristics of a survivable system include its ability to prevent or resist attacks, accidents, other forms of stress, recognize a survivability event and the state of the system under stress and to recover from the adverse impact of a survivability event in a timely manner. Survivability is marked by graceful degradation under stress, with essential services maintained.

2.6. User Characteristics

Many of the security requirements within this document are written with respect to a generic notion of an actor or user, rather than identifying specific users such as a maintenance engineer or residential customer. When such a requirement is applied to an architectural element, it should be tailored to specific types of users by taking into account the characteristics of each type of user and how that informs the requirement.

Typical classes of users (at a high level) include (refer to the Contextual View for insight into these classes of users)

- Utility
- Customer
- Third-party

Some of the characteristics that distinguish these classes of users, and even different types of users within these classes, are:

- Organizational responsibility
- Organizational authority
- Ability to delegate authority
- Privileges within the domain
- Access of users

When tailoring a requirement, one might generate several versions of a requirement, each of which differs by identifying a different user and requiring slightly different responses (e.g., level of access control required for a given behavior).

2.7. Assumptions and Dependencies

This document is an ad hoc security specification, and as such does not contain requirements pertaining to business (functional) requirements or quality of service (non-functional) requirements (e.g., performance, usability, or maintainability issues). It is assumed that business requirements have already been established for deploying an AMI solution. It does contain a collection of security requirements that have been drawn from industry best practices and government sources documenting best practices for security.

It is not the intent of this document to specify the security requirements for any particular AMI system. Instead, the goal is to provide guidance likely to be suitable across a variety of different AMI implementations. No assumptions are made regarding context specific characteristics such as available computing, software and/or infrastructure resources, unless specifically cited. No assumptions are made regarding the presence or absence of specific business requirements.

This document contains high-level requirements, not detailed specifications. Details such as specific interfaces, algorithms, protocols, and technology solutions are not addressed. These requirements should provide the impetus for the creation of more detailed specifications for AMI systems, the specifics of which depend on each AMI system's context (e.g., actual assets and information flows, business requirements, and detailed risk assessments).

3. System Security Requirements

The requirements found throughout this section are fine grained. A given section may contain related requirements addressing the same need that differ in terms of the strength of mechanism, rigor and protection each offers.

Requirements are given a lettering scheme as follows:

- Requirements that begin with an “F” are functional requirements.
- Requirements that end with an “S” are supporting services to functional requirements.
- Requirements that begin with an “A” are assurance requirements.
- Remaining letters in the identifier help associate the requirement to its requirement class.

3.1. Primary Security Services

This area uses business/mission needs to define requirements. It answers the question, "What security is needed?"

3.1.1. Confidentiality and Privacy (FCP)

This class contains confidentiality and privacy requirements. These requirements provide a user, service or object protection against discovery and misuse of identity by other users/subjects.

FCP.1	The security function shall ensure that [assignment: set of unauthorized users and/or subjects] are unable to determine the real user name bound to [assignment: list of subjects and/or operations and/or objects].
FCP.2	The security function shall provide [selection: an authorized user, [assignment: list of trusted subjects]] a capability to determine the user identity based on the provided alias only under the following [assignment: list of conditions].
FCP.3	The security function shall be able to provide [assignment: number of aliases] aliases of the real identity (e.g., user name) to [assignment: list of subjects].
FCP.4	The security function shall [selection, choose one of: determine an alias for a user, accept the alias from the user] and verify that it conforms to the [assignment: alias metric].
FCP.5	The security function shall provide an alias to the real user name which shall be identical to an alias provided previously under the following [assignment: list of conditions] otherwise the alias provided shall be unrelated to previously provided aliases.
FCP.6	The security function shall ensure that [assignment: list of users and/or subjects] are unable to determine whether [assignment: list of operations][selection: were caused by the same user, are related as follows[assignment: list of relations]].
FCP.7	The security function shall ensure that [assignment: list of users and/or subjects] are unable to observe the operation [assignment: list of operations] on [assignment: list of objects] by [assignment: list of protected users and/or subjects].
FCP.8	The security function shall allocate the [assignment: unobservability related information] among different parts of the module such that the following conditions hold during the lifetime of the information: [assignment: list of conditions].
FCP.9	The security function shall provide [assignment: list of services] to [assignment: list of subjects] without soliciting any reference to [assignment: privacy related information (e.g., real username)].
FCP.10	The security function shall provide [assignment: list of authorized users] with the capability to observe the usage of [assignment: list of resources and/or services].
FCP.11	The security function shall prevent unauthorized and unintended information transfer via shared system resources.
FCP.12	The functions provided by the security function to recover from failure or service discontinuity shall ensure that the secure initial state is restored without exceeding [assignment: quantification] for loss of security function data or objects under the control of the module's security function.
FCP.13	The security function shall protect security function data from unauthorized disclosure when it is transmitted between separate parts of the system.
FCP.14	The security function shall identify and handle error conditions in an expeditious manner without providing information that could be exploited by adversaries.
FCP.15	The authentication mechanisms in the system shall obscure feedback of authentication information during the authentication process to protect the information from possible exploitation or use by unauthorized individuals.
FCP.16	The security function shall ensure that the security attributes, when exported outside the system, are

	unambiguously associated with the exported user data.

3.1.2. Integrity (FIN)

"Maintaining a control system, including information integrity, increases assurance that sensitive data have neither been modified nor deleted in an unauthorized or undetected manner. The security controls described under the system and information integrity family provide policy and procedure for identifying, reporting, and correcting control system flaws. Controls exist for malicious code detection, spam protection, and intrusion detection tools and techniques. Also provided are controls for receiving security alerts and advisories and the verification of security functions on the control system. In addition, there are controls within this family to detect and protect against unauthorized changes to software and data, restrict data input and output, check the accuracy, completeness, and validity of data, and handle error conditions." [DHS]

FIN.1	The security function shall preserve a secure state when the following types of failures occur: [List of types of failure in the module]
FIN.2	The security function shall provide the capability to detect modification of all security function data during transmission between the security function and another trusted IT product within the following metric: [assignment: a defined modification metric].
FIN.3	The security function shall provide the capability to verify the integrity of all security function data transmitted between the security function and another trusted IT product and perform [assignment: action to be taken] if modifications are detected.
FIN.4	The security function shall provide the capability to correct [assignment: type of modification] of all security function data transmitted between the security function and another trusted IT product.
FIN.5	The security function shall be able to detect [selection: modification of data, substitution of data, re-ordering of data, deletion of data, [assignment: other integrity errors]] for security function data transmitted between separate parts of the module.
FIN.6	Upon detection of a data integrity error, the security function shall take the following actions: [assignment: specify the action to be taken].
FIN.7	The security function shall provide detection of physical tampering that might compromise the module's security function.
FIN.8	The security function shall provide the capability to determine whether physical tampering with the module's security function's devices or module's security function's elements has occurred.
FIN.9	For [assignment: list of security function devices/elements for which active detection is required], the security function shall monitor the devices and elements and notify [assignment: a designated user or role] when physical tampering with the module's security function's devices or module's security function's elements has occurred.
FIN.10	The security function shall resist [assignment: physical tampering scenarios] to the [assignment: list of security function devices/elements] by responding automatically such that the integrity is maintained.
FIN.11	After [assignment: list of failures/service discontinuities] the security function shall enter a [assignment: mode (e.g., maintenance mode)] where the ability to return to a secure state is provided.
FIN.12	For [assignment: list of failures/service discontinuities], the security function shall ensure the return of the module to a secure state using automated procedures.
FIN.13	When automated recovery from [assignment: list of failures/service discontinuities] is not possible, the security function shall enter [assignment: mode (e.g., a maintenance mode)] where the ability to

	return to a secure state is provided.
FIN.14	The utility provided by the security function to recover from failure or service discontinuity shall ensure that the secure initial state is restored without exceeding [assignment: quantification] for loss of module's security function data or objects under the control of the module's security function.
FIN.15	If the security function and/or system experience failure or service discontinuity, the security function shall provide the capability to determine the objects that were or were not capable of being recovered; as a result, the following actions should be taken [assignment: action to be taken].
FIN.16	The security function shall detect replay for the following entities: [assignment: list entities].
FIN.17	The security function shall use [assignment: list of interpretation rules to be applied by the module's security function] to consistently interpret security function data from another trusted IT product.
FIN.18	The security function shall run a suite of tests [selection: during initial start-up, periodically during normal operation, at the request of an authorized user, [assignment: other conditions]] to check the fulfillment of [assignment: list of properties of the external entities]. If the test fails, the security function shall [assignment: action(s)].
FIN.19	The security function shall ensure that security function data is consistent when replicated between [assignment: parts of the system].
FIN.20	When parts of the module containing replicated security function data are disconnected, the security function shall ensure the consistency of the replicated security function data upon reconnection before processing any requests for [assignment: list of functions dependent on security function data replication consistency].
FIN.21	The security function shall run a suite of *self-tests* during initial start-up, periodically during normal operation, at the request of the authorized user, at the conditions [assignment: conditions under which self-test should occur] to demonstrate the correct operation of [selection: [assignment: parts of security function (e.g. key management)], the module's security function.
FIN.22	The security function shall provide authorized users with the capability to verify the integrity of [selection: [assignment: parts of module's security function], security function data].
FIN.23	The security function shall provide authorized users with the capability to verify the integrity of stored security function executable code.
FIN.24	The security function shall verify the correct operation of security utilities [Selection (one or more): upon system startup and restart, upon command by user with appropriate privilege, periodically every [Assignment: organization-defined time-period]] and [Selection (one or more): notifies [assignment: user, etc. (e.g., system administrator), shuts the system down, restarts the system] when anomalies are discovered.
FIN.25	The security function shall detect and protect against unauthorized changes to software and information.
FIN.26	The security function shall restrict the capability to input information to the information system to authorized personnel.
FIN.27	The security function shall check information for accuracy, completeness, validity, and authenticity.
FIN.28	The organization shall handle and retain output from the information system in accordance with applicable laws, Executive Orders, directives, policies, regulations, standards, and operational requirements.
FIN.29	The organization shall develop, disseminate, and periodically review/update: 1. Formal, documented, system and control integrity policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; 2. Formal, documented procedures to facilitate the implementation of the system and information integrity policy and associated system and information integrity controls.
FIN.30	The organization shall identify, report, and remediate control system flaws per organizational, legal, and/or regulatory policies.

FIN.31	The security function employs malicious code protection.
FIN.32	The security function shall verify the correct operation of security functions within the control system upon system startup and restart; upon command by user with appropriate privilege; periodically; and/or at defined time periods. The security function notifies the [assignment: system administrator, system component, etc.] when anomalies are discovered.
FIN.33	The security function shall monitor and detect unauthorized changes to software and information.
FIN.34	The security function shall implement security measures to restrict information input to the control system to authorized personnel only.
FIN.35	The security function shall employ mechanisms to check information for accuracy, completeness, validity, and authenticity.
FIN.36	The organization shall handle and retain output from the security function in accordance with applicable laws, regulations, standards, and organizational policy, as well as operational requirements of the control process.
FIN.37	The security function shall protect the integrity of transmitted information.
FIN.38	The security function shall reliably associate [assignment: security parameters] with information exchanged between [assignment: information systems].
FIN.39	The security function that provides name/address resolution service for local clients shall perform data origin authentication and data integrity verification on the resolution responses it receives from authoritative sources when requested by client systems.
FIN.40	The security function that collectively provides name/address resolution service for an organization shall be fault tolerant and implement role separation.
FIN.41	The security function shall protect security function data from modification when it is transmitted between separate parts of the system.
FIN.42	The security function shall mark output using standard naming conventions to identify any special dissemination, handling, or distribution instructions.
FIN.43	The security function shall provide [assignment: list of subjects] with the ability to verify evidence of the validity of the indicated information and the identity of the [assignment: user, object, etc.] that generated the evidence.

3.1.3. Availability (FAV)

This involves the ability of the system to continue to operate and satisfy business/mission needs under diverse operating conditions, including but not limited to peak load conditions, attacks, maintenance operations, and normal operating conditions.

FAV.1	The security function shall ensure the operation of [assignment: list of system's capabilities] when the following failures occur: [assignment: list of type of failures].
FAV.2	The security function shall assign a priority to each subject in the system's security function in terms of availability.
FAV.3	The security function shall ensure that each access to [assignment: controlled resources] shall be mediated on the basis of the subjects assigned priority.
FAV.4	The security function shall ensure that each access to all shareable resources shall be mediated on the basis of the subjects assigned priority.
FAV.5	The security function shall enforce maximum quotas of the following resources: [assignment: controlled resources] that [selection: individual user, defined group of users, subjects] can use [selection: simultaneously, over a specified period of time].

FAV.6	The security function shall ensure the provision of minimum quantity of each [assignment: controlled resource] that is available for [selection: an individual user, defined group of users, subjects] to use [selection: simultaneously, over a specified period of time].
FAV.7	The security function shall protect against or limits the effects of the following types of denial of service attacks: [Assignment: organization-defined list of types of denial of service attacks or reference to source for current list].
FAV.8	The security function shall limit the use of resources by priority.
FAV.9	The functions provided by the security function to recover from failure or service discontinuity shall ensure that the secure initial state is restored without exceeding [assignment: quantification] for loss of security function data or objects under the control of the module's security function.
FAV.10	The security function shall ensure the availability of [assignment: list of types of security function data] provided to another trusted IT product within [assignment: a defined availability metric] given the following conditions [assignment: conditions to ensure availability].

3.1.4. Identification (FID)

This section covers requirements around who an actor claims to be.

FID.1	The security function shall require each user to be successfully identified before allowing any other system's security function-mediated actions on behalf of that user unless is one of the following: [list of system’s security function-mediated actions] that may be allowed before the user is identified.
FID.2	The security function shall associate the following user security attributes with subjects acting on the behalf of that user: [assignment: list of user security attributes].
FID.3	The security function shall enforce the following rules on the initial association of user security attributes with subjects acting on the behalf of users: [assignment: rules for the initial association of attributes].
FID.4	The security function shall enforce the following rules governing changes to the user security attributes associated with subjects acting on the behalf of users: [assignment: rules for the changing of attributes].
FID.5	The security function shall uniquely identify (and authenticate) [assignment: users, processes acting on behalf of users, devices, etc.] before establishing a connection.
FID.6	The organization shall manage user identifiers by: 1. Uniquely identifying each user; 2. Verifying the identity of each user; 3. Receiving authorization to issue a user identifier from an appropriate organization official; 4. Issuing the user identifier to the intended party; 5. Disabling the user identifier after [Assignment: organization-defined time period] of inactivity; and 6. Archiving user identifiers.
FID.7	The security function shall have mechanisms to uniquely identify (and authenticate) [assignment: users, processes acting on behalf of users, etc.].
FID.8	The security function shall appropriately label information in storage, in process and in transmission.

3.1.5. Authentication (FAT)

This section covers requirements around the proof of identity of an actor.

FAT.1	After a predetermined period of inactivity, the system shall prevent further access to the system by

	initiating a session lock that remains in effect until the user reestablishes access using appropriate (identification and) authentication procedures.
FAT.2	The security function shall employ a mechanism to authenticate specific devices before establishing a connection.
FAT.3	The security function shall employ authentication methods that meet the requirements of applicable laws, Executive Orders, directives, policies, regulations, standards, and guidance for authentication to a cryptographic module.
FAT.4	The security function shall have mechanisms to authenticate users (or processes acting on behalf of users).
FAT.5	The security function enforces assigned authorizations for controlling access to the system in accordance with applicable policy.
FAT.6	The security function shall employ authentication methods that meet the requirements of applicable laws, Executive Orders, directives, policies, regulations, standards, and guidance for authentication to a cryptographic module.
FAT.7	The security function shall enforce assigned authorizations for controlling the flow of information within the system and between interconnected systems in accordance with applicable policy.
FAT.8	The security function shall enforce the most restrictive set of rights and privileges or accesses needed by [assignment: users, processes acting on behalf of users, etc.] for the performance of specified tasks.
FAT.9	The security function shall (identify and) authenticate specific devices before establishing a connection.
FAT.10	The security function shall obscure feedback of authentication information during the authentication process to protect the information from possible exploitation and unauthorized use.
FAT.11	The security function shall uniquely authenticate [assignment: users, processes acting on behalf of users, etc.].
FAT.12	The organization shall authorize all methods of remote access to the system.
FAT.13	The organization shall develop and enforce policies and procedures for system users concerning the generation and use of passwords. These policies stipulate rules of complexity, based on the criticality level of the systems to be accessed.
FAT.14	The organization shall develop, disseminate and periodically review and update: 1. A formal, documented, access control policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; and 2. Formal, documented procedures to facilitate the implementation of the access control policy and associated access controls.
FAT.15	The organization shall develop, disseminate and periodically review and update: 1. A formal, documented, authentication policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; and 2. Formal, documented procedures to facilitate the implementation of the identification and authentication policy and associated authentication controls.
FAT.16	The organization shall employ mechanisms in the design and implementation of a system to restrict public access to the system from the organization's enterprise network.
FAT.17	The organization shall establish terms and conditions for authorized individuals to: 1. Access the information system from an external information system; and 2. Process, store, and/or transmit organization-controlled information using an external information system.
FAT.18	The organization shall identify and document specific user actions (authorizations) that can be performed on the information system without identification or authentication.

FAT.19	The organization shall manage information system authenticators by: 1. Defining initial authenticator content; 2. Establishing administrative procedures for initial authenticator distribution, for lost/compromised, or damaged authenticators, and for revoking authenticators; 3. Changing default authenticators upon information system installation; and 4. Changing/refreshing authenticators periodically
FAT.20	The organization shall supervise and review the activities of users with respect to the enforcement and usage of system access controls.
FAT.21	The organization shall: 1. Establish usage restrictions and implementation guidance for [assignment: devices (e.g., wireless technologies, portable and mobile devices and media)]; and, 2. Authorize, monitor and control access to the system. 3. Document, monitor, log, and limit access of these devices to the organization's system. 4. Appropriate organizational officials shall authorize the use of these devices per organization's established security policy and procedures.
FAT.22	The security function authenticates specific devices before establishing a connection.
FAT.23	The security function shall [selection: detect, prevent] use of authentication data that has been copied or forged by any actor of the system.
FAT.24	The security function shall allow [assignment: list of security function mediated actions] on behalf of the user to be performed before the user is authenticated.
FAT.25	The security function shall allow the [assignment: the authorized identified roles] to specify alternative initial values to override the default values when an object or information is created.
FAT.26	The security function shall authenticate any user's claimed identity according to the [assignment: rules describing how the multiple authentication mechanisms provide authentication].
FAT.27	The security function shall be able to associate [assignment: users] with roles.
FAT.28	The security function shall be able to enforce the use of security function generated secrets for [assignment: list of functions].
FAT.29	The security function shall enforce the [assignment: access control security function policy] on [assignment: list of subjects and objects] and all operations among subjects and objects covered by the security function's policy.
FAT.30	The security function shall enforce the [assignment: access control security function policy] to objects based on the following: [assignment: list of subjects and objects controlled under the indicated security function policy, and for each, the security function policy-relevant security attributes, or named groups of security function policy-relevant security attributes].
FAT.31	The security function shall enforce the [assignment: access control security function policy(s), information flow control security function policy(s)] to restrict the ability to [selection: change, default, query, modify, delete, [assignment: other operations]] the security attributes [assignment: list of security attributes] to [assignment: the authorized identified roles].
FAT.32	The security function shall enforce the [assignment: access control security function policy, information flow control security function policy] to provide [selection, choose one of: restrictive, permissive, [assignment: other property]] default values for security attributes that are used to enforce the security function policy.
FAT.33	The security function shall enforce the following rules to determine if an operation among controlled subjects and controlled objects is allowed: [assignment: rules governing access among controlled subjects and controlled objects using controlled operations on controlled objects].
FAT.34	The security function shall enforce the rules [assignment: specification of revocation rules].
FAT.35	The security function shall ensure that all operations between any subject controlled by the security function and any object controlled by the security function are covered by an access control security function policy.

FAT.36	The security function shall ensure that the conditions [assignment: conditions for the different roles] are satisfied.
FAT.37	The security function shall explicitly [selection: authorize, deny] an information flow based on the following rules: [assignment: rules, based on security attributes that explicitly [selection: authorize, deny] information flows].
FAT.38	The security function shall explicitly deny access of subjects to objects based on the [assignment: rules, based on security attributes that explicitly deny access of subjects to objects].
FAT.39	The security function shall maintain the following list of security attributes belonging to individual users: [assignment: list of security attributes].
FAT.40	The security function shall maintain the roles: [assignment: authorized identified roles].
FAT.41	The security function shall prevent reuse of authentication data related to [assignment: identified authentication mechanism(s)].
FAT.42	The security function shall provide [assignment: list of multiple authentication mechanisms] to support user authentication.
FAT.43	The security function shall provide a mechanism to *generate* secrets that meet [assignment: a defined quality metric].
FAT.44	The security function shall provide a mechanism to *verify* that secrets meet [assignment: a defined quality metric].
FAT.45	The security function shall provide only [assignment: list of feedback] to the user while the authentication is in progress.
FAT.46	The security function shall re-authenticate the user under the conditions [assignment: list of conditions under which re-authentication is required].
FAT.47	The security function shall require an explicit request to assume the following roles: [assignment: the roles].
FAT.48	The security function shall require each user to be successfully authenticated before allowing any other system's security function-mediated actions on behalf of that user.
FAT.49	The security function shall restrict the ability to [selection: change, default, query, modify, delete, clear, [assignment: other operations]] the [assignment: list of security function data] to [assignment: the authorized identified roles].
FAT.50	The security function shall restrict the ability to [selection: determine the behavior of, disable, enable, modify the behavior of] the functions [assignment: list of functions] to [assignment: the authorized identified roles].
FAT.51	The security function shall restrict the ability to revoke [assignment: list of security attributes] associated with the [selection: users, subjects, objects, [assignment: other additional resources]] under the control of the security function to [assignment: the authorized identified roles].
FAT.52	The security function shall restrict the capability to specify an expiration time for [assignment: list of security attributes for which expiration is to be supported] to [assignment: the authorized identified roles].
FAT.53	The security function shall restrict the specification of the limits for [assignment: list of security function data] to [assignment: the authorized identified roles].
FAT.54	The security function shall use the following rules to set the value of security attributes: [assignment: rules for setting the values of security attributes]
FAT.55	Based on the criticality level of the systems to be accessed, the organization shall develop and enforce policies and procedures for system users concerning the generation, use and rules of complexity for passwords.
FAT.56	The security function shall prevent further access to the system by initiating a session lock after [Assignment: organization-defined time period] of inactivity, and the session lock remains in effect

	until the user reestablishes access using appropriate identification and authentication procedures.
FAT.57	When the defined number of unsuccessful authentication attempts has been [selection: met, surpassed], the security function shall [assignment: list of actions].

3.1.6. Authorization (FAZ)

Authorization is the approval of an actor to perform an action.

FAZ.1	The security function shall enforce assigned authorizations for controlling access to the system in accordance with applicable policy.
FAZ.2	The security function shall enforce separation of duties through assigned access authorizations.
FAZ.3	The security function shall enforce assigned authorizations for controlling the flow of information within the system and between interconnected systems in accordance with applicable policy.
FAZ.4	The organization shall document authorization and approval policies and procedures and maintains a list of personnel authorized to perform maintenance on the control system. Only authorized and qualified organization or vendor personnel perform maintenance on the system.
FAZ.5	The organization shall develop and keep current a list of personnel with authorized access to the facility where [assignment: type of system (e.g., control system, information system)] resides (except for those areas within the facility officially designated as publicly accessible) and issues appropriate authorization credentials (e.g., badges, identification cards, smart cards). Designated officials within the organization review and approve the access list and authorization credentials [Assignment: organization-defined frequency, at least annually].
FAZ.6	The organization shall control all physical access points (including designated entry/exit points) to the facility where the information system resides (except for those areas within the facility officially designated as publicly accessible) and verifies individual access authorizations before granting access to the facility. The organization shall control access to areas officially designated as publicly accessible, as appropriate, in accordance with the organization's assessment of risk.
FAZ.7	The organization shall review information system and facility access authorizations when personnel are reassigned or transferred to other positions within the organization and initiates appropriate actions
FAZ.8	The organization shall limits physical access to all control system facilities and assets and verifies individual access authorizations before granting access. The organization shall limit access to areas officially designated as publicly accessible, as appropriate, in accordance with the organization's assessment of risk.
FAZ.9	The organization shall authorize (i.e., accredit) the system for processing before operations and periodically update the authorization [assignment: organization-defined frequency] or when there is a significant change to the system. A senior organizational official shall sign and approve the security accreditation.
FAZ.10	The security function shall enforce the most restrictive set of rights, privileges or accesses needed by users or workstations (or processes acting on behalf of users) for the performance of specified tasks.
FAZ.11	The security function shall explicitly authorize access of subjects to objects based on the following additional rules: [assignment: rules, based on security attributes that explicitly authorize access of subjects to objects].
FAZ.12	The security function shall enforce a limit of [assignment: organization-defined number] consecutive invalid access attempts by a user during a [assignment: organization-defined time period] time period. The security function shall automatically [Selection: locks the account/node for an [assignment: organization-defined time period], delays next login prompt according to [assignment: organization-defined delay algorithm.]] when the maximum number of unsuccessful attempts is exceeded.

FAZ.13	The security function automatically terminates a remote session after [assignment: defined period of inactivity] for [assignment: workstations, servers, etc.] that are used for [assignment: system monitoring, maintenance activities, etc.] based on the risk assessment of the system and the organization's security policy.
FAZ.14	The security function shall limit the number of concurrent sessions for any user to [assignment: organization-defined number of sessions] on the system.

3.1.7. Non-Repudiation (FNR)

Non-repudiation is the ability to irrefutably, tie an actor to an action.

FNR.1	The security function shall be able to generate evidence of origin for transmitted [assignment: list of information types] at the request of the [selection: originator, recipient, [assignment: list of third parties]].
FNR.2	The security function shall be able to relate the [assignment: list of attributes] of the originator of the information, and the [assignment: list of information fields] of the information to which the evidence applies.
FNR.3	The security function shall provide a capability to verify the evidence of origin of information to [selection: originator, recipient, [assignment: list of third parties]] given [assignment: limitations on the evidence of origin].
FNR.4	The security function shall enforce the generation of evidence of origin for transmitted [assignment: list of information types] at all times.
FNR.5	The security function shall be able to generate evidence of receipt for received [assignment: list of information types] at the request of the [selection: originator, recipient, [assignment: list of third parties]].
FNR.6	The security function shall be able to relate the [assignment: list of attributes] of the recipient of the information, and the [assignment: list of information fields] of the information to which the evidence applies.
FNR.7	The security function shall provide a capability to verify the evidence of receipt of information to [selection: originator, recipient, [assignment: list of third parties]] given [assignment: limitations on the evidence of receipt].
FNR.8	The security function shall enforce the generation of evidence of receipt for received [assignment: list of information types] at all times.
FNR.9	The security function shall provide mechanisms to protect the authenticity of communications sessions.
FNR.10	The security function shall provide a capability to generate evidence that can be used as a guarantee of the validity of [assignment: list of objects or information types].
FNR.11	The security function shall provide the capability to determine whether a [assignment: given individual, system, etc.] took a particular [assignment: action].

3.1.8. Accounting (FAC)

This section covers the recording of activity by actors/elements throughout the system. Accounting requirements provide the means to perform a successful audit of events that occur on the system.

FAC.1	The security function shall take [assignment: list of actions] upon detection of a potential security

	violation.
FAC.2	The security function shall be able to generate an accounting record of the following auditable events: 1. Start-up and shutdown of the audit functions; 2. All auditable events for the [selection, choose one of: minimum, basic, detailed, not specified] level of audit; and 3. [assignment: other specifically defined auditable events]
FAC.3	The security function shall generate audit records, at a minimum, for the following events whether or not the attempts were successful: 1. Attempts to logon; 2. Attempts to change local account attributes such as privileges; 3. Attempts to change local security policy
FAC.4	The security function shall provide [assignment: authorized users] with the capability to read [assignment: list of audit information] from the audit records.
FAC.5	The security function shall prohibit all users read access to the audit records, except those users that have been granted explicit read-access.
FAC.6	The security function shall ensure that [assignment: metric for saving audit records] stored audit records will be maintained when the following conditions occur: [selection: audit storage exhaustion, failure, attack]
FAC.7	The security function shall generate audit records for the following events: [Assignment: organization-defined auditable events].
FAC.8	The security function shall record within each accounting record at least the following information: 1. Date and time of the event, type of event, subject identity and/or source of the event, and the outcome (e.g., success or failure) of the event; and 2. For each audit event type [assignment: other audit relevant information].
FAC.9	For audit events resulting from actions of identified users, the security function shall be able to associate each auditable event with the identity of the user that caused the event.
FAC.10	The security function shall be able to apply a set of rules in monitoring the audited events and based upon these rules indicate a potential violation of the enforcement of the security function requirements.
FAC.11	The security function shall enforce the following rules for monitoring audited events: 1. Accumulation or combination of [assignment: subset of defined auditable events] known to indicate a potential security violation; 2. [assignment: any other rules]
FAC.12	The security function shall be able to maintain profiles of system usage, where an individual profile represents the historical patterns of usage performed by the member(s) of [assignment: the profile target group].
FAC.13	The security function shall be able to maintain a suspicion rating associated with each user whose activity is recorded in a profile, where the suspicion rating represents the degree to which the user's current activity is found inconsistent with the established patterns of usage represented in the profile.
FAC.14	The security function shall be able to indicate a possible violation of the enforcement of the security function requirements when a user's suspicion rating exceeds the following threshold conditions [assignment: conditions under which anomalous activity is reported by the module's security function].
FAC.15	The security function shall be able to maintain an internal representation of the following signature events [assignment: a subset of system events] that may indicate a violation of the enforcement of the security function requirements.
FAC.16	The security function shall be able to compare the signature events against the record of system activity discernible from an examination of [assignment: the information used to determine system activity].

FAC.17	The security function shall be able to indicate a potential violation of the enforcement of the security function requirements when a system event is found to match a signature event or event sequence that indicates a potential violation of the enforcement of the security function requirements.
FAC.18	The security function shall be able to maintain an internal representation of the following event sequences of known intrusion scenarios [assignment: list of sequences of system events whose occurrence are representative of known penetration scenarios] and the following signature events [assignment: a subset of system events] that may indicate a potential violation of the enforcement of the security function requirements.
FAC.19	The security function shall be able to compare the signature events and event sequences against the record of system activity discernible from an examination of [assignment: the information to be used to determine system activity].
FAC.20	The security function shall provide the audit records in a manner suitable for the user to interpret the information.
FAC.21	The security function shall provide the ability to apply [assignment: methods of selection and/or ordering] of audit data based on [assignment: criteria with logical relations].
FAC.22	The security function shall be able to select the set of audited events from the set of all auditable events based on the following attributes: 1. [selection: object identity, user identity, subject identity, host identity, event type] 2. [assignment: list of additional attributes that audit selectivity is based upon]
FAC.23	The security function shall be able to [selection, choose one of: prevent, detect] unauthorized modifications to the stored audit records in the audit trail.
FAC.24	The security function shall protect audit information and audit tools from unauthorized access, modification, and deletion.
FAC.25	The security function shall [assignment: actions to be taken in case of possible audit storage failure] if the audit trail exceeds [assignment: pre-defined limit].
FAC.26	The security function shall [selection, choose one of: “ignore audited events”, “prevent audited events, except those taken by the authorized user with special rights”, “overwrite the oldest stored audit records”] and [assignment: other actions to be taken in case of audit storage failure] if the audit trail is full.
FAC.27	The organization shall allocate sufficient audit record storage capacity and configures auditing to reduce the likelihood of exceeding storage capacity.
FAC.28	The security function shall alert appropriate organizational officials in the event of an audit processing failure and takes the following additional actions: [Assignment: organization-defined actions to be taken (e.g., shut down information system, overwrite oldest audit records, stop generating audit records)].
FAC.29	The security function shall provide an audit reduction and report generation capability.
FAC.30	The security function shall provide time stamps for use in audit record generation.
FAC.31	The security function/system shall notify the user, upon successful logon, of the date and time of the last logon and the number of unsuccessful logon attempts since the last successful logon.
FAC.32	The security function shall display an approved, system use notification message before granting system access informing potential users: 1. That the user is accessing a [assignment: name of organization’s information system]; 2. That system usage may be monitored, recorded, and subject to audit; 3. That unauthorized use of the system is prohibited and subject to criminal and civil penalties; and 4. That use of the system indicates consent to monitoring and recording. The system use notification message provides appropriate privacy and security notices (based on associated privacy and security policies or summaries) and remains on the screen until the user takes explicit actions to log on to the information system.

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3.2. Supporting Security Services

Supporting Security Services requirements are how security is realized for primary security requirements. Each requirement in this section maps to requirements in Section 3.1. The mapping should indicate which requirements from Section 3.1 are satisfied (in whole or in part) given satisfaction of the identified 3.2 requirement. The litmus test for inclusion in this section is simple. If any requirement in this section cannot be mapped to at least two requirements across confidentiality, integrity and availability (CIA), then it should appear in Section 3.1.

Policy requirements can appear in this section, so long as they are relevant to a specific supporting security service area.

3.2.1. Anomaly Detection Services (FAS)

Detection services detect events outside of the bounds of normally anticipated or desired behavior such as attacks, intrusions, or errors.

FAS.1	Upon detection of a data integrity error, the security function shall take the following actions: [assignment: specify the action to be taken].
FAS.2	The security function shall provide unambiguous detection of physical tampering that might compromise the module's security function.
FAS.3	For [assignment: list of security function devices/elements for which active detection is required], the security function shall monitor the devices and elements and notify [assignment: a designated user or role] when physical tampering with the module's security function's devices or module's security function's elements has occurred.
FAS.4	The security function shall take [assignment: list of actions] upon detection of a potential security violation.
FAS.5	The organization shall employ and maintain fire suppression and detection devices/systems that can be activated in the event of a fire.
FAS.6	The organization shall implement and maintain fire suppression and detection devices/systems that can be activated in the event of a fire.
FAS.7	The organization shall implement an incident handling capability for security incidents that includes preparation, detection and analysis, containment, eradication, and recovery.
FAS.8	The organization shall implement control system incident handling capabilities for security incidents that includes preparation, detection and analysis, containment, eradication, and recovery.

3.2.2. Boundary Services (FBS)

This section provides requirements around boundary services. Boundary services provide isolation between system elements or between the system and external entities. Boundary services explain what occurs at the transition between two separate security domains such as examination or changing constraints on the border relationship.

Boundary requirements are oriented towards maintaining the strength and integrity of the boundary (isolation) between inside and outside of the system boundary. The requirements for a firewall configuration are one set of examples.

FBS.1	The security function shall restrict the scope of the session security attributes [assignment: session security attributes], based on [assignment: attributes].

FBS.2	The security function shall restrict the maximum number of concurrent sessions that belong to the same user.
FBS.3	The security function shall enforce, by default, a limit of [assignment: default number] sessions per user.
FBS.4	The security function shall restrict the maximum number of concurrent sessions that belong to the same user according to the rules [assignment: rules for the number of maximum concurrent sessions].
FBS.5	The security function shall lock an interactive session after [assignment: time interval of user inactivity] by: a) clearing or overwriting display devices, making the current contents unreadable; b) disabling any activity of the user's data access/display devices other than unlocking the session.
FBS.6	The security function shall require the following events to occur prior to unlocking the session: [assignment: events to occur].
FBS.7	The security function shall allow user-initiated locking of the user's own interactive session, by: a) clearing or overwriting display devices, making the current contents unreadable; b) disabling any activity of the user's data access/display devices other than unlocking the session.
FBS.8	The security function shall terminate an interactive session after a [assignment: time interval of user inactivity].
FBS.9	The security function shall allow user-initiated termination of the user's own interactive session.
FBS.10	Before establishing a user session, the security function shall display an advisory warning message regarding unauthorized use of the module.
FBS.11	Upon successful session establishment, the security function shall display the [selection: date, time, method, location] of the last successful session establishment to the user.
FBS.12	Upon successful session establishment, the security function shall display the [selection: date, time, method, location] of the last unsuccessful attempt to session establishment and the number of unsuccessful attempts since the last successful session establishment.
FBS.13	The security function shall not erase the access history information from the user interface without giving the user an opportunity to review the information.
FBS.14	The security function shall be able to deny session establishment based on [assignment: attributes].
FBS.15	The security function shall provide a communication channel between itself and another trusted IT product that is logically distinct from other communication channels and provides assured identification of its end points and protection of the channel data from modification or disclosure.
FBS.16	The security function shall permit [selection: the module's security function, another trusted IT product] to initiate communication via the trusted channel.
FBS.17	The security function shall initiate communication via the trusted channel for [assignment: list of functions for which a trusted channel is required].
FBS.18	The security function shall provide a communication path between itself and [selection: remote, local] users that is logically distinct from other communication paths and provides assured identification of its end points and protection of the communicated data from [selection: modification, disclosure, [assignment: other types of integrity or confidentiality violation]].
FBS.19	The security function shall permit [selection: the module's security function, local users, remote users] to initiate communication via the trusted path.
FBS.20	The security function shall require the use of the trusted path for [selection: initial user authentication, [assignment: other services for which trusted path is required]].

FBS.21	The organization shall develop, implement, and periodically review and update: 1. A formal, documented, control system security policy that addresses: a. The purpose of the security program as it relates to protecting the organization’s personnel and assets; b. The scope of the security program as it applies to all the organizational staff and third-party contractors; c. The roles, responsibilities, and management accountability structure of the security program to ensure compliance with the organization’s security policy and other regulatory commitments. 2. Formal, documented procedures to implement the security policy and associated requirements. A control system security policy considers controls from each of the families contained in this document.
FBS.22	The organization shall establish policies and procedures to define roles, responsibilities, behaviors, and practices for the implementation of an overall security program.
FBS.23	The organization shall define a framework of management leadership accountability. This framework establishes roles and responsibilities to approve cyber security policy, assign security roles, and coordinate the implementation of cyber security across the organization.
FBS.24	Baseline practices that organizations employ for organizational security include, but are not limited to: 1. Executive management accountability for the security program; 2. Responsibility for control system security within the organization includes sufficient authority and an appropriate level of funding to implement the organization’s security policy; 3. The organization’s security policies and procedures that provide clear direction, accountability, and oversight for the organization’s security team. The security team assigns roles and responsibilities in accordance with the organization’s policies and confirms that processes are in place to protect company assets and critical information; 4. The organization’s contracts with external entities that address the organization’s security policies and procedures with business partners, third-party contractors, and outsourcing partners; 5. The organization’s security policies and procedures ensure coordination or integration with the organization’s physical security plan. Organization roles and responsibilities are established that address the overlap and synergy between physical and control system security risks.
FBS.25	The organization’s security policies and procedures shall delineate how the organization implements its emergency response plan and coordinates efforts with law enforcement agencies, regulators, Internet service providers and other relevant organizations in the event of a security incident.
FBS.26	The organization shall hold external suppliers and contractors that have an impact on the security of the control center to the same security policies and procedures as the organization's own personnel; and shall ensure security policies and procedures of second- and third-tier suppliers comply with corporate cyber security policies and procedures if they will impact control system security.
FBS.27	The organization shall establish procedures to remove external supplier access at the conclusion/termination of the contract.
FBS.28	The security function shall monitor and control communications at the external boundary of the information system and at key internal boundaries within the system.

3.2.3. Cryptographic Services (FCS)

Cryptographic services include encryption, signing, key management and key revocation. The security function may employ cryptographic functionality to help satisfy several high-level security objectives. These include, but are not limited to identification and authentication, non-repudiation, trusted path, trusted channel and data separation. This class is used when the security component implements cryptographic functions, the implementation of which could be in hardware, firmware and/or software.

The FCS: Cryptographic support class is composed of two families: Cryptographic key management (FCS_CKM) and Cryptographic operation (FCS_COP). The Cryptographic key management (FCS_CKM) family addresses the management aspects of cryptographic keys, while the Cryptographic operation (FCS_COP) family is concerned with the operational use of those cryptographic keys. [DHS]

FCS.1	The security function shall generate cryptographic keys in accordance with a specified cryptographic key generation algorithm [assignment: cryptographic key generation algorithm] and specified cryptographic key sizes [assignment: cryptographic key sizes] that meet the following: [assignment: list of standards].
FCS.2	The security function shall distribute cryptographic keys in accordance with a specified cryptographic key distribution method [assignment: cryptographic key distribution method] that meets the following: [assignment: list of standards].
FCS.3	The security function shall perform [assignment: type of cryptographic key access] in accordance with a specified cryptographic key access method [assignment: cryptographic key access method] that meets the following: [assignment: list of standards].
FCS.4	The security function shall destroy cryptographic keys in accordance with a specified cryptographic key destruction method [assignment: cryptographic key destruction method] that meets the following: [assignment: list of standards].
FCS.5	The security function shall perform [assignment: list of cryptographic operations] in accordance with a specified cryptographic algorithm [assignment: cryptographic algorithm] and cryptographic key sizes [assignment: cryptographic key sizes] that meet the following: [assignment: list of standards].
FCS.6	For information requiring cryptographic protection, the information system shall implement cryptographic mechanisms that comply with applicable laws, Executive Orders, directives, policies, regulations, standards, and guidance.

3.2.4. Notification and Signaling Services (FNS)

Notification and signaling services are oriented towards providing system activity information and command result logging.

FNS.1	For [assignment: list of security function devices/elements for which active detection is required], the security function shall monitor the devices and elements and notify [assignment: a designated user or role] when physical or logical tampering with the module's security function's devices or module's security function's elements has occurred.
FNS.2	The security function verifies the correct operation of security utility [Selection (one or more): upon system startup and restart, upon command by user with appropriate privilege, periodically every [Assignment: organization-defined time-period]] and [Selection (one or more): notifies system administrator, shuts the system down, restarts the system] when anomalies are discovered.
FNS.3	The organization shall verify the correct operation of security functions within the control system upon system startup and restart; upon command by user with appropriate privilege; periodically; and/or at defined time periods. The security function notifies the system administrator when anomalies are discovered.
FNS.4	The security function shall notify the user, upon successful logon, of the date and time of the last logon and the number of unsuccessful logon attempts since the last successful logon.
FNS.5	The security function shall display an approved, system use notification message before granting system access informing potential users: 1. That the user is accessing a [assignment: organization] information system; 2. That system usage may be monitored, recorded, and subject to audit; 3. That unauthorized use of the system is prohibited and subject to criminal and civil penalties;

	and 4. That use of the system indicates consent to monitoring and recording. The system use notification message provides appropriate privacy and security notices (based on associated privacy and security policies or summaries) and remains on the screen until the user takes explicit actions to log on to the information system.
FNS.6	The security function shall perform [assignment: list of specific actions] when replay is detected.

3.2.5. Resource Management Services (FRS)

This section covers resource management services requirements. Resources Management Services include management of runtime resources, such as network/communication paths, processors, memory or disk space (e.g., for audit log capacity), and other limited system resources.

FRS.1	The organization shall develop, disseminate, and periodically review and update: 1. A formal, documented system and communication protection policy that addresses: a. The purpose of the system and communication protection policy as it relates to protecting the organization's personnel and assets; b. The scope of the system and communication protection policy as it applies to all the organizational staff and third-party contractors; c. The roles, responsibilities and management accountability structure of the security program to ensure compliance with the organization's system and communications protection policy and other regulatory commitments; 2. Formal, documented procedures to facilitate the implementation of the control system and communication protection policy and associated systems and communication protection controls
FRS.2	The security function shall separate telemetry/data acquisition services from management port functionality.
FRS.3	The security function shall isolate security functions from non-security functions.
FRS.4	The security function shall prevent unauthorized or unintended information transfer via shared system resources.
FRS.5	The security function shall protect against or limits the effects of denial-of-service attacks based on an organization's defined list of types of denial-of-service attacks.
FRS.6	The security function shall limit the use of resources by priority.
FRS.7	The organization shall define the external boundary(ies) of the control system. Procedural and policy security functions define the operational system boundary, the strength required of the boundary, and the respective barriers to unauthorized access and control of system assets and components. The control system monitors and manages communications at the operational system boundary and at key internal boundaries within the system.
FRS.10	The security function shall establish a trusted communications path between the user and the system.
FRS.11	When cryptography is required and employed within the system, the organization shall establish and manage cryptographic keys using automated mechanisms with supporting procedures or manual procedures.
FRS.12	The organization shall develop and implement a policy governing the use of cryptographic mechanisms for the protection of control system information. The organization shall ensure all cryptographic mechanisms comply with applicable laws, regulatory requirements, directives, policies, standards, and guidance.
FRS.13	The use of collaborative computing mechanisms on control system is strongly discouraged and provides an explicit indication of use to the local users.

FRS.14	The system shall reliably associate security parameters (e.g., security labels and markings) with information exchanged between the enterprise information systems and the system.
FRS.15	The organization shall issue public key certificates under an appropriate certificate policy or obtains public key certificates under an appropriate certificate policy from an approved service provider.
FRS.16	The organization shall: 1. Establish usage restrictions and implementation guidance for mobile code technologies based on the potential to cause damage to the control system if used maliciously; 2. Document, monitor, and manage the use of mobile code within the control system. Appropriate organizational officials should authorize the use of mobile code.
FRS.17	The organization shall: 1. Establish usage restrictions and implementation guidance for Voice over Internet Protocol (VOIP) technologies based on the potential to cause damage to the information system if used maliciously; and 2. Authorize, monitor, and limit the use of VOIP within the control system.
FRS.18	All external system and communication connections shall be identified and adequately protected from tampering or damage.
FRS.19	The system design and implementation shall specify the security roles and responsibilities for the users of the system.
FRS.20	The system shall provide mechanisms to protect the authenticity of device-to-device communications.
FRS.21	The system's devices that collectively provide name/address resolution services for an organization shall be fault tolerant and implement address space separation.
FRS.22	The system resource (i.e., authoritative DNS server) that provides name/address resolution service shall provide additional artifacts (e.g., digital signatures and cryptographic keys) along with the authoritative DNS resource records it returns in response to resolution queries.
FRS.23	The system resource (i.e., resolving or caching name server) that provides name/address resolution service for local clients shall perform data origin authentication and data integrity verification on the resolution responses it receives from authoritative DNS servers when requested by client systems.
FRS.24	The security function shall restrict the ability to [selection: determine the behavior of, disable, enable, modify the behavior of] the functions [assignment: list of functions] to [assignment: the authorized identified roles].
FRS.25	The security function shall enforce the [assignment: access control security function policy(s), information flow control security function policy(s)] to restrict the ability to [selection: change, default, query, modify, delete, [assignment: other operations]] the security attributes [assignment: list of security attributes] to [assignment: the authorized identified roles].
FRS.26	The security function shall ensure that only secure values are accepted for [assignment: list of security attributes].
FRS.27	The security function shall enforce the [assignment: access control security function policy, information flow control security function policy] to provide [selection, choose one of: restrictive, permissive, [assignment: other property]] default values for security attributes that are used to enforce the security function policy.
FRS.28	The security function shall allow the [assignment: the authorized identified roles] to specify alternative initial values to override the default values when an object or information is created.
FRS.29	The security function shall use the following rules to set the value of security attributes: [assignment: rules for setting the values of security attributes]
FRS.30	The security function shall restrict the ability to [selection: change_default, query, modify, delete, clear, [assignment: other operations]] the [assignment: list of security function data] to [assignment: the authorized identified roles].
FRS.31	The security function shall restrict the specification of the limits for [assignment: list of security function data] to [assignment: the authorized identified roles].

FRS.32	The security function shall take the following actions, if the security function data are at, or exceed, the indicated limits: [assignment: actions to be taken].
FRS.33	The security function shall ensure that only secure values are accepted for [assignment: list of security function data].
FRS.34	The security function shall restrict the ability to revoke [assignment: list of security attributes] associated with the [selection: users, subjects, objects, [assignment: other additional resources]] under the control of the security function to [assignment: the authorized identified roles].
FRS.35	The security function shall enforce the rules [assignment: specification of revocation rules].
FRS.36	The security function shall restrict the capability to specify an expiration time for [assignment: list of security attributes for which expiration is to be supported] to [assignment: the authorized identified roles].
FRS.37	For each of these security attributes, the security function shall be able to [assignment: list of actions to be taken for each security attribute] after the expiration time for the indicated security attribute has passed.
FRS.38	The security function shall be capable of performing the following management functions: [assignment: list of management functions to be provided by the module's security function].
FRS.39	The security function shall maintain the roles [assignment: the authorized identified roles].
FRS.40	The security function shall be able to associate users with roles.
FRS.41	The security function shall maintain the roles: [assignment: authorized identified roles].
FRS.42	The security function shall ensure that the conditions [assignment: conditions for the different roles] are satisfied.
FRS.43	The security function shall require an explicit request to assume the following roles: [assignment: the roles].
FRS.44	The security function shall terminate the network session at the end of a session or after [Assignment: organization-defined time period] of inactivity.

3.2.6. Trust and Certificate Services (FTS)

Description of relationships between entities and the faith placed on the relationship certificates that have uses outside of cryptography for example, material relating to creation, storage, and revocation of certificates.

FTS.1	The security function shall issue public key certificates based on an appropriate certificate policy or obtain public key certificates under an appropriate certificate policy from an [assignment: approved service provider].
FTS.2	When cryptography is required and employed within the security function, the organization shall establish and manage cryptographic keys using automated mechanisms with supporting procedures or manual procedures.

3.3. Assurance

3.3.1. Development Rigor (ADR)

Not all solutions are created equal. Differing degrees of care and consideration can go into developing solutions that satisfy any given security requirement. This section contains requirements regarding the activities involved in developing smart grid system solutions. Topics including:

- acquisition issues
- configuration management
- development practices

This is about the creation of smart grid systems, not their deployment, operation, or maintenance.

ADR.1	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, information system maintenance policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; and 2. Formal, documented procedures to facilitate the implementation of the information system maintenance policy and associated system maintenance controls.
ADR.2	The organization shall schedule, perform, document and reviews records of routine preventative and regular maintenance (including repairs) on the components of the information system in accordance with manufacturer or vendor specifications and/or organizational requirements.
ADR.3	The organization shall approve, control and monitor the use of information system maintenance tools and maintains the tools on an ongoing basis.
ADR.4	The organization shall authorize, monitor and control any remotely executed maintenance and diagnostic activities, if employed.
ADR.5	The organization shall allow only authorized personnel to perform maintenance on the information system.
ADR.6	The organization shall obtain maintenance support and spare parts for [Assignment: organization-defined list of key information system components] within [Assignment: organization-defined time period] of failure.
ADR.7	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, system and services acquisition policy that includes information security considerations and that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; and 2. Formal, documented procedures to facilitate the implementation of the system and services acquisition policy and associated system and services acquisition controls.
ADR.8	The organization shall determine, document and allocate as part of its capital planning and investment control process, the resources required to adequately protect the information system.
ADR.9	The organization shall manage the information system using a system development life cycle methodology that includes information security considerations.
ADR.10	The organization shall include security requirements and/or security specifications, either explicitly or by reference, in information system acquisition contracts based on an assessment of risk and in accordance with applicable laws, Executive Orders, directives, policies, regulations, and standards.
ADR.11	The organization shall obtain, protect as required, and make available to authorized personnel, adequate documentation for the information system.
ADR.12	The organization shall comply with software usage restrictions.
ADR.13	The organization shall enforce explicit rules governing the installation of software by users.
ADR.14	The organization shall design and implement the information system using security engineering principles.
ADR.15	The organization shall: 1. Requires that providers of external information system services employ adequate security controls in accordance with applicable laws, Executive Orders, directives, policies,

	regulations, standards, guidance, and established service-level agreements; and 2. Monitors security control compliance
ADR.16	The organization shall require that information system developers create and implement a configuration management plan that controls changes to the system during development, tracks security flaws, requires authorization of changes, and provides documentation of the plan and its implementation.
ADR.17	The organization shall require that information system developers create a security test and evaluation plan, implement the plan, and document the results.
ADR.18	The organization shall develop, disseminate and periodically review/update: 1. A formal, documented, system and services acquisition policy that addresses: a. The purpose of the security program as it relates to protecting the organization's personnel and assets; b. The scope of the security program as it applies to all the organizational staff and third-party contractors; c. The roles, responsibilities and management accountability structure of the security program to ensure compliance with the organization's security policy and other regulatory commitments. 2. Formal, documented procedures to facilitate the implementation of the system and services acquisition policy and associated system and services acquisition controls.
ADR.19	The organization shall implement a process to determine, document, approve, and allocate the resources required to adequately protect the control system as part of its capital planning and investment control process.
ADR.20	The organization shall manage the control system using a system development life-cycle methodology that includes control system security considerations.
ADR.21	The organization shall include security requirements and/or security specifications, either explicitly or by reference, in control system acquisition contracts based on an assessment of risk and in accordance with applicable laws, Executive Orders, directives, policies, regulations, and standards.
ADR.22	The organization shall ensure that adequate documentation for the control system and its constituent components are available, protected when required, and are accessible to authorized personnel.
ADR.23	The organization's security program shall deploy policy and procedures to enforce compliance with software license usage restrictions.
ADR.24	The organization shall implement policies and procedures to enforce explicit rules and management expectations governing user installation of software.
ADR.25	The organization shall design and implement the control system using security engineering principles and best practices.
ADR.26	The organization shall ensure that third-party providers of control system services employ adequate security mechanisms in accordance with established service-level agreements and monitor compliance.
ADR.27	The control system vendor shall create and implement a configuration management plan and procedures that limit changes to the control system during design and installation. This plan tracks security flaws. The vendor shall obtain the organization's written approval for any changes to the plan. The vendor shall provide documentation of the plan and its implementation.
ADR.28	The control system vendor shall develop a security test and evaluation plan. The vendor shall submit the plan to the organization for approval and implements the plan once written approval is obtained. The vendor shall then documents the results of the testing and evaluation and submits them to the organization for approval.
ADR.29	The control system vendor shall adopt appropriate software development life-cycle practices to eliminate common coding errors that affect security, particularly with respect to input data validation and buffer management.
ADR.30	The organization shall develop, disseminate, and periodically review and update:

	1. A formal, documented Configuration Management policy that addresses: a. The purpose of the configuration management policy as it relates to protecting the organization's personnel and assets; b. The scope of the configuration management policy as it applies to all the organizational staff and third-party contractors; c. The roles, responsibilities and management accountability structure contained in the configuration management policy to ensure compliance with the organization's security policy and other regulatory commitments 2. Formal, documented procedures to facilitate the implementation of the configuration management policy and associated configuration management controls. 3. The personnel qualification levels required to make changes, the conditions under which changes are allowed, and what approvals are required for those changes.
ADR.31	The organization shall develop, document, and maintain a current baseline configuration of the control system and an inventory of the system's constituent components.
ADR.32	The organization shall authorize, document and manage changes to the control system.
ADR.33	The organization shall implement a process to monitor changes to the control system and conducts security impact analyses to determine the effects of the changes.
ADR.34	The organization shall: 1. Approves individual access privileges and enforces physical and logical access restrictions associated with configuration changes to the control system; 2. Generates, retains, and reviews records reflecting all such changes.
ADR.35	The organization shall: 1. Establishes mandatory configuration settings for IT products employed within the control system; 2. Configures the security settings of control systems technology products to the most restrictive mode consistent with control system operational requirements; 3. Documents the changed configuration settings.
ADR.36	The organization shall configure the control system to provide only essential capabilities and specifically prohibit and/or restrict the use of functions, ports, protocols, and/or services as defined in an organizationally generated "prohibited and/or restricted" list.
ADR.37	The organization shall create and maintains a list of all end-user configurable assets and the configurations of those assets used by the organization.
ADR.38	The organization shall implement policy and procedures to address the addition, removal, and disposal of all control system equipment. All control system assets and information shall be documented, identified and tracked so that their location and function are known.
ADR.39	The organization shall change all factory default authentication credentials on control system components and applications upon installation.
ADR.40	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, control system maintenance policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; 2. Formal, documented procedures to facilitate the implementation of the control system maintenance policy and associated system maintenance controls.
ADR.41	The organization shall develop policies and procedures to upgrade existing legacy control systems to include security mitigating measures commensurate with the organization's risk tolerance and the risk to the system and processes controlled.
ADR.42	The organization shall conduct periodic security vulnerability assessments according to the risk management plan. Then, the control system shall be updated to address any identified vulnerabilities in accordance with organization's control system maintenance policy.
ADR.43	The organization shall make and secure backups of critical system software, applications and data

	for use if the control system operating system software becomes corrupted or destroyed.
ADR.44	The organization shall review and follow security requirements for a control system before undertaking any unplanned maintenance activities of control system components (including field devices). Documentation includes the following: 1. The date and time of maintenance; 2. The name of the individual(s) performing the maintenance; 3. The name of the escort, if necessary; 4. A description of the maintenance performed; 5. A list of equipment removed or replaced (including identification numbers, if applicable).
ADR.45	The organization shall schedule, perform and document routine preventive and regular maintenance on the components of the control system in accordance with manufacturer or vendor specifications and/or organizational policies and procedures.
ADR.46	The organization shall approve, manage, protect and monitor the use of control system maintenance tools and maintains the integrity of tools on an ongoing basis.
ADR.47	The organization shall document authorization and approval policies and procedures and maintains a list of personnel authorized to perform maintenance on the control system. Only authorized and qualified organization or vendor personnel shall perform maintenance on the control system.
ADR.48	The organization shall authorize, manage, and monitor remotely executed maintenance and diagnostic activities on the control system. When remote maintenance is completed, the organization (or control system in certain cases) shall terminate all sessions and remote connections invoked in the performance of that activity. If password-based authentication is used to accomplish remote maintenance, the organization shall change the password following each remote maintenance service.
ADR.49	The organization shall acquire maintenance support and spare parts for key control system components within a specified time period of failure.
ADR.50	The organization shall: 1. Establish usage restrictions and implementation guidance for mobile code technologies based on the potential to cause damage to the information system if used maliciously; and 2. Authorize, monitor, and control the use of mobile code within the information system.
ADR.51	The security function shall separate user data from security function data when such data is transmitted between separate parts of the module.
ADR.52	The organization shall require that information system developers create and implement a configuration management plan that controls changes to the system during development, tracks security flaws, requires authorization of changes, and provides documentation of the plan and its implementation.

3.3.2. Organizational Rigor (AOR)

This section contains requirements regarding the policies employed by the organization(s) with access to assets of a deployed smart grid system. These requirements reflect on an organization's ability to continue to operate a smart grid system reliably over time. Topics include

- training procedures
- personnel security
- strategic planning
- monitoring and reviewing security policies

AOR.1	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, security awareness and training policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; and 2. Formal, documented procedures to facilitate the implementation of the security awareness and training policy and associated security awareness and training controls.
AOR.2	The organization shall provide basic security awareness training to all information system users (including managers and senior executives) before authorizing access to the system, when required by system changes, and [Assignment: organization-defined frequency, at least annually] thereafter.
AOR.3	The organization shall identify personnel that have significant information system security roles and responsibilities during the system development life cycle, documents those roles and responsibilities, and provides appropriate information system security training: 1. Before authorizing access to the system or performing assigned duties; 2. When required by system changes; and 3. [Assignment: organization-defined frequency] thereafter
AOR.4	The organization shall document and monitor individual information system security training activities including basic security awareness training and specific information system security training.
AOR.5	The organization shall establish and maintain contacts with special interest groups, specialized forums, professional associations, news groups, and/or peer groups of security professionals in similar organizations to stay up to date with the latest recommended security practices, techniques, and technologies and to share the latest security-related information including threats, vulnerabilities, and incidents.
AOR.6	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, media protection policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; and 2. Formal, documented procedures to facilitate the implementation of the media protection policy and associated media protection controls.
AOR.7	The organization shall restricts access to information system media to authorized individuals.
AOR.8	The organization shall: 1. Affix external labels to removable information system media and information system output indicating the distribution limitations, handling caveats and applicable security markings (if any) of the information; and 2. Exempt [Assignment: organization-defined list of media types or hardware components] from labeling so long as they remain within [Assignment: organization-defined protected environment].
AOR.9	The organization shall physically control and securely store information system media within controlled areas.
AOR.10	The organization shall protect and control information system media during transport outside of controlled areas and restricts the activities associated with transport of such media to authorized personnel.
AOR.11	The organization shall sanitize information system media, both digital and non-digital, prior to disposal or release for reuse.
AOR.12	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, physical and environmental protection policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; and 2. Formal, documented procedures to facilitate the implementation of the physical and environmental protection policy and associated physical and environmental protection controls.

AOR.13	The organization shall develop and keep a current a list of personnel with authorized access to the facility where the information system resides (except for those areas within the facility officially designated as publicly accessible) and issues appropriate authorization credentials. Designated officials within the organization shall review and approve the access list and authorization credentials [Assignment: organization-defined frequency, at least annually].
AOR.14	The organization shall control all physical access points (including designated entry/exit points) to the facility where the information system resides (except for those areas within the facility officially designated as publicly accessible) and verifies individual access authorizations before granting access to the facility. The organization shall control access to areas officially designated as publicly accessible, as appropriate, in accordance with the organization's assessment of risk.
AOR.15	The organization shall control physical access to information system distribution and transmission lines within organizational facilities.
AOR.16	The organization shall control physical access to information system devices that display information to prevent unauthorized individuals from observing the display output.
AOR.17	The organization shall monitor physical access to the information system to detect and respond to physical security incidents.
AOR.18	The organization shall control physical access to the information system by authenticating visitors before authorizing access to the facility where the information system resides other than areas designated as publicly accessible.
AOR.19	The organization shall maintain visitor access records to the facility where the information system resides (except for those areas within the facility officially designated as publicly accessible) that includes: 1. Name and organization of the person visiting; 2. Signature of the visitor; 3. Form of identification; 4. Date of access; 5. Time of entry and departure; 6. Purpose of visit; and 7. Name and organization of person visited. Designated officials within the organization shall review the visitor access records [Assignment: organization-defined frequency].
AOR.20	The organization shall protect power equipment and power cabling for the information system from damage and destruction.
AOR.21	The organization shall provide, for specific locations within a facility containing concentrations of information system resources, the capability of shutting off power to any information system component that may be malfunctioning or threatened without endangering personnel by requiring them to approach the equipment.
AOR.22	The organization shall provide a short-term uninterruptible power supply to facilitate an orderly shutdown of the information system in the event of a primary power source loss.
AOR.23	The organization shall employ and maintain automatic emergency lighting that activates in the event of a power outage or disruption and that covers emergency exits and evacuation routes.
AOR.24	The organization shall employ and maintain fire suppression and detection devices/systems that can be activated in the event of a fire.
AOR.25	The organization shall regularly maintain, within acceptable levels, and monitor the temperature and humidity within the facility where the information system resides.
AOR.26	The organization shall protect the information system from water damage resulting from broken plumbing lines or other sources of water leakage by providing master shutoff valves that are accessible, working properly, and known to key personnel.
AOR.27	The organization shall authorize and control information system-related items entering and exiting the facility and maintains appropriate records of those items.

AOR.28	The organization shall employ appropriate management, operational, and technical information system security controls at alternate work sites.
AOR.29	The organization shall position information system components within the facility to minimize potential damage from physical and environmental hazards and to minimize the opportunity for unauthorized access.
AOR.30	The organization shall protect the information system from information leakage due to electromagnetic signals emanations.
AOR.31	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, security planning policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; and 2. Formal, documented procedures to facilitate the implementation of the security planning policy and associated security planning controls.
AOR.32	The organization shall develop and implement a security plan for the information system that provides an overview of the security requirements for the system and a description of the security controls in place or planned for meeting those requirements. Designated officials within the organization shall review and approve the plan
AOR.33	The organization shall review the security plan for the information system [Assignment: organization-defined frequency, at least annually] and revises the plan to address system/organizational changes or problems identified during plan implementation or security control assessments.
AOR.34	The organization shall establish and make readily available to all information system users, a set of rules that describes their responsibilities and expected behavior with regard to information and information system usage. The organization shall receive signed acknowledgment from users indicating that they have read, understand, and agree to abide by the rules of behavior, before authorizing access to the information system and its resident information.
AOR.35	The organization shall conduct a privacy impact assessment on the information system in accordance with regulatory and the organization's policy.
AOR.36	The organization shall plan and coordinate security-related activities affecting the information system before conducting such activities in order to reduce the impact on organizational operations (i.e., mission, functions, image, and reputation), organizational assets, and individuals.
AOR.37	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, personnel security policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; and 2. Formal, documented procedures to facilitate the implementation of the personnel security policy and associated personnel security controls
AOR.38	The organization shall assign a risk designation to all positions and establishes screening criteria for individuals filling those positions. The organization shall review and revise position risk designations [Assignment: organization-defined frequency].
AOR.39	The organization shall screen individuals requiring access to organizational information and information systems before authorizing access.
AOR.40	The organization, upon termination of individual employment, shall terminate information system access, conducts exit interviews, retrieves all organizational information system-related property, and provide appropriate personnel with access to official records created by the terminated employee that are stored on organizational information systems.
AOR.41	The organization shall review information systems/facilities access authorizations when personnel are reassigned or transferred to other positions within the organization and initiates appropriate actions
AOR.42	The organization shall complete appropriate signed access agreements for individuals requiring access to organizational information and information systems before authorizing access and reviews/updates the agreements [Assignment: organization-defined frequency].

AOR.43	The organization shall establish personnel security requirements including security roles and responsibilities for third-party providers and monitors provider compliance.
AOR.44	The organization shall employ a formal sanctions process for personnel failing to comply with established information security policies and procedures.
AOR.45	The organization shall develop, disseminate, and periodically review and update: 1. A formal, documented, personnel security policy that addresses: a. The purpose of the security program as it relates to protecting the organization's personnel and assets; b. The scope of the security program as it applies to all the organizational staff and third-party contractors; c. The roles, responsibilities, and management accountability structure of the security program to ensure compliance with the organization's security policy and other regulatory commitments; 2. Formal, documented procedures to facilitate the implementation of the personnel security policy and associated personnel security controls. 3. Formal procedure to review and document list of approved personnel with access to control systems.
AOR.46	The organization shall assign a risk designation to all positions and establishes screening criteria for individuals filling those positions. The organization shall review and revise position risk designations periodically based on the organization's requirements or regulatory commitments.
AOR.47	The organization shall screen individuals requiring access to the control system before access is authorized.
AOR.48	When an employee is terminated, the organization shall revoke logical and physical access to control systems and facilities and ensure all organization-owned property is returned and that organization-owned documents and/or data files relating to the control system that are in the employee's possession be transferred to the new authorized owner within the organization. Complete execution of this control shall occur within 24 hours for employees or contractors terminated for cause.
AOR.49	The organization shall review logical and physical access permissions to control systems and facilities when individuals are reassigned or transferred to other positions within the organization and initiates appropriate actions. Complete execution of this control shall occur within 7 days for employees or contractors who no longer need to access control system resources.
AOR.50	The organization shall complete appropriate agreements for control system access before access is granted. This requirement applies to all parties, including third parties and contractors, who desire access to the control system. The organization shall review and update access agreements periodically.
AOR.51	The organization shall enforce security controls for third-party personnel and monitors service provider behavior and compliance.
AOR.52	The organization shall employ a formal accountability process for personnel failing to comply with established control system security policies and procedures and clearly documents potential disciplinary actions for failing to comply.
AOR.53	The organization shall provide employees and contractors with complete job descriptions and unambiguous and detailed expectations of conduct, duties, terms and conditions of employment, legal rights, and responsibilities.
AOR.54	The organization develops, implements, and periodically reviews and updates: 1. A formal, documented physical security policy that addresses: a. The purpose of the physical security program as it relates to protecting the organization's personnel and assets; b. The scope of the physical security program as it applies to all the organizational staff and third-party contractors; c. The roles, responsibilities and management accountability structure of the physical security program to ensure compliance with the organization's security policy and other regulatory commitments. 2. Formal, documented procedures to facilitate the implementation of the physical and

	environmental protection policy and associated physical and environmental protection controls.
AOR.55	The organization shall develop and maintain lists of personnel with authorized access to facilities containing control systems (except for areas within facilities officially designated as publicly accessible) and issue appropriate authorization credentials (e.g., badges, identification cards, smart cards). Designated officials within the organization shall review and approve the access list and authorization credentials at least annually.
AOR.56	The organization shall limit physical access to all control system facilities and assets and verify individual access authorizations before granting access. The organization shall limit access to areas officially designated as publicly accessible, as appropriate, in accordance with the organization's assessment of risk.
AOR.57	The organization shall monitor physical access to the control system facilities to detect and respond to physical security incidents.
AOR.58	The organization shall limit physical access to control systems by authenticating visitors before authorizing access to facilities or areas other than areas designated as publicly accessible.
AOR.59	The organization shall maintain visitor access records to the control system facility (except for those areas within the facility officially designated as publicly accessible) that include: Name and organization of the person visiting; 1. Signature of the visitor; 2. Form of identification; 3. Date of access; 4. Time of entry and departure; 5. Purpose of visit; 6. Name and organization of person visited.
AOR.60	The organization shall retain all physical access logs for as long as dictated by any applicable regulations or based on an organization-defined period by approved policy.
AOR.61	For specific locations within a facility containing concentrations of control system resources (e.g., control centers, server rooms), the organization shall provide the capability of shutting off power to any component that may be malfunctioning (e.g., due to an electrical fire) or threatened (e.g., due to a water leak) without compromising personnel safety.
AOR.62	The organization shall provide a short-term Uninterruptible Power Supply (UPS) to facilitate an orderly shutdown of non-critical control system components in the event of a primary power source loss.
AOR.63	The organization shall employ and maintain automatic emergency lighting systems that activate in the event of a power outage or disruption and includes lighting for emergency exits and evacuation routes.
AOR.64	The organization shall implement and maintain fire suppression and detection devices/systems that can be activated in the event of a fire.
AOR.65	The organization shall regularly monitors the temperature and humidity within facilities containing control system assets and ensures they are maintained within acceptable levels.
AOR.66	The organization shall protect the control systems from water damage resulting from broken plumbing lines, fire control systems or other sources of water leakage by ensuring that master shutoff valves are accessible, working properly, and known to key personnel.
AOR.67	The organization shall authorize and limit the delivery and removal of control system components (i.e., hardware, firmware, software) from control system facilities and maintain appropriate records and control of that equipment. The organization shall document policies and procedures governing

	the delivery and removal of control system assets in the control system security plan.
AOR.68	The organization shall establish an alternate control center with proper equipment and communication infrastructure to compensate for the loss of the primary control system worksite. The organization shall implement appropriate management, operational, and technical security measures at alternate control centers.
AOR.69	The organization shall monitor and prohibit the use of unapproved portable media use on the control system.
AOR.70	The organization shall implement asset location technologies to track and monitor the movements of personnel and vehicles within the organization's controlled areas to ensure they stay in authorized areas, to identify personnel needing assistance, and to support emergency response.
AOR.71	The organization shall locate control system assets to minimize potential damage from physical and environmental hazards and to minimize the opportunity for unauthorized access.
AOR.72	The organization shall protect the control system from information leakage.
AOR.73	The organization shall protect control system power equipment and power cabling from damage and destruction.
AOR.74	The organization shall employ hardware (cages, locks, cases, etc.) to detect and deter unauthorized physical access to control system devices.
AOR.75	The organization shall develop, disseminate, and periodically review and update: 1. A formal, documented, planning policy that addresses: a. The purpose of the strategic planning program as it relates to protecting the organization's personnel and assets; b. The scope of the strategic planning program as it applies to all the organizational staff and third-party contractors; c. The roles, responsibilities, and management accountability structure of the strategic planning program to ensure compliance with the organization's security policy and other regulatory commitments. 2. Formal, documented procedures to facilitate the implementation of the strategic planning policy and associated strategic planning controls.
AOR.76	The organization shall develop and implement a security plan for the control system that provides an overview of the security requirements for the system and a description of the security measures in place or planned for meeting those requirements. Designated officials within the organization shall review and approve the control system security plan.
AOR.77	The organization shall identify potential interruptions and classify them as to "cause," "effects," and "likelihood."
AOR.78	The organization's control system security plan shall define and communicate the specific roles and responsibilities in relation to various types of incidents.
AOR.79	The organization shall include training on the implementation of the control system security plans for employees, contractors, and stakeholders into the organization's planning process.
AOR.80	The organization shall regularly test security plans to validate the control system objectives.
AOR.81	The organization shall include investigation and analysis of control system incidents in the planning process.
AOR.82	The organization shall include processes and mechanisms in the planning to ensure that corrective actions identified as the result of a cyber security and system incidents are fully implemented.
AOR.83	Risk-reduction mitigation measures shall be planned and implemented and the results monitored to ensure effectiveness of the organization's risk management plan.
AOR.84	The organization shall regularly, at prescribed frequencies, review the security plan for the control system and revise the plan to address system/organizational changes or problems identified during system security plan implementation or security controls assessment.

AOR.85	The organization shall establish and make readily available to all control system users a set of rules that describes their responsibilities and expected behavior with regards to control system usage. The organization shall obtain signed acknowledgement from users indicating that they have read, understand, and agree to abide by the rules of behavior before authorizing access to the control system.
AOR.86	The organization shall plan and coordinate security-related activities affecting the control system before conducting such activities to reduce the impact on organizational operations (i.e., mission, functions, image, and reputation), organizational assets, or individuals.
AOR.87	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, security awareness and training policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; and 2. Formal, documented procedures to facilitate the implementation of the security awareness and training policy and associated security awareness and training controls.
AOR.88	The organization shall provide basic security awareness training to all control system users (including managers and senior executives) before authorizing access to the system, when required by system changes, and at least annually thereafter. The effectiveness of security awareness training, at the organization level, shall be reviewed at a minimum [assignment: once a year, etc.].
AOR.89	The organization shall identify and train personnel with significant control system security roles and responsibilities. The organization shall document the roles and responsibilities and provide appropriate control system security training before authorizing access to the system, when required by system changes, and with periodic training thereafter.
AOR.90	The organization shall document, maintain, and monitor individual control system security training activities, including basic security awareness training and specific information and control system security training in accordance with the organization's records retention policy.
AOR.91	The organization shall establish, participate with, and maintain contacts with special interest groups, industry vendor forums, specialized public or governmental forums, or professional associations to stay up to date with the latest recommended security practices, techniques, and technologies and to share the latest security-related information including threats, vulnerabilities, and incidents.
AOR.92	The organization shall document and test the knowledge of personnel on security policies and procedures based on their roles and responsibilities to ensure that they understand their responsibilities in securing the control system.
AOR.93	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, media protection policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; 2. Formal, documented procedures to facilitate the implementation of the media protection policy and associated media protection controls.
AOR.94	The organization shall ensure that only authorized users have access to information in printed form or on digital media, whether integral to or removed from the control system.
AOR.95	The organization shall review and classify all removable information storage media and the control system output to determine distribution limitations [assignment: public, confidential, classified, etc.].
AOR.96	The organization shall affix external labels to removable information system media and to the control system output that indicate the distribution limitations [assignment: public, confidential, classified, etc.] and handling caveats of the information. The organization may exempt specific types of media or hardware components from labeling as long as they remain within a secure environment (as defined by the organization).
AOR.97	The organization shall physically manage and securely store control system media within protected areas. The sensitivity of the material delineates how the media is stored.
AOR.98	The organization shall develop security measures for paper and digital media extracted from the control system and restricts the pickup, receipt, transfer, and delivery of such media to authorized personnel.

AOR.99	The organization shall sanitize control system digital and non-digital media, before disposal or release for reuse.
AOR.100	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, monitoring and reviewing control system security management policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; 2. Formal, documented procedures to facilitate the implementation of the monitoring and reviewing control system security management policy and associated audit and accountability controls.
AOR.101	The organization's security program shall implement continuous improvement practices to ensure that industry lessons-learned and best practices are incorporated into control system security policies and procedures.
AOR.102	The organization shall include a process for monitoring and reviewing the performance of their cyber security policy.
AOR.103	The organization shall incorporate industry best practices into the organization's security program for control systems.
AOR.104	The organization shall authorize (i.e., accredit) the control system for processing before operations and periodically updates the authorization based on organization-defined frequency or when there is a significant change to the system. A senior organizational official shall sign and approve the security accreditation.
AOR.105	The organization shall conduct an assessment of the security mechanisms in the control system to determine the extent to which the security measures are implemented correctly, operating as intended, and producing the desired outcome with respect to meeting the security requirements for the system.
AOR.106	The organization shall establish policies and procedures to define roles, responsibilities, behaviors, and practices for the implementation of an overall security program.
AOR.107	The organization shall define a framework of management leadership accountability. This framework establishes roles and responsibilities to approve cyber security policy, assign security roles, and coordinate the implementation of cyber security across the organization.
AOR.108	Baseline practices that the organization shall employ for organizational security include, but are not limited to: 1. Executive management accountability for the security program; 2. Responsibility for control system security within the organization includes sufficient authority and an appropriate level of funding to implement the organization's security policy; 3. The organization's security policies and procedures that provide clear direction, accountability, and oversight for the organization's security team. The security team assigns roles and responsibilities in accordance with the organization's policies and confirms that processes are in place to protect company assets and critical information; 4. The organization's contracts with external entities that address the organization's security policies and procedures with business partners, third-party contractors, and outsourcing partners; 5. The organization's security policies and procedures ensure coordination or integration with the organization's physical security plan. Organization roles and responsibilities are established that address the overlap and synergy between physical and control system security risks.
AOR.109	The organization's security policies and procedures shall delineate how the organization implements its emergency response plan and coordinates efforts with law enforcement agencies, regulators, Internet service providers and other relevant organizations in the event of a security incident.
AOR.110	The organization shall hold external suppliers and contractors that have an impact on the security of the control center to the same security policies and procedures as the organization's own personnel. The organization shall ensure security policies and procedures of second- and third-tier suppliers comply with corporate cyber security policies and procedures if they will impact control system security.

AOR.111	The organization shall establish procedures to remove external supplier access at the conclusion/termination of the contract.
AOR.112	The organization shall: 1. Establish usage restrictions and implementation guidance for Voice over Internet Protocol (VoIP) technologies based on the potential to cause damage to the information system if used maliciously; and 2. Authorize, monitor, and control the use of VoIP within the information system.
AOR.113	The organization shall display an approved system use notification (message) before granting access to the system.
AOR.114	The organization shall develop a formal written policy and appropriate security procedures to address and protect against the risks of remote access to the system, field devices, and communication facilities.
AOR.115	The organization shall restrict the use of personally owned information copied to the system or system user workstation that is used for official organization business. This includes the processing, storage, or transmission of organization business and critical system information. The terms and conditions need to address, at a minimum: 1. The types of applications that can be accessed from personally owned IT, either remotely or from within the organization's system; 2. The maximum security category of information that can processed, stored, and transmitted; 3. How other users of the personally owned system will be prevented from accessing organization information; 4. The use of virtual private networking (VPN) and firewall technologies; 5. The use of and protection against the vulnerabilities of wireless technologies; 6. The maintenance of adequate physical security mechanisms; 7. The use of virus and spyware protection software; and 8. How often the security capabilities of installed software are to be updated (e.g., operating system and other software security patches, virus definitions, firewall version updates, malware definitions).
AOR.116	The organization shall develop, disseminate and periodically review and update: 1. A formal, documented identification policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; and 2. Formal, documented procedures to facilitate the implementation of the identification policy and associated identification controls.
AOR.117	The organization shall develop, disseminate, and periodically review and update: 1. A formal, documented, access control policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; 2. Formal, documented procedures to facilitate the implementation of the access control policy and associated access controls.
AOR.118	The organization shall manage system accounts, including establishing, activating, modifying, reviewing, disabling, and removing accounts. The organization reviews system accounts at least [assignment: period of time (e.g., annually)].
AOR.119	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, accountability policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; and 2. Formal, documented procedures to facilitate the implementation of the accountability policy and associated audit and accountability controls.
AOR.120	The organization shall regularly review and analyze information system audit records: 1. For indications of inappropriate or unusual activity 2. To investigate suspicious activity or suspected violations 3. To report findings to appropriate officials, and 4. Take necessary actions.

AOR.121	The organization shall conduct audits at planned intervals to determine whether the security objectives, measures, processes, and procedures: 1. Conform to the requirements and relevant legislation or regulations; 2. Conform to the identified information security requirements; 3. Are effectively implemented and maintained; 4. Perform as expected; 5. Identify inappropriate activities.
AOR.122	The organization's audit program shall specify auditor qualifications in accordance with the organization's documented training program.
AOR.123	The organization under the audit program shall specify strict rules and careful use of audit tools when auditing control system functions.
AOR.124	The organization shall demonstrate compliance to the organization's security policy through audits in accordance with the organization's audit program.

3.3.3. Handling/Operating Rigor (AHR)

This section contains requirements regarding the activities involved in the day-to-day operation of deployed smart grid systems. Topics include

- information and document management policies
- incident response procedures
- maintenance procedures
- physical and environmental security
- media protection

AHR.1	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, contingency planning policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; and 2. Formal, documented procedures to facilitate the implementation of the contingency planning policy and associated contingency planning controls.
AHR.2	The organization shall develop and implement a contingency plan for the information system addressing contingency roles, responsibilities, assigned individuals with contact information, and activities associated with restoring the system after a disruption or failure. Designated officials within the organization shall review and approve the contingency plan and distribute copies of the plan to key contingency personnel.
AHR.3	The organization shall train personnel in their contingency roles and responsibilities with respect to the information system and provides refresher training [Assignment: organization-defined frequency, at least annually].
AHR.4	The organization shall: 1. Test and/or exercise the contingency plan for the information system [Assignment: organization-defined frequency, at least annually] using [Assignment: organization-defined tests and/or exercises] to determine the plan's effectiveness and the organization's readiness to execute the plan; and 2. Review the contingency plan test/exercise results and initiates corrective actions.
AHR.5	The organization shall review the contingency plan for the information system [Assignment: organization-defined frequency, at least annually] and revises the plan to address system/organizational changes or problems encountered during plan implementation, execution, or testing.

AHR.6	The organization shall identify an alternate storage site and initiates necessary agreements to permit the storage of information system backup information.
AHR.7	The organization shall identify an alternate processing site and initiates necessary agreements to permit the resumption of information system operations for critical mission/business functions within [Assignment: organization-defined time period] when the primary processing capabilities are unavailable.
AHR.8	The organization shall identify primary and alternate telecommunications services to support the information system and initiates necessary agreements to permit the resumption of system operations for critical mission/business functions within [Assignment: organization-defined time period] when the primary telecommunications capabilities are unavailable.
AHR.9	The organization shall conduct backups of user-level and system-level information (including system state information) contained in the information system [Assignment: organization-defined frequency] and protects backup information at the storage location.
AHR.10	The organization shall employ mechanisms with supporting procedures to allow the information system to be recovered and reconstituted to a known secure state after a disruption or failure.
AHR.11	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, incident response policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; and 2. Formal, documented procedures to facilitate the implementation of the incident response policy and associated incident response controls.
AHR.12	The organization shall train personnel in their incident response roles and responsibilities with respect to the information system and provides refresher training [Assignment: organization-defined frequency, at least annually].
AHR.13	The organization shall test and/or exercise the incident response capability for the information system [Assignment: organization-defined frequency, at least annually] using [Assignment: organization-defined tests and/or exercises] to determine the incident response effectiveness and documents the results.
AHR.14	The organization shall implement an incident handling capability for security incidents that includes preparation, detection and analysis, containment, eradication, and recovery.
AHR.15	The organization tracks and documents information system security incidents on an ongoing basis.
AHR.16	The organization promptly reports incident information to appropriate authorities.
AHR.17	The organization shall provide an incident response support resource that offers advice and assistance to users of the information system for the handling and reporting of security incident (The support resource is an integral part of the organization's incident response capability).
AHR.18	The organization shall develop, disseminate and periodically review/update: 1. A formal, documented, control system information and document management policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance. 2. Formal, documented procedures to facilitate the implementation of the control system information and document management policy and associated system maintenance controls.
AHR.19	The organization shall manage control system related data, including establishing retention policies and procedures for both electronic and paper data, and manages access to the data based on formally assigned roles and responsibilities.
AHR.20	Organization implemented policies and procedures detailing the handling of information shall be developed and periodically reviewed and updated.
AHR.21	All information shall be classified to indicate the protection required commensurate with its sensitivity and consequence.
AHR.22	Formal contractual and confidentiality agreements shall be established for the exchange of

	information and software between the organization and external parties.
AHR.23	The organization shall develop policies and procedures to classify data, including establishing: 1. Retention policies and procedures for both electronic and paper media; 2. Classification policies and methods, (e.g., restricted, classified, general, etc.).; 3. Access and control policies, to include sharing, copying, transmittal, and distribution appropriate for the level of protection required; 4. Access to the data based on formally assigned roles and responsibilities for the control system.
AHR.24	The organization shall develop policies and procedures that provide details of the retrieval of written and electronic records, equipment, and other media for the control system in the overall information and document management policy.
AHR.25	The organization shall develop policies and procedures detailing the destruction of written and electronic records, equipment, and other media for the control system, without compromising the confidentiality of the data.
AHR.26	The organization shall perform periodic reviews of compliance with the control system information and document security management policy to ensure compliance with any laws and regulatory requirements.
AHR.27	The control system shall automatically marks data output using standard naming conventions to identify any special dissemination, handling, or distribution instructions.
AHR.28	The control system shall automatically label information in storage, in process and in transmission.
AHR.29	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, incident response policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; and 2. Formal, documented procedures to facilitate the implementation of the incident response policy and associated incident response controls.
AHR.30	The organization shall develop and implement a continuity of operations plan dealing with the overall issue of maintaining or re-establishing production in case of an undesirable interruption for a control system. The plan shall address roles, responsibilities, assigned individuals with contact information, and activities associated with restoring system operations after a disruption or failure. Designated officials within the organization shall review and approve the continuity of operations plan.
AHR.31	The organization's continuity of operations plan shall define and communicate the specific roles and responsibilities for each part of the plan in relation to various types of control system incidents.
AHR.32	The organization shall train personnel in their continuity of operations plan roles and responsibilities with respect to the control system. The organization shall provide refresher training at least annually. The training covers employees, contractors, and stakeholders in the implementation of the continuity of operations plan.
AHR.33	The organization shall test the continuity of operations plan to determine its effectiveness and documents the results. Appropriate officials within the organization shall review the documented test results and initiate corrective actions if necessary. The organization shall test the continuity of operations plan for the control system at least annually, using organization prescribed tests and exercises to determine the plan's effectiveness and the organization's readiness to execute the plan.
AHR.34	The organization shall review the continuity of operations plan for the control system at least annually and updates the plan to address system, organizational, and technology changes or problems encountered during plan implementation, execution, or testing.
AHR.35	The organization shall implement control system incident handling capabilities for security incidents that includes preparation, detection and analysis, containment, eradication, and recovery.
AHR.36	The organization shall track and document control system network security incidents on an ongoing basis.
AHR.37	The organization shall promptly report cyber and control system security incident information to the appropriate authorities.

AHR.38	The organization shall provide an incident response support resource that offers advice and assistance to users of the control system for the handling and reporting of security incidents (The support resource is an integral part of the organization’s incident response capability).
AHR.39	The organization shall document its policies and procedures to show that investigation and analysis of incidents are included in the planning process. The procedures shall ensure that the control system is capable of providing event data to the proper personnel for analysis and for developing mitigation steps. The organization shall ensure that a dedicated group of personnel is assigned to periodically review the data at a minimum monthly.
AHR.40	The organization shall include processes and mechanisms in the planning to ensure that corrective actions identified as the result of a cyber security incident are fully implemented.
AHR.41	The organization shall identify an alternate storage site and initiates necessary agreements to permit the storage of control system configuration information.
AHR.42	The organization shall identify alternate command/control methods for the control system and initiates necessary agreements to permit the resumption of operations for the safe operation of the control system within an organization-defined time period when the primary system capabilities are unavailable.
AHR.43	The organization shall identify an alternate control center, necessary telecommunications, and initiates necessary agreements to permit the resumption of control system operations for critical functions within [assignment: an organization-prescribed time period] when the primary control center is unavailable.
AHR.44	The organization shall conduct backups of critical control system information, including state of the user-level and system level information, process formulas, system inventories, etc., contained in the control system, on a regular schedule as defined by the organization, and stores the information at an appropriately secured location.
AHR.45	The organization shall employ mechanisms with supporting procedures to allow the control system to be recovered and reconstituted to the system’s original state after a disruption or failure.
AHR.46	The control system shall have the ability to execute an appropriate fail safe procedure upon the loss of communications with the control system or the loss of the control system itself.
AHR.47	The organization shall retain audit records for [Assignment: organization-defined time period] to provide support for after-the-fact investigations of security incidents and to meet regulatory and organizational information retention requirements.

3.3.4. Accountability (AAY)

"Security auditing involves recognizing, recording, storing, and analyzing information related to security relevant activities (i.e. activities controlled by the TSF). The resulting audit records can be examined to determine which security relevant activities took place and whom (which user) is responsible for them." [CC]

AAY.1	The organization shall manage control system accounts, including establishing, activating, modifying, reviewing, disabling, and removing accounts. The organization shall review control system accounts [assignment: time period (e.g., at least annually)].
AAY.3	The organization shall manage information system accounts, including establishing, activating, modifying, reviewing, disabling, and removing accounts. The organization shall review information system accounts [Assignment: organization-defined frequency, at least annually].
AAY.4	The information system shall enforce a limit of [Assignment: organization-defined number] consecutive invalid access attempts by a user during a [Assignment: organization-defined time period] time period. The information system automatically [Selection: locks the account/node for an [Assignment: organization-defined time period], delays next login prompt according to [Assignment: organization-defined delay algorithm.]] when the maximum number of unsuccessful attempts is

	exceeded.
AAY.5	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, audit and accountability policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; and 2. Formal, documented procedures to facilitate the implementation of the audit and accountability policy and associated audit and accountability controls.
AAY.6	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, audit and accountability policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; 2. Formal, documented procedures to facilitate the implementation of the audit and accountability policy and associated audit and accountability controls.
AAY.7	The control system shall generate audit records, at a minimum, for the following events whether or not the attempts were successful: 1. Attempts to logon; 2. Attempts to change local account attributes such as privileges; 3. Attempts to change local security policy.
AAY.8	The organization shall develop, implement, and periodically review and update: 1. A formal, documented, control system security policy that addresses: a. The purpose of the security program as it relates to protecting the organization's personnel and assets; b. The scope of the security program as it applies to all the organizational staff and third-party contractors; c. The roles, responsibilities, and management accountability structure of the security program to ensure compliance with the organization's security policy and other regulatory commitments. 2. Formal, documented procedures to implement the security policy and associated requirements. A control system security policy considers controls from each of the families contained in this document.
AAY.9	The organization shall define a framework of management leadership accountability. This framework establishes roles and responsibilities to approve cyber security policy, assign security roles, and coordinate the implementation of cyber security across the organization.
AAY.10	Baseline practices that organizations employ for organizational security shall include, but are not limited to: 1. Executive management accountability for the security program; 2. Responsibility for control system security within the organization includes sufficient authority and an appropriate level of funding to implement the organization's security policy; 3. The organization's security policies and procedures that provide clear direction, accountability, and oversight for the organization's security team. The security team assigns roles and responsibilities in accordance with the organization's policies and confirms that processes are in place to protect company assets and critical information; 4. The organization's contracts with external entities that address the organization's security policies and procedures with business partners, third-party contractors, and outsourcing partners; 5. The organization's security policies and procedures ensure coordination or integration with the organization's physical security plan. Organization roles and responsibilities are established that address the overlap and synergy between physical and control system security risks.
AAY.11	The organization shall develop, disseminate, and periodically review and update: 1. A formal, documented system and communication protection policy that addresses: a. The purpose of the system and communication protection policy as it relates to protecting the organization's personnel and assets; b. The scope of the system and communication protection policy as it applies to all

	the organizational staff and third-party contractors; c. The roles, responsibilities and management accountability structure of the security program to ensure compliance with the organization's system and communications protection policy and other regulatory commitments; 2. Formal, documented procedures to facilitate the implementation of the control system and communication protection policy and associated systems and communication protection controls.
AAY.12	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, system and services acquisition policy that addresses: a. The purpose of the security program as it relates to protecting the organization's personnel and assets; b. The scope of the security program as it applies to all the organizational staff and third-party contractors; c. The roles, responsibilities and management accountability structure of the security program to ensure compliance with the organization's security policy and other regulatory commitments. 2. Formal, documented procedures to facilitate the implementation of the system and services acquisition policy and associated system and services acquisition controls.
AAY.13	The organization shall develop, disseminate, and periodically review and update: 1. A formal, documented Configuration Management policy that addresses: a. The purpose of the configuration management policy as it relates to protecting the organization's personnel and assets; b. The scope of the configuration management policy as it applies to all the organizational staff and third-party contractors; c. The roles, responsibilities and management accountability structure contained in the configuration management policy to ensure compliance with the organization's security policy and other regulatory commitments. 2. Formal, documented procedures to facilitate the implementation of the configuration management policy and associated configuration management controls. 3. The personnel qualification levels required to make changes, the conditions under which changes are allowed, and what approvals are required for those changes.
AAY.14	The organization shall develop, disseminate, and periodically review and update: 1. A formal, documented, personnel security policy that addresses: a. The purpose of the security program as it relates to protecting the organization's personnel and assets; b. The scope of the security program as it applies to all the organizational staff and third-party contractors; c. The roles, responsibilities, and management accountability structure of the security program to ensure compliance with the organization's security policy and other regulatory commitments; 2. Formal, documented procedures to facilitate the implementation of the personnel security policy and associated personnel security controls. 3. Formal procedure to review and document list of approved personnel with access to control systems.
AAY.15	The organization shall employ a formal accountability process for personnel failing to comply with established control system security policies and procedures, and clearly document potential disciplinary actions for failing to comply.
AAY.16	The organization shall develop, implement, and periodically review and update: 1. A formal, documented physical security policy that addresses: a. The purpose of the physical security program as it relates to protecting the organization's personnel and assets; b. The scope of the physical security program as it applies to all the organizational staff and third-party contractors; c. The roles, responsibilities and management accountability structure of the physical security program to ensure compliance with the organization's security policy and other regulatory commitments. 2. Formal, documented procedures to facilitate the implementation of the physical and environmental protection policy and associated physical and environmental protection

	controls.
AAY.17	The organization shall develop, disseminate, and periodically review and update: 1. A formal, documented, planning policy that addresses: a. The purpose of the strategic planning program as it relates to protecting the organization’s personnel and assets; b. The scope of the strategic planning program as it applies to all the organizational staff and third-party contractors; c. The roles, responsibilities, and management accountability structure of the strategic planning program to ensure compliance with the organization’s security policy and other regulatory commitments. 2. Formal, documented procedures to facilitate the implementation of the strategic planning policy and associated strategic planning controls.
AAY.18	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, monitoring and reviewing control system security management policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; 2. Formal, documented procedures to facilitate the implementation of the monitoring and reviewing control system security management policy and associated audit and accountability controls.
AAY.19	Baseline practices that the organization employs for organizational security shall include, but are not limited to: 1. Executive management accountability for the security program; 2. Responsibility for control system security within the organization includes sufficient authority and an appropriate level of funding to implement the organization’s security policy; 3. The organization’s security policies and procedures that provide clear direction, accountability, and oversight for the organization’s security team. The security team assigns roles and responsibilities in accordance with the organization’s policies and confirms that processes are in place to protect company assets and critical information; 4. The organization’s contracts with external entities that address the organization’s security policies and procedures with business partners, third-party contractors, and outsourcing partners; 5. The organization’s security policies and procedures ensure coordination or integration with the organization’s physical security plan. Organization roles and responsibilities are established that address the overlap and synergy between physical and control system security risks.

3.3.5. Access Control (AAC)

"The focus of access control is ensuring that resources are only accessed by the appropriate personnel and that personnel are correctly identified. The first step in access control is creating access control lists with access privileges for personnel. The next step is to implement security mechanisms to enforce the access control lists. Mechanisms also need to be put into place to monitor access activities for inappropriate activity. The access control lists need to be managed through adding, altering, and removing access rights as necessary.

Identification and authentication is the process of verifying the identity of a user, process, or device, as a prerequisite for granting access to resources in a control system. Identification could be a password, a token, or a fingerprint. Authentication is the challenge process to prove (validate) the identification provided. An example would be using a fingerprint (identification) to access a computer via a biometric device (authentication). The biometric device authenticates the identity of the fingerprint." [DHS]

AAC.1	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, access control policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; 2. Formal, documented procedures to facilitate the implementation of the access control policy and associated access controls.
AAC.2	The organization shall supervise and review the activities of users with respect to the enforcement and usage of control system access control.
AAC.3	The security function shall enforce the [assignment: access control security function policy] on [assignment: list of subjects, objects, and operations among subjects and objects covered by the security function policy].
AAC.4	The security function shall enforce the [assignment: access control security function policy] on [assignment: list of subjects and objects] and all operations among subjects and objects covered by the security function policy.
AAC.5	The security function shall ensure that all operations between any subject controlled by the security function and any object controlled by the security functionare covered by an access control security function policy.
AAC.6	The security function shall enforce the [assignment: access control security function policy] to objects based on the following: [assignment: list of subjects and objects controlled under the indicated security function policy, and for each, the security function policy-relevant security attributes, or named groups of security function policy-relevant security attributes].
AAC.7	The security function shall enforce the [assignment: access control security function policy(s) and/or information flow control security function policy(s)] when exporting user data, controlled under the security function policy(s), outside of the module.
AAC.8	The organization shall develop, disseminate, and periodically review/update: 1. A formal, documented, access control policy that addresses purpose, scope, roles, responsibilities, management commitment, coordination among organizational entities, and compliance; and 2. Formal, documented procedures to facilitate the implementation of the access control policy and associated access controls.
AAC.9	The organization shall supervise and review the activities of users with respect to the enforcement and usage of information system access controls.
AAC.10	The security function shall enforce the [assignment: access control security function policy(s), information flow control security function policy(s)] to restrict the ability to [selection: change_default, query, modify, delete, [assignment: other operations]] the security attributes [assignment: list of security attributes] to [assignment: the authorized identified roles].
AAC.11	The security function shall enforce the [assignment: access control security function policy, information flow control security function policy] to provide [selection, choose one of: restrictive, permissive, [assignment: other property]] default values for security attributes that are used to enforce the security function policy.
AAC.12	The organization shall review logical and physical access permissions to control systems and facilities when individuals are reassigned or transferred to other positions within the organization and initiates appropriate actions. Complete execution of this control occurs within [Assignment: time period (e.g., 7 days)] for employees or contractors who no longer need to access control system resources.
AAC.13	The organization shall supervise and review the activities of users with respect to the enforcement and usage of system access control.

Appendix A: Architectural Description

This appendix contains information that is non-formative to the architecture of AMI security, but provides useful background and understanding.

A.1. Scope

Advanced Metering Infrastructure (AMI) Security Architecture as defined by the AMI-SEC taskforce is:

The communications hardware and software and associated system and data management software that creates a network between advanced meters and utility business systems and which allows collection and distribution of information to customers and other parties such as competitive retail providers, in addition to providing it to the utility itself. AMI is further defined as: 1) The hardware and software residing in, on, or closest to the customer premise for which the utility or its legal proxies are primarily responsible for proper operation; and 2) The hardware and software owned and operated by the utility or its legal proxies which has as its primary purpose the facilitation of Advanced Metering.

The goal of this document is to describe the abstract (logical, platform-agnostic) mitigation plan for addressing requirements identified in the Risk Assessment / System Requirements Document.

The following approach has been taken in designing the system:

Approach

- Architectural Representation of Security Systems
- Logical Function Descriptions
- System, Subsystem, and Function Boundaries
- Reference: IEEE 1471-2000

This document is intended to focus on security architecture, and is not intended to cover enterprise level AMI architecture, except to describe a security concept. The objective of architecting is to decompose the system into its primary views in order to describe the system enough to complete the mission of AMI security. The architecture does not extend beyond the external visible properties of the elements of the system. That is, non-visible properties are left to the designers, implementers and integrators of the system.

The following image represents the 10,000 foot view of AMI. This document begins by explaining the interactions between external actors and the AMI system (see section 3.1). The next view zooms in on the AMI system by describing the system with a decomposition view (section 3.2). Each iteration provides deeper granularity and traceability between views.

AMI-SEC is developing other relevant documentation in parallel that supports the Architectural Description (AD) including the AMI Risk Analysis and System Security Requirements (SSR) documents. The Risk Analysis walks the utility through a method of determining a risk-to-value of an asset. Assets in terms of these documents are considered to be the business level value streams to the utility. The appendix of the AMI Risk Analysis includes catalogues for assets, vulnerabilities, and threats. The SSR document includes AMI-SEC's approach to conducting a requirements assessment and applying requirements. Traceability between views in the AD and requirements defined in the SSR are maintained for consistency and rationale.

This document develops security around commonly known AMI use cases selected from use cases shared by utilities to AMI-SEC. It is assumed that AMI will evolve supporting additional uses and variants, but these uses cannot be predicted. Therefore, a goal of this AD is to group use cases that possess commonality in security treatment in order to support the evolution of AMI.

A.2. Mission

The mission of the AMI Security Architecture is to provide understanding of AMI security, communication among stakeholders and serve as a basis for system analysis. It is important to understand that the task of this architecture is not to provide the groundwork to build the entire AMI system, but to secure it, which is inherently nontrivial.

The information contained in this document will provide an introduction to AMI Security to interested parties. Newcomers will find this document a starting point for understanding the elements, interfaces, and structure of AMI security.

This document will serve to provide communication among stakeholders including designers of the system, implementers, integrators, testers and operators. All architecture is design, but not all design is considered architecture. The mission in communication is to produce sufficient guidance for stakeholders so that they understand the architecture well enough to perform their role.

The architecture will also serve to provide information needed the support analysis performed for security objectives including availability, integrity, confidentiality, access control and accounting.

The architecture will cross-check with information contained in the Requirements document to provide reasoning for requirements selection.

A.3. Stakeholders & Concerns

This section describes the stakeholders and their concerns. A stakeholder is any individual or group of individuals with interests or concerns associated with the system. All actors of the system are stakeholders, but not all stakeholders are actors. For example, an investor may have a stake in the success of the AMI system, but may not interact directly with the AMI system.

Stakeholders identified to be relevant to the security architecture are:

- Customer Users of the system
- Operators of the system
- Responsible Entities of the systems
- Developers of the system
- Implementers of the system
- Maintainers of the system

Concerns that stakeholders may have from a security perspective for the entire AMI system

General Stakeholder Concerns:

- Integrity of the system
- Availability of the system

- Confidentiality of the system
- The purpose or missions of the system as pertains to security
- The appropriateness of the system for use in fulfilling its missions to security
- The feasibility of constructing the system
- The risks of system development and operation to users, acquirers, and developers of the system
- Maintainability, deploy-ability, and evolve-ability of the system

Each viewpoint defined for AMI security possesses specific concerns defined with each viewpoint under the following section.

Potential examples of AMI security concerns by stakeholders:

STAKEHOLDER	SECURITY CONCERN
Residential Customer	Privacy
Utility Operator	Integrity of information and system control
Regulators	Integrity of system and compliance with regulations
Telecom Provider	Compliance with contractual obligations and regulations

Table 10 – Stakeholder Security Concerns

A.4. Security Analysis Approach

The security analysis approach is to evaluate each view under the security principles of availability, integrity, confidentiality, access control and accountability. The high level models are in the form of Use Cases. At least one security objective is identified with each Use Case by evaluating against these security principles.

- Availability
  - Ensure the desired resource is available at the time it is needed.
  - Ensure the desired resource is accessible in the intended manner by the appropriate entity.
- Integrity
  - Ensure the desired resource contains accurate information.
  - Ensure the desired resource performs precisely as intended.
- Confidentiality
  - Ensure the desired resource is only accessible to the desired targets.
  - Ensure the desired resource is only accessible under the designated conditions.
- Access Control
  - Ensure resource access follows the designated procedure.

- Ensure access mechanisms provide sufficient management capabilities to establish, modify, and remove desired criteria.

- Accountability
  - Ensure system activities can be reconstructed, reviewed, and examined from transaction inception to output of final results.
  - Ensure system controls are provably compliant with established policy and procedures.

A.5. Architecture Description Approach

This section is an introduction to the approach of describing the AMI architecture based on IEEE 1471-2000, *IEEE Recommended Practice for Architectural Description of Software-Intensive Systems*. This section serves as a Roadmap for appendix A and provides a guide for where to locate information.

This section introduces templates and patterns that will be used in subsequent sections. Each view describes:

- What viewpoint it realizes
  - Name & definition of the viewpoint (external pointer or brief definition)
  - What stakeholders and concerns it addresses (and to what extent)
  - Language/notation to be used
- One or more models, where a model includes:
  - Context diagram (i.e., how it relates to AMI as a whole or to other models within the same view)
  - A picture or other primary presentation, always with a key or legend
  - Brief descriptions (or pointers to such) for each element and relation type in the primary presentation
  - Related models, such as scenarios related to the view
  - Known or anticipated variations (likely very important here)
  - Rationale, assumptions, or other background for the decisions depicted in the view

A.5.1. Viewpoints

IEEE 1471-2000 describes a viewpoint on a system as – "a form of abstraction achieved using a selected set of architectural constructs and structuring rules, in order to focus on particular concerns within a system. The relationship between viewpoint and view is analogous to that of a template and an instance of that template." Therefore, a viewpoint may contain:

- Specifications of each viewpoint that has been selected to organize the representation of the architecture and the rationale for those selections
- One or more architectural views

- A record of all known inconsistencies among the architectural description's required constituents
- A rationale for selection of the architecture

Each viewpoint shall be specified by:

1. A viewpoint name,
2. The stakeholders to be addressed by the viewpoint,
3. The concerns to be addressed by the viewpoint,
4. The language, modeling techniques, or analytical methods to be used in constructing a view based upon the viewpoint,
5. The source, for a library viewpoint (the source could include author, date, or reference to other documents, as determined by the using organization).

A viewpoint specification may include additional information on architectural practices associated with using the viewpoint, as follows:

- Formal or informal consistency and completeness tests to be applied to the models making up an associated view
- Evaluation or analysis techniques to be applied to the models
- Heuristics, patterns, or other guidelines to assist in synthesis of an associated view

Viewpoint specifications may be incorporated by reference (such as to a suitable recommended practice or previously defined practice). An architectural description shall include a rationale for the selection of each viewpoint. The rationale shall address the extent to which the stakeholders and concerns are covered by the viewpoints selected.

A.5.2. Views

An architectural description is organized into one or more constituents called (architectural) views. Each view addresses one or more of the concerns of the system stakeholders. The term view is used to refer to the expression of a system's architecture with respect to a particular viewpoint.

The relationship between viewpoint and view is analogous to that of a template and an instance of that template. The *viewpoint* is the template and the *view* is the instance of the template.

A.6 Contextual View

The primary goal of this view is to identify the external points of interaction (physical and logical/data) between AMI and anything outside of AMI. Once these points of interaction are defined, security architecture is developed to address the concerns of the stakeholders involved. Use cases are used to model customer, third party and utility interactions with AMI in sections 2.1.2, 2.1.3 and 2.1.4.
Elaborations of the interactions in this view are unlikely to be complete; they should however provide representative examples of –

- Use cases of the outside world interacting with (stimulating) AMI
- Use cases of AMI interacting with (stimulating) the outside world
- Misuse or abuse cases in either direction; that is, specific uses that should be prevented
- Any actor sub-categories where the actor uses the system in a fashion that implies security needs that differ from major actors (e.g., leading to identification of access domains/privilege levels)
- Physical interactions (e.g., installing a meter or physical access to assets like collectors)
- Logical interactions (e.g., user monitors or modifies settings with the utility via web browser or utility initiates a demand-response interaction with a residence)

Elements of the view are the AMI system (as a black box), human actors, and connected systems. Relations of the view are vague - "interacts with", with elaboration in the prose.

A.7 Top Level Model

The top level model represents a high level view of the external stakeholders that interact with the AMI system. This model is used to provide an understanding of security concerns of interaction with AMI for these stakeholders.

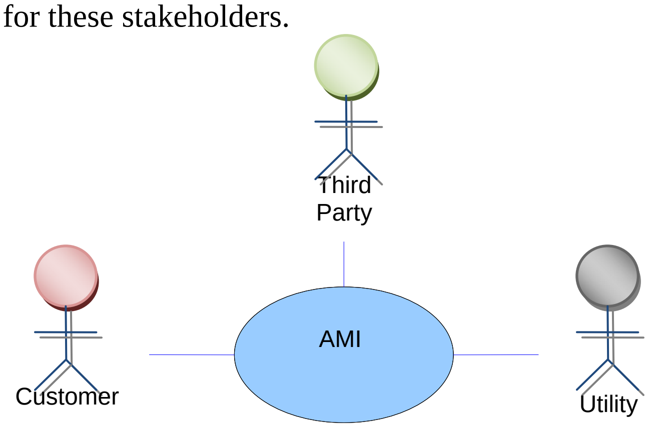

Figure 4 – AMI Top Level Model

General security interaction needs:

- Customers are the consumers of AMI services and have a primary desire of availability and privacy from AMI and service value.
- Third Parties manage AMI resources with delegated authority from the Customer or Utility through an established trust relationship.
- Utilities provide AMI services and primary desire reliably gather information from the Customer to support the availability, resiliency and survivability of the electric grid.

Constraints:

- Bandwidth – current technologies have limited bandwidth for providing security services (examples: encryption, network management services).

- Latency – the time between when data is requested or generated and the time it is received. In many cases, data is only useful if received within a specific window of time.
- Storage – devices that store information either persistently or stage data temporarily are limited in the amount of data they are capable of storing at any given time.
- Processing – the rate at which a device can process information. It is important to keep in mind cryptographic functions require additional processing horsepower above normal processor usage.

A.7.1. Customer Model

The customer model focuses on the interactions between a customer and the AMI system. Customers may include sub-actors such as:

- Residential Customer (Private home owners)
- Commercial Customer (Office buildings, Apartment Complexes)
- Industrial Customer (Manufacturing plants)
- Municipalities Customer (Street lights, traffic lights, subways)

Sub-actors may be considered in the instance that there is different security treatment applied based on the role a sub-actor plays. If the security treatment of all sub-actors is the same or similar then the group is treated as a whole. The differentiating properties are identified in the cases where sub-actors only differ slightly in the treatment of security. The following diagram represents the relationship between the customer and AMI system where the customer may perform a stimulus on the AMI system or vice versa.

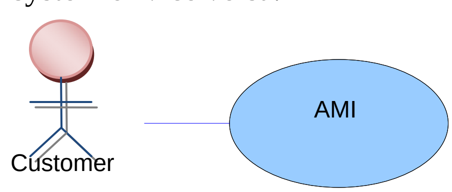

Figure 5 - Customer Model

The following use cases are used to define the relationship between the customer and AMI:

Customer reduces their usage in response to pricing or voluntary load reduction event:

- The utility can notify customers through the AMI system that demand reduction is requested for the purposes of either improving grid reliability, performing economic dispatch (energy trading), or deferring buying energy.

  There are two levels of advanced warning which are envisioned for AMI demand response systems as outlined in Distribution Use Case 2. The first being predicted energy shortages—a few hours notice in advanced—and the emergency shortages—minute to sub-minute notices.

  Security Objective:

  - Prevent false warnings from reaching the customer.

- Ensure that only people and/or systems that are authorized by the utility can send warnings to the customer
- Ensure that the system is resilient to periods of over-subscribed network utilization, especially in the case of emergency shortages.

- **Customer has access to recent energy usage and cost at their site:**
- Customers can view a variety of information being gathered by their meter, permitting them to make energy-efficient choices and to shift demand to off-peak periods. Customers may access this information through a variety methods.

  Security Objective:

  - Protect the variety of methods of access from unauthorized access by unauthorized persons outside of the site.
  - Protect the confidentiality of the usage and data associated with a particular customer or site.
  - Protect the devices that communicate the usage and cost data from tampering.
  - Validate that the communication of the usage and cost data is in a manner that is consistent with the utilities intent. For example, display only “need to know” data; ensure that all displayed data is consistent with respect to reality.

Customer prepays for electric services:

- Customers of the AMI system can prepay their accounts and read their current balance. Pre-pay may be done through the internet, phone, or other method.

  Security Objective:

  - Compliance with PCI or other applicable standard is required by utilities or financial entities
  - Ensure that the AMI system and/or payment devices are resistant to payment fraud of many types
  - Ensure that payment data confidentiality is maintained

External clients use the AMI system to interact with devices at customer site:

- The Advanced Meter Infrastructure (AMI) will enable third parties, such as energy management companies, to use the communication infrastructure as a gateway to monitor and control customer equipment located at the customer’s premise. The AMI will be required to enable on-demand requests and support a secure environment for the transmission of customer confidential information.

  Security Objective:

  - Ensure that all third-parties agree to some standard of data confidentiality agreement.
  - Ensure that all third-parties agree to some standard of granting access to systems which allow access to monitor and control customer equipment at the premise.

- Ensure that all communications that result in an action with equipment at a customer premise is authorized, authenticated, non-repudiated, logged.
- Ensure that the communication path to a customer premise that allows control of equipment is secured and tamper proof.
- Ensure that customers are required to agree to specific third-party access to their premise gateway.

A.7.2. Third Party Model

The third party model represents the interaction between third parties and the AMI system. Third parties include utility contracted organizations such as a telecom provider, other utility, etc. Third parties may also include organizations that have established contracts with the customer for managing their premise devices within the home area network, for example an energy management system.

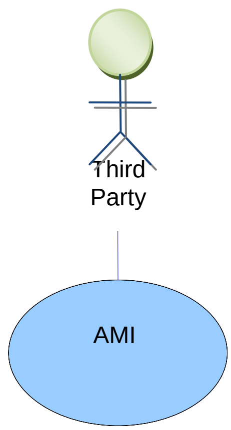

Figure 6 - Third Party Model

The following are use cases describing the relationships between potential third parties and the AMI system.

Multiple Clients Read Demand and Energy Data Automatically from Customer Premises:

- The AMI system can be used to permit gas and water utilities, contract meter readers, aggregators and other third parties to read electrical meters, read gas and water meters, or control third-party equipment on customer premises.

  Security Objective:

  - To protect customer information. Customer grants the right to what information is disseminated and to whom.
  - To maintain integrity of meter data. Meter data should be protected from manipulation or deletion.
  - To establish timely availability of the meter data to the clients for direct scheduled and non-scheduled reads.

A.7.3. Utility Model

The utility model describes interactions between the Utility stakeholder and the AMI system in order to describe the security treatments that need to be applied.

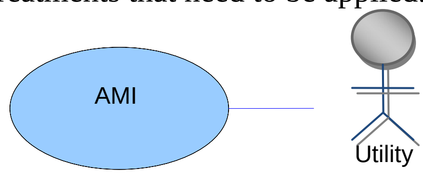

Figure 7 - Utility Model

Utility stakeholder security concerns about AMI:

- Loss of competitive advantage
- Loss of billing integrity
- Service degraded
- Increased cost
- Regulatory compliance

The following are use cases describing the relationships between the Utility and AMI.

Remote Meter Reads

- The AMI system permits the utility to remotely read meter data in intervals so that customers may be billed on their time of use, and demand can therefore be shifted from peak periods to off-peak periods, improving energy efficiency.

  Security Objective:

  - To maintain privacy of customer information in transit and within temporary and permanent memory storage.
  - To protect meter data from manipulation or deletion.
  - To provide timely availability of meter data.

Remote Connect / Disconnect

- The AMI system permits customers' electrical service to be remotely connected or disconnected for a variety of reasons, eliminating the need for utility personnel to visit the customer premises.

  Security Objective:

  - To protect integrity of connect/disconnect control messages; avoiding fake messages, fake senders, unintended receivers, manipulated messages
  - To establish a secure connection in transporting connect/disconnect control messages
  - To establish timely connectivity to connect/disconnect service

- It should also provide an efficient way in which to initiate/terminate a service agreement between customer and utility via remote switching service(on/off)

  Security Objective:

  - To establish timely connectivity to connect/disconnect service

- Posses the ability to remotely limit customer usage as a response to constrained supply as well as the customer's inability to pay the cost for the service

  Security Objective:

  - To protect integrity of connect/disconnect/limit control messages; avoiding fake messages, fake senders, unintended receivers, manipulated messages
  - To establish a secure connection in transporting connect/disconnect/limit control messages

- In addition to the aforementioned the following business transactions should also be made available to the customer and utility:
  - Routine shut-off of service (move out)
  - Routine turn-on of service (move in)
  - Credit & Collections termination of service
  - Local/on site shut-off of service
  - Local/on site turn-on of service
  - Credit and Collection Service Limiting

  Security Objective:

  - To establish timely connectivity to connect/disconnect/limit service
  - To produce historical, non-reputable record of event

Energy Theft

- The AMI system can be used to report when customers are stealing energy or tampering with their meter.

  Security Objective:

  - To produce reliable tamper indication
  - To successfully transmit and receive a tamper signal
  - To securely transmit tamper signal from a non-reputable source

Outage Management

- The AMI system can be used to report outages with greater precision than other sources, or verify outage reports from other sources.

  Security Objective:

Power Quality Analysis

- The AMI system can be used to analyze the quality of electrical power by reporting harmonic data, RMS variations, Voltage and VARs, and can communicate directly with distribution automation networks to improve power quality and fault recovery times.

  Security Objective:

  - To maintain integrity of meter data sent; avoid manipulation and deletion
  - To security meter data being transmitted; avoid customer's private data being released or intercepted
  - To maintain availability of quality analysis information

Distributed Generation Management

- The AMI system can be used to dispatch, measure, regulate and detect distributed generation by customers.

  Security Objective:

  - To maintain integrity of AMI data being transmitted and stored to avoid manipulation and deletion
  - To provide timely availability to system data

- Additional benefits include, but are not limited, to the following:
  - An increase in customer's willingness to participate in a load management program with the utilities
  - Provides a channel of communication from utility to load management devices
  - Reduction in the costs associated with the installation of AMI system components which would enable customer-provided distributed generation (this could increase customer's willingness to participate as well since there wouldn't be any out of pocket costs for the customer)
  - Creates an avenue for the utilities to dispatch and monitor those participants in distributed generation

  Security Objective:

  - To protect confidentiality of customer's data and maintain customer trust

Optimizing Lifetime of Network

- With the advent of new communications, in particular: wireless communication systems, PLC, and BPL, AMI devices would have the ability to interact with the critical physical infrastructure (e.g. IED's such as CBC (Capacitor Bank Controller) systems in order to improve: circuit efficiency, loss reduction, and energy savings). This will help optimize the lifetime of the physical infrastructure. (Ref: Distribution Use Case 2)

  Security Objective:

  - To protect integrity of data stored and in transit between AMI/Smart Grid devices

- To provide AMI/Smart Grid device information in a timely manner
- To protect AMI/Smart Grid communications from manipulation, deletion and interception

Management of the End-to-End Lifecycle of the Metering System

- An important requirement of such an AMI system would be the ability of the system to diagnose itself. The system should be able to: collect information about the status/health of certain devices, conduct remote diagnostics, and optimize operating parameters remotely.

  Security Objective:

  - To protect diagnostic data from being manipulated, deleted or masqueraded
  - To validate the authenticity of the diagnostic messages being transmitted
  - To provide timely availability to diagnostic data
  - To secure diagnostic data from eavesdropping or capture

AMI system adaptability

- The system should be able to adapt to anticipated changes that may or may not occur such as:
  - New physical communications methods
  - New features available from equipment vendors
  - New tariffs possibly with certain restrictions (e.g. number of rates or time)
  - Connections to new types of load control equipment
  - New communications protocols
  - Changes to operating parameters
  - New computing applications

Security Objective:

- The aforementioned should be accomplishable with minimal incremental cost in stark contrast to a wholesale system replacement

  Security Objective:

  - Objectives to be determined and prioritized based on technology implemented

Prepay

- Utilities use the AMI system to enforce disconnection when the prepayment balance reaches zero.

  Security Objective:

- To provide confidentiality to customer payment and associated information; avoid eavesdropping, interception or collection of customer data stored (temporary or permanent) or in transit
- To provide integrity of data being transmitted including non-repudiation and validation of customer information transmitted
- To provide the customer availability to their respective account(s) within customer payment services

A.8 Security Domains View

This section describes the internal use cases; cases where activity is stimulated from entirely within AMI itself. Examples are automation and intelligent responses. The following diagram describes the internal services provided by AMI. Assumption is made that measurement, monitoring, and application control encompass all services.

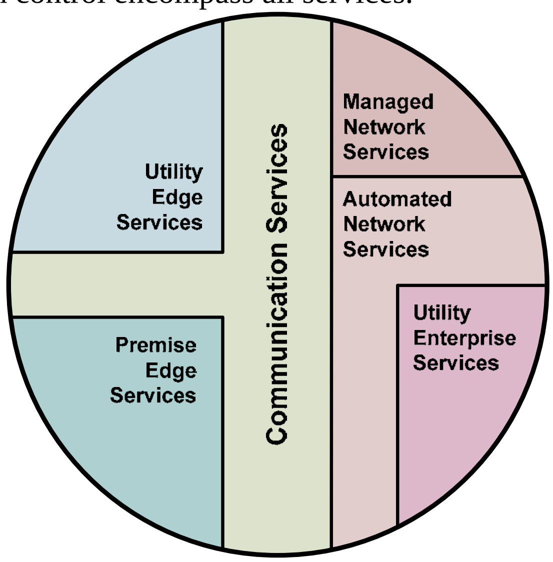

Figure 8 - AMI Service Domains

Legend:

- **Utility Edge Services** – All field services applications including monitoring, measurement and control controlled by the Utility
- **Premise Edge Services** – All field services applications including monitoring, measurement and control controlled by the Customer (Customer has control to delegate to third party)
- **Communications Services** – are applications that relay, route, and field aggregation, field communication aggregation, field communication distribution information.
- **Management Services** – attended support services for automated and communication services (includes device management)
- **Automated Services** – unattended collection, transmission of data and performs the necessary translation, transformation, response, and data staging
- **Business Services** – core business applications (includes asset management)

Stakeholders:

- Customer Users of the system
- Operators of the system
- Responsible Entities of the systems
- Implementers of the system
- Maintainers of the system

Concerns:

How is integrity maintained for processes?
How is integrity maintained for data?
How is confidentiality of customer data maintained (e.g. customer usage)?
How is availability to utility assets maintained?

Viewpoint language:

Use Cases (Misuse Cases)
Note: Potentially move down from business functions.

Analytic Methods:

Penetration Testing
Auditing

Rationale:

This viewpoint was selected because it shows the relationship between AMI services requiring security measures. Drivers for this viewpoint include control, ownership, environmental, and functionality (capability) concerns.

A.8.1. Utility Edge Services Domain

Summary

The Utility Edge Services Domain allows the utility to interact with non-customer-owned edge assets, such a meter (electric, gas, or water) or other end-point device.

Assumptions

The Utility Edge Services Domain assumes a singular service endpoint (point of service).

Ownership and Control Concerns

The utility owns at least some of the assets within the Utility Edge Services Domain. Any asset not owned by the utility in question is owned by a peer entity, such as another utility.

The utility controls all assets within the Utility Edge Services Domain. Assets owned by another entity are controlled by the utility as a proxy for the owner.

A.8.2 Premise Edge Services Domain

Summary

The Premise Edge Services Domain allows the utility to interact with customer-owned edge assets, such as Home Area Network (HAN) devices.

Assumptions

The Premise Edge Services Domain assumes a singular customer.

Ownership and Control Concerns

The utility may own the assets within the Premise Edge Services Domain. Alternatively, assets in the Premise Edge Services Domain may be owned by the Customer or a Third Party Service Provider.

The utility controls all assets within the Premise Edge Services Domain. Control of assets owned by another entity is delegated to the utility as part of admission to the Premise Edge Services Domain.

A.8.3. Communication Services Domain

Summary

The Communication Services Domain facilitates communication between assets in adjacent service domains (Utility Edge, Premise Edge, Managed Network, and Automated Network) and may facilitate communication between assets within the same domain.

Assumptions

The Communication Services Domain assumes interfaces to multiple Utility Edge and Premise Edge Services Domains, and may include interfaces to multiple Managed Network and Automated Network Services Domains.

Ownership and Control Concerns

The utility may own the assets within the Communication Services Domain. Alternatively, assets in the Communication Services Domain may be owned by a Communication Services Provider.

The utility may control assets within the Communication Services Domain. Alternatively, assets in the Communication Services Domain may be controlled by a Communication Services Provider. Assets controlled by a Communication Services Provider may be included in a contractual services agreement with the utility.

A.8.4. Managed Network Services Domain

Summary

The Managed Network Services Domain allows the utility to manage communication configuration, settings, capabilities, and resources in each of the other service domains.

Assumptions

The utility primarily uses assets in the Managed Network Services Domain to manipulate configurations and settings in the Automated Network Services Domain (i.e., human interface).

Ownership and Control Concerns

The utility may own the assets within the Managed Network Services Domain. Alternatively, assets in the Managed Network Services Domain may be owned by a Communication Services Provider.

The utility controls all assets within the Managed Network Services Domain. Control of assets owned by another entity is delegated to the utility as part of admission to the Managed Network Services Domain.

A.8.5. Automated Network Services Domain

Summary

The Automated Network Services Domain allows the utility to implement the communication parameters specified using assets in the Managed Network Services Domain.

Assumptions

The utility primarily uses assets in the Automated Network Services Domain to perform routine and/or repetitive operations at high speed without manual intervention.

Ownership and Control Concerns

The utility may own the assets within the Automated Network Services Domain. Alternatively, assets in the Automated Network Services Domain may be owned by a Communication Services Provider.

The utility controls all assets within the Automated Network Services Domain. Control of assets owned by another entity is delegated to the utility as part of admission to the Automated Network Services Domain.

A.8.6. Utility Enterprise Services Domain

Summary

The Utility Enterprise Services Domain allows the utility to perform the business functions required by enterprise applications.

Assumptions

The assets in the Utility Enterprise Services Domain provide the interface to AMI systems and data for the remainder of the enterprise.

Ownership and Control Concerns

The utility owns all assets within the Utility Enterprise Services Domain.

The utility controls all assets within the Utility Enterprise Services Domain.

Appendix B – Supplemental Material: Business Functions as Stakeholders in AMI Systems

B.1 Introduction

The information provided in this appendix provides supplemental background material for understanding potential business functions within AMI systems. Some of the business functions provide a forward-looking perspective into AMI systems. This information may be used in the development of a utility's specific use cases, but the information in this section is not intended to be regarded as security requirements for AMI.

B.1.2 Scope of AMI Systems

As Smart Grid requirements drive the development new technologies and the deployment of new systems, more and more new and existing Business Functions are becoming stakeholders in these new systems. Advanced Metering Infrastructure (AMI) systems are prime examples of these new technologies: they clearly can provide Smart Grid benefits. However, AMI systems are still a work in process, which can clearly benefit some business functions, but which appear potentially useful for others while not yet obviously beneficial. In addition, there will inevitably be business functions which are not yet foreseen that will suddenly become viable.

AMI systems consist of the hardware, software and associated system and data management applications that create a communications network between end systems at customer premises (including meters, gateways, and other equipment) and diverse business and operational systems of utilities and third parties. AMI systems provide the technology to allow the exchange of information between customer end systems and those other utility and third party systems. In order to protect this critical infrastructure, end-to-end security must be provided across the AMI systems, encompassing the customer end systems as well as the utility and third party systems which are interfaced to the AMI systems (see Figure 1).

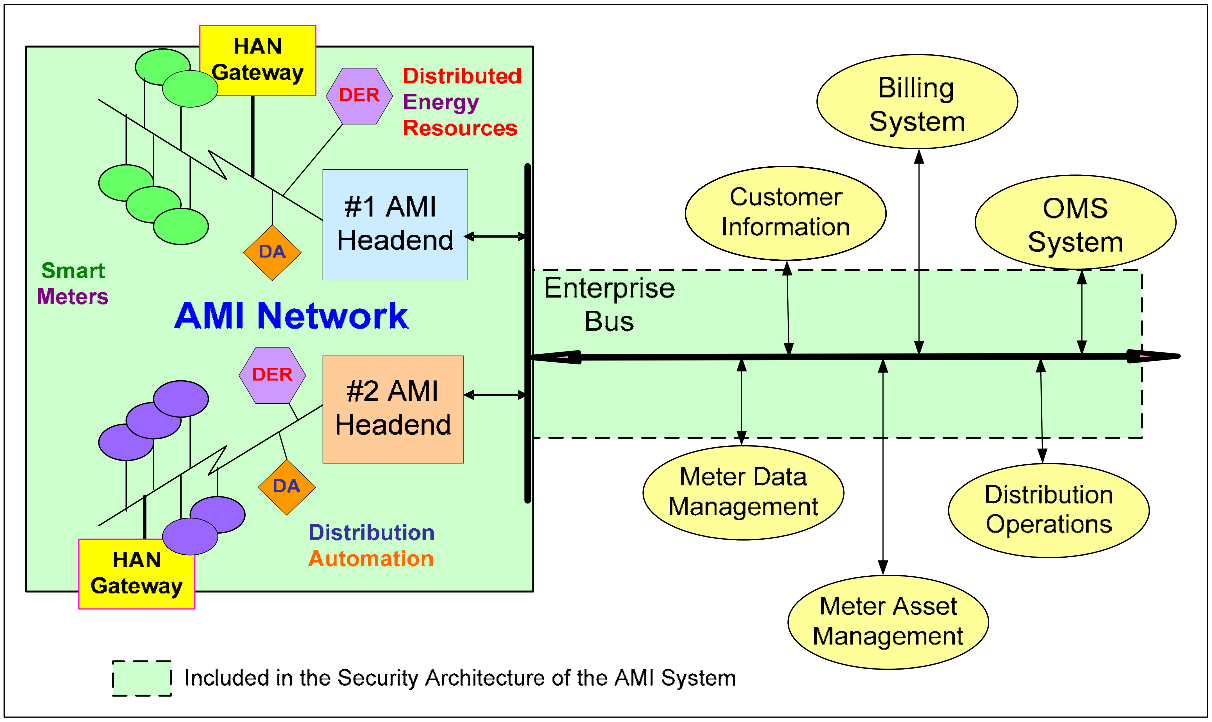

Figure 9 - Scope of AMI Systems

B.2 Overview of Business Functions Utilizing AMI Systems

Identifying and describing Business Functions are the most effective methods for understanding the information exchange requirements. The range of Business Functions utilizing the AMI systems is shown in Figure 2.

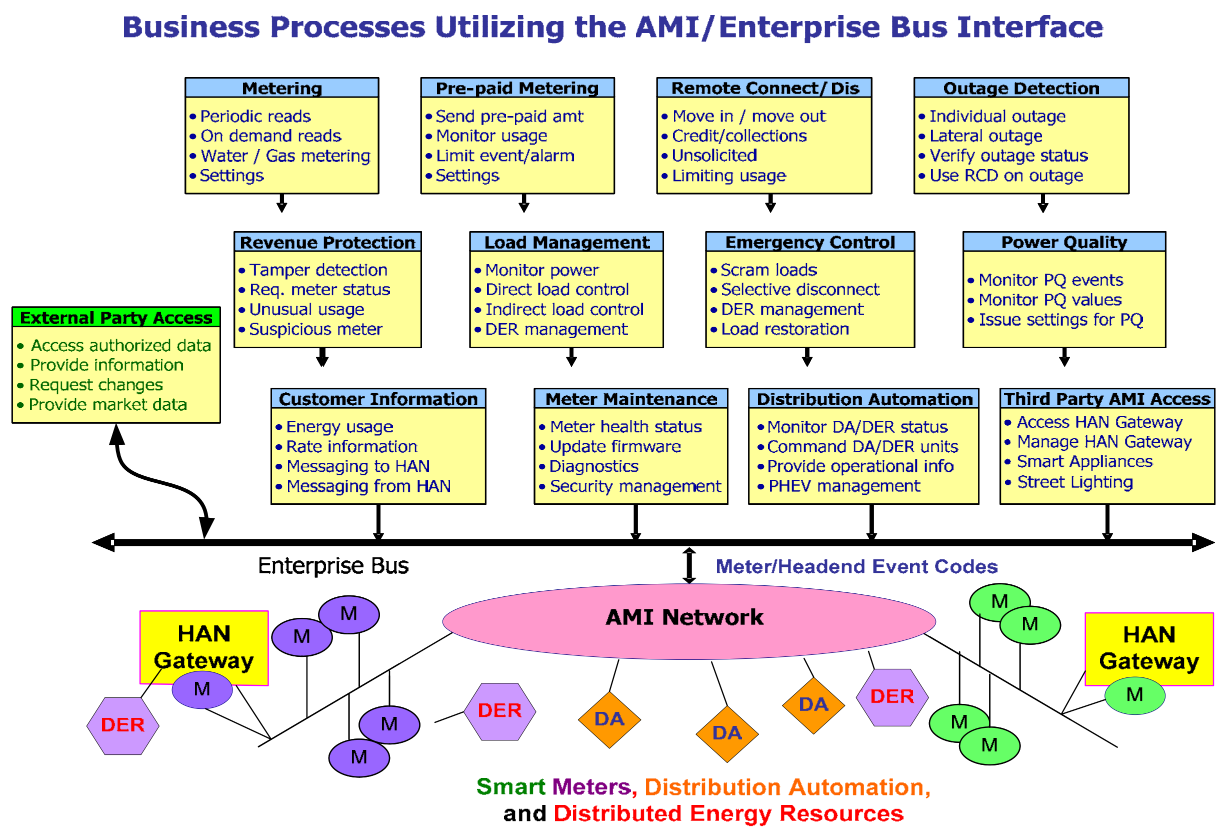

Figure 10 - Business Functions Utilizing the AMI/Enterprise Bus Interface

The following sections expand on these Business Functions.

B.3 AMI Metering Business Functions

B.3.1 Metering Services

Metering services provide the basic meter reading capabilities for generating customer bills. Different types of metering services are usually provided, depending upon the type of customer (residential, smaller commercial, larger commercial, smaller industrial, larger industrial) and upon the applicable customer tariff.

B.3.1.1 Periodic Meter Reading

Traditionally for residential customers and the smaller C&I customers, periodic meter reading services are performed monthly via a meter reader, possibly using handheld or mobile meter reading tools. It takes the current index reading from the meter and records it for billing and other purposes. For Time-of-Use (TOU) data from net metering or other TOU meters, intervals can be established such as “on-peak” and “off-peak”, as defined in the utility’s tariffs. In some utilities or under certain circumstances, actual meter reading is done less frequently, and bills rely on meter reading estimates which are “trued up” later.

In AMI systems, periodic meter reading will retrieve interval data (usually hourly data but possibly 15-minute or 5-minute data). The frequency of retrieving the data from the meter can vary from every 5 minutes, to hourly, to daily, and to monthly.

Among the benefits of AMI for periodic meter readings are the increased accuracy (fewer estimated reads, more exact reading dates/times), and the availability of the to-date meter readings during the billing cycle.

B.3.1.2 On-Demand Meter Reading

Traditionally, on-demand meter reading is performed by sending a meter reader to the meter site around the time requested for the meter reading. Typically reasons for on-demand meter readings include:

- Move in / move out
- Limited usage tariffs
- Billing questions by the customer
- Revenue protection concerns

AMI systems will permit on-demand reads to take place almost immediately or more precisely at the scheduled date and time.

B.3.1.3 Net Metering for DER

When customers have the ability to generate or store power as well as consume power, net metering is installed to measure not only the flow of power in each direction, but also when the net power flows occurred. Often Time of Use (TOU) tariffs are employed.

Today larger C&I customers and an increasing number of residential and smaller C&I customers have net metering installed for their photovoltaic systems, wind turbines, combined heat and power (CHP), and other DER devices. As plug-in hybrid electric vehicles (PHEVs) become available, net metering will increasingly be implemented in homes and small businesses, even parking lots.

AMI systems can facilitate the management of net metering, particularly if pricing becomes more dynamic and/or more fine-grained than currently used for TOU rates.

B.3.1.4 Bill - Paycheck Matching

Today, depending on the utility bills arrive monthly, quarterly or yearly and not on a schedule selected by the customer, rather they are based on a schedule that matches the meter reading schedules. Small scale trials have proven that for customers who are living on the margin and miss occasional payments, that matching the date and frequency of the customer's paycheck reduces the number of late or missing payments significantly, cutting collection costs and reducing the cost to all customers.

AMI systems provide the flexibility to provide customers with bills when the customers prefer to receive them.

B.3.2 Pre-Paid Metering

B.3.2.1 Prepayment Tariffs

Customers who either want a lower rate or have a history of slow payment can benefit from prepayment of power. Smart metering makes it easier to deploy new types of prepayment to customers and provide them with better visibility on the remaining hours of power, as well as extending time of use rates to prepayment customers.

AMI systems can also trigger notifications when the pre-payment limits are close to being reached and/or have been exceeded.

B.3.2.2 Limited Energy Usage

Traditionally, customers who use pre-payment tariffs need to go through the utility customer representatives to learn about their current usage or to extend their energy limits. With AMI systems, customers can see their current usage and limits, and may be able to automatically extend their limits electronically (e.g. pay over the Internet with the AMI system then updating their energy limits).

B.3.2.3 Limited Demand

Customers can also have tariffs that limit demand. Some C&I customers have rates that depended on the peak 15-minute demand. Some other customers actually have current limiting equipment to ensure limited demand.

AMI systems can provide the customer with the information necessary to manage their demand limits more precisely and effectively.

B.3.3 Revenue Protection

B.3.3.1 Tamper Detection

Non-technical losses (or theft of power by another name) has long been an on-going battle between utilities and certain customers. In a traditional meter, when the meter reader arrives, they can look for visual signs of tampering, such as broken seals and meters plugged in upside down. During the analysis of the data, tampering that is not visually obvious may be detected, such as anomalous low usage.

With AMI systems, smart meters can immediately issue “tampering” alarms that are set off by a number of different sensors and routines in the meter. These tampering actions can include meter removal, tilt, and unauthorized access attempts (smart meters cannot be plugged in upside down).

B.3.3.2 Anomalous Readings

Some anomalous readings in the meter can trigger warning events which can be immediately investigated to determine if they are legitimate (people are on vacation or the factory has shut down an assembly line) or if they are due to tampering, such as wiring around the meter.

B.3.3.3 Meter Status

Some theft of power has occurred by the bypassing of the meter for a few days between scheduled readings by a meter reader. AMI systems will permit the status of meters to be verified at any time during the reading cycle.

B.3.3.4 Suspicious Meter

Some theft of power has occurred by the replacement of a certified meter with a “slow run” meter. AMI systems with smart meters will have each meter “registered” with an identity that cannot be tampered with without showing evidence of that tampering.

B.3.4 Remote Connect / Disconnect

B.3.4.1 Remote Connect for Move-In

The customer initiates a request to move into a location that has electric service but is currently disconnected at the meter. The request can be for immediate action or for a connection at a specific date and time.

Traditionally, utilities send a metering service person to connect the meter. With an AMI system, the connection can be performed remotely by closing the remote connect/disconnect (RCD) switch, using the following steps:

- At the appropriate date and time, read the meter to get the latest reading and to verify that the meter is functional.
- Determine there is no backfeed current detected by the meter
- Issue the connect command to the meter
- Verify that the meter is connected

B.3.4.2 Remote Connect for Reinstatement on Payment

Once a customer pays who was disconnected due to non-payment (or works out some mutually accepted agreements), the meter needs to be reconnected by closing the remote connect/disconnect (RCD) switch. The same process as for a move-in would be used.

B.3.4.3 Remote Disconnect for Move-Out

Traditionally, move-outs are handled by performing a special meter read (“soft” disconnect) around the time of the move-out. Since the power is not actually disconnected, this method can lead to illegal use of power after the move-out and before the next move-in.

With an AMI system, a move-out can have a “hard” disconnect that opens the RCD switch, typically using the following steps:

- Verify that the meter can be disconnected remotely
- Issue the disconnect command at the appropriate date and time
- Verify that the meter is disconnected
- Read the meter for the final billing.

In conjunction with the next meter reading during a move-in connection, any delta between the readings can be detected as a possible tampering or illegal usage of power.

B.3.4.4 Remote Disconnect for Non-Payment

The cost of collections is high, typically higher yet is the cost of disconnecting a customer – not only the lost revenue, but the cost of two special trips to the location, one to turn the power off and eventually another to turn it back on again. While remote disconnects are still pricy today, they offer a much lower cost for turning the power off and once customers understand that a disconnect can be done immediately, collections costs also seem to decline.

B.3.4.5 Remote Disconnect for Emergency Load Control

Some customers could get special rates if they agree to the temporary suspension of electric service in support emergency load shed activities. This is an alternative to wide-scale rolling blackouts and circuit level interruptions. Customers who choose to participate in such a program are eligible to have their power cut during the critical periods.

This type of selective black-out provides the means for reducing power demands on the overall grid while selectively maintaining service to critical customers such as public infrastructure (i.e. traffic lights) and medical facilities.

B.3.4.6 Unsolicited Connect / Disconnect Event

Unsolicited connect/disconnect events can be caused by a number of activities, covered in the following Business Functions:

- Meter manually switched off by utility employee, including both valid and invalid switching
- Meter manually switched off by unknown party, including both valid and invalid switching
- Software/hardware failure switches meter off/on (also includes unauthorized command causing switch)
- Miscellaneous event causes meter to switch off/on
- Meter manually switched on by utility employee, including both valid and invalid switching
- Meter manually switched on by unknown party, including both valid and invalid switching

B.3.5 Meter Maintenance

B.3.5.1 Connectivity Validation

Determination that the customer is connected to the grid and even with the right signally which phase and circuit they are on. In several reviews of customer connectivity today for utilities the phase information is missing from many single phase connections and in some cases the circuit information is missing or wrong. Validation helps with making sure the data analysis is correct for engineering studies and other purposes.

B.3.5.2 Geo-Location

In asset data bases today many meters are literally miles (kilometers) from their physical location in the real world. During the installation of the meters GPS or other geo-location techniques can be used to provide accurate information on the meter’s location. If the location of the meter accidently is changed in the database it is possible to flag the problem. This is possible since the location of the circuit is known, helping to eliminate problems that creep in over the long life of electric (gas and water) networks.

B.3.5.3 Battery Management

If there were no smart meters, there would be no need to do battery management, so the benefit only works for smart meter equipped networks. In an operational world the meters communicate more, running the battery down faster. It is important to have good battery management or the cost of maintaining the system will skyrocket. Remote battery monitoring (as part of the regular communications) can help deal with battery replacement planning and battery life extension.

B.4 Distribution Operations Business Functions

B.4.1 Distribution Automation (DA)

B.4.1.1 DA Equipment Monitoring and Control

Some utilities are planning to use the AMI system for distribution automation, as a minimum for direct monitoring and more sophisticated control of capacitor banks and voltage regulators on feeders, rather than relying on local actions triggered by time, current, or voltage levels. Others also would like to monitor and control automated switches and fault indicators if the AMI network were able to stay alive during grid power outages, presumably via battery backup for critical nodes.

B.4.1.2 Use of Smart Meters for Power System Information

If more sensors were available in the distribution network, it would be possible to do distribution SCADA, with the deployment of smart meters and a near real-time communications network, it is possible to pick a sub-set of the smart meters and use them as bell weather devices in the grid to provide a distribution SCADA like capability. In addition some utilities are installing smart meters in place of RTUs for extending their current SCADA system further into the grid.

B.4.1.3 Power System Security/Reliability

As interference with the operation of the distribution grid becomes more common, it becomes more and more important to monitor the integrity of the grid at all times. Smart meters offer a way to get a “heart beat” from the whole of the distribution system on a regular basis thus providing assurance that the grid is intact. That it has not been attacked by a mad man in a backhoe or a copper thief with a chainsaw.

B.4.1.4 Power System Protection

Overloads on the system once were not a big issue devices could operate at two or even three times their rated capacity for several hours on a peak day. Today devices have been engineered to run at loads much closer to their ratings, and overloads of several hours can cause degradation in the devices. By being able to monitor the load on the device and with the deployment of direct load control or disconnect switches, the load on the device can be managed until it can be replaced or upgraded, the same goes for other physical assets that may be de-rated, allowing at least some of the lights to stay on.

B.4.1.5 Site/Line Status

Tag out procedures are supposed to render a segment of the network dead and safe to work on, unfortunately with the addition of true distributed generation, it is possible to have an islanding failure and to have a line that the crew expects to be ready for work, to actually still be live. With the correct smart metering system and the right connectivity mapping, it is possible to use the smart meters to determine if any power is still flowing through the lines. With the potential for the sales of plug-in hybrids to ramp up quickly in the next decade and the lack of protection schemes currently this may become an even larger issue.

B.4.1.6 Automation of Emergency Response

Today in a fire, the fire department normally handles the disconnection of the power and other utilities from the involved structures. Often with a fire axe! With the advent of remote disconnects in the meters it will be possible to cut the power to the structure, as well as gas and other utilities. This makes it easier to restore service after small problems and to more rapidly remove a possible source of problems from the structure.

B.4.1.7 Dynamic Rating of Feeders

Operators can dynamically rate feeders based on the more accurate power system information retrieved via the AMI system from strategic locations. This permits the operators to decide when they can run feeders beyond their ostensible ratings or when to perform multi-level feeder reconfigurations to balance the loads and avoid overloads.

B.4.2 Outage Detection and Restoration

B.4.2.1 Outage Detection

Today the majority of real time information about a customer, comes from the customer, they pick up the phone and call about issues they have, such as an outage, and provide information to the utility. In the future, the smart meter will be able to provide up to date information about the customer and the status of their service.

B.4.2.2 Scheduled Outage Notification

For either scheduled outages for maintenance or for notification of a customer that the power is out in their home when they are at work or away from home, smart metering provides a needed piece. For scheduled outages, if there are in home displays deployed the metering system can provide the outage times and durations to the customers directly impacted and no others. This minimizes possible security issues of the information getting into the wrong hands as security systems that require power stop functioning, etc. It also helps with the number of phone calls that have to be placed to customers to let them know that maintenance is happening. With the connectivity verification, it is possible to really know who is on a specific path and to accurately manage the outage. For unscheduled outages, it possible to use the information coming from the meters to let customers know that they will be returning to a location with no power (water, gas) and that will let them make alternate plans, rather than walking into a surprise.

B.4.2.3 Street Lighting Outage Detection

Street lighting can be critical to safety and crime-prevention, and yet monitoring which street lights are out is currently performed haphazardly by civil servants and concerned citizens. AMI systems could be used to monitor these lights.

B.4.2.4 Outage Restoration Verification

Restoration verification has the metering system report in as the power it returned to the meters. This alert function is built into many meters that are being deployed as smart meters today and includes a timestamp for the restoration time. For some utilities this is improving their IEEE indices, since their crews may take several minutes to complete other actions before reporting the power back on. It can also be used to help isolate nested outages and help the field crews get to the root cause of those nested outages before they leave the scene.

B.4.2.5 Planned Outage Scheduling

Ideally, planned outages should be done at a time when they have the least impact on the customers. Today we use rules of thumb about when to take a planned outage, in the future with a complete data set it is possible to adjust the time of the outage to correspond with the lowest number of customers demanding power. This minimizes the impact to the customers.

B.4.2.6 Planned Outage Restoration Verification

In completing work orders, it is useful to know that all of the customers that were affected by the work order have power and that there are no outstanding issues that need to be corrected, prior to the crew leaving the area. The ability to “ping” every meter in the area that was affected by the work order and determine if there are any customers who are not communicating that they have power is useful to minimize return trips to the work area to restore single customers.

B.4.2.7 Calculation of IEEE Outage Indices

Today the IEEE indices are manually calculated in most utilities and they are not up to date, since the information needed to track them comes from field reports and other documents that do not feed into a central location. Additionally since not every single point is tracked in any system for outages, it is impossible to accurately determine the indices. Most utilities have gotten very good at the development of indices that are very close to the reality that their customers are seeing and to the limits of the information available.

B.4.2.8 Call Center Unloading

Today we rely on customers to call in when there is an outage; this normally is one of the factors in sizing call centers and staffing them. When smart metering is deployed in the right way, it is possible for the system to determine where the outages are and to let the utility call the customer with an outage message and an estimated time to repair. In the long run this will reduce the loading on the call center during periods of high outage levels.

B.4.3 Load Management

B.4.3.1 Direct Load Control

Direct Load Control provides active control by the utility of customer appliances (e.g. cycling of air conditioner, water heaters, and pool pumps) and certain C&I customer systems (e.g. plenum pre-cooling, heat storage management). Direct load control is thus a callable and schedulable resource, and can be used in place of operational reserves in generation scheduling. Customer like it (if it is invisible), because they do not have to think about it, they sign up, allow the installation and forget it.

AMI systems will enhance the ability of utilities to include more customers in (appropriate) programs of direct load control, since it will increase the number of appliances accessible for participation in load control, and will improve the “near-real-time” monitoring of the results of the load control actions.

B.4.3.2 Demand Side Management

Management of the use of energy is important in a number of ways. Demand Side Management is a step beyond just tariff based load reduction. It assumes that customer will setup or allow to be set up equipment to reduce load when signals are sent to the customer’s location. The customer is in charge of making demand side management decisions.

B.4.3.3 Load Shift Scheduling

Given the ability to get customers to shift load when requested, and to do bottom up simulation it becomes possible to work with customers who have the ability to shift load to different times of the day or week. This ability to do load scheduling could have an impact on transmission and other capital expenses.

B.4.3.4 Curtailment Planning

To do proper load reduction, for either de-rated equipment or for planned outage or even to deal with load growth that has gotten ahead of system upgrades takes having data on what the loads are and what can be curtailed. In California, load curtailment has been called rolling blackouts, the best that can be done without an ability to control the demand on the system in a more granular fashion. By using curtailment planning, notice can be given in advance to the impacted customers and they have enough time to respond if they have an option in their contract to keep the power on.

B.4.3.5 Selective Load Management through Home Area Networks

With the deployment of home area networks the utility can choose to manage the load on the grid, to manage peak, to manage customer bills, to allow for a generation or transmission issue to be corrected or other reasons. This can permit, with the right equipment the reduction in the need for reserve margin in generation and for rolling reserve, the selective load management becoming a virtual power plant that is a callable and schedulable asset.

B.4.4 Power Quality Management

B.4.4.1 Power Quality Monitoring

Today for some larger customers and at select locations on the grid we are able to monitor harmonics, wave form, phase angles and other power quality indicators. The need continues to grow as large screen televisions and other consumer electronics devices are increasingly adding harmonics to the system. With the newest metering technology some power quality monitoring is built into the meter and more is on the way. While not every house needs to monitor power quality, a percentage of the meters deployed should probably have this advanced capability.

B.4.4.2 Asset Load Monitoring

With Connectivity Verification and Geo-Location information it is possible to group the devices in a tree structure that correctly shows connection points in the grid. With the ability to read intervals from the meters it is then possible to build a picture of the load that each asset (e.g. transformers, conductors, etc.) are subjected to. This allows an operator to monitor heavily loaded assets and look for ways to off load some of the demand from that asset. It also allows a maintenance planner to prioritize what maintenance should be done to maximize the reliability of the grid, as part of a reliability centered maintenance program.

B.4.4.3 Phase Balancing

One of the least talked about issues with losses in the distribution grid today is single phase load and the imbalance it can cause between the phases. These losses have seldom been measured in the grid and little study has been done of the amount of phase imbalance on the grid today. In early studies the chronic phase imbalance in several circuits that were monitored averaged over 10 percent. While correction is hard when the circuit is run as single phase laterals, in many cases there is enough load on the feeder portion of the circuit to allow rebalancing of the circuit to eliminate more than half of the chronic phase imbalance.

B.4.4.4 Load Balancing

Where there is an option to move a portion of the load from one circuit to another, the instrumentation is not always available to make good choices or to be able to forecast the load in a way that makes the movement pro-active instead of reactive. Automated feeder switches, and segmentation devices are becoming more and more common in the grid. The ability to use metering data to support the operation of these devices will only increase their value to the grid operator. Today with information only at the substation end of the circuit, it is tough to determine where on the circuit the load really is and where to position segmentation and when to activate a segmentation device when more than one is available. Operators today typically learn the right way by trial and error on the system.

B.4.5 Distributed Energy Resource (DER) Management

In the future, more and more of the resources on the grid will be connected to the distribution network and will complicate the operation of the grid for the future. Failure to integrate these resources into the grid and understand their impact will only degrade the operation of the grid and its reliability. It is no longer an option to deal with distributed resources, the time for refusing to allow them has passed. The only choice is to either embrace them and manage their impact or ignore them and suffer the consequences.

B.4.5.1 Direct Monitoring and Control of DER

Some DER units at customer sites could be monitored in "near-real-time" and possibly directly controlled by the utility or a third party (e.g. an aggregator) via the AMI system, in an equivalent manner to load control.

B.4.5.2 Shut-Down or Islanding Verification for DER

Each time an outage occurs that affect the power grid with DER, the DER should either shut down or island itself from the rest of the grid, only feeding the "microgrid" that is directly attached to. In many cases the shut-down or islanding equipment in smaller installations is poorly installed or poorly maintained. This leads to leakage of the power into the rest of the grid and potential problems for the field crews.

Each time an outage occurs, meters that are designed to monitor net power can tell if the islanding occurred correctly, if they are installed at the right point in the system. This reporting can minimize crew safety and allow the utility to let the customer know that maintenance is required on their DER system. In most cases when the islanding fails, other problems also exist that reduce the efficiency of the DER system, costing the customer the power that they expected to get from the system.

B.4.5.3 Plug-in Hybrid Vehicle (PHEV) Management

Depending on how plug-in hybrids are sold and how the consumers take to them, they may either become one of the largest new uses of power or they may not have an impact. A major problem is that planners are now assuming that they will be mobile generation plants, that the drivers will burn fuel and store power in the battery to be drawn during the peak times while parked in the company garage. Others have assumed that the cars will become the largest new consumer of power in the downtown grid, an overstressed part of the grid already.

How plug-ins are managed and how consumers will use them is a social experiment. What is not is that they will draw a large amount of power from somewhere and have the potential to store a lot of power for later use. How the power company measures which car provides or takes how many megawatt hours and proves it and bills for it, will be an interesting change. Smart meters can help with this if the right standards are place to deal with communication from the car to the meter.

B.4.5.4 Net and Gross DER Monitoring

There are two different generation results from distributed generation, the gross output of the device and the net input into the grid, after the owner takes their needed energy. The two can be very different at times when the DER is creating most power the owner may also be drawing so heavily that the net result to the grid is still negative. At other times, the demand from the owner may be less than the output, even though the output may be well under the design output of the device.

Some utilities have decided to reward renewable generation owners on the gross output, while other utilities have decided to reward them on the net output, possibly with TOU rates. But to manage a utility and the reliability of the grid it is important to know both the net and the gross output of the device for simulation, load forecasting and for engineering design.

B.4.5.5 Storage Fill/Draw Management

If someone has installed distributed storage, when should it be topped off, and when should the storage discharge? Today’s answer is to use a timer in most cases or a phone based trigger. For one utility the use of electric thermal storage for winter heat and time of use tariffs that encouraged topping up at a specific time of the day resulted in the destruction of a number of pieces of equipment on the grid as demand exceeded the local ability to supply that demand. The attempt to improve the load factor on the grid with this storage system resulted instead with demand that exceeded all expectations.

Smart metering with a home area network capability can trigger each storage device based on the total load in the area, leveling out the peaks in the system and providing better use of generation resources that may be variable in nature.

B.4.5.6 Supply Following Tariffs

DER has a strong probability of having a large percentage of renewable generation which has a strong variable component. Since the supply will be variable and highly variable on short notice, it may be that to avoid either a large component of rolling reserve that uses fossil fuels, it may be that a supply following tariff could be possible. It would require a very high speed forecasting system, excellent weather information and near real time communications to devices in the homes and in businesses with almost instant response. This is a tall order in today’s world, but the cable companies have proven that millions of devices are possible to broadcast to in near real-time, so it is possible.

Smart meters on the right communications network and with the right in home gateway could provide a piece of this supply following tariff system.

B.4.5.7 Small Fossil Source Management

There is a large amount of diesel generation that is installed on customer sites to deal with outages on the grid. Some companies are now forming to manage these resources, not for outage, but for peak power production, bidding into the market a few megawatts at a time. While the use of these resources is a good thing, the penetration of private companies will never be as complete as if the utility were to work with their customers to equip most of this generation with controls and monitoring equipment.

Whether the utility operates and maintains these resources or allows third parties to take responsibility is not important. What is important is that smart metering can reduce the cost and complexity of making these resources available. In California more than 2,000 Megawatts of generation are already installed, more than enough to end most rolling blackouts (if the resources are in the right areas).

B.4.6 Distribution Planning

B.4.6.1 Vegetation Management

Momentary outages normally increase as vegetation grows back in an area and starts to become potential issue for overhead lines. Smart metering allows the return of momentary outage information and allows the outage counts to be overlaid on a GIS system. This allows the planners to better target vegetation management people to the right locations. In the underground world, cable failures and splice failures can be found early, prior to a complete failure.

B.4.6.2 Regional and Local Load Forecasting

Given the ability to draw a full data set from the field, it is now possible to forecast regional and local loads and generation that can be used to prepare for and to set prices for both demand and supply.

B.4.6.3 Simulations of Responses to Pricing and Direct Control Actions

As more detailed information is available through AMI systems on regional and local loads and generation, it will be possible to assess the responses of both customers and the power system to price-related actions as well as direct control actions. This ability to simulate the market a day or more in advance should allow for better planning and for the system to run with smaller amounts of rolling reserve and ancillary services.

B.4.6.4 Asset Load Analysis

With the ability to have a real load history on a specific asset and to be able to do bottom up forecasting, the same can be done for assets in the connection tree. This should allow planners and others to see potential problem areas before they really exist.

B.4.6.5 Design Standards

Many of today’s standards assume that complete data is not available so there are factors of safety built into the calculations at each step of the design process for the transmission and distribution grid to make sure that the design is useful for its full design life. The improvement in load and demand data from the smart meters will make it possible to remove many of the rules of thumb and design to the real needs of the customers.

B.4.6.6 Maintenance Standards

Maintenance is done with incomplete information. So the maintenance standards allow for this, in some cases too much maintenance is done and sometimes too little is done, standards call for the best possible maintenance planning that incomplete information can provide. The good news is that the reliability of the system is very high, better than any other service (including telecommunications and cable TV) that is available to a customer. The bad news is with all the retirements in the industry, the experienced technicians that are required to make the judgment calls in the field will all be replaced in a few years. Improving the standards for maintenance with better information will mean that the new field workers will be routed to the highest priority work almost every time.

B.4.6.7 Rebuild Cycle

When is the right time to rebuild a circuit and how much of it really needs to be upgraded? Today with the information we have, we hang some recorders and use a few weeks or months of data from a few locations to determine what to rebuild, with the improved data set and the improved standards it is possible to actually determine the sections of the grid to rebuild and how much to reinforce them.

B.4.6.8 Replacement Planning

Equipment replacement is based on the estimated load or a load study that is normally conducted with less than perfect information. This has resulted in the engineering team being conservative and over sizing many of the replacement equipment. Smart metering offers better information to make better sizing decisions.

B.4.7 Work Management

B.4.7.1 Work Dispatch Improvement

Today we use manufacturers' recommendations, models, estimates, and visual inspection to determine when a lot of maintenance work should be done. While it works, in some utilities it means more maintenance than others think is required and in others it means less. In almost every case, some maintenance is performed that is not really required for reliability centered maintenance strategies. When smart metering information is available and used to do asset loading analysis and other data analysis, work can be more accurately dispatched to the crews in the field improving reliability in the system for the same number of jobs completed.

B.4.7.2 Order Completion Automation

Some utilities have the field crew log the completion of their job prior to packing up; others want the crew ready to roll prior to completion of the order. Some want the crews to look around before leaving, some want the crew to leave and let the customers call if there is still an issue in the area. With smart metering, as restoration alerts come in, it is possible to automate the time the job was completed and some of the closing paperwork, allowing the crew to stay in the field longer each day and to do less paperwork overall.

B.4.7.3 Field Worker Data Access

Today if a line worker wants to know the status of an area of the grid, she can measure power flow, she can look at meters or he can call dispatch. Access to near real time information on the status of the customers close to the worker's location is limited today. With the deployment of smart metering, depending on how the software is configured and the security setup, it may be possible for a field worker to get access to the a near real-time map of the status of the customers in their working area, minimizing the need for dispatch to tell the worker where to go next and what to do.

With experience, field workers have proven to be very good at determining where in their work area a likely root cause is, based on outage information, reducing the time it takes to find the cause and start the repair work.

B.4.7.4 Reliability Centered Maintenance (RCM) Planning

Today we guess at the loading on devices using models, and use that information to develop a reliability centered maintenance plan. Based on that information we do our best to perform the maintenance that the system requires to make sure that people have power. With the ability to do load monitoring and load forecasting more accurately, preseason maintenance can be scheduled based on the facts that the system generates. While it will never prevent all failures in the system, use of this information and a well designed RCM plan can result in significantly less outage for non-natural disaster causes.

B.5 Customer Interactions Business Functions

B.5.1 Customer Services

B.5.1.1 Remote Issue Validation

When a customer calls today with a problem, other than twenty questions on the phone or rolling a truck to the location, there is no way to understand if the customer really knows what the problem is or if they do not understand the problem. Use of near real time information from smart meters can allow the customer service representative (CSR) to provide better information to the customer and to provide better advice on what to do with the current situation. It can also reduce the dispatch of trucks for customer complaints. In general it reduces both call volume and call handling times.

B.5.1.2 Customer Dispute Management

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 non-phone 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.

B.5.1.3 Outbound Customer Issue Notification

Not only can customers be called at work for problems with outage, but other problems can be determined and customers notified, in one case, a meter looked like it had been tampered with, but the customer had a complaint about low voltage on file. A review of the situation determined that one of the wires was probably loose in the customer’s breaker panel. That call resulted in the customer hiring an electrician and fixing a number of electrical problems in their home that the electrician uncovered while fixing the loose wire in the panel. This is one example of a number of proactive actions that can be taken with the customer to help them be safe and know what is going on with their energy consumption. Similar work was undertaken on behalf of a water company and a number of beyond the meter leaks were identified with night time readings on homes with high water bill complaints.

B.5.1.4 Customer Energy Advisory

Some utilities have undertaken to provide a customer energy consumption advisory that allowed customers to indicate what they have for energy consuming devices and information about their home. In return, the utilities rank their consumption against similar homes and provide feedback on the equipment and appliances that were consuming significant energy.

This advisory can even suggest what should be replaced and the payback period on the replacement, based on energy usage. The comparison allows customers to see how they did against similar customers and where they ranked in energy consumption. This has been very useful in getting customers to pay more attention to their consumption.

B.5.1.5 Customer Price Display

To make a realistic decision about using or not using energy and water, customers need to know how much it will cost. As we have seen with Gasoline the global consumption decreased very little (in reality only the projection of growth in consumption declined, not the actual usage) when the price tripled at the pump in many countries. Electricity, gas and water today are in the noise of running a household for most families and for many businesses the cost does not enter the top five costs for the business. To this end, making a decision to consume energy and water is easy.

For a few businesses and a small percentage of residential customers this is not true and they have strong motivation to conserve power. With critical peak pricing or time of use pricing and rising prices for energy and water, the percentage of the average family income consumed by these utilities will no longer be noise and having information about pricing, will drive some conservation. Expect that customers will need to know the price to wash a load of clothes, not the price of a kilowatt hour.

B.5.2 Tariffs and Pricing Schemes

B.5.2.1 Tariff Design

Today a sample of the customers is used to determine what the customer profile should be and how that profile should be priced. In many cases the classification of the customers is very broad and does not really take into account the different ways that customers actually consume power. For example, a young educated single male living in an apartment may have a lower usage than the young family across the hallway and they may both pay the same per kilowatt-hour of power.

However, the young male many actually cost the utility more to serve, since the load factor for that single male may be much lower than the load factor for the young family. By being able to provide accurate data, better tariffs can be designed and better segmentation done to support a fair power price.

B.5.2.2 Rate Case Support

Today to get almost any change in what can be charged to the customers or what is placed in the rate base, it requires a rate case. In some rate cases the documents filed fill rooms and rooms in a building, mostly because the issues can be handled in a black and white manner. Experts are required to testify on many aspects of the rate case using data from other locations, since the complete data set to answer the question does not exist at the utility. While experts will not go away, and there will still be a lot of estimating, it is important to realize that smart meters provide a large data set to assist with the rate cases.

B.5.2.3 Tariff Assessments

Do critical peak tariffs create the response expected, does it do it for all segments of customers, and does it impact some customer segments more harshly than others. Use of smart meter data allows a better review of how the customers are responding to the tariffs and how to re-work them to better fit the needs of the society.

B.5.2.4 Cross Subsidization

An issue that is raised over and over again is cross subsidization of customers, one group of customers paying part of the cost of another group of customers. With our example in Tariff Design, more than likely the young family is subsidizing the young male. Regulators want to know what the cross subsidization is, they do not always want to eliminate it (e.g. the long distance rates for the telephone companies for decades financed the ability of everyone to have a phone). By having complete data on each and every customer, subsidization arguments no longer fall on “I think” arguments, but fall into the “I know” allowing the regulator to only have intended subsidies.

B.5.2.5 Customer Segmentation

Customer segmentation has traditionally been done by industry or by business segment or by customer type, not by the actual needs or profile of the customers. Regulators have never had enough data to make segmentation decisions that really classify customers together by the way they consume power and their needs for power quality or their creation of power quality issues that the utility needs to fix. Smart metering can provide the data to make meaningful segmentation decisions.

B.5.3 Demand Response

Demand response is a general capability that could be implemented in many different ways. The primary focus is to provide the customer with pricing information for current or future time periods so they may respond by modifying their demand. This may entail just decreasing load or may involve shifting load by increasing demand during lower priced time periods so that they can decrease demand during higher priced time periods. The pricing periods may be real-time based or may be tariff-based, while the prices may also be operationally-based or fixed or some combination. As noted below, real-time pricing inherently requires computer-based responses, while the fixed time-of-use pricing may be manually handled once the customer is aware of the time periods and the pricing.

Sub functions for demand response, which may or may not involve the AMI system directly, could include:

- Enroll Customer
- Enroll in Program
- Enroll Device

- Update Firmware in HAN Device
- Send Pricing to device
- Initiate Load Shedding event
- Charge/Discharge PHEV – storage device
- Commission HAN device
- HAN Network attachment verification (e.g. which device belongs to which HAN)
- Third Party enroll customer in program (similar to, but not the same as the customer enrolling directly)
- Customer self-enrollment
- Manage in home DG (e.g. MicroCHP)
- Enroll building network (C&I – e.g. Modbus)
- Decommission device
- Update security keys
- Validate device
- Test operational status of device

B.5.3.1 Real Time Pricing (RTP)

Use of real time pricing for electricity is common for very large customers affording them an ability to determine when to use power and minimize the costs of energy for their business, one aluminum company cut the cost of power by more than 70% with real time pricing and flexible scheduling. The extension of real time pricing to smaller customers and even residential customers is possible with smart metering and in home displays. Most residential customers will probably decline to participate individually because of the complexity of managing power consumption, but may be quite willing to participate if they are part of a community whose power usage is managed by an aggregator or energy service provider.

B.5.3.2 Time of Use (TOU) Pricing

Time of use pricing creates blocks of time and seasonal differences that allow smaller customers with less time to manage power consumption to gain some of the benefits of real time pricing. This is the favored regulatory method in most of the world for dealing with global warming.

Although Real Time Pricing is more flexible than Time of Use, it is likely that TOU will still provide many customers will all of the benefits that they can profitably use or manage.

B.5.3.3 Critical Peak Pricing

Critical Peak Pricing builds on Time of Use Pricing by selecting a small number of days each year where the electric delivery system will be heavily stressed and increasing the peak (and sometime shoulder peak) prices by up to 10 times the normal peak price. This is intended to reduce the stress on the system during these days.

California is the largest proponent of this tariff program at this time. Most of the California utilities would prefer an incentive program instead to encourage the same behavior. There is some question as to whether retailers in unregulated markets would have to pass thru the Critical Peak Pricing to customers or if they could offer a flat price and hedge the risk of the critical peak pricing.

B.6 External Parties Business Functions

B.6.1 Gas and Water Metering

B.6.1.1 Leak Detection

In the world of gas and water, non-revenue water and leaking gas pipes are important to track down. In the water industry, use of pressure transducers on smart meters has proven useful when doing minimum night flows to find unexpected pressure drops in the system. Normally the need is one pressure transducer meter per 500 to 1000 customers in an urban environment.

B.6.1.2 Water Meter Flood Prevention

With a disconnect in the water meter, it is possible if there is a sudden increase in flow and a drop in pressure that is sustained and unusual, that the disconnect can be activated and prevent flooding. Much work will have to be done in the control software algorithms to make this a useful benefit and not one the shuts off the water when the sprinkler system and the shower are both running.

B.6.1.3 Gas Leak Isolation

Similar to flood prevention, again the software needs to get much better or their needs to be a gas leak sensor in the structure that communicates with the meter.

B.6.1.4 Pressure Management

If there is a home area network, then shut off devices or throttling devices can be attached to specific water taps and the gas meter can communicate to thermostats and water heater controls to manage the rate of consumption in the location and help with pressure management on critical days.

B.6.2 Third Party Access

B.6.2.1 Third Party Access for Outsourced Utility Functions

For some utilities, many of the business functions listed in the previous sections may be provided by third parties, rather than by the utility. In these situations, messaging will come through the "external party access" avenue, rather than an internally-driven messaging. The business processes will be fundamentally the same, but the security requirements could be significantly different and probably requiring stronger authentication at each system handoff.

Some of the business functions provided by third parties could include:

- Prepaid metering
- Remote connect/disconnect
- Load management
- Emergency control
- Distribution automation
- Customer usage information
- HAN management

B.6.2.2 Third Party Security Management of HAN Applications

Customers will need access to HAN application accounts through a secure web portal where they can upload device and software security keys. Those keys will need to be sent through the AMI network to the meter to allow the HAN devices to provision and join with the meter.

Future functionality may include extraction of security keys out of the meter for storage in the utility's database. This will allow the keys to be downloaded back to a meter if it ever has to be replaced. This functionality will be required to eliminate the need to re-provision all the HAN devices in the house in the event of a meter replacement.

B.6.2.3 Appliance Monitoring

Appliances seldom last as long in the home as they do in the lab, part of this is that home owners do not do maintenance when they should, and part of it is that when small problems occur that are not handled, so they become big and expensive problems. Smart meters are a key part of an appliance monitoring solution, even for appliances that were installed long ago.

B.6.2.4 Home Security Monitoring

Today's security monitoring industry uses phone lines and other communications methods to monitor homes. The ability to hook security monitoring devices into a home area network and provide alerts and alarms over the smart metering network could lower the cost of home security monitoring making it more affordable to the people who live in areas most likely to need it.

B.6.2.5 Home Control Gateway

Home owners may want to control their home devices themselves or they may want a third party to do so, in either case, the smart metering system can be a method of providing that home area network gateway and allowing that control to be done.

B.6.2.6 Medical Equipment Monitoring

More and more medical equipment is being installed in homes as nursing homes and hospitals are getting too expensive to live in and more life support equipment is required for people who still can live at home unassisted most of the time. Today that equipment is only monitored by specialized companies and this seldom happens. It is a growing need especially for the elderly customers of the utility. While utilities may not wish to step into this role, the smart metering infrastructure can provide a way for authorized third parties to do so.

B.6.3 External Party Information

B.6.3.1 Regulatory Issues

There are a number of issues that regulators need to judge the performance of a utility and the fairness of a utility to its customers. Smart metering has a role to play in providing facts to the regulator to help them manage these issues.

B.6.3.2 Investment Decision Support

When a utility goes to the regulator for a major capital expense there is a need for proof that the expense is required. Today like other regulator interactions, the data is typically made up of sampled data and expert opinions. With smart metering the complete data set is available to support the decisions.

B.6.4 Education

B.6.4.1 Customer Education

Customers today call the call center and receive bills. They have little interaction with their utilities, less than 40% of the customer base interacts with the utility annually. The majority of the call volume is related to outage or other power quality issues. The second highest interaction reason is billing issues. If the industry is to be successful in changing people's habits and helping to reduce consumption, then there will need to be more interaction with customers, some on billing issues, some on power quality, but more on the way they consume power and what they have for appliances.

AMI systems will provide a means of interacting more with the customer, but only if the customer understands the capabilities – as well as being assured that AMI systems are not "Big Brother" watching over them.

B.6.4.2 Utility Worker Education

Utility workers will need significant education to learn not only their own roles in a utility with AMI, but also the issues of security and privacy that will become far more critical with the widespread scope of AMI systems.

B.6.5 Third Party Access for Certain Utility Functions

For some utilities, many of the business functions listed in the previous sections may be provided by third parties, rather than by the utility. In these situations, messaging will come through the "external party access" avenue, rather than an internally-driven messaging. The business processes will be fundamentally the same, but the security requirements could be significantly different and probably requiring stronger authentication at each system handoff.

Appendix F-2

Itron OpenWay Security Overview

> Itron white paper

OpenWay® Security Overview

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Introduction

The smart grid represents an evolution transformation in the way electricity is delivered from suppliers and the way it is used by consumers. With a smart grid, electricity is controlled throughout the delivery system via a two-way digital communication channel to appliances within a consumer's premise to save energy, shift peak load, reduce costs and increase reliability. To that end, smart meters play a key role as a communication, monitoring and control device in the overall evolution of the power distribution system. With this evolution comes significant challenges in ensuring that the smart grid is both secure and reliable.

Smart grid and smart metering systems promise to deliver on a wide variety of capabilities, including dynamic pricing by electric service providers (ESPs); increased customer control of their energy usage and ESP rates; fine-grained demand-response by ESPs in conjunction with customers; and improved reliability of the electric grid. A well-designed security architecture is an absolute requirement in order to provide these capabilities. Threats to smart grid systems come from a wide range of sources, or "threat agents." These include unethical customers, curious and motivated eavesdroppers as well as active and passive attackers (LeMay, Gross, Gunter, & Garg, 2007). The motivations of these threat agents vary from publicity seekers to those with a focused and directed agenda. Regardless of the specific attacker's motives, threats can include unauthorized access to communications; interruption of service; and injection of commands into the system to gain access and control either core systems or meters.

The ultimate concern, from a national security perspective, is one where a rogue or enemy state or a terrorist organization cripples the electric power grid during a conflict or as part of an organized attack. To address these concerns, smart grid vendors are developing secure, resilient architectures that are designed to withstand both casual and focused attacks. These architectures require strong authentication and encryption to protect both core systems as well as meters from both amateur and sophisticated adversaries.

The electric grid has changed dramatically over the past 20 years and will change even more in the years ahead. In the past, the standard meter on the grid was a very simple device measuring monthly electricity usage that required manual, visual readings by meter readers. Over time, meters became more sophisticated to include a radio broadcast capability where the meter can be read without physically approaching it. More recently, automated meter reading (AMR) has evolved into advanced metering and smart grid initiatives where meters can now receive commands as well as requests for meter readings over a radio-based local area network (RFLAN), as well as provide data at regular intervals to the utility billing system. These capabilities are necessary as the power generation grid evolves to include a larger portfolio of renewable and/or distributed energy generation sources such as solar and wind.

Regulatory and Industry Drivers

As smart grid and smart metering initiatives have gained momentum, and utilities look to deploy these technologies more broadly, an obvious concern turns toward the security of these systems. One of the key factors that drive this concern is the North American Electric Reliability Corporation (NERC), which has been chartered by the Federal Energy Regulatory Commission (FERC) to develop and drive critical infrastructure protection (CIP) requirements for the electric grid. The NERC CIP requirements cover a wide range of topics—from sabotage reporting to cyber security and critical cyber system identification to cyber security to personnel training, as well as other topics. These requirements are written in a broad enough fashion to allow the energy providers the ability to tailor their cyber security policies in order to be in compliance.

While the NERC CIP guidelines do not explicitly state what is or what is not a critical cyber asset (CCA), it does provide sufficient guidelines that could include most smart grid deployments as CCAs. NERC CIP-002 provides the criteria for determining whether something is or isn't a critical cyber asset. These criteria include:

- Control and backup control centers
- Transmission substations
- Generation resources
- Systems and facilities critical to system restoration.
- Systems and facilities capable of shedding 300 MW or more.
- Any additional assets that support the reliable operation of the Bulk Electric System (North American Electric Reliability Corporation, 2009)

In addition to NERC, other organizations have been developing guidelines for smart grid security. These include the National Institute of Standards and Technology (NIST) and the AMI-SEC Task Force (TF). NIST published NIST IR 7628 in September of 2010 covering smart grid security guidelines. This work covers both an overall smart grid security strategy as well as privacy concerns in a smart grid. The AMI-SEC Task Force published version 2.0 of the AMI Security Profile in June of 2010.

NISTIR 7628

The NISTIR 7628 – Guidelines for Smart Grid Cyber Security – is divided into three volumes. Volume one covers smart grid security strategy, architecture and high-level requirements; volume two covers privacy in the smart grid; volume three provides supportive analyses and references for the overall work. One key aspect that must be considered when evaluating the information in the NISTIR document is that the information in the report is written to provide organizations planning a smart grid deployment with guidelines. The NISTIR does not prescribe particular solutions but rather requires organizations to leverage the information in the documents and develop their own cyber security approach as well as a risk assessment methodology for the smart grid. It is essential that any utility looking to deploy their own smart grid infrastructure should leverage the information in the NISTIR 7628 documents in order to develop their cyber security policies with respect to smart grid and AMI.

NERC Critical Infrastructure Protection

NERC CIP is currently divided into a series of nine documents – NERC CIP-001 to NERC CIP-002. These NERC CIP standards specify requirements that are policy and process focused rather than technology focused. The key NERC CIP documents that apply most directly to a smart grid or AMI deployment include the following:

- NERC CIP-002 – Critical Cyber Security Asset Identification
- NERC CIP-003 – Security Management Controls
- NERC CIP-005 – Electronic Security Perimeters
- NERC CIP-006 – Physical Security of Critical Cyber Assets
- NERC CIP-007 – Systems Security Management
- NERC CIP-008 – Cyber Security – Incident Reporting and Response Planning

It is important to note that the requirements in the NERC CIP standards do not speak to a specific technology directly but rather help drive the necessary technology standards.

Smart Grid Threats

A smart grid deployment presents significant challenges to the security architect in providing a defense against a wide variety of threats. The majority of the smart grid components—the smart meters themselves—are located *at* the end user's facility (either home or business), and are considered to be in an extremely hostile environment. Theoretically, an attacker can have nearly 24/7 access to the component in order to identify a vulnerability or devise an attack. In addition to environmental and physical threats, smart grid components must also contend with a wide variety of electronic threats such as hacking and denial of service. Given the nature of the smart grid, there are several general categories of attack against it. These threats are shown in Figure 1 and pertain to the following smart grid/AMI system components:

- The smart meters
- The RFLAN
- The wireless devices bridging the RFLAN to the wide area network (WAN)
- The WAN providing backhaul for the RFLAN
- The collection system head-end

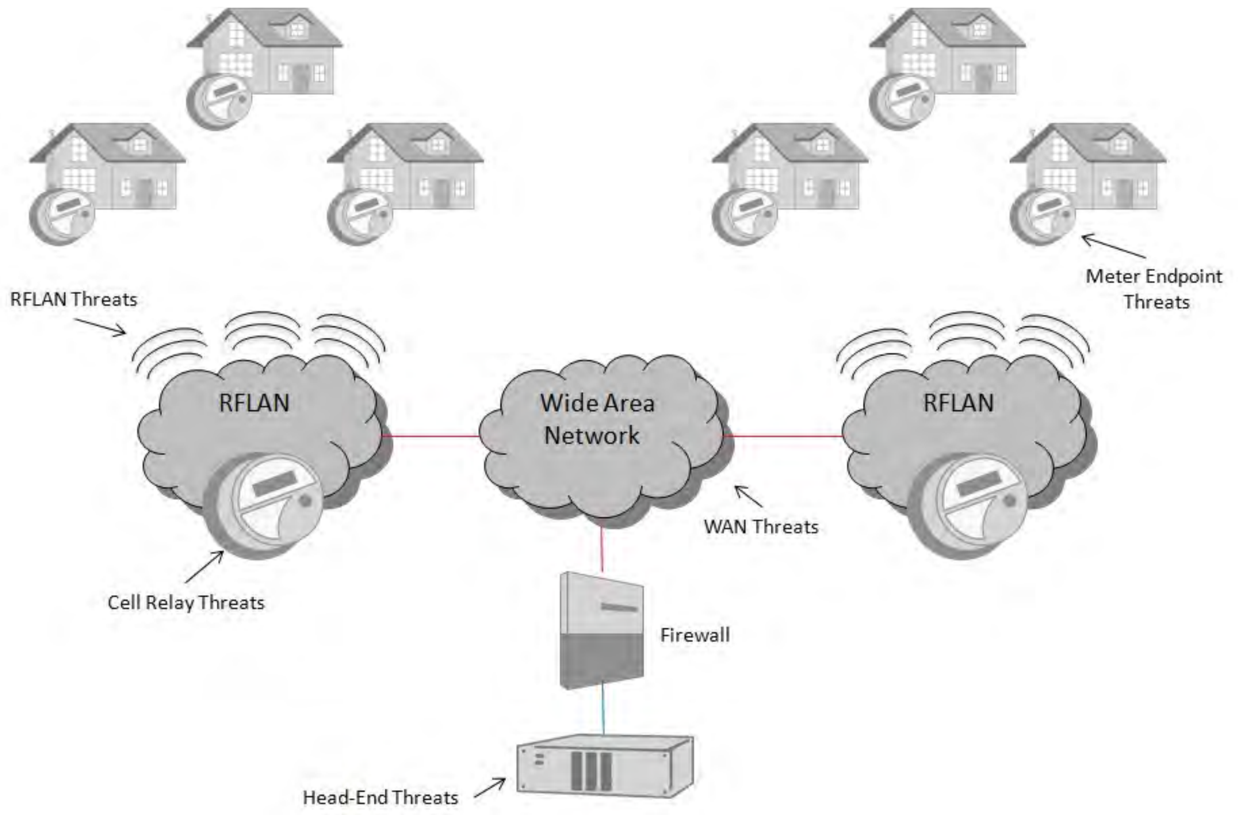

Figure 1 – Potential Threat Points in an AMI Deployment

Given the unique nature of smart grid deployments operating in an exposed and actively hostile environment, it is critical that the security of the components be comprehensive and of the highest caliber and scrutinized in detail. To address these threats and needs, smart grid components must leverage strong software and hardware development processes that include threat modeling, a software development lifecycle and security testing to identify potential, undiscovered vulnerabilities and to remediate them before the components are released to the market.

OpenWay Architecture

The OpenWay architecture is designed to provide flexibility as well as robust security in a smart grid deployment. AMI systems could be classified as CCAs according to NERC CIP-002-3, as they often comprise systems capable of automatic load shedding of 300MW or more (R1.2.5) *and* because they utilize a routable protocol to communicate outside the Electronic Security Perimeter (R3.1) (North American Electric Reliability Corporation, 2009). Itron's OpenWay architecture is designed to address the specific security requirements of a smart grid deployment.

The OpenWay solution consists of several primary components: OpenWay CENTRON® meters, OpenWay Cell Relays and a head-end system known as the OpenWay Collection Engine. Figure 2 shows the OpenWay architecture's Enhanced Security Configuration. Together, all of these components play in integral part in securing a deployment and these components and associated security measures are discussed in more detail below.

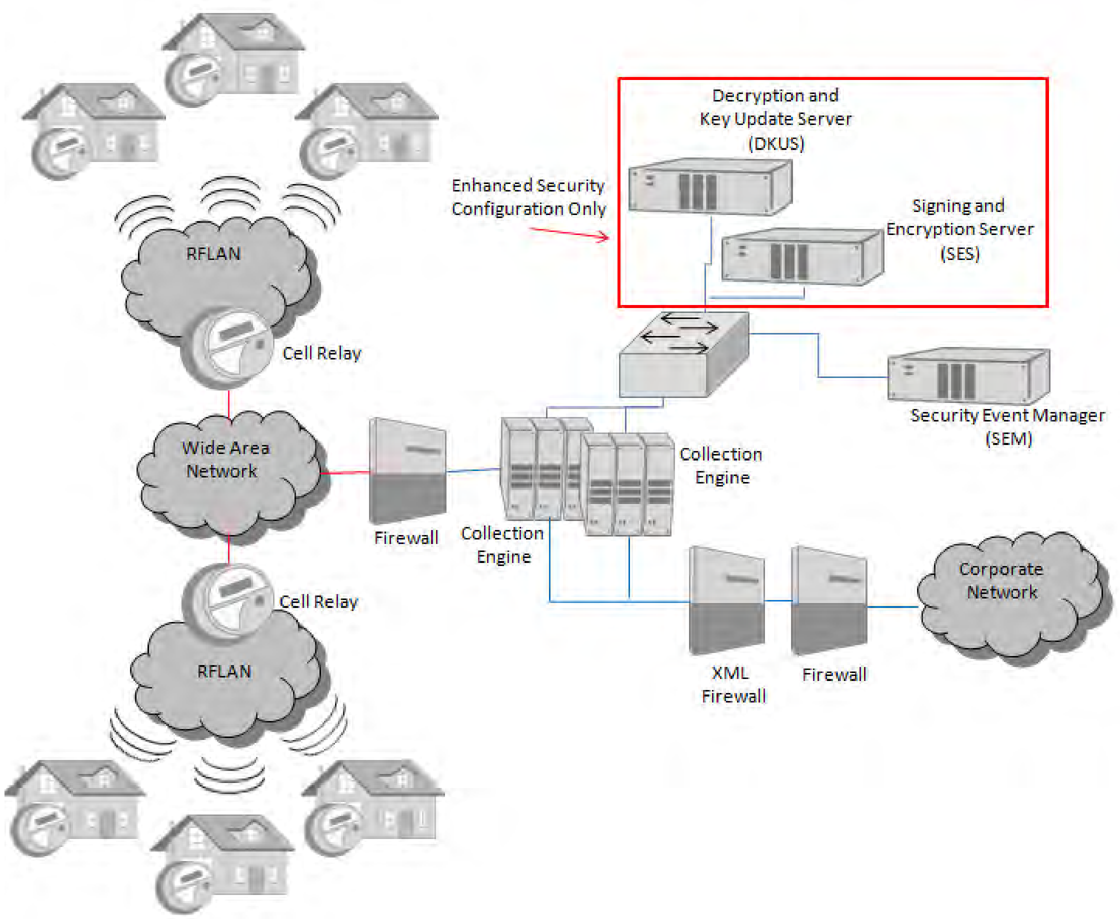

Figure 2 – Itron's OpenWay Smart Grid Architecture Enhanced Security Configuration

Collection Engine

The OpenWay collection engine is the core of the OpenWay solution. Built upon the Windows .NET framework, the collection engine provides both inbound data collection services from the infrastructure as well as outbound meter command and key management. The Collection Engine is responsible for supporting the integrity of the system.

RFLAN and Cell Relay Communications

The OpenWay radio frequency LAN (RFLAN) is a frequency-hopping RF network that utilizes the 900 MHz ISM band. Messages are transmitted in accordance with the ANSI C12.22 protocol, and are encrypted using 128-bit AES keys. The command messages are also signed using ECC public/private keys.

The Collection Engine interfaces with meters through Cell Relays. Firewalls are recommended between portions of the system; however, the OpenWay architecture requires full two-way communication between the Collection Engine and the Cell Relay. The Collection Engine can be placed behind a firewall and allow traffic on port 1153 (C12.22) to pass through. The Collection Engine needs to be able to access its database as well as the enterprise management system and the meter data management (MDM) application. These applications may be behind additional firewalls, or they may be on the same network as the Collection Engine itself, provided that the Collection Engine has full two-way access to the appropriate ports for data transfer. This initial communication is done using TCP/IP. As either the Collection Engine or the Cell Relay can initiate communications, both products must accept incoming C12.22 messages on TCP/IP port 1153. The Collection Engine listens on port 1153 for C12.22 communication and monitors the network for Web services calls.

OpenWay CENTRON Meters

The C12.22 architecture plays an important role regarding the implementation of security. The major benefit of the design of a C12.22 network is that the Collection Engine interfaces at an application level protocol layer, enabling both session- and sessionless-based communication directly to the meter register. Unlike designs tied to a single communications network, with OpenWay the security architecture does not need to change if the communication architecture changes. OpenWay Security protects the entire communication from the head-end-system into the processor in the meter, giving the utility flexibility to select an underlying communications' infrastructure appropriate to the utilities strategic needs.

OpenWay also benefits from the ability to perform broadcast and multicast communications to meters, minimizing the amount of messages that require encryption and processing, as opposed to sending multiple messages point to point to meters.

Security Event Manager

As with any deployed IT system security, events must be monitored and evaluated in order to determine if a potential security breach has occurred, and if so, how to appropriately respond to it. One of the key features of a security event manager (SEM) in a smart grid deployment is the ability to accurately identify a developing or ongoing attack against the system. Attacks can vary considerably but include such threats as:

- An attacker attempting to shut off a population of meters
- An attacker trying to obtain key material from the system

- An attacker attempting to execute a denial of service attack against a population of meters
- An attempt to hijack or spoof on or more trusted systems
- Attempts to recover key material from endpoints
- Attempts to modify an endpoint to change metrology or other parameters

The above events represent a sample of possible events that should be monitored by a security event manager.

A SEM is deployed to collect, correlate and analyze audit events in order to detect intrusions and attacks. Examples of audit events in OpenWay include but are not limited to: endpoint reprogramming, endpoint authentication failure, signature verification failure, message decryption failure, home area network (HAN) traffic rate exceeding threshold, device firmware upgrade and spurious HAN and local area network (LAN) messages. These events are primarily generated at the meter or from wide area network (WAN) devices and sent to the OpenWay Collection Engine, which then sends the events to the security event monitor.

OpenWay Security

OpenWay Enhanced Security provides for both the confidentiality of data and commands, and also provides data integrity and non-repudiation for commands from the Collection Engine to the endpoints. New threats and looming regulatory requirements have driven the need for a higher level of security. To fulfill that need, OpenWay provides a strong security layer in a smart grid deployment known as Enhanced Security. Enhanced Security leverages public key cryptography in addition to symmetric key cryptography to secure the communication between the Collection Engine and the meter endpoint. Asymmetric cryptography is used to provide digital signatures for command verification and symmetric cryptography is used to provide data confidentiality. OpenWay also supports the following security standards for security controls and functions:

- NIST FIPS 197 approved encryption algorithms (AES)
- NIST FIPS 186-3 approved signature algorithms (ECDSA)
- NIST FIPS 180-2 approved hashing algorithms (HMAC-SHA-1,HMAC-SHA-256)

Collection Engine with Enhanced Security

The Collection Engine is responsible for supporting the integrity of the control of the system. As a result, asymmetric cryptography is supported for command and control messages. Every node in the system has a set of asymmetric keys that are used for authentication and non-repudiation functions. Initial meter registration involves a key exchange process that establishes mutual authentication. When sending out messages, the C12.22 payload is signed and encrypted before being wrapped it in the C12.22 protocol. This is accomplished by the integrated Signing and Encryption appliance. As control over this operation is absolutely critical to ensuring control over the system, the Signing and Encryption Server will never expose the signing key. When the meter communicates information upstream to the Collection Engine, the C12.22 messages are encrypted to protect the confidentiality of data and decrypted by the DKUS appliance. An overview of this exchange is depicted in Figure 3.

Enhanced Security with OpenWay CENTRON Meters

With OpenWay Enhanced Security, cryptographic processing at the meter is done using algorithms recommended by the National Security Agency under their "Suite B" recommendations for commercial security. Elliptic Curve Cryptography (ECC) provides the most security per bit of any known public-key scheme. Leveraging enhanced security provides not just confidentiality for the information flow between the Collection Engine and the meter but also message integrity. This makes it considerably more difficult for an attacker to inject falsified messages into the system either from the Collection Engine to the meter or from the meter to the Collection Engine. Each OpenWay CENTRON meter has a unique private key, which is used to validate digitally signed commands received from the Collection Engine and to authenticate the meter to the Collection Engine during initial meter registration.

Messages from the Collection Engine to the Meter

Messages from the Collection Engine to the meter are encrypted using an AES-128 bit key and signed using an ECC-283 bit key as shown in Figure 3. The OpenWay security architecture allows for broadcast and multicast communications, where a single message from the Collection Engine can direct behavior for a large number, potentially millions, of meters simultaneously as well as for unicast communications. Signature verification and decryption is pushed out to the meters in a distributed fashion. The meter processes these security functions in milliseconds once the command is received. Thus, while each meter will need to validate the signature on the message to ensure its authenticity, those validations occur in parallel resulting in very little latency being added to a group operation no matter how many meters are involved. At the collection engine, the system can easily sign and encrypt 200 operations per second.

Messages from the Meter to the Collection Engine

Messages from the meter to the Collection Engine are encrypted using an AES-128 bit key to provide customer data confidentiality as shown in Figure 3. The OpenWay architecture is optimized such that an IP load balancer shapes the incoming traffic and distributing it equally among the Collection Engine subcomponents for processing. The Collection Engine removes the network portion of the packet and passes the payload to the OpenWay Decryption and Key Update Server for processing. This appliance is scaled to decrypt 20,000 messages per second, which maps out to over a million meters per minute processing.

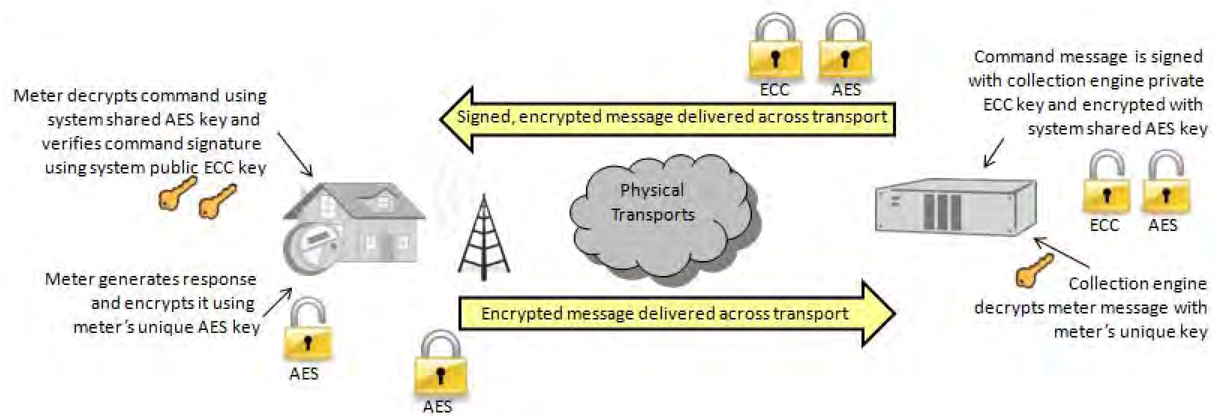

Figure 3 – Enhanced Security in OpenWay

The security architecture was designed specifically for OpenWay operational use cases centered on performing multiple functions such as meter data collection, demand response and remote disconnects simultaneously for 10 million meters or more. It is important to note that while command and control messages are signed all command, control and data messages are encrypted. In addition, the OpenWay SES and DKUS security appliances are designed so one appliance pair can handle the message traffic of a system with 10 million devices. Customers need only install additional appliances for high availability and disaster recovery, not performance.

Signing and Encryption Server (SES)

The Signing and Encryption Server is responsible for securing command messages being sent from the Collection Engine to the meters. As a result, the number of keys managed for these messages is quite small, potentially as little as two keys that need active control. However, these keys must be very tightly controlled to ensure that the system is not compromised. The private signing key of the Collection Engine is never exposed in raw form, though there are facilities to back it up. To protect the keys, the Signing and Encryption Server includes an integral hardware security module (HSM). The HSM is FIPS 140-2 level 3 compliant, meaning that it is meets the government guidelines to protect the keys it contains against both physical and electronic attacks.

Decryption and Key Update Server (DKUS)

This component provides rapid message decryption and comprehensive key management. Messages coming from the meters to the Collection Engine need to be quickly decrypted. In a large-scale OpenWay implementation, the system can decrypt more than 20,000 messages a second, each with its own unique key. While the messages are small, over the course of several hours, the system may need to decrypt messages using between 5 and 10 million unique AES keys. The solution must be able to quickly handle accessing millions of keys, decrypting thousands of messages and passing them on to the Collection Engine.

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System Security

The OpenWay Collection Engine uses role-based security for authenticated users. Administrators can be assigned different levels of privileges with each administrator using an individual password. Administrators can also be integrated into Microsoft's Active Directory. Administrator web access to the Collection Engine is protected using X.509 certificates and TLS for session encryption. In addition, the Collection Engine is always installed in the utility's data center behind its firewall and intrusion prevention systems.

Data Management programs, such as a Meter Data Management System (MDMS), which access the Collection Engine to instruct the collection engine to issue a command to the meter endpoint, are authenticated through X.509 Certificates and the communications is kept confidential through the use of TLS. The Collection Engine's data management interface can also use Secure Assertion Markup Language (SAML) or Kerberos if these techniques are supported by the MDM.

Conclusion

In summary, OpenWay's security architecture is designed specifically for key security functions, without sacrificing the performance requirements that are needed for two-way command and control for AMI and smart grid network operations. The OpenWay security architecture provides customers the ability to comply with applicable NERC and FIPS requirements to protect their smart grid network. In addition, OpenWay security supports the operational requirements of OpenWay to support up to 10 million meters without impacting the system's performance managing upstream and downstream message processing. OpenWay's architecture also reduces the complexity around security through the use of C12.22 and node-to-node communication between the Collection Engine and the meter register.

Itron Inc.

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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