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FARRIS

File No: 00019-1144-0000

September 28, 2022

BY ELECTRONIC FILING

British Columbia Utilities Commission
Suite 410, 900 Howe Street Vancouver, BC
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**Attention: Sara Hardgrave,
Acting Commission Secretary and Manager**

Dear Ms. Hardgrave:

Re: FortisBC Energy Inc. (FEI)

Application for a Certificate of Public Convenience and Necessity (CPCN) for Approval of the Advanced Metering Infrastructure (AMI) Project (Application) ~ Project 1599211

FEI Final Argument

In accordance with the regulatory timetable in the above proceeding, we enclose for filing the Final Argument of FortisBC Energy Inc., dated September 28, 2022.

Yours truly,

FARRIS LLP

Per:

Nicholas T. Hooge

NTH/kl

c.c.: Registered Interveners;
Client;
Ludmila B. Herbst, K.C.

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

the *Utilities Commission Act*, R.S.B.C. 1996, Chapter 473

and

FortisBC Energy Inc.

Application for a Certificate of Public Convenience and Necessity for Approval of the Advanced Metering Infrastructure Project ~ Project 1599211

FINAL ARGUMENT OF FORTISBC ENERGY INC.

SEPTEMBER 28, 2022

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Nicholas T. Hooge

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PART I - OVERVIEW

1. FortisBC Energy Inc. (**FEI** or the **Company**) submits this Final Argument pursuant to British Columbia Utilities Commission (**BCUC**) Order G-259-22.

2. The proposed Advanced Metering Infrastructure (**AMI**) Project (the **Project** or **AMI Project**) is in the public interest and, correspondingly, FEI asks that the BCUC issue a certificate of public convenience and necessity (**CPCN**) and related approvals as set out in the Draft Final Order, Appendix K to the Application (Exhibit B-1).

3. FEI filed the Application in May 2021 and the evidentiary record is substantial. FEI relies on the material it has filed through the course of this proceeding and will not repeat the contents of that material in its entirety. In this Final Argument, FEI highlights certain aspects of the record for ease of reference and addresses certain issues that have arisen. FEI will address in reply particular additional points that interveners raise in their responding arguments.

4. FEI submits that the need for the AMI Project is well established and its implementation will deliver a number of important benefits through automation of the meter reading process (**Automation**). The Project reduces FEI's exposure to emerging labour and materials market challenges, as FEI would no longer be reliant on third-party manual meter reading and outmoded diaphragm meter technology. The Project will ensure FEI has a cost-effective meter technology in place and available for the foreseeable future that delivers a number of benefits that the status quo or other automation technology do not. The Project will have minimal impact on customer annualized rates over the analysis period, at less than half a percent. FEI submits that the need for and benefits of the AMI Project are significant and the CPCN is justified.

PART II – BACKGROUND

A. Metering Technology

5. The vast majority of the gas meters currently deployed in FEI's service territory are diaphragm meters that measure the volume of gas that is displaced for each stroke of the diaphragm. A very small number of other meter types (ultrasonic, rotary, and turbine) are also deployed, with highest prevalence in the commercial and industrial customer sectors. FEI reads nearly all of the over 1,000,000 gas meters manually each month, as these meters do not contain a remote communication device. Additional details regarding the existing complement of meters are set out in Table 3-1 of the Application.[1]

[1] Ex. B-1, p. 15-16

6. The Project for which a CPCN is sought would automate the reading of substantially all meters in FEI's service territory. FEI would accomplish this through replacement of the over 1,000,000 diaphragm meters (only deployed in the residential and small commercial sectors), replacement of the 4,592 ultrasonic meters currently deployed in the residential sector, and retrofitting of large commercial and industrial meters with remote communication devices.[2] The existing residential and small commercial meters will be replaced with ultrasonic, automated gas meters that allow for remote reading through a long-range radio "field area" network (**FAN**).[3] The metering and network technology involved with the AMI Project are discussed in more detail, below, in Part VI.B.

B. Development of Automated and Advanced Metering Generally

7. As set out in the Application and the appended reports from Util-Assist Inc. (**Util-Assist**) and Natural Resources Canada (**NRCAN**), at Appendices A and B of Exhibit B-1, respectively, the development and deployment of automated meter reading technologies for utility meters is well developed and well established across North America.

8. As Util-Assist's report describes, partial automation of meter reading using one-way Automated Meter Reading (**AMR**) technology has been in use for decades in North America and has been implemented by approximately 90 percent of gas utilities across the United States.[4] Ultrasonic meters began to be adopted for industrial applications in the 1970s and 1980s and the technology is now well established for widespread residential use. Residential ultrasonic gas meters were first deployed in the United Kingdom in 1991 and are already in their second and third generations of development overseas.[5]

9. In Canada, 82 percent of electric meters in Canada had been classified as AMI by December 12, 2018. According to NRCAN, AMI technology has been completely or partially approved to be deployed by electric utilities in all Canadian provinces except Manitoba and Newfoundland.[6]

10. Util-Assist explains that gas meters, by comparison to electric, faced greater challenges in costs and engineering switching from traditional diaphragm design to the solid-state of an ultrasonic meter.[7] However, ultrasonic AMI solutions for gas utilities are now at a mature state.[8] There is a clear trend towards the adoption of automated technology in the gas sector. According to an independent consumer research report that FEI commissioned (attached as Appendix C to the Application), by the time of that report approximately 2,000,000 meters out of an estimated 7,000,000 total gas meters in Canada had already been migrated to some form of automated technology. The remaining approximately

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[2] Ibid., p. 15-16
[3] Ibid., p. 77
[4] Ex. B-1, App. A, p. 9
[5] Ibid., p. 6
[6] Ex. B-1, p. 29
[7] Ex. B-1, App. A, p. 6
[8] Ibid.

5,000,000 meters that had not been automated were attributable to FEI and two other utilities – Enbridge and Manitoba Hydro – both of which are investigating the installation of some form of automation in the near future.[9]

11. The proliferation of automated meter reading across utilities has been accompanied by a transition in manufacturers' business models away from traditional diaphragm meters towards ultrasonic meters. One of the three vendors of diaphragm meters, Itron Inc. (**Itron**), provided notice that it was ending the manufacture of all diaphragm meters, effective 2021, to focus its efforts on manufacturing and marketing ultrasonic gas meters.[10] FEI's understanding is that one of the two remaining suppliers of diaphragm meters continues to work toward developing an ultrasonic meter for supply to the North American market; further, in December 2021, the other remaining supplier, Sensus, opened a full-scale manufacturing facility located in Dubois, Pennsylvania dedicated to the production of ultrasonic meters.[11]

12. As utilities move to AMI technology, FEI expects ultrasonic meters will replace diaphragm meters due to:[12]

(a) The advanced capabilities that ultrasonic meters equipped with AMI technology have in comparison to diaphragm meters. Ultrasonic meters incorporate more advanced features such as onboard diagnostics, communications modules, and remotely operable shut-off valves compared with today's mechanical diaphragm meters retrofitted with an AMI module, which do not include any of these advanced features.[13]

(b) The price of advanced metering technology dropping in recent years, which allows ultrasonic meters to be a realistic option for gas utilities, as diaphragm meters do not allow utilities to capture the full benefits of AMI.[14]

13. As discussed in FEI's Evidentiary Update filed in this proceeding July 5, 2022 (Ex. B-30; **Evidentiary Update**), meter vendors have been switching more quickly than FEI expected when it filed the Application from the manufacture of diaphragm meters to the manufacture of ultrasonic meters.[15] FEI has experienced increased costs for diaphragm meters between the filing of the Application and the Evidentiary Update just over 14 months later and, in FEI's recent experience, diaphragm meter delivery timelines required for operating the utility cannot be met.[16]

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9 Ex. B-1, p. 29
10 Ibid., p. 33
11 FEI Response to BCOAPO IR2 2.1 (Ex. B-18)
12 Ibid.
13 Ex. B-1, App. A, p. 6-8
14 FEI Response to BCSEA IR1 12.1 (Ex. B-9)
15 Ex. B-30, p. 5
16 Ibid.

C. AMI in BC

14. In the last ten years, the two major electric utilities within British Columbia, British Columbia Hydro and Power Authority (**BC Hydro**) and FortisBC Inc. (**FBC**), have both transitioned to AMI technology for their electricity meters. In 2011, BC Hydro began implementing an AMI system known as its "Smart Metering Initiative" across its service territory.[17] BC Hydro was mandated by government to implement AMI technology. In particular, section 17 of the *Clean Energy Act*, S.B.C. 2010, c. 22 (***CEA***), provided that BC Hydro "must install and put into operation smart meters and related equipment in accordance with and to the extent required by the regulations". The *Smart Meters and Smart Grid Regulation*, B.C. Reg. 368/2010, which is discussed in detail later in these submissions, further defined the technical properties and attributes of the smart meters BC Hydro was required to install and required that the smart meters be installed on all "eligible premises" (generally all customer properties connected to BC Hydro's electricity distribution system).

15. The benefits that BC Hydro cited for installing advanced meters included 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."[18] These benefits also largely apply in the case of natural gas. By the completion of the Smart Metering Initiative in 2015, BC Hydro had installed almost 2,000,000 smart meters at customer premises.[19]

16. With respect to FBC, an application to the BCUC for a CPCN was required in order to proceed with installation of AMI in FBC's electricity service territory. FBC filed an Application for a CPCN for the Advanced Metering Infrastructure Project (the **FBC AMI Project**) on July 26, 2012. As described in additional detail below, on July 23, 2013, the BCUC issued its Decision and Order C-7-13 approving a CPCN for the FBC AMI Project (the **2013 AMI Decision**) subject to the condition that FBC would apply for an opt-out provision. Following BCUC approval of FBC's Radio-off AMI Meter Option on December 19, 2013, FBC began implementing its AMI system across its service territory and completed deployment in 2016.[20]

17. In addition to BC electric utilities, the province's other major distributor of natural gas, Pacific Northern Gas (N.E.) Ltd. (**PNG(NE)**) recently received BCUC approval to transition to AMR. In its application to the BCUC, PNG(NE) set out several non-financial benefits of pursuing Automation, including timely and accurate meter reading, reduced workforce injuries, increased customer satisfaction, environmental benefits from reduced vehicle emissions, and improved revenue protection.[21] In approving PNG(NE)'s proposed

[17] Ex. B-1, p. 30
[18] Ibid.
[19] Ibid.
[20] Ibid.
[21] BCUC Decision and Order C-3-20, p. 7

AMR upgrade, the BCUC panel stated that it was satisfied with the need for operational efficiencies, savings on operating costs and noted that worker safety will be improved.[22] The BCUC also concluded that, given PNG(NE)'s operating circumstances, the proposed AMR project was more appropriate than the increased costs required for AMI in PNG(NE)'s service territory; among other things, the Panel noted there was a low risk of redundancy in choosing to implement AMR technology given that the system had the capability to be upgraded to AMI in the future.[23]

18. Once PNG(NE) has completed deployment of its AMR system, FEI will be the only remaining large, regulated utility in BC that does not use Automation technology for meter reading.[24]

D. The BCUC's 2013 AMI Decision

19. The BCUC's 2013 decision approving the FBC AMI Project followed a 10-day oral hearing in Kelowna over the period from March 4 to March 15, 2012. The oral hearing addressed security, environmental, and health topics related to FBC's proposed electric AMI; these and other topics were also addressed in later written submissions. FBC presented two witness panels that included expert witnesses from Exponent, Inc. (**Exponent**) on issues related to the potential health effects of radiofrequency (**RF**) emissions. One of the Exponent witnesses involved in this prior oral hearing, Dr. William Bailey, Ph.D is a co-author of the Exponent RF Health Report filed with the current FEI Application.[25]

20. One of the interveners in the 2012-2013 BCUC proceeding regarding the FBC AMI CPCN, the Citizens for Safe Technology Society (**CSTS**), vigorously opposed the application on the basis of alleged negative health effects of the RF emissions associated with AMI. Five expert witnesses filed evidence on behalf of CSTS and were subject to cross-examination during the oral hearing.[26] Two other interveners, Area D, Regional District of Central Kootenay (**RDCK**), represented by Andy Shadrack, and Nelson Creston Green Party (**NCGP**), represented by Michael Jessen, also made similar submissions regarding the purported RF health effects associated with advanced meters.[27]

21. In addition, the 2013 AMI Decision noted "the high degree of public interest in this Proceeding". This included "178 Letters of Comment, with nearly all of them expressing opposition to the Application. When signatures from petitions are included, the number of individuals who wrote to the Commission in opposition to the Application was over 2,200".[28] The BCUC also heard from participants at several community input sessions.

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[22] Ibid.
[23] Ibid., p. 9
[24] Ex. B-1, p. 31
[25] Ex. B-1, App. F-2
[26] 2013 AMI Decision, p. 5 [Book of Authorities, Tab 14]
[27] See e.g. Ibid., p. 135-136
[28] Ibid., p. 50

22. In its 2013 AMI Decision, the BCUC Panel qualified the two proffered Exponent witnesses to give expert opinion evidence on behalf of FBC. The Panel qualified Dr. Bailey as an exper, to give opinion evidence in the field of bio-electromagnetics and in particular, in the health risk assessment of exposure to electromagnetic fields, including RF signals.[29] The Panel described Dr. Bailey as "demonstrat[ing] a comprehensive knowledge and understanding of a wide range of studies that have been conducted within the area of his qualified expertise." The Panel further commented that, "His assessment of comparative studies and their interrelation was objective and presented in an understandable way" and that, "The evidence provided by Dr. Bailey was very useful to the Panel."[30] Another Exponent witness, Dr. Yakov Shkolnikov, who prepared the equivalent of the report submitted in the FEI Application as Appendix F-2, referred to as the Exponent RF Technology Report, was also qualified by the 2013 BCUC Panel, "as an expert to give opinion evidence in the fields of electromagnetic exposure, electromagnetic interference and engineering physics, including the physics of electromagnetic fields, which includes radio frequency fields".[31] The Panel noted that Dr. Shkolnikov was "very thorough in his responses and exhibited no apparent signs of bias. He also did not advocate for any particular position."[32]

23. The BCUC found the FBC AMI Project to be in the public interest and approved the CPCN. The Panel found the need for AMI in FBC's electric service territory was "not singular, but flows from a number of needs, including: replace metering technology that is no longer supported and provide a foundation for future upgrades to the grid. In addition, the Project provides FortisBC with opportunities to reduce the amount of energy theft, reduce operating costs and improve customer service, all to the benefit of the customer".[33] The Panel found, among other things, that FBC had "adequately analyzed the project alternatives and the project risk".[34]

24. The 2013 AMI Decision includes a number of findings regarding the regulation of RF health risks in Canada and the effects of RF associated with AMI that are relevant and applicable in the present proceeding given the intervention of the Coalition to Reduce Electropollution (**CORE**) and the evidence filed on its behalf. These prior BCUC findings are discussed in detail in Part XI.B, below. In brief summary, in the 2013 AMI Decision, the Panel found that:

(a) The FBC AMI Project complied with Canadian safety standards as set out by Health Canada with respect to RF emissions;

[29] Ibid., p. 14
[30] Ibid., p. 17
[31] Ibid., p. 28
[32] Ibid.
[33] Ibid., p. 152
[34] Ibid.

(b) Health Canada's Safety Code 6 takes into account the scientific evidence related to the impact of thermal and non-thermal effects of RF emissions on human health and provides an appropriate degree of precaution in setting the limits for these emissions;

(c) The RF emissions generated by the FBC AMI Project are significantly below the levels set out in Safety Code 6 established by Health Canada to ensure such emissions are not harmful to human health;

(d) While there are individuals who feel strongly that low levels of electromagnetic emissions will have a negative impact on their health, the scientific evidence did not persuade the Panel that there is a causal link between RF emissions and the symptoms of electromagnetic hypersensitivity.[35]

E. Procedural Summary

25. FEI filed the present Application on May 5, 2021. Requests to intervene were filed on behalf of 12 separate parties. The intervener CORE, in response to a BCUC direction (Ex. A-16), subsequently joined with the individual interveners Mr. and Ms. de Raadt, Mr. Schluschen, and Ms. Noble, for the purposes of pursuing a collective intervention.[36] As used in this Final Argument, "CORE" should be taken to mean this collective group of interveners.

26. The BCUC approved the interventions of all of the interveners that now comprise CORE for the purposes of this proceeding. However, in each case, the orders approving intervention (Ex. A-8, A-9, A-11, and A-12) state that the request to intervene "is accepted on the ground of being 'directly or sufficiently affected by the Commission's decision in this matter' rather than on the ground of 'experience, information, or expertise relevant to this matter that would contribute to the Commission's decision making'". These BCUC orders further state that, "Pursuant to Rules 9.07 and 9.08, <u>intervention is limited to matters of direct and sufficient relevance to you</u>" (underlining added).

27. In addition, although there is some overlap with the interventions, 16 parties requested interested party status and 11 letters of comment are currently filed in this proceeding.

28. On September 8, 2021, CORE sought an extension of the deadline for interveners to register by at least five weeks and for additional publication of the Public Notice of this proceeding in newspapers in the Penticton area. On September 14, 2021, pursuant to Exhibit A-14, the BCUC denied this request. On November 12, 2021, CORE filed an application for reconsideration (**Reconsideration Application**) of the BCUC's decision declining the extension request. Following receipt of written submissions from FEI and other interveners and reply submissions from CORE, on March 8, 2022, the BCUC issued Order G-66-22 denying CORE's Reconsideration Application.

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[35] Ibid., Executive Summary, p. (i)-(ii)
[36] Ex. C7-11, para. 3

29. FEI responded to two initial rounds of Information Requests (**IRs**) from interveners and the BCUC on October 26, 2021 and February 17, 2022.

30. On March 3, 2022, in advance of a scheduled Procedural Conference, CORE filed submissions regarding the scope of intervener evidence it intended to file. CORE's submissions (Ex. C7-11) stated, among other things, its "position that the AMI Project is not in the public interest, and the BCUC must not give its approval for the Certificate of Public Convenience and Necessity sought".[37]

31. On March 11, 2022, the BCUC held a Procedural Conference. Topics of submissions at the Procedural Conference included the scope of intervener evidence CORE intended to file and further process in respect of the Application. In its order (Order G-92-22) dated March 31, 2022 following the Procedural Conference, the BCUC accepted that the scope of CORE's intervener evidence could include expert evidence from three named witnesses, Drs. Paul Héroux, Magda Havas and Anthony Miller, regarding, "the possible biological impacts of radiofrequency, electromagnetic fields and electromagnetic radiation on humans, topics identified by CORE in its application to intervene as accepted by the Panel".[38] CORE was also granted leave to file non-expert evidence from Mr. Hans Karow, but the Panel stated that Mr. Karow should "restrict his evidence to the topics in scope for CORE's intervention in this proceeding, as set out in section 2.2 above, and that his evidence does not duplicate that provided by CORE's experts".[39]

32. Order G-92-22 includes the Panel's finding that, "CORE's scope of intervention does not include privacy, security or electrical engineering issues. None of these issues were identified by CORE in its request to intervene, nor were they identified by the other interveners who have joined CORE since, and CORE did not contest this point during the Procedural Conference when it was noted by FEI".[40] The Panel also set a further regulatory timetable for the submission of CORE's intervener evidence, rebuttal evidence and an evidentiary update from FEI, and associated IRs in respect of these evidentiary filings.

33. On April 14, 2022, CORE filed its intervener evidence in the form of expert reports from Drs. Héroux, Havas, and Miller, as well as a non-expert witness statement of Mr. Karow (Exs. C7-12 and C7-12-1). On June 2, 2022, CORE responded to IRs from FEI, the BCUC, and other interveners.

34. On June 23, 2022, FEI filed its rebuttal evidence (Ex. B-26) in respect of CORE's intervener evidence. FEI's rebuttal evidence consists of two parts: rebuttal evidence from FEI itself and separate rebuttal evidence from Exponent (together, the **Rebuttal Evidence**). On July 5, 2022, FEI submitted the Evidentiary Update noted above (Ex. B-30).

[37] Ibid., para. 4
[38] Order G-92-22, p. 9
[39] Ibid., p. 12
[40] Ibid.

35. On July 22, 2022, following written submissions from participants in this proceeding, the BCUC issued Order G-206-22, which denied CORE's request to convene an oral hearing in respect of the Application. The Panel found that there was "no compelling need to enhance the evidence in this proceeding or test the evidence through cross examination".[41]

36. On September 16, 2022, after receiving written submissions from participants on the appropriate further process for the Application, the BCUC issued Order G-259-22 determining that the proceeding will be concluded through written argument from FEI and interveners, followed by reply argument from FEI.

PART III – LEGAL AND REGULATORY FRAMEWORK

A. The *Utilities Commission Act* and Other Applicable Enactments

37. Sections 45 and 46 of the *Utilities Commission Act*, R.S.B.C. 1996, c. 473 (***UCA***) set out the legislative framework for the BCUC's review of CPCN applications. Section 45(1) of the *UCA* states that, "Except as otherwise provided, after September 11, 1980, a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the commission a certificate that public convenience and necessity require or will require the construction or operation."

38. Section 46(3) provides that the BCUC may issue or refuse to issue a CPCN or may issue a CPCN for the construction or operation of only a part of the proposed facility, line, plant, system, or extension, and may attach terms and conditions to the CPCN. Section 46(3.1) requires the BCUC to consider:

(a) the applicable of British Columbia's energy objectives;

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any; and

(c) the extent to which the application for the CPCN is consistent with the applicable requirements under sections 6 and 19 of the *CEA*.

39. British Columbia's energy objectives referenced in section 46(3.1) of the *UCA* are set out in section 2 of the *CEA*. Applicable objectives in respect of the AMI Project include the following:

(a) to take demand-side measures and to conserve energy (s. 2(b));

(b) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency (s. 2(d));

(c) to reduce B.C. greenhouse gas emissions (s. 2(g));

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[41] BCUC Order G-206-22, p. 6

(d) to encourage communities to use energy efficiently (s. 2(i));

(e) to encourage economic development and the creation and retention of jobs (s. 2(k)).

40. The Project's support and promotion of these provincial energy objectives is discussed below in Part XIII of this Final Argument.

41. In addition, FEI notes that section 17(6) of the *CEA* refers to a provincial government "goal" of having "other advanced meters … in use with respect to customers other than those of [BC Hydro]". The advanced meters proposed as part of the Project fit within this description and their implementation is therefore consistent with this specific government energy objective or "goal".

42. The BCUC has previously held that sections 6 and 19 of the *CEA*, referred to in section 46(3)(c) of the *UCA*, "apply to electric utilities only".[42] Accordingly, these provisions do not apply in respect of the CPCN applications of a gas utility such as FEI.

43. The BCUC's *Certificate of Public Convenience and Necessity Application Guidelines*, issued pursuant to Order G-20-15 (**CPCN Guidelines**) provide general guidance regarding the information that should be included in a CPCN application. In summary, the CPCN Guidelines generally require CPCN applications to include various information regarding:

(a) the applicant for the project;

(b) project need, alternatives, and justification;

(c) First Nations and public consultation;

(d) project description;

(e) project cost estimate;

(f) provincial government energy objectives and policy considerations.

44. The information FEI submitted with the Application[43] for the AMI Project conforms with and includes all necessary information required under the CPCN Guidelines.

45. In addition to a CPCN, FEI's Application also seeks approval of four new asset accounts, with associated depreciation and net salvage rates, as well as four new deferral accounts. These aspects of the Application engage the BCUC's rate setting authority under section

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[42] Terasen Utilities (Terasen Gas Inc., Terasen Gas (Whistler) Inc. and Terasen Gas (Vancouver Island) Inc.) 2010 Long Term Resource Plan – BCUC Decision and Order G-14-11, p. 16 **[Book of Authorities, Tab 17]**; FortisBC Energy Inc. 2017 Long Term Gas Resource Plan – Decision and Order G-39-19, p. 3 **[Book of Authorities, Tab 15]**

[43] Supplemented by the FEI Supplemental Information filing (Ex. B-2) and FEI's Evidentiary Update (Ex. B-30)

59-61 of the *UCA*, as well as section 56(2) of the *UCA*, which provides that "[t]he commission must determine and, by order after a hearing, set proper and adequate rates of depreciation."

B. The CPCN Test

46. In the 2013 AMI Decision, at page 7, the BCUC described the Supreme Court of Canada's decision in *Memorial Gardens Assn. (Can.) Ltd. v. Colwood Cemetery Co.*, [1958] S.C.R. 353, 1958 CanLII 82 (***Memorial Gardens***) as the "leading case on public convenience and necessity" and noted a number of prior BCUC decisions that had adopted its description of the CPCN test.

47. The majority judgment in *Memorial Gardens* holds that it would "be both impracticable and undesirable to attempt a precise definition of general application of what constitutes public convenience and necessity" and that "the meaning in a given case should be ascertained by reference to the context and to the objects and purposes of the statute in which it is found". The majority then describes the appropriate determination of public convenience and necessity as follows:

> As the Court held in the *Union Gas* case the question whether public convenience and necessity requires a certain action is not one of fact. It is predominantly the formulation of an opinion. Facts must, of course, be established to justify a decision by the Commission but that decision is one which cannot be made without a substantial exercise of administration discretion. In delegating this administration discretion to the Commission the Legislature has delegated to that body the responsibility of deciding in the public interest, the need and desirability of additional cemetery facilities, and in reaching that decision the degree of need and of desirability is left to the discretion of the Commission.[44]

48. Prior BCUC decisions had also stated that determining what constitutes public convenience and necessity involves a "flexible test" and that there are "a broad range of interests that should be considered in determining whether an applied for project is in the public convenience and necessity".[45]

49. The 2013 AMI Decision found that "future needs can be considered" in CPCN decision-making given the wording of section 45(1) of the *UCA*, which refers to "a certificate that public convenience and necessity require <u>or will require</u> the construction or operation" of the utility plant or system in issue.[46]

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[44] *Memorial Gardens*, at p. 357 **[Book of Authorities, Tab 9]**
[45] See 2013 AMI Decision, p. 8
[46] Ibid., p. 9 (underlining added)

PART IV – THE APPLICANT

50. Section 1 of the CPCN Guidelines requires a CPCN application to include various information about the applicant for the project in issue.

51. FEI's Application includes all required information set out in Section 1 of the CPCN Guidelines, primarily in Section 2 of the Application, but also in Sections 5.6.1-5.6.2, which describe the Project leadership team and Executive Sponsorship for the Project within FEI. In particular, Sections 2.2 and 2.3 of the Application establish FEI's financial and technical capacity to undertake the Project.

PART V – PROJECT NEED

A. Summary

52. As addressed in detail in Section 3 of the Application, FEI's need for the Project is to automate the meter reading process (as defined above, Automation) for FEI customers. In this context, Automation refers to the ability to communicate with the meters at customer premises to collect gas consumption readings, alarms, and other diagnostic information. The benefits of Automation, addressed in more detail in Part VIII below, include a more accurate and more convenient process for customers and a stable, cost-effective meter reading solution for the long term. Automation also provides access to more timely information, which will improve safety and system resiliency, as well as empower customers to make informed energy decisions, enhance their energy conservation efforts, and have more control over their energy costs.[47]

53. The need for Automation of the meter reading process encapsulates a number of subsidiary Project needs, such as:

(a) To provide more accurate and convenient billing processes for FEI's customers;

(b) To reduce the cost and service risks of manual meter reading;

(c) To provide a cost-effective, long-term metering alternative, particularly given supply issues for diaphragm meters are already occurring and the expectation is that meter manufacturers will continue to transition business models to ultrasonic meters;

(d) To empower customers to make informed energy decisions, enhance their energy conservation efforts, and have more control over their energy costs.

54. In sum, manual meter-reading and traditional mechanical diaphragm meters are becoming outdated and an Automation solution, via AMI, is required to address the Project need summarized above. FEI submits that need for Automation and, specifically the AMI

[47] Ex. B-1, p. 14

Project, is compelling and well-established in the Application and other evidence filed in this proceeding.

55. One of FEI's commitments to its customers is to deliver energy safely and reliably for the lowest reasonable cost and meter reading plays an important role in FEI's ability to provide that service.[48] Automation of the meter reading process further supports FEI's ability to deliver on these commitments while supporting other drivers of the Project need described below and in Section 3 of the Application.

56. FEI has been investigating the adoption of Automation of some form for many years; however, FEI has always previously determined the benefits for customers and the Company offered by the available technology, combined with the relative cost of Automation compared to the cost of existing operations, did not support the move to adopt Automation.[49] That has now changed.[50]

57. FEI submits that that the need for the AMI Project is present now and not at some indefinite time in the future. Continuing to read meters manually for an indeterminate period would delay Automation, but would not remove the need for it. The longer that FEI waits to automate, the more vulnerable FEI and its customers are in respect of the ability to have access to continuous manual meter reading at a competitive market price, while also continuing to face service risks.[51] Given increasing material and metering costs described in the Evidentiary Update, and FEI's existing fixed contract price with Sensus, together with the significant benefits of AMI described below, proceeding with the AMI Project now is prudent and in the public interest.

B. Customer Service Issues and Drawbacks for Manual Meter Reading

58. FEI's current manual meter-reading process creates a variety of customer service issues due to lack of Automation.

59. Meter readers manually collect readings from the vast majority of FEI's over 1,000,000 meters each month. With off-cycle reads included, the number of reads per month further increases. As shown in Table 3-2 of the Application, FEI's meter reading needs have been gradually increasing to the point that FEI now requires over 12,000,000 reads per year, averaging well-over 1,000,000 manual meter reads per month in the last three years.[52]

60. As described in further detail in Section 3 of the Application, the highly manual meter reading process FEI currently employs creates a number of operational and customer-service issues. From a customer's perspective, the meter reading process requires an

[48] FEI Response to RCIA IR2 49.3 (Ex. B-20)
[49] FEI Response to CEC IR1 13.1 (Ex. B-8-1)
[50] Ibid.
[51] FEI Response to BCSEA IR1 6.1 (Ex. B-9)
[52] Ex. B-1, p. 19

unfamiliar third party (the meter reader) to access their property on a monthly basis. Some customers have to provide spare keys or entry codes to FEI for access to the meter on their property. This is inconvenient for customers, but also managing and maintaining up-to-date keys and access codes are ongoing challenges.[53]

61. In addition, the current meter reading process results in estimated bills and billing inaccuracies that affect the quality of service provided to FEI's customers. The manual meter reading process requires meter readers to view the digits on the meter and manually enter those digits into a handheld device. This gives rise to two primary causes of inaccurate bills: (i) human error by meter readers inputting data; and (ii) estimated bills in circumstances where meter readers cannot perform a monthly read due to access issues, bad weather, or meter reader availability.

62. As explained in section 3.1.2 of the Application, inaccurate bills and estimated bills both negatively impact customer experience and result in additional processes (and associated costs), as well as customer confusion and dissatisfaction, and potential payment issues. With respect to estimated bills, Tables 3-4 and 3-6 in the Application suggest that manual meter reading was responsible for approximately 9% more estimated bills in 2020 than would have been the case under an automated process when FEI billing is compared with FBC's billing via AMI.[54] FEI estimates that Automation would improve the accuracy of approximately 260,000 to 390,000 bills each year, all else being equal, resulting in an improved experience for a large number of customers each year.[55]

63. Another issue is that meter testing and exchanges associated with diaphragm meters significantly impact residential and commercial customers. The testing process for residential diaphragm meters required by Measurement Canada is different from other meter types and is described in detail in section 3.1.1.2 of the Application. The meter testing and exchange process impacts approximately 60,000 FEI customers on average per year.[56] Figure 3-1 in the Application shows in detail the various required customer interactions and appointment bookings that occur to support the current meter exchange process. There is also a risk that FEI will need to cancel a given meter exchange appointment, in the event of an emergency requiring personnel to attend elsewhere, or because the customer is not present at the time the technician is on site, in which case additional interactions are required to book a new appointment window. Subject to Measurement Canada regulations, the complete replacement of FEI's diaphragm meters for residential and most commercial customers to support Automation will mean that the meter testing and exchange process will not thereafter be required for residential and most commercial customers for several years.[57]

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[53] Ibid., p. 20
[54] Ibid., p. 23-24
[55] Ibid., p. 24
[56] Ibid., p. 18
[57] Ibid.

C. Operational Issues and Costs of Manual Meter Reading

64. Currently, there are approximately 150 meter readers reading FEI meters throughout BC on a daily basis. These meter readers are typically based out of more than 30 of FEI's muster sites, which are situated as far north as Fort Nelson, and as far south as Langford.[58] The work is physically demanding; job postings for meter readers require incumbents to be physically fit with the ability to walk long distances (15-20 km) on a daily basis in order to fulfill the duties of the job.[59]

65. The work involved in manual meter reading affects FEI in different ways. For one, the nature of the work inevitably leads to safety-related incidents where meter readers attempt, but are unable to complete, meter reads. This results in billing estimates (and the associated issues described above) and, in addition, FEI's meter reading contractor, Olameter Inc. (**Olameter**), invoices FEI for these attempted reads, at an average of $334,000 per year, which factors into customer rates.[60] The nature of meter reading makes it difficult to retain meter readers, which creates operational issues and a risk to customer service. Regular recruitment is required in order to maintain sufficient numbers of trained staff. This negatively impacts FEI and, in turn, its customers because lack of available staff or new meter reading personnel leads to larger numbers of estimated bills.[61]

66. In addition, FEI's current manual meter-reading operations face the real risk of increased long-term costs due to the industry trend towards Automation, discussed above. Suppliers of both products and services that support manual meter reading have gradually been adapting to the changing market place. In response to the continued automation of meter reading by utilities, members of industries that support manually read meters and manual meter reading are shifting their business models. As noted above and described in more detail in section 3.3.2 of the Application, one of the three vendors of diaphragm meters, Itron, provided notice that it was ending the manufacture of all diaphragm meters, effective 2021, to focus its efforts on manufacturing and marketing ultrasonic gas meters.[62] FEI's expectation is that new market participants for diaphragm meters are unlikely to materialize and as such, the absence of Itron as a supplier in the diaphragm meter market place is expected to result in an increase in the unit price and an overall decrease in the supply available.

67. The expected increase in cost of diaphragm meters manifested itself during the approximately 14 months between FEI's filing of the Application on May 5, 2021 and the Evidentiary Update on July 5, 2022. The increase in costs for diaphragm meters is reflected in the increase in the financial analysis for the status quo scenario (**Baseline**) in the

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[58] Ibid., p. 20
[59] Ibid., p. 31
[60] Ibid., p. 32
[61] Ibid.
[62] Ibid., p. 33

Evidentiary Update.[63] Diaphragm meter costs have increased 26 percent for residential type meters and 6 percent for commercial type meters over the amount originally reflected in the Application, which was based on 2020 cost information.[64] Further, in FEI's recent experience diaphragm meter delivery timelines required for operating the utility cannot be met. The late 2021 and 2022 delivery lead times for diaphragm meters increased from the typical 12 to 16 weeks to more than 36 weeks.[65] This impacts the ultimate viability of the Baseline scenario.[66]

68. The long-term costs of manual meter reading services are also uncertain but expected to increase. FEI has chosen to continue contracting for meter reading services from Olameter in the short term. Other than Olameter, FEI is not aware of another manual meter reading service provider able to provide meter reading service on the scale required by the Company.

69. FEI believes the viability of contracted meter reading services in the future is uncertain, in terms of both cost and availability. There is a material risk to customers and the Company that the current practice of outsourcing manual meter reading will not be sustainable in the long term. That is, either the existing provider(s) may move on to other lines of business, similar to the case of the manufacturers of the diaphragm meters, or the costs for this third-party support will continue to grow. FEI has certainty that, under the terms of its current contract with Olameter, inflationary increases are embedded in pricing until the end of 2026 (although Olameter does have the ability to terminate the contract on 6 months' written notice).[67] Beyond that, the cost of manual meter reading by an external vendor is unknown, as is the availability of such vendors.[68]

70. FEI considers repatriation of the meter reading function to be the only manual meter reading solution that could be viable in the long term, which would be more costly than the current outsourced model.[69] Transitioning to an in-house model is a significant task, requiring time for planning, development, recruiting, and training.[70]

D. Limitations on Data and FEI's Ability to Meet Evolving Customer Expectations

71. As discussed in section 3.4.1 of the Application, customers' expectations for service have changed over the last several years and FEI expects they will continue changing based on improvements and access to technology and experiences with other service providers. With customers comparing their FEI experiences with their last best customer experience, the

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63 Ex. B-30, p. 5 and Confidential Appendix C in Confidential Appendix G-2, Baseline Cost Inputs Schedule 1, Line 16 (residential) and 17 (commercial)
64 Ibid.
65 FEI Response to RCIA IR1 10.2 (Ex. B-13)
66 Ex. B-30, p. 5
67 FEI Response to RCIA IR1 6.1 (Ex. B-13)
68 FEI Response to BCUC IR1 22.1 (Ex. B-6)
69 Ex. B-1, p. 35
70 FEI Response to BCUC IR1 22.3 (Ex. B-6)

limited information they have access to currently as a result of manual meter reading means that FEI is falling short in this aspect of service as compared to other customer service experiences. Specifically, due to the limitations of monthly manual meter reads under the current system, FEI customers only have access to usage and consumption data on a per month basis. As shown in Figures 3-4 and 3-5 of the Application, this is significantly more limited than the granularity of usage data (down to the hour) that is available to customers of utilities (such as FBC) that employ AMI for meter reading.[71]

72. Customer feedback has indicated that detailed consumption information is high on the list of customer priorities for their bill from FEI and FBC (together, **FortisBC**); in particular, in a recent poll of FortisBC's MyVoice panel, approximately 75 percent of respondents rated having comprehensive online information about home energy use as very important.[72]

73. Additionally, without Automation, the current manual meter reading system leaves FEI unable to develop and implement future opportunities for enhancements to other components of customer experience, including enhanced billing options, and targeted demand side management (**DSM**) opportunities.[73] Similarly, the lack of detailed usage and other customer data under the manual meter reading system means that customers will find it increasingly challenging to make informed energy choices and implement efficiency and conservation measures that support FEI, the Province, and customers themselves in meeting long-term energy conservation and greenhouse gas (**GHG**) reduction goals.[74]

PART VI - PROJECT DESCRIPTION

A. AMI Project Overview

74. In broad terms, the AMI Project involves the replacement of over 1,000,000 existing diaphragm meters in use in the residential and small commercial customer sectors with advanced, ultrasonic gas meters, and the associated implementation of a radio network to enable remote communication of gas consumption and other metering information from the advanced meters/modules at customer premises to FEI.

75. Section 5 of the Application (as updated pursuant to the Evidentiary Update) includes detailed information describing the AMI Project, including its scope and technical components, the history of FEI's Project development activities, a description of FEI's Project implementation approach and schedule, and a discussion of identified risks and FEI's approach to risk management.

[71] Ex. B-1., p. 38-39
[72] Ibid., p. 36
[73] Ibid., p. 40
[74] Ibid.

76. FEI submits that it has provided all necessary information required for a description of the AMI Project under section 4 of the CPCN Guidelines. The following submissions summarize some of the key aspects of the Project.

B. AMI Project Scope

i. Overall Project Scope

77. As set out in section 5.2.1 of the Application, FEI's proposed AMI Project will deliver the scope described below, with associated capabilities:

Installation of:

(a) Approximately 1,100,000 residential, commercial, and industrial advanced meters and meter retrofits of communication modules capable of remote gas consumption measurement;

(b) Approximately 1,100 communication modules on the gas network to increase operational awareness of the gas system state;

(c) The AMI network and infrastructure to communicate with customer meters and other communication modules on the FEI gas network;

(d) Approximately 780,000 bypass valve sets, as required, on residential and small commercial meter sets;

(e) Residential and small commercial meter set regulators to replace those that will exceed their expected service life prior to the first meter exchange planned for post-AMI Project deployment.

Capabilities to:

(f) Remotely monitor the condition of AMI network infrastructure;

(g) Provide alarms for critical status of meters, for residential and small commercial customer meters, such as meter tamper, high temperature, low battery, high consumption, reverse gas flow, meter health and others;

(h) Enable remote turn off/on (valve closure/open) of gas service for residential and small commercial meters, including automatic shut off in the event of high flow detection;

(i) Turn off gas supply to large groups of customers quickly in the event of an emergency, for residential and small commercial meters;

(j) Detect and deter gas theft;

(k) Facilitate automated data collection, including daily consumption register readings and hourly consumption interval readings from approximately 1,100,000 residential, commercial, and industrial customer meters;

(l) Enable customer access to hourly consumption information via enhancements to FEI's secure customer portal;

(m) Provide notification of gas flow anomalies for use in identifying potential gas leaks, faulty customer appliances and appliances/equipment mistakenly left on, for residential, commercial, and small industrial customers.

78. Section 5.4 of the Application describes the end-to-end architecture of the AMI Project as well as the technical components that comprise the AMI Project and their associated functions. In broad terms, these components are as follows:

(a) Sensus FlexNet Field Area Network, including Sensus Sonix IQ advanced gas meters and other two-way communication modules (**End Points**) for transmission of data to Sensus FlexNet Base Stations (**Base Stations**) (Section 5.4.1.1);

(b) Sensus Head End System (Section 5.4.1.2);

(c) Sensus FlexNet Communication Network (Section 5.4.1.3);

(d) AMI Applications (Section 5.4.1.4); and

(e) FEI Enterprise Systems (Section 5.4.1.5).

ii. Sensus Sonix IQ Gas Meters

79. The advanced meters themselves are the most customer-facing part of the AMI Project and have been the subject of intervener evidence. These and the other components of the proposed Sensus FlexNet network are described in Section 5.4.1.1 of the Application, as well as in the Exponent RF Technology Report (Ex. B-1, App. F-1).

80. The Sensus Sonix IQ gas meters to be deployed at customer premises are the main type of "End Point" within the FlexNet network. The End Points are meters or other modules that communicate directly with network Base Stations. The Sonix IQ gas meters are proposed to constitute more than 90% of the approximately 1,000,000 End Points anticipated to be deployed.[75] Sonix IQ gas meters are residential and small commercial gas meters that operate using ultrasonic sound to measure flow and have an integrated two-way RF transceiver that is used for two-way wireless communication.[76]

[75] Ex. B-1, App. F-1, p. 15
[76] Ex. B-1, p. 78 and App. F-1, p. 16

81. The Sensus FlexNet network would operate on a dedicated licensed radio spectrum, unlike some other network architectures, which has the benefit of limiting external interference sources, as well as limiting how frequently data needs to be communicated from individual meters to Base Stations.[77] Each Sonix IQ gas meter is configured to transmit every 4 hours on a pseudo-random schedule, which results in a constantly shifting but regular transmission schedule. The total transmission time for the Sonix IQ gas meters under typical operation is approximately 0.34 seconds per day.[78] This short, intermittent transmission time reflects a duty cycle of 0.00039%.[79] Further detail regarding the transmission characteristics and resulting RF exposure levels of the Sonix IQ gas meters is provided below in Part XI.E.

82. The Sonix IQ gas meters are also equipped with automated shut-off capability. The advanced meters can detect large leaks downstream and be programmed to automatically shut off the internal valve, significantly decreasing the potential for the development of a hazardous situation.[80] FEI intends to deploy the leak detection and automatic shutoff capability for all customers. To enhance leak detection, data analytics will be used to analyze hourly consumption information.[81] FEI will be automatically notified when the meter's internal valve closes because of an unexpectedly high flowrate. When this notification is received, FEI will attempt to contact the customer to determine why the meter detected a high flow rate and, if necessary, FEI will also dispatch a field employee to investigate the source of the high flow rate.[82] The advanced meter's automatic shutoff capability will provide FEI with a new tool to enhance the Company's public safety efforts.

83. Mr. Karow's non-expert evidence on behalf of CORE expresses concerns about the potential for the lithium batteries in the Sonix IQ gas meters to explode at high temperatures, if heated to 212 degrees Fahrenheit.[83] Mr. Karow and CORE have not presented any credible evidence demonstrating a risk of temperatures reaching this level in actual operations and putting the meter batteries at risk. However, and more importantly, as explained in FEI's Rebuttal Evidence, this battery technology has been used safely by gas utilities across North America for over 30 years, including in many existing FEI gas meters and other field devices.[84] FEI has not previously had batteries of this type in its own measurement equipment fail in an unsafe manner in that time.[85]

[77] Ex. B-1, App. F-1, p. 13
[78] Ibid., p. 20; See also FEI Response to CORE IR2 33.a (Ex. B-22), explaining that the 0.34 seconds per day value is calculated based on 6 transmissions per day, each lasting 52.58 milliseconds, plus approximately 3 additional status updates per weeks.
[79] Ex. B-1, App. F-1, p. 20
[80] Ex. B-1, p. 61
[81] FEI Response to BCUC IR1 2.1 (Ex. B-6)
[82] FEI Response to BCUC IR1 2.2.1(Ex. B-6)
[83] Ex. C7-12-1, App. A, p. 2
[84] Ex. B-26, Part 1, p. 2
[85] Ibid.

iii. Meter Set Bypass Valves and Regulators

84. FEI's engineering standard for meter set design includes installation of meter set bypass valves and regulators. As part of FEI's existing meter exchange sustainment program, meter set bypass valves are installed and regulators are replaced. Given that the Project will require every meter to be either exchanged or upgraded with a communication module, the Project will deploy bypass valves and replace residential and small commercial regulators for all applicable meters.[86]

85. The scope of work for bypass valve replacement typically includes replacing the existing meter set inlet shutoff valve and adding an additional valve to the meter set outlet. These allow a portable bypass assembly to be used during future meter exchanges or other work on the meter set equipment, which avoids interrupting the flow of gas (and hence the occasion for the technician to enter customer premises to relight appliances). The benefits of this replacement work include: increased customer satisfaction by eliminating scheduled meter exchange appointments requiring customers to be present in relation to appliance relights, increased operational efficiencies and associated cost savings related to the bulk purchase of bypass valve materials and geographically clustered installation, capital savings for future contact centre costs, and future O&M savings for the increased operational efficiencies with reduced time to complete each meter exchange.[87]

86. Given the various benefits, FEI considers the most appropriate long-term decision was to include installation of bypass valves in the scope of the AMI Project so that the program's full benefits could be realized sooner.[88]

87. Based on FEI's experience, approximately 50 percent of the time a meter is exchanged, the regulator also needs to be replaced. Based on the age of FEI's current in-service regulators and FEI's experience in managing this sustainment capital program, FEI expects that 50 percent of the existing small commercial and residential regulators will be replaced during the AMI Project.[89] The same approximate amount of regulator replacements would also be expected under the status quo or Baseline scenario discussed in the Application where Automation is not implemented.[90]

C. Project Development Activities and Project Schedule

88. As described in Sections 5.3.1-5.3.2 of the Application, FEI leveraged significant learnings and feedback from two major sources in developing the AMI Project as presented in the Application. First were the learnings from FBC's now fully implemented and operational AMI project. Second was the gas AMI pilot project (**Pilot**) conducted in 2017 through

[86] Ex. B-1, p. 5
[87] FEI Response to RCIA IR1 3.2 (Ex. B-13); FEI Response to RCIA2 55.1 (Ex. B-20)
[88] FEI Response to RCIA IR1 3.2 (Ex. B-13)
[89] FEI Response to BCUC IR1 21.1 (Ex. B-6)
[90] Ibid.

early 2018. During the Pilot, FEI installed AMI meters and communication modules on existing residential services at single and multi-family dwellings and commercial properties in the Fraser Valley. Learnings from the Pilot highlighted planning considerations for a full-scale deployment of an AMI network and planning for the AMI Project itself incorporated a number of key insights from the Pilot as discussed in Section 5.3.2.4 of the Application.

89. FEI used Request for Proposal (**RFP**) processes for the selection of the Project network and infrastructure, installation deployment services, the supply of bypass valves, and the supply of residential and small commercial regulators. While planning for the Project, FEI used an iterative approach to research, design and define high-level functional requirements. These requirements were used as the basis for the RFP processes described in Section 5.3.3 of the Application. A cross-functional team of FEI subject matter experts evaluated proposals received through these RFP processes.[91]

90. FEI submits that the planning, procurement and other development activities it has conducted to date in respect of the AMI Project have been thorough and robust.

91. Section 5.5 of the Application sets out the details of the preliminary integrated, master Project schedule covering key project activities. The implementation start date will be set after receipt of regulatory approval, with a complete integrated system and operational processes in-service date approximately 4.5 years later. Implementation of the Project would be divided into several phases as described in Section 5.5.1 of the Application. FEI notes that it has not updated Section 5 of the Application as part of the Evidentiary Update filed on July 5, 2022. The fundamental activities and sequence set out in Section 5.5.1 have not changed; once BCUC approval was received, FEI would enter the “Define” phase of the Project and issue Notices to Proceed to Sensus USA Inc. and Sensus Canada Inc. (**Sensus**), the AMI Network Vendor, and FEI’s to-be-selected Deployment Vendor.[92] FEI would report the final AMI Project schedule and activities to the BCUC as part of its CPCN reporting obligations.[93]

PART VII - PROJECT COSTS AND RATE IMPACT

92. FEI set out a detailed analysis of Project cost and rate impact in Section 6 of the Application.[94] FEI updated the costs set out in the Application, and the attendant rate impact, in the Evidentiary Update filed on July 5, 2022, addressing changes to the labour and materials markets that had occurred in the interim.[95]

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[91] Ex. B-1, p. 74
[92] Ex. B-30, p. 1
[93] Ibid.
[94] Ex. B-1
[95] Ex. B-30

93. At the time the Application was filed, the AMI Project was expected to incur $638.4 million in capital expenditures through the Deployment phase, which is equal to $476.0 million incremental to what would otherwise be spent under the Baseline scenario (during normal operations of the existing meter program). The $476.0 million of incremental capital was projected to be offset by future savings in capital and O&M expenditures in the Post-deployment phase.[96]

94. The impact of the cost increases in the labour and materials categories described in the Evidentiary Update results in an increase of approximately $92 million to the total capital cost for the AMI Project (over the pre-deployment and deployment period from 2021 to 2026), from $638.4 million in the Application to $730.8 million.[97]

95. FEI recognizes that the Project represents a large investment in FEI's system and that the updated costs result in a greater increase in customer rates than FEI originally forecast in its Application. However, the benefits of the full AMI Project solution are still significant and indeed, the current conditions have reinforced their importance.[98] In this regard, as set out in the Evidentiary Update, in FEI's recent experience diaphragm meter delivery timelines required for operating the utility cannot be met, which ultimately impacts the viability of the Baseline scenario.[99] Even apart from experiencing their own labour and materials issues, or perhaps because of them, vendors have been switching their business models even more quickly than expected from the manufacture of diaphragm meters to the manufacture of ultrasonic meters.[100] This was alluded to above and is discussed as well in Part IX below.

96. Further, even to the extent viable given the issues with the diaphragm meters used for both the Baseline and AMR scenarios, those scenarios would also be becoming more costly. The Evidentiary Update noted the increasing labour costs associated with the meter reading required in those scenarios, as well as the fact that increasing costs for bypass valves and regulators affect all scenarios.[101]

97. The cost pressures described in the Evidentiary Update also favour proceeding with the Project in the near future rather than simply at some later date. Even in the relatively near term, the later BCUC approval is received, the more FEI is exposed to the potential of inflationary pressures on labour rates, facilities and materials that are not tied to fixed price contracts and the more FEI and its customers are exposed to potential supply chain issues related to accessing the above.[102] For example, if conditions precedent are satisfied by June 30, 2023, the Sensus contract ensures fixed pricing for the duration of the Project.[103]

[96] Ex. B-1, p. 118
[97] Ex. B-30, pp. 5-6
[98] Ibid., pp. 8-9
[99] Ibid., p. 5; see also FEI Response to CEC IR4 20.2 (Ex. B-37)
[100] Ex. B-30, p. 5
[101] Ex. B-10, pp. 3-5
[102] Ex. B-30, p. 8
[103] FEI Response to CEC IR4 18.1 and 18.2 (Ex. B-37)

98. Even without those new cost pressures, delaying the Project – for example for further exploration of infrastructure sharing opportunities – was also already problematic in deferring benefits and potentially leaving FEI and its customers (for example, if dependent on manual meter reading) in a vulnerable position later, requiring a significant, short-term investment in a meter reading solution that is trending toward obsolescence.[104] Further, FEI's analysis of the possibility of embarking on a slower rollout of meters based on the age of the meter demonstrated that any potential savings from deferring costs or avoiding the need to write-off undepreciated meters would be more than offset by higher costs related to the loss of economies of scale. This included increased pricing on meters and higher project management and manual meter reading costs. At the same time, no savings would be available for the deployment of the network due to the fact that the oldest meters replaced are randomly distributed throughout the service territory (and so installation of the complete fixed network would still be required at the outset of the project).[105]

99. Even with the increased costs reflected in the Evidentiary Update, the Project will still have a minimal impact on customer annualized rates over the analysis period, at less than half of a percent.[106] In this regard, when combining the impact of increasing costs and the changes to the Measurement Canada dispensation policy also described in the Evidentiary Update (and subsequent responses to information requests), the total incremental levelized delivery rate impact over the 26-year analysis period due to the AMI Project (when compared to the Baseline scenario) is 0.442 percent, as compared to 0.125 percent in the Application.[107]

PART VIII – PROJECT BENEFITS AND JUSTIFICATION

100. The AMI Project's overall benefit is in addressing the various operational and customer services issues identified in the Application and outlined above in Part V of this Final Argument – Project Need. The AMI Project also results in various cost savings, described above, that result in minimal impact on customer rates over the analysis period, at less than half of a percent. Further, the AMI Project provides benefits in supporting the safety, resiliency, and efficient operation of FEI's gas distribution system.

101. First, the AMI Project will automate the meter reading process, which provides clear and immediate benefits for FEI's operations as well as for its ratepayers. These benefits include:

(a) No longer being required to perform over 1,000,000 manual meter reads per month.

(b) Reduced billing inaccuracies. Automation will eliminate human error, of the nature described earlier in these submissions, leading to incorrect billing under the current manual meter reading process and will reduce the use of billing estimates. With

[104] Ex. B-19, response to CEC IR2 106.2, pp. 16-17.
[105] Ex. B-8-1, response to CEC IR1 69.3, p. 107.
[106] Ex. B-30, p. 9; Ex. B-38, response to CORE IR 3b, pp. 4-5.
[107] Ex. B-30, p. 7.

Automation, FEI expects that its billing estimates would be in a similar range as FBC as a percentage of meter read requests and fall within a range of 1-2 percent per year. This would improve the accuracy of approximately 260,000 to 390,000 bills each year, all else being equal.[108]

(c) Improved convenience for customers in not having unfamiliar third party meter readers gaining access to their property on a monthly basis. FEI receives an average of over 500 customer complaints associated with manual meter reading each year.[109] Beyond the generic privacy benefit for all customers, this will particularly improve convenience for customers that have either locked gates or an identified dog on the property (approximately 8,000 customers as of March 2021).[110] Under the AMI Project, such customers will no longer have to provide keys or gate codes or be asked to keep dogs inside of their premises. Conversely, FEI will no longer need to manage and update these access issues associated with manual meter reading.

102. The AMI Project would also have the benefit of updating FEI's now outdated manual meter reading system and bringing it into line with the current state of meter Automation in British Columbia and across North America, discussed above. Specific to British Columbia, both of the major electric utilities have long since implemented AMI systems and the other major nature gas distributor, PNG(NE) has received BCUC approval to transition to AMR. Once PNG(NE) has completed deployment, and in the absence of the AMI Project, FEI would be the only remaining large regulated utility in BC to continue to perform meter reading manually.[111]

103. Relatedly, the AMI Project has the benefit of alleviating the long-term risk and uncertainties of increased costs and supply issues for both products and services that support manual meters discussed above, given the clear industry trend towards Automation. The AMI Project would, in effect, "future proof" FEI's metering technology by eliminating risk and increased costs associated with procuring diaphragm meters at reasonable prices as manufacturers transition to ultrasonic meters and by allowing FEI to take advantage of potential future enhancements to meter capabilities through remote firmware, increased data analytics and connection of new types of field devices to the network.[112]

104. The AMI Project also presents an opportunity to provide transformational change to key components of the utility customer experience, creating a platform for future customer enhancements, and providing operational benefits that support safety, resiliency and efficiency of FEI's gas system.

[108] Ex. B-1, p. 24
[109] Ibid., p. 25
[110] Ibid.
[111] Ibid., p. 31
[112] Ibid., p. 58

105. In terms of customer experience enhancements, the AMI Project will provide customers the benefit of access to usage and consumption data in much greater detail and with increased granularity compared to the existing system, which only provides data on a monthly basis. Under the AMI Project, customers will have the ability to access their hourly consumption information through FEI's secure and private online customer portal, and to be notified of gas flow anomalies for use by FEI and the customer to help identify potential gas leaks, faulty appliances or appliances/equipment mistakenly left on.[113]

106. This detailed billing and consumption information that will be available to customers pursuant to the AMI Project will, in turn, enhance energy efficiency and conservation programs and help customers to better manage their gas consumption.[114] Details regarding new opportunities for DSM programs that AMI would open up are set out in Section 4.3.2.2 of the Application.[115] In addition to potential future reductions through new DSM programs and enhanced customer conservation, the AMI Project would also reduce GHG emissions as a result of removing meter reading vehicles from service; taking into account the need for 150 meter readers to cover FEI's service territory and that a meter reader drives 35,000 km per year, this is the equivalent of 1,100 metric tonnes of carbon dioxide equivalent (**tCO2e**).[116]

107. Additionally, the AMI Project would provide FEI with the ability to offer customers with enhanced billing options in the future. This would include flexibility in billing dates to meet customer needs, rather than being restricted to billing dates dictated by scheduled meter reading, as well as consolidated billing for multiple customer locations.[117]

108. The AMI Project provides further benefits for FEI's operation of the gas system in terms of safety, efficiency, and resiliency. These benefits include:

(a) Enhanced system planning. While the current diaphragm meters play a limited role in system planning, advanced AMI meters would enhance FEI's understanding of the real-time behavior of gas consumers and the direct response of the gas system. Improved understanding of usage patterns can be used to support system design, use of peak resources, and quantify capacity benefits of DSM activities.[118]

(b) Safety benefits through near real-time alarms to alert FEI to issues at the meter, such as gas theft or meter tampering.[119]

(c) Safety benefits through improved emergency response to gas leaks downstream of the meter via remote monitoring and the advanced meter's remote shut-off valve

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[113] Ibid., p. 5
[114] Ibid., p. 142
[115] Ibid., p. 57
[116] Ibid., p. 20
[117] Ibid., p. 62
[118] Ibid., p. 60
[119] Ibid., p. 61

capability.[120] While AMI may not detect every leak before a customer would, there will be important instances when AMI will detect leaks or unexpected consumption before they are detected by a customer, such as leaks occurring inside a home when the residents are away for an extended period or when appliances like barbeques are left on mistakenly.[121] The AMI Project would also allow for monitoring and detection of smaller leaks through generation of exception reports for high consumption and flow anomalies.[122]

(d) Enhanced system integrity management: AMI would allow FEI to deploy cathodic protection sensors on its gas network for remote monitoring purposes, which would provide near real-time visibility on the performance of the cathodic protection system that helps maintain the integrity of FEI's distribution system gaslines.[123]

(e) Enhanced system resiliency. As discussed in detail in Section 4.3.2.4.1 of the Application, AMI will provide significant benefits for system resiliency in the event of system failures or gas supply emergencies. AMI will provide FEI with the ability to monitor, in near real-time, all customer consumption, as well as aggregate total system demand. FEI will use this near-real time aggregated total demand on the system of interest, and supply performance, to determine which parts of FEI's system are vulnerable to a pressure collapse. With this knowledge, AMI will also provide FEI with the ability to conduct targeted remote disconnects to residential and small commercial customers, in order to decrease the possibility of a pressure collapse.[124] In addition, AMI would provide benefits and would decrease recovery time in the event a pressure collapse does occur.[125] FEI submits that the AMI Project provides a sophisticated and intelligent approach for responding to and increasing system resiliency in the face of major natural disasters, such as earthquakes, flooding, or forest fires, and in the face of the potential resulting damage to some customers' gas lines and equipment.[126]

109. Overall, FEI submits that the AMI Project has numerous benefits and is a reasonable and justified response to Project need.

PART IX – PROJECT ALTERNATIVES CONSIDERED

110. To address the Project need for Automation as described in Section 3 of the Application, FEI compared the two Automation technologies available in the gas metering industry. Those are: (a) Partial Automation of meter reading using AMR technology to enable drive-by meter reading; and (b) Full Automation of meter reading using AMI technology

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[120] Ibid.
[121] FEI Response to BCUC IR1 3.4 (Ex. B-6)
[122] Ex. B-1, p. 61
[123] Ibid., p. 62
[124] FEI Response to BCSEA IR1 17.2 (Ex. B-9)
[125] FEI Response to BCSEA IR2 42.2 (Ex. B-23)
[126] FEI Response to ICLR IR1 16.1 (Ex. B-21)

characterized by a fixed two-way communication network – that is, the solution proposed in the Application.[127]

111. A comparison of these alternatives determined that while AMR could partially satisfy some of the drivers of the Project need, only by implementing AMI would customers and the Company realize the full value of Automation.[128]

112. FEI's alternatives analysis was informed by FEI's knowledge and experience of automated metering technology. Over the 15 years prior to filing the Application, FEI had been following both the evolving meter technology market and the types of technology adopted by other North American gas and electric utilities.[129] FEI also reached out to other North American utilities that had already deployed different variations of the two available technologies to understand how their customers and organization were able to benefit by deploying Automation. FEI expanded upon this work by commissioning a benchmarking study – referenced earlier in these submissions – of recent gas AMI projects completed by other utilities within North America to fully appreciate the business drivers, opportunities and challenges this technology presented (the Util-Assist Report, which was included as Appendix A to Exhibit B-1).[130]

113. FEI is also familiar with the vendors that supply different technologies as the Company has been procuring both diaphragm and ultrasonic meters from these vendors for many years. In addition, FBC's experience in procuring and deploying an electric AMI system provided the Company with an understanding of the scope and depth of information necessary to define the best alternatives available for FEI.[131] Further, FEI assessed the value proposition offered by both AMR and AMI technologies by conducting an RFP process; the RFP responses gave FEI the opportunity to evaluate the capital and ongoing operational costs in addition to validating the capabilities of each technology, giving FEI the opportunity to confirm the ability of each alternative to support the different drivers of the Project need identified in Section 3 of the Application.[132]

114. AMR is a system in which customer meter reads are retrieved using an automatic means, most commonly by driving by with a vehicle (which is the method that FEI evaluated[133]). AMR is a one-way communication technology, where communication modules retrofitted to the meter are used to transmit readings using radio signals to a vehicular-based mobile meter reading base station. A meter reader drives the vehicle carrying the mobile base station along a predetermined route through a section of the service territory and meter reads are transmitted remotely from the meter communication modules to the base station.

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[127] Ex. B-1, p. 43
[128] Ibid., p. 43
[129] Ibid., p. 44
[130] Ibid.
[131] Ibid.
[132] Ibid.
[133] This is the industry-standard drive-by option proposed by AMR RFP proponents: Response to BCUC IR1 11.2, pp. 27-28 (Ex. B-6)

The meter reader then returns to a utility facility in order to connect the mobile base station to the utility network where the meter reads are downloaded for use by the billing system.[134]

115. An AMR alternative would provide partial Automation of the manual meter reading function by allowing FEI to collect monthly meter reads via a vehicular-based mobile meter reading base station, and address some of the challenges encountered by manually reading meters (such as eliminating the need for meter readers to enter customer premises, and reducing human error).[135] However, as AMR is not a fully automated solution, there would continue to be challenges related to bill accuracy and customer inconvenience, stemming from factors such as vehicle access issues that impact meter reading, and the inability to complete "on-demand" reads.[136] Additionally, although AMR would enable an overall reduction in vehicle usage compared to the Baseline, AMR still relies on vehicular-based meter reading and would only result in an approximately 50 reduction of GHG emissions as compared with the AMI solution.[137]

116. Further, while the implementation of AMR would reduce the number of people currently required to read meters within FEI's service territory, as meter readers would still be required to complete this work, all the risks relating to the availability of manual meter reading vendors and price risks in the future as utilities across Canada transition to Automation would still be applicable.[138]

117. The additional benefits and operational opportunities realized from AMI are set out in Table 3-11 of the Application. These were central to FEI's selection of the AMI option. However, the makeup of the capital costs is different between AMR and AMI; there is a fundamental difference in the underlying work required between AMR and AMI, which is not just because of the additional benefits and operational opportunities associated with AMI.[139] For example, as discussed in Section 4 of the Application, the nature of work required, as well as the actual equipment, is different between AMR and AMI:

(a) For AMR, the capital cost includes retrofitting each existing diaphragm meter with a battery powered electronic module while the existing meter, bypass valve, and regulator will continue to be replaced/exchanged under the existing sustainment capital program (i.e., same as status quo).

(b) For AMI, the capital cost includes replacing each existing diaphragm meter with a new advanced meter. Furthermore, the existing programs to replace regulators and install bypass valves will be accelerated and completed during the AMI deployment phase.[140]

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[134] Ex. B-1, p. 45
[135] Ibid., p. 47
[136] Ibid..
[137] Ibid., p. 47
[138] Ibid., p. 48
[139] FEI Response to BCOAPO IR2 3.1 (Ex. B-18)
[140] Ibid.

118. The deployment of AMR technology would also mean the risk associated with procuring diaphragm meters at a reasonable price would continue to exist.[141] Indeed, the Evidentiary Update indicates that these risks may be increasing. As noted earlier, in FEI's recent experience diaphragm meter delivery timelines required for operating the utility cannot be met and vendors have been switching their business models even more quickly than expected from the manufacture of such meters to the manufacture of ultrasonic meters.[142] While the Evidentiary Update assumed the continued viability of the AMR alternative for the purpose of the analysis undertaken, the inability to meet delivery timelines ultimately impacts the viability of a scenario dependent on diaphragm meters (which is the case for both the Baseline scenario described in the Application, and the AMR alternative) at all.[143]

119. Additionally, AMR offers no improvement to the amount, timing or availability of consumption data for customers to use in informing their energy choices, as meter readings would still be obtained and recorded monthly for billing purposes; with AMR rather than AMI, FEI would also continue to be unable to offer enhanced DSM programs to further support customers with opportunities to support energy conservation and save money.[144] AMR also has limited ability to accept technical enhancements, so as new innovations are developed within the gas metering industry, AMR would provide minimal opportunity to realize future benefits for either customers or the Company.[145]

120. Key operating benefits that AMR would not be able to provide include:[146]

(a) advancing the resiliency of the system, including the ability to monitor load on the system, conduct targeted temporary shutdowns to reduce load, and enable timely restoration of service;

(b) improvements to system planning which requires granular gas usage and system pressure data to model customer usage patterns which help to define emerging capacity constraints;

(c) improvement to the integrity management system in relation to the monitoring for pipeline corrosion;

(d) availability of field data to support operational and project work;

(e) detection of smaller leaks and unintended gas flows and timely response to larger leaks;

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[141] Ex. B-1, p. 48
[142] Ex. B-30, p. 5
[143] Ibid., p. 5, cross-referencing to analysis of the Baseline scenario ("[a]s the AMR Alternative also requires diaphragm meters, the discussion under Baseline scenario applies here as well").
[144] Ex. B-1., p. 48
[145] Ibid., p. 49
[146] Ibid., pp. 49-50

(f) enhanced safety with the ability to shut off gas flow remotely and automatic shut off due to high flow detection (such as in the event of earthquakes or other natural disasters);

(g) improved safety for the meter reading function; and

(h) the ability to offer enhanced billing options for customers.

121. Adopting AMI technology would put FEI in line with those of its utility peers that have adopted AMI technology (in particular its utility peers in BC) and potentially ahead of others that have previously adopted AMR technology. More importantly, as described in Section 4.2.2.3 of the Application, adopting AMR technology would lock FEI into a commitment to a technology that is currently trending towards obsolescence and therefore would not resolve concerns FEI has regarding lagging behind its peer utilities.[147]

122. FEI's financial analysis of an AMR alternative at the time of the Application demonstrated that an AMR alternative could be deployed at an estimated $34.4 million decrease in the net present value (**NPV**) of the Company's revenue requirement, which would amount to a decrease in customer rates by 0.286 percent on a levelized basis over the 26-year analysis period.[148] However, as the AMR alternative was also impacted by factors considered in the Evidentiary Update, those numbers changed. As of the Evidentiary Update, FEI's financial analysis of an AMR alternative demonstrates that an AMR alternative could be deployed at an estimated $7.2 million decrease in the NPV of the Company's revenue requirement, which amounts to a decrease in customer rates by 0.059 percent on a levelized basis over the 26-year analysis period.[149]

123. Even under the more favourable (to AMR) numbers in the Application, and while this alternative was forecast to result in a small (though now smaller) reduction in rates, it was already clear that the AMR alternative would deliver only a portion of the many potential benefits that could be provided by automating a metering system. For this reason, FEI concluded that AMR would not provide a cost-effective, long-term solution.[150]

PART X – PUBLIC CONSULTATION AND INPUT

A. General Public Consultation

124. Due to the broad nature of the AMI Project, which would involve meter replacement activities reaching nearly 1.1 million customers in 135 communities across BC, FEI has engaged in an appropriately comprehensive and multifaceted public consultation process to date.

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[147] FEI Response to BCSEA IR1 1.1 (Ex. B-9)
[148] Ex. B-1, p. 54
[149] Ex. B-30, PDF p. 16 of 66
[150] Ex. B-1, p. 54

125. FEI's Consultation, Engagement and Communications Plan for the Project was developed following a Customer Perception Survey, which FEI used to gain a better understanding of customers' preferred communication and consultation methods and helped to maximize reach and ensure customers and communities across the province were informed of the Project. The Consultation, Engagement and Communications Plan, which FEI began to implement starting in late 2019 with the announcement of the Project, included outreach over a variety of channels including direct stakeholder and general media communications, a news release, digital and print ads, in-person and virtual information sessions, and direct customer communications. FEI also set up a website, phone number and email address to provide ongoing consultation opportunities.[151]

126. The details of FEI's general public consultation work pursuant to the Consultation, Engagement and Communications Plan, which FEI continued throughout 2020 and early 2021, are set out in Section 7.2 of the Application. FEI also notes that the BCUC, in dismissing CORE's Reconsideration Application (described above in Part II.E) stated that FEI had "demonstrate[d] a comprehensive and thoughtful approach to maximizing the effectiveness of the Public Notice without incurring unreasonable cost".[152] FEI submits that the Application presents all required information regarding consultation in the CPCN Guidelines and that its consultation work was and is more than adequate and generated effective public engagement with the Project. Without purporting to be exhaustive in the list below of the work undertaken, FEI's public consultation to date has included:

(a) 12 in-person public information sessions held in different locations throughout BC in October and November 2019;

(b) Four virtual information sessions held in February 2021 to provide customers and other stakeholders with a Project update;

(c) Contracting a third-party firm to complete a Customer Perception Survey, the full results of which are included in Appendix H-5 to the Application;

(d) Developing and conducting an in-person survey of participants at the 2019 in-person information sessions;

(e) A variety of customer and public communications through a number of different communication channels, including (in addition to the above) outreach to media outlets resulting in a number of print, online, radio and television stories about the Project, social media posts on Facebook and Twitter, a Project webpage, updates in *Energy Moment* newsletter, paid advertisements, bill inserts, Project email and phone line, and employee communications.

127. FEI has also consulted regarding the Project with stakeholders in provincial, local, and regional governments, as well as in industry, as detailed in Section 7.2.6 of the Application

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[151] Ex. B-1, p. 121
[152] BCUC Order and Decision G-66-22, p. 9

and also in FEI's Stakeholder and Government Consultation Log included as Appendix H-2 to the Application.

128. FEI's consultation efforts in respect of the Project to date have surpassed the Company's standard outreach and consultation for a typical major project.[153] FEI anticipates that, if the Project is approved, public interest in the Project will increase as deployment approaches; FEI is committed to on-going future public consultation in respect of the Project and intends to update the Consultation, Engagement and Communications Plan as outlined in Section 7.2.11 of the Application.

B. Engagement with Indigenous Groups

129. FEI engages meaningfully with Indigenous groups through transparent, frequent, two-way dialogue. FEI is guided in these engagement activities by its "Statement of Indigenous Principles", developed in 2001, with guidance and input from Indigenous leaders across British Columbia (a copy of the "Statement of Indigenous Principles" is included as Appendix I-1 to the Application). FEI submits that this collaborative approach leads to early identification of issues or concerns, and a shared interest in finding mutually agreeable solutions.

130. FEI's Indigenous engagement activities are described in detail in Section 7.3 of the Application, which includes all information required under the CPNC Guidelines.

131. These engagement activities involved generating a list of 54 potentially affected Indigenous Groups, which is set out in Table 7-1 of the Application. Due to the nature of the Project, FEI anticipates the potential impacts for Indigenous groups to be minimal.[154] FEI has identified potentially affected groups as being those Indigenous communities that have customers on Crown reserve lands and FEI is committed to continued engagement with these groups.

132. In line with FEI's outreach activities to all customers, FEI commenced Indigenous engagement activities on October 3, 2019, with the mail-out of electronic and hard copy letters (see Appendix I-2 of the Application for engagement details and Appendix I-3 for a copy of the letter).[155] FEI followed this with targeted outreach discussions, phone calls and follow-up emails to all 54 Indigenous communities listed in Table 7-1. On February 9, 2021, FEI emailed a letter to these Indigenous groups, providing a Project update and inviting them to participate in FEI's public virtual information sessions on February 23 and 24, 2021 (see Appendix I-2 for engagement details and Appendix I-4 for a copy of the letter).[156]

[153] Ex. B-1., p. 134
[154] Ibid., p. 135
[155] Ibid., p. 136
[156] Ibid.

133. Through the course of FEI's initial engagement, Indigenous groups raised minimal issues or concerns.[157] Following the first notification from October 3, 2019, two communities contacted FEI requesting in-person meetings, the details of which are summarized in Section 7.3.3 of the Application, and which FEI submits do not raise substantive issues with the AMI Project. Three Indigenous groups reached out to FEI for more information following the distribution of the update letter on February 9, 2021.

134. FEI identified Indigenous communities that are potentially affected by the Project and engaged with them through multiple rounds of engagement.[158] FEI submits that its engagement processes as summarized above and presented in more detail in the Application demonstrate sufficient and appropriate Indigenous engagement regarding the Project. At the time of filing, there are no outstanding issues or concerns that have been raised by Indigenous communities. FEI will continue to inform and engage with Indigenous communities as the Project progresses and FEI is committed to responding and addressing any such issues or concerns that may be raised in a respectful, timely, and transparent manner.

PART XI – RADIOFREQUENCY EMISSIONS AND HEALTH

A. Summary

135. The potential adverse health effects of RF signals from the advanced meters and End Points that are part of the AMI Project are the main subject of CORE's intervener evidence in this proceeding. This topic is discussed in detail in the Application, Rebuttal Evidence, and IR responses. FEI addresses the main issues arising from CORE's position in this proceeding and its intervener evidence in the submissions that follow. To the extent any matters or statements in CORE's evidence are not specifically addressed below, it should not be taken as FEI's agreement that such statements are correct.

136. In summary, FEI submits that:

(a) Health Canada's Safety Code 6 (2015) – Limits to Human Exposure to Radiofrequency Electromagnetic Energy in the Frequency Range from 3 KHZ to 300 GHZ is the applicable regulation regarding the safe exposure limits for RF emitting devices in Canada;

(b) The Sonix IQ gas meters and other End Points comply with the RF exposure limits in Safety Code 6 and, in fact, RF exposure from the meters and End Points is orders of magnitude below the Safety Code 6 limits;

(c) CORE has not provided any credible or compelling evidence that Safety Code 6 does not adequately protect the public from the potential health effects of RF exposure or that the proposed advanced meters present any health risk to FEI's customers.

[157] Ibid., p. 137
[158] Ibid., p. 138

(d) Further, Exponent's comprehensive review of recent scientific research regarding the health effects of RF exposure concludes that the research does not confirm that RF fields at levels encountered in the everyday environment are a cause of cancer, chronic disease, or other adverse health effects.

B. RF Findings in the BCUC's 2013 AMI Decision

137. As referred to above, the BCUC proceeding in 2012-2013 regarding the FBC AMI Project involved an extensive 10-day oral hearing that primarily addressed issues related to RF emissions and human health. Seven expert witnesses appeared at the hearing in March 2013 and were subject to cross-examination on their expert reports. One intervener in the 2012-2013 proceeding, CSTS, vigorously opposed the FBC AMI Project and its evidence and positions taken in that proceeding are similar to and in some cases substantially overlap with the evidence CORE has filed in this proceeding.

138. The BCUC approved the CPCN for the FBC AMI Project despite the vigorous opposition from CSTS and certain other participants to the implementation of RF-emitting advanced electric meters on customer premises.

139. The BCUC's 2013 AMI Decision addressed two broad issues in respect of AMI technology's use of RF to transmit customer usage data:[159]

(a) First was whether Health Canada's Safety Code 6, which specifies the requirements for the safe use of, or exposure to, devices that emit electromagnetic radiation was applicable to the type of technology used in the FBC AMI Project. CSTS took the position that Safety Code 6 was not applicable.

(b) Second, the 2013 BCUC Panel addressed whether the emission standards set out in Safety Code 6, if they were found to be applicable to AMI meters, were sufficient to protect the health of FBC's customers. Again, CSTS took the position that Safety Code 6 was "fundamentally flawed" and did not adequately protect the public from RF emissions associated with AMI.

140. The 2013 Panel also addressed a variety of specific RF concerns with the FBC AMI Project raised by interveners and at community input sessions.

i. Applicability of Safety Code 6

141. Regarding the applicability of Safety Code 6 to AMI, the 2013 Panel referred to Industry Canada's "Radio Standard Specifications" (**RSS**) applicable to radio equipment in Canada and determined that Safety Code 6 was both applicable and mandatory for FBC's AMI meters. The BCUC's determination was as follows:

[159] 2013 BCUC Decision, p. 106 [Book of Authorities, Tab 14]

> Upon review of the contents of Industry Canada's RSS-102 specifications, the Panel agrees with FortisBC that while the proposed AMI technology is exempted from the routine evaluation as laid out in RSS-102, <u>it is not exempt from compliance with Safety Code 6</u>. Safety Code 6 remains the relevant standard for health effects from radio-frequency EMF. Further, the Panel finds that the frequency of the RF emissions from the Project are within the range of frequencies addressed by Safety Code 6.
>
> **Accordingly, the Panel finds that Safety Code 6 applies to FortisBC's AMI Program and <u>emissions from the proposed AMI meters must comply with the requirements of Safety Code 6</u>.**[160]

ii. Adequacy of Safety Code 6

142. Regarding the adequacy of Safety Code 6 to protect the health of FBC's customers, the 2013 Panel addressed two main issues: (i) the treatment of non-thermal effects of RF exposure; and (ii) whether the precautionary principle is adequately embodied in Safety Code 6. No interveners in the 2012-2013 proceeding took the position that thermal effects were not adequately covered by Safety Code 6.[161]

143. Similar to CORE's filed evidence in this proceeding, CSTS took the position in respect of the FBC AMI Project that Safety Code 6 is "fundamentally flawed in that it does not account for these potential non-thermal health effects from EMF energy emitted by devices like the proposed AMI meters," and further that "there is some scientific evidence of negative health effects from exposures below the level at which tissue heating occurs, which makes the Safety Code 6 threshold insufficient to protect the public".[162]

144. The 2013 Panel rejected CSTS's arguments in this regard. The 2013 Decision refers to FBC's response that Safety Code 6 does, in fact, specifically address non-thermal health effects and noted a relevant passage from Safety Code 6 itself, which states, among other things, that, "the exposure limits specified in Safety Code 6 have been established based upon a thorough evaluation of the scientific literature related to the thermal <u>and possible non-thermal effects of RF energy</u> on biological systems".[163] The BCUC's 2013 AMI Decision also noted, in particular, the testimony of Dr. James McNamee of Health Canada from a hearing in Quebec Superior Court in 2013 regarding scientific evidence of potential non-thermal effects. Notably, CORE has referred to Dr. McNamee's prior testimony as well, in its response to an IR in the current proceeding.[164] The following testimony was quoted in the 2013 AMI Decision:

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[160] Ibid., p. 108 (bolding in original; underlining added)
[161] Ibid., p. 109
[162] Ibid., p. 109
[163] Ibid., p. 110-111 (underlining added)
[164] CORE Response to CEC IR1 2.1 (Ex. C7-16)

> Q. And do I understand that, even though there is out there some studies regarding non-thermal effects for our frequency, the position of Health Canada is that none of these studies, because it's what it's saying in Safety Code 6, is relevant and there's no change?
>
> A.: We recognize that there are a large number of studies assessing virtually every health endpoint there is. There are a large number that show an adverse effect here, an adverse effect there. So, I'm not denying that there are studies showing effects, no question. <u>There are also a large number of studies that don't show effects, and generally, a much larger number of studies, in many cases much more thorough and much more well-conducted</u>.
>
> (Exhibit B-46, pp. 69-70)[165]

145. In addition to issues related to non-thermal effects of RF, CSTS also argued that Safety Code 6 does not incorporate a sufficient degree of precaution in its RF emission standards. CSTS's position was that any potential risk was unacceptable and that, "If there is evidence that AMI meters 'could be a risk', it would be unconscionable to impose those meters on customers at their residential dwellings against their will".[166] The BCUC's 2013 AMI Decision rejected this argument. In particular, the 2013 Panel referred to the following evidence regarding the adequacy of Safety Code 6:

(a) The oral testimony of Exponent's Dr. William Bailey that, "scientific agencies, particularly dealing with health, are extraordinarily cautious, and exercise prudency in their assessments. And have at various times set into place in their deliberations ways that would err on the side of caution. And the fact that we have safety factors in these guidelines and Safety Code 6 and the FCC guideline and the ICNIRP guideline, is part of that precautionary basis".[167]

(b) Evidence from the testimony of Health Canada's Dr. McNamee referred to above that:

> Safety Code 6, when we developed the limits, when we're establishing the basic restrictions, we're sort of using the worst-case scenarios for both the development of the basic restrictions and then the derived reference limits that go with them. So, that's the worst-case body size, worst-case frequency, worst case orientation with the field, standing on, you know, bare foot on a wet surface. <u>All of these worst-case scenarios are taken into account to establish the envelope of the lowest exposure level which is allowable. So, there's precaution taken into account there</u>.

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[165] Ibid., p. 111 (underlining added); see also FEI Rebuttal Evidence, Part 1 (Ex. B-26), at p. 14
[166] 2013 BCUC Decision, p. 112
[167] Ibid., p. 112

> Beyond that, we then apply a safety margin of 50-fold for the general public as another precautionary measure. So, precautionary measures are already taken into account and we do other measures such as ongoing review of the science, ongoing studies, research studies. This is not something that we pick up and drop and move on to something else, this is something we do all the time." (Exhibit B-46, pp. 50-52)[168]

(c) Health Canada's publication, "Health Canada Decision-Making Framework for Identifying, Assessing, and Managing Health Risks (2000)", which states: "The Health Canada Decision Making Framework treats the concept of precaution as pervasive. As such it does not require extremes in the actions taken. Instead, risk management strategies reflect the context and nature of the issue, including the urgency, scope and level of action required."[169]

(d) The Chief Medical Health Officer at Vancouver Coastal Health's endorsement of Safety Code: "[t]he current Canadian (Safety Code 6 revised 2009) … standards provide significant safety margins for public exposure to RF".[170]

146. Based on this evidence, the 2013 BCUC Panel reached the following conclusions in respect of the adequacy of Safety Code 6 to protect FBC customers from potential health effects of RF associated with AMI:

> The Panel notes in reviewing the evidence that there was general agreement during cross-examination of experts that the role of Health Canada is to protect the health of Canadians. Safety Code 6 is the result of the ongoing study by Health Canada on the health effects of RF emissions. With regard to thermal effects there is no evidence that Safety Code 6 does not adequately protect FortisBC customers. While there was disagreement over the adequacy of Safety Code 6 in dealing with non-thermal effects, the Panel agrees with FortisBC that the exposure limits in Safety Code 6 were established based upon a thorough evaluation of the scientific literature including potential non-thermal effects. No intervener provided scientific evidence that persuaded the Panel that Safety Code 6 fails to adequately protect FortisBC customers from non-thermal effects. Safety Code 6 has applied a significant safety factor to the allowable exposure levels and is subject to an ongoing evaluation of scientific literature by Health Canada. **For these reasons, the Panel finds that Safety Code 6 provides protection**

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[168] Ibid., p. 113 (underlining added)
[169] Ibid.
[170] Ibid.

> **from thermal effects, non-thermal effects and incorporates an adequate degree of precaution.**[171]

iii. Other RF Findings

147. In addition to the primary issues discussed above, the BCUC's 2013 AMI Decision also addressed and made findings regarding a number of other RF topics that are relevant in the current proceeding.

148. In discussing the actual amount of RF emissions FBC customers could be exposed to from AMI meters, the 2013 Panel referred to evidence: that the time-averaged power density from the advanced meters at different distances was orders of magnitude below the Safety Code 6 limit (0.00018% of the limit at 1 m distance from the source); that the RF signal strength drops off with the square of the distance between the meter and an individual; that the signal gets weaker as it goes through different media, such as walls; that because the advanced meter is installed on the outside wall of the residence, the signal sent by the meter toward the house is 1/10th of the signal sent away from the house; and that the additional RF exposure from other, more distant advanced meters is negligible due to the attenuation of the strength at the square of the distance to the meter.[172]

149. After reviewing this evidence, the 2013 Panel stated its conclusion "based on the scientific evidence, that FortisBC customers would experience RF exposure from AMI meters far below the limits of Safety Code 6". The Panel also confirmed this would be the case for situations "where individuals would be sleeping next to a wall and an AMI meter was located on the outside of the wall" due to the "attenuating effect of different media such as walls".[173]

150. The 2013 AMI Decision next addressed the then recent World Health Organization International Agency for Research on Cancer (**IARC**) classification of RF electromagnetic fields as "possibly carcinogenic to humans (Group 2B)". The 2013 Panel noted that this categorization "includes other substances such as coffee, pickled vegetables, some uses of talcum power and nickel alloys" and that, "The very breadth of substances under this category lends weight to the view that this designation, in and of itself, is of no quantitative significance". The Panel concluded that the IARC designation was not "sufficient to undermine the validity of Health Canada's research in establishing the Safety Code 6 limits for human exposure".[174]

151. The 2013 AMI Decision also addressed concerns from some individuals in FBC's service area who live in multi-family dwellings such as apartments and condos, and who were concerned that living near a bank of advanced meters will result in higher exposure to RF

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[171] Ibid., p. 113-114 (bolding in original)
[172] Ibid., p. 114-115
[173] Ibid.
[174] Ibid., p. 119

emissions. After referring extensively to cross-examination transcript of FBC and Exponent witnesses, the 2013 Panel concluded that proximity to multiple meters in a bank results in exposure that remains considerably below the Safety Code 6 limits.[175]

152. Further, the 2013 AMI Decision addressed concerns regarding "aggregate" exposure to RF emissions from "various sources present in modern society, and that the proposed Smart Meter system would add to the aggregate exposure". The 2013 Panel was "satisfied that RF emissions from the proposed AMI system add a small fraction to the overall RF exposure of an individual, and this aggregate exposure is significantly below the limit established in Safety Code 6".[176]

153. Another issue in the 2012-2013 FBC AMI proceeding was whether or not the transmissions produced by the AMI meters constituted "chronic exposure", and whether or not "chronic" exposure differed in any way from the type of exposure calculated by Safety Code 6. The 2013 AMI Decision noted that, "Safety Code 6 states, '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'".[177] Based on this and other evidence the Panel was "not persuaded by the evidence provided that Safety Code 6 fails to protect the public from cumulative or chronic health risks from RF emissions".[178]

154. In addition, the 2013 AMI Decision notes that, "The issue of electromagnetic hypersensitivity was of great concern to some of the Interveners and members of the public". After reviewing the evidence and arguments of interveners and FBC, the Panel reached the following determination regarding electromagnetic hypersensitivity (**EHS**):

> The Panel recognizes that there are individuals who feel strongly that low-level EMF emissions will have a negative impact on their health. However based on the scientific evidence in this Proceeding, the Panel is not persuaded that there is a causal link between RF emissions and the symptoms of EHS. The Panel notes that according to the World Health Organization, there is "no scientific basis to link EHS symptoms to EMF exposure."[179]

iv. Legal Significance of the 2013 AMI Decision in the Present Proceeding

155. FEI recognizes that, under section 75 of the *UCA*, the BCUC "must make its decision on the merits and justice of the case, and is not bound to follow its own decisions".

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[175] Ibid., p. 123
[176] Ibid., p. 125
[177] Ibid., p. 130; the current 2015 edition of Safety Code 6 contains the same statement at p. 2. See here: https://www.canada.ca/content/dam/hc-sc/migration/hc-sc/ewh-semt/alt_formats/pdf/consult/_2014/safety_code_6-code_securite_6/final-finale-eng.pdf **[Book of Authorities, Tab 7]**
[178] 2013 AMI Decision, p. 130 [Book of Authorities, Tab 14]
[179] Ibid., p. 137

156. Nonetheless, FEI submits that the 2013 AMI Decision is a strongly persuasive decision on various issues related to RF emissions from advanced utility meters and their potential human health effects. The BCUC rendered the decision following a lengthy oral hearing and based on an extensive record, which included numerous expert reports on RF issues, and after receiving detailed written submissions from FBC and various interveners.

157. Further, FEI notes that, as will be discussed below, the Sonix IQ gas meters it proposes to install at customer premises have substantially similar RF characteristics as the advanced electric meters at issue in the FBC AMI CPCN proceeding in 2012-2013. Indeed, the evidence shows that the Sonix IQ gas meters emit even lower RF than the FBC electric meters as a percentage of the Safety Code 6 limits.[180] The FEI advanced gas meters will be part of an AMI network operating on a dedicated radio spectrum license and will only be transmitting data via RF during a vanishingly short period of each day (approximately 0.34 seconds per day total under typical operations).

158. FEI submits that, to the extent any intervener opposes the AMI Project on the grounds of RF health risks, the intervener would need to present compelling and cogent evidence that new or other scientific developments mean that the BCUC's prior detailed findings on these issues are no longer valid. CORE is the only intervener to file evidence in this proceeding. As addressed below, FEI submits that CORE's evidence does not come close to reaching this level and does not establish that either Safety Code 6 is an inadequate regulatory standard or that the RF characteristics of FEI's proposed AMI meters make them unsafe to be installed on customer premises.

C. Evidence and Witnesses in this Proceeding

i. FEI/Exponent Witnesses

159. FEI retained Exponent to provide an independent study examining the specific technology proposed for the AMI Project and to compare exposure levels from all End Points of the proposed FEI network to the Safety Code 6 exposure limits, as well as to other commonly used devices.[181] Exponent's Dr. Benjamin Cotts, Ph.D., P.E. prepared this expert report, referred to as the "Exponent RF Technology Report", which FEI provided as Appendix F-1 to the Application. Dr. Cotts' report, dated May 3, 2021, concludes that the proposed meters are many orders of magnitude below the safe exposure limits set out in Safety Code 6. In particular, the Exponent RF Technology Report states that:

> Under typical operation, the Sonix IQ gas meter transmits RF energy a total of approximately 0.34 seconds per day. This very short transmission time also means that the indoor RF exposure from the Sonix IQ gas meter is about 24 million times lower than the SC6

[180] Ex. B-1, App. F-1, p. ix
[181] Ex. B-1, p. 92

> exposure limit, and substantially lower than the RF exposures from common natural and man-made sources.[182]

160. FEI also commissioned Exponent to provide an independent study reviewing the latest scientific research on the potential health effects of RF emissions.[183] Exponent's Dr. Pamela Dopart, Ph.D., CIH, and Dr. William Bailey, Ph.D. prepared this expert report, provided as Appendix F-2 to the Application and referred to as the "RF Health Report". This report, dated May 3, 2021, summarizes the comprehensive risk assessments and reviews of RF exposure and health conducted by independent scientists with expertise in relevant scientific disciplines, which have consistently concluded that the scientific evidence in the large number of published scientific studies does not confirm that RF fields at levels below the scientifically-based exposure limits are a cause or contribute to development of any adverse health effects, including cancer, other chronic diseases, or non-specific adverse symptoms that affect well-being.

161. FEI and Sensus have reviewed both Exponent reports and confirmed that all statements made with respect to the technology and how FEI intends to implement it, are accurate.[184]

162. Drs. Cotts, Dopart, and Bailey also provided responses to a number of IRs on behalf of Exponent in this proceeding and delivered further written testimony as part of FEI's Rebuttal Evidence.[185]

163. Drs. Cotts, Dopart, and Bailey are all eminently qualified in their fields of study, have extensive academic and other relevant experience, and should be qualified as experts in this proceeding.

164. Dr. Cotts' Curriculum Vitae is filed under Exhibit B-1-1-1 in this proceeding. His C.V. reflects that Dr. Cotts holds a Ph.D. in Electrical Engineering from Stanford University (2011) and is a Licensed Professional Electrical Engineer in the state of California. It also states that Dr. Cotts is "is experienced in both applied and theoretical electromagnetics and plasma physics including modeling and measurement analyses of natural and anthropogenic electromagnetic fields". It further states that:

> Dr. Cotts also performs various types of electromagnetic field evaluations for devices and systems including smart meter mesh networks and government/military communications facilities as well as exposure, EMI or EMC assessments. These assessments are provided for clients such as federal and state agencies, utilities, hospitals, medical-device manufacturers, construction developers, the U.S. military. In addition, Dr. Cotts regularly receives requests

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[182] Ex. B-1, App. F-1, p. 30
[183] Ex. B-1, p. 92
[184] Ibid.
[185] Ex. B-26, Part 2

to perform exposure assessments for patients with pacemakers, ICDs, and other implantable medical devices and to remediate EMI issues for medical devices and in health care settings.

165. Dr. Pamela Dopart's C.V. is also filed under Exhibit B-1-1-1 and reflects that she holds a Ph.D., Environmental Health Sciences, from Johns Hopkins School of Public Health (2015) and is a Certified Industrial Hygienist (CIH). Prior to joining Exponent, Dr. Dopart was in the Occupational and Environmental Epidemiology branch of the Division of Cancer Epidemiology and Genetics at the U.S. National Cancer Institute. Dr. Dopart specializes in exposure assessment methods to inform epidemiologic studies and health risk assessments. She has experience measuring, modeling, and evaluating exposures in occupational and environmental settings and from consumer products, and has developed estimates of exposure for a wide range of agents. Her experience includes the assessment of exposure to extremely low frequency and radiofrequency electromagnetic fields in relation to potential biological and health effects. Her health risk assessments also have included, asbestos, chlorinated solvents, formaldehyde, ionizing radiation, lead and other metals, pesticides, and volatile organic compounds.

166. Dr. Bailey was, as noted, qualified as an expert witness in the BCUC's 2012-2013 proceeding in respect of the FBC AMI Project. The 2013 Panel was of the view that, "Dr Bailey demonstrated a comprehensive knowledge and understanding of a wide range of studies that have been conducted within the area of his qualified expertise". He was stated to be "objective" and "exhibited no apparent signs of bias" in his prior oral testimony before the BCUC. His C.V. is also filed in this proceeding under Exhibit B-1-1-1.

167. The independence and impartiality of the Exponent witnesses are demonstrated through the evidence of their experience and credentials; the content of their reports, which are thorough and objective; and the BCUC's findings in qualifying Exponent witnesses in the 2013 AMI Decision.

ii. CORE Witnesses

168. As noted, CORE filed a non-expert witness statement from Mr. Karow, as well as expert reports of Drs. Héroux, Havas, and Miller.

<u>Mr. Karow</u>

169. FEI objects to certain portions of Mr. Karow's witness statement as including evidence on matters for which he is not qualified as an expert.[186] FEI does not object to Mr. Karow stating that matters are of "concern" to him or to CORE; however, in other cases Mr. Karow

[186] FEI gave notice, in its covering letter filing Rebuttal Evidence (Ex. B-26), that it considered various portions of CORE's intervener evidence to be objectionable and that FEI reserved the right to make submissions on the admissibility and/or weight of certain portions of CORE's evidence in final written argument.

provides opinion evidence on topics that require expert experience or knowledge and for which he is not qualified. Specifically:

(a) At pages 1-2 of his witness statement, Mr. Karow makes various statements regarding the power density and other technical characteristics of the Sensus IQ gas meters, including that, "When data signals are not being sent, the meter will be sending out weaker signals to communicate with the grid". These statements are inaccurate and not within Mr. Karow's experience to make; indeed CORE acknowledged that Mr. Karow's statement regarding power density was in error in its IR responses.[187]

(b) At page 2 of his witness statement, Mr. Karow states that "CORE is of the view that the use of Tadiran batteries poses safety issues" and then questions why the battery in the AMI meters has not been "certified as 'intrinsically safe' so that it can be worked on in the presence of a possible methane atmosphere". Mr. Karow makes this statement after having received an IR response from FEI confirming that Sensushad the devices certified as "intrinsically safe".[188] Further and in any case, Mr. Karow is not qualified to give expert opinion evidence on these topics. When CEC posed an IR regarding Mr. Karow's statement about a "possible methane atmosphere", CORE responded that, "CORE is unable to provide a response as the above IR raises technical matters that are not within the scope of CORE's knowledge".[189]

(c) At page 2 of his witness statement, Mr. Karow makes a statement that Exponent's RF Health Report "missed identifying at least 88% of the primary references on studies done specifically 900 MHz and over 70% of other relevant literature for the year 2020". To FEI's knowledge, Mr. Karow does not have any training or experience with epidemiological research that would qualify him to make this assessment.

<u>Dr. Héroux</u>

170. FEI does not take a position on Dr. Héroux's credentials to be qualified as an expert witness in his areas of academic training and experience. However, Dr. Héroux's report includes content on topics that are outside his area of expertise. Further, his report includes various intemperate language and unfounded allegations that are not reflective of an objective and neutral expert scientist. The first section of Dr. Héroux's report, titled "The Pseudo-Science of RF Safety Limits" contains various statements and comments about the motivations and perceived biases of various international standard setting bodies, in particular the Institute of Electrical and Electronics Engineers (**IEEE**).[190] For example:

(a) At page 6 of his report, in describing a standards committee of IEEE, Dr. Héroux states that, "given the need to insure stability of investments in wireless, it seemed critical to

[187] CORE Response to BCUC IR1 1.1 (Ex. C7-13)
[188] FEI Response to CORE IR1 2.1 (Ex. B-10)
[189] CORE Response to CEC IR1 5.1 (Ex. C7-16)
[190] Ex. C7-12-1, App. B, p. 4-10

convince everyone that health impacts of non-ionizing RF were impossible, or at the very least negligible".

(b) At page 8 of his report, Dr. Héroux describes Health Canada as having used "Copy and Paste" from the IEEE's C95.1 RF standard to establish Safety Code 6. He describes the "adoption of the C95.1 model" as "only a formality for many countries, occasionally with small variations in their national versions to maintain the illusion of national sovereignty, as happened in Canada with SC6". He goes on to describe the RF limits in Safety Code 6 as "written by industry" and as promoting "excessively permissive exposures based on heating, for the purposes of favoring deployment of as many wireless devices as possible ('expand the market')".

171. These statements in Dr. Héroux's report have no evidentiary basis and are not befitting of an objective and impartial expert scientist providing evidence in a BCUC proceeding.

172. Regarding statements that are also outside of Dr. Héroux's knowledge or expertise, FEI notes in particular the following passage from his report, under the heading, "The Trojan Horse":

> The design of the FortisBC meter deployment goes beyond its stated objectives. <u>This is deception (claiming one objective to hide another)</u>. Beyond gathering billing information, <u>the system steals data from customers</u>, and sets an infrastructure for large future increases in the RF exposures of one million customers by adhering to an irrational IoT philosophy. Acquiring data beyond what is necessary for the legitimate operations of billing is <u>equivalent to placing a surveillance device in a home, without the owner's consent. It is important to realize that, as these meters evolve, they could gain the capability of detailed mapping of user behavior, equivalent to placing a camera inside a home</u>.[191]

173. In this passage, Dr. Héroux makes unfounded and unsupported allegations that FEI's proposed deployment of advanced gas meters is an attempt to "deceive" its customers and would involve FEI "steal[ing]" customer data. These are reckless allegations, provided without any explanation or substantiation and again are not befitting of an impartial expert witness. This passage further involves Dr. Héroux giving his opinion on matters of system security and customer privacy that are not within his stated areas of expertise. Such topics are also outside the scope of CORE's intervention; in Order G-92-22 the Panel expressly found that that "CORE's scope of intervention does not include privacy, security or electrical engineering issues".[192]

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[191] Ex. C7-12-1, App. B, p. 27 (underlining added)
[192] BCUC Order G-92-22 at p. 9

174. Based on the above, and the tenor of Dr. Héroux's report more generally, FEI submits that, if the BCUC does qualify Dr. Héroux as an expert witness in this proceeding, the Panel should be skeptical of his report and evidence and give it reduced weight.

175. FEI also notes that Dr. Héroux (and Dr. Miller) gave evidence about the long-term health effects of electromagnetic fields in a recent Alberta Utilities Commission (**AUC**) proceeding regarding an ATCO transmission project. The AUC declined to follow this evidence, stating that:

> The Commission finds that the evidence of Dr. P. Héroux and Dr. A. Miller on the health risks associated with ELF magnetic fields and the precautionary measures they advocate for are inconsistent with the conclusions of the WHO, Health Canada and other national and international organizations; and further that neither Dr. A. Miller nor Dr. P. Héroux provided sufficient evidence to displace the conclusions of those organizations.[193]

Dr. Havas

176. Similarly, FEI does not take a position on Dr. Havas being qualified to give expert opinion evidence, but does object to evidence in her report that is outside of her experience and training.

177. Specifically, Dr. Havas provides video evidence (Exhibit C7-12) that includes her apparent measurement of the RF emissions from various devices, including an iPad, cell phone, microwave, as well as a number of people. Dr. Havas refers to the testing results from these measurements throughout her report (Exhibit C7-12-1, Appendix D). Dr. Havas' C.V. (Exhibit C7-12-1, Appendix H) does not reflect any relevant practical experience or accreditation for the measurement of RF emissions. As noted by Exponent, "Expertise in microwave engineering is required to properly operate such detectors in conjunction with the appropriate focusing and waveguiding elements due to the low signal level of the RF/microwave energy from the blackbody".[194]

178. More generally, Dr. Havas' report is largely focused on matters involving physics, engineering and RF exposure, which based on her C.V., appear to be outside Dr. Havas' academic training and experience.[195] Dr. Havas holds a B.Sc. degree in Biology and a Ph.D. from the University of Toronto's Department of Botany & Institute for Environmental Sciences. Further, the Academic Employment and Positions listed in her C.V. all appear to involve environmental sciences, ecology, forestry, and health studies.[196]

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[193] AUC Decision 25469-D01-2021: Central East Transfer-out Transmission Development Project (August 10, 2021), para. 216 **[Book of Authorities, Tab 10]**
[194] FEI Response to CEC IR3 12.1.1 (Ex. B-33)
[195] Ex. B-26, FEI Rebuttal Evidence, Part 2, p. 173
[196] Ex. C7-12-1, App. H, p. 172

179. FEI also notes that Dr. Havas previously provided evidence in a 2006 BCUC proceeding involving the BC Transmission Corporation's Application for a CPCN for the VITR Project. The BCUC's CPCN decision regarding the VITR Project describes Dr. Havas' opinion that, "magnetic fields associated with high voltage transmission lines are a cancer promoter" and that "…power lines should not be built in residential areas, near schools or near play areas unless peak exposures for the entire lifetime of the line can be guaranteed to be under 2 mG (and preferably under 1 mG) at the edge of the [ROW]… and where prolonged human exposure is likely".[197] The decision describes her as "disagree[ing] with the conclusions of the IARC, ICNIRP, the National Health Radiological Board, Health Canada and the World Health Organization". The BCUC panel stated that, "she was unable to provide evidence to support that allegation [that scientific and expert panel conclusions that do not conform to established views are 'often delayed or suppressed'] or to conclude that the IARC, ICNIRP and National Radiological Protection Board reviews are biased".[198] The BCUC's decision goes on to state as follows:

> The Commission Panel finds Dr. Havas's evidence to be selective and her opinions unconvincing. Dr. Havas conducted one comprehensive study of the pre-2000 research but did not review the more recent scientific research and therefore could not support her position that recent scientific research indicated a need for lower exposure guidelines.[199]

<u>Dr. Miller</u>

180. FEI does not object to Dr. Miller's qualification as an expert witness in this proceeding, within his area of expertise. In his report, however, Dr. Miller goes on to opine on whether or how the BCUC would be "liable" in certain circumstances.[200] FEI submits that apart from the fact that the evidence does not support those circumstances, opinions as to liability are beyond Dr. Miller's area of expertise, as he is not a lawyer. Further, matters of law (other than foreign law) are not properly the subject of expert evidence. In any case, FEI submits that the AMI Project will be compliant with the applicable legal framework and does not expect that findings of liability would be made against it or others or that compensation would be awarded in connection with the operation of AMI.[201]

181. As noted above, the AUC recently rejected Dr. Miller's testimony on matters related to electromagnetic fields and health as being inconsistent with the conclusions of the WHO, Health Canada and other national and international organizations and insufficient to displace the conclusions of those organizations.

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[197] BCUC Order and Decision C-4-06, p. 68 **[Book of Authorities, Tab 11]**
[198] Ibid., p. 69
[199] Ibid., p. 71
[200] Exhibit C7-12-1, Appendix C, p. 53
[201] FEI Response to CORE IR1 14.0

D. Applicability of Safety Code 6 to the AMI Project

i. 2015 Update to Safety Code 6

182. As described in the BCUC's 2013 AMI Decision, Safety Code 6 is "One of a series of safety codes prepared by the Consumer and Clinical Radiation Protection Bureau, Health Canada" and "specifies the requirements for the safe use of, or exposure to, radiation emitting devices".

183. Health Canada published the version of Safety Code 6 in effect at the time of the 2013 AMI Decision in 2009. Health Canada subsequently published an updated version of Safety Code 6 in 2015. As described in Exponent's RF Health Report: "Since its initial publication, SC6 has been periodically updated as new scientific literature becomes available and has undergone a number of revisions with new versions published in 1999, 2009, and 2015, each time with input from the Royal Society of Canada (RSC). During the revision process prior to finalizing SC6, Health Canada also considered input from the public and scientists for the 9 months before the release of the revised SC6 in 2015."[202]

184. The updated Safety Code 6 (2015) contains substantially the same content as the 2009 version that was before the BCUC panel at the time of the 2013 AMI Decision. For example, Safety Code 6 (2015) contains the following equivalent content that the 2013 Panel relied on its decision:

> 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 non-thermal health effects of RF fields. 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 exposure to RF fields[.] […] The exposure limits in Safety Code 6 are based upon the lowest exposure level at which any scientifically established adverse health effect occurs. Safety margins have been incorporated into the exposure limits to ensure that even worst-case exposures remain far below the threshold for harm.[203]

185. Safety Code 6 (2015) also describes developments since the 2009 version in the following passage:

> The scientific literature with respect to possible biological effects of RF fields has been monitored by Health Canada scientists on an ongoing basis. Since the last version of Safety Code 6 was published (2009), a significant number of new studies have evaluated the

[202] Ex. B-1, App. F-2, p. 20
[203] Safety Code 6 (2015), p. 1 [Book of Authorities, Tab 7]

> potential for acute and chronic RF field exposures to elicit possible effects on a wide range of biological endpoints including: human cancers; 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 among others. Numerous authoritative reviews have summarized the current literature (4–8, 17–40).
>
> <u>Despite the advent of numerous additional research studies on RF fields and health, the only established adverse health effects associated with RF field exposures in the frequency range from 3 kHz to 300 GHz relate to the occurrence of tissue heating and nerve stimulation (NS) from short-term (acute) exposures. At present, there is no scientific basis for the occurrence of acute, chronic and/or cumulative adverse health risks from RF field exposure at levels below the limits outlined in Safety Code 6</u>. The hypotheses of other proposed adverse health effects occurring at levels below the exposure limits outlined in Safety Code 6 suffer from a lack of evidence of causality, biological plausibility and reproducibility and do not provide a credible foundation for making science-based recommendations for limiting human exposures to low-intensity RF fields.[204]

ii. The Legal Status of Safety Code 6

186. Various statements made by CORE or its witnesses indicate that, contrary to the BCUC's findings in the 2013 AMI Decision, CORE does not consider Safety Code 6 to be applicable or mandatory in respect of FEI's AMI Project. In particular:

(a) In CORE's response to BCSCEA IR1 2.1, CORE states that, "Safety Code 6 is not a health standard, but rather a guideline that applies to federally regulated sites, such as cell towers. Our homes are not federally regulated sites." (Ex. C7-15)

(b) Similarly, in CORE's response to CEC IR1 3.2, CORE states that, "Safety Code [6] is not a law but rather is a guideline for federally regulated sites, such as cell towers". (Ex. C7-16)

(c) In CORE's response to BCUC IR1 3.2, Dr. Héroux states that, "SC6 is a national recommendation not a requirement". (Ex. C7-13)

(d) In CORE's response to BCUC IR1 4.2, Dr. Havas states that, "I don't understand why HC SC6 is being relied upon for RF exposure in this case or in any cases related to

[204] Safety Code 6 (2015), underlining added

wireless radiation emissions". Among Dr. Havas' explanations for this statement is that Safety Code 6 "is a guideline rather than a standard and hence is voluntary". (Ex. C7-13)

187. These statements are all contrary to the BCUC's findings regarding Safety Code 6 in the 2013 AMI Decision and, specifically, the BCUC's determination that "emissions from the proposed AMI meters must comply with the requirements of Safety Code 6".[205] The following legal explanation supports this conclusion and its continuing validity.

188. The federal *Radiocommunication Act*, 30 R.S.C. 1985, c. R-2, governs, among other things, the manufacture, marketing, and operation of "radio apparatus" anywhere within Canada (section 3(1)(3)). "Radio apparatus" are defined in the Act as "devices … intended for, or capable of being used for, radiocommunication".[206] The Sonix IQ gas meters that are part of the AMI Project undoubtedly fit this definition.

189. Under the *Radiocommunication Act*, the Minister of Industry has enacted the *Radiocommunication Regulations*, SOR/96-484, providing that certain categories of radio apparatus, which include the AMI gas meters, must be certified and may only be operated if maintained in conformity with various applicable standards, which are in turn published by Industry Canada. These applicable standards include, among others, Industry Canada's RSS 102 – Radio Frequency (RF) Exposure Compliance of Radiocommunication Apparatus (All Frequency Bands).[207] RSS 102 states that, "It is the responsibility of proponents and operators of antenna system installations to ensure that all radiocommunication and broadcasting installations <u>comply at all times with Health Canada's Safety Code 6</u>, including consideration of combined effects of nearby installations within the local radio environment".[208]

190. RSS 102 sets out various requirements, processes, and evaluation methods for certification of radiofrequency apparatus as being compliant with RF exposure limits. Under section 4, RSS 102 states that, "For the purpose of this standard, Industry Canada has adopted the SAR and RF field strength limits established in Health Canada's RF exposure guideline, Safety Code 6".

191. Safety Code 6 itself is drafted in mandatory terms. In its Preface, Safety Code 6 states that, "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 <u>the requirements</u> for the safe use of, or exposure to, radiation emitting devices".[209] The Preface also notes that, "This code has been adopted as the scientific basis for equipment certification and RF field exposure compliance specifications outlined in Industry Canada's regulatory

[205] 2013 AMI Decision, p. 108 [Book of Authorities, Tab 14]
[206] *Radiocommunication Act*, section 2 **[Book of Authorities, Tab 4]**
[207] Ex. B-26, FEI Rebuttal Evidence Part 1, p. 12
[208] RSS 102, section 5 (underlining added) **[Book of Authorities, Tab 6]**
[209] Health Canada, Safety Code 6 (2015), p. I; underlining added **[Book of Authorities, Tab 7]**

documents (1-3), that govern the use of wireless devices in Canada, such as cell phones, cell towers (base stations) and broadcast antennas". Further, section 1 of Safety Code 6, "Introduction", states that, "In the following sections, the maximum exposure levels for persons in both controlled and uncontrolled environments are specified. <u>These levels shall not be exceeded</u>."[210]

192. Based on this regulatory framework, FEI's understanding is that the AMI gas meters are required to comply with the RF exposure limits specified in Safety Code 6.[211] The RF exposure levels set out in Safety Code 6 are not "recommendations" or "voluntary" as CORE and its witnesses suggest. Additionally, CORE's argument that "our homes are not federally regulated sites" to which Safety Code 6 does not apply is inapt given that the meters themselves are subject to federal regulation, including Safety Code 6.

193. As referenced in FEI's prior response to CORE IR 2.36.a., the AMI gas meters produced by Sensus have received certification from Innovation, Science and Economic Development Canada (**ISED**), the details of which are set out in Appendix F-1 of the Application, Table 2 at p. 20.

E. The Project's Advanced Gas Meters Comply with Safety Code 6

i. ISED Certification

194. As noted above, RSS-102 published by Industry Canada, now known as ISED, sets out conditions and processes for obtaining certification that radiocommunication apparatus comply with the requirements of the standard. These requirements include, as explained above, compliance with Safety Code 6.

195. The AMI Project gas meters and other End Points that are part of the AMI Project have received necessary certification from ISED.[212] Exponent's RF Technology Report, which Sensus reviewed and confirmed to be accurate, notes that RF certification documents are available online with each End Point assigned a unique identifier; Table 2 of the RF Technology Report lists both the ISED certification number, as well as the U.S. Federal Communications Commission (**FCC**) certification number for each of the End Points, including the Sonix IQ gas meters.[213]

196. Given that radiocommunication apparatus require certification under RSS-102 and RSS-102 requires compliance with Safety Code 6, FEI understands that ISED's certification of the Sonix IQ gas meters signifies their compliance with applicable RF limits in Safety Code 6 for regulatory compliance purposes in Canada.

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[210] Ibid., p. 1
[211] Ex. B-26, FEI Rebuttal Evidence Part 1, p. 12
[212] FEI Response to CORE IR2 36.a (Ex. B-22)
[213] Ex. B-1, App. F-1, p. 19-20

ii. Exponent Evidence

197. In addition, FEI submits that Exponent's expert evidence filed in this proceeding conclusively demonstrates that RF exposure from the Sonix IQ gas meters in typical operations will be orders of magnitude – approximately 24 million times – lower than the Safety Code 6 exposure limit.

198. Exponent's RF Technology Report, prepared by Dr. Cotts, includes a variety of RF exposure calculations for the Sonix IQ gas meters and other End Points and a comparison to the exposure limits in Safety Code 6. As explained in section 3 of the report, Dr. Cotts calculated the power density of an RF signal, based on the meter's duty cycle, at different distances from the meter using the power and gain data from Sensus' ISED certification documents. Dr. Cotts made adjustments in his calculations for attenuation of signal strength from walls or other boundary materials, as well as preferential transmission of the signal forward and away from the device rather than backward towards an occupant.[214] Dr. Cotts also included a conservative adjustment factor to account for potential ground reflection that may increase exposure above the standard inverse square law.[215]

199. Appendix B to the RF Technology includes, at Table B-2, a detailed listing of these RF exposure calculations for the different network End Points at different distances from the source, both inside and outside a building. As an example, Dr. Cotts calculated the indoor RF exposure at a distance of 1 meter behind the Sonix IQ meter, for a typical duty cycle of 0.00039% (i.e. one message, 52.48 milliseconds in length, every 4 hours, plus approximately 4 additional status update messages per week, or 0.34 seconds per day) to result in a power density of 0.000000011 milliwatts per square centimeter (**mW/cm^2**).[216] This is 0.0000042% of, or approximately 24 million times below, the Safety Code 6 limit (set out in Table 1 of the report).[217] Even at a maximum duty cycle, during one-time startup and network connection, at a distance of 0.25 meters directly in front of the Sonix IQ gas meter (outside), Dr. Cotts calculates the power density to be 0.00028 mW/cm^2, which is approximately 1,000 times below the Safety Code 6 limit.[218]

200. Dr. Cotts further explains that RF exposure from the Sonix IQ gas meters is "extremely small" due to the low power output and very short and infrequent transmissions. The daily transmission time is so short, at 0.34 seconds total per day, that it would take more than 2 years and 5 months, or approximately 890 days, for a Sonix IQ gas meter to transmit for the same amount of time as a 5-minute call on a cell phone.[219] Indeed, typical RF exposure from a cell phone call next to the head (which itself is well below the Safety Code 6 limit) is approximately 1.8 million times greater than exposure to the Sonix IQ gas meter at 1

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[214] Ibid., p. 21
[215] Ibid.
[216] Ibid., p. 21-22 and App. B, Tables B-1 and B-2
[217] Ibid.
[218] Ibid.
[219] Ibid., p. 28

meter away.[220] Perhaps most strikingly, Dr. Cotts calculates that residents of British Columbia from Vancouver to Castlegar are currently exposed to greater power density RF signals from the CBC television broadcast station in Vancouver than they would be 1 meter away from a Sonix IQ gas meter installed outside their home.[221]

201. FEI submits that the evidence shows that potential RF exposure from the Sonix IQ gas meters and other End Points to be installed as part of the AMI Project is extremely small and far below the Safety Code 6 limits, which, as noted, are themselves established using a significant precautionary margin for safety.

iii. CORE Evidence Regarding Safety Code 6 Compliance

202. Despite CORE's opposition to the AMI Project, its own witness evidence effectively acknowledges that the proposed meters are compliant with Safety Code 6. For example:

(a) In response to a BCUC IR asking CORE to "confirm, or otherwise explain that the proposed Sensus Sonix IQ meters meet Health Canada Safety Code 6", Dr. Héroux did not deny that this was the case, but instead responded that, "Almost any device that radiates intermittently meets SC6, irrespective of power, because SC6 is based on average heat over 6 minutes, and takes only heat into account".[222]

(b) In another response, Dr. Héroux acknowledged that a meter would only be capable of exceeding the Safety Code 6 limit at 26 cm if it "was irradiating continuously (not a foreseen condition)" and then noted that the Sonix IQ meter's "duty cycle is very small: 55 msec every 4 hours … which provides a very large reduction factor of ~6,545, as the signal is averaged over 6 minutes, according to SC6. So, by the metric of energy averaging, the meter is perfectly safe for everyone".[223]

(c) When asked by the BCUC in its IR1 4.2 to "confirm, otherwise explain, that if the RF emissions from the Sonix IQ meters were measured at the peak signal strength, instead of averaged, the peak RF emissions would meet the Health Canada Safety Code 6 standard":

(i) Dr. Héroux provided a non-responsive answer that "peak RF emissions of the smart meter would rate much higher than the average emissions, but would still be based on heat …" and then referred to other "health based standards" before raising issues for individuals suffering EHS.

(ii) Dr. Havas stated, "I have no first-hand experience regarding the emissions (average or peak) from the Sonix IQ meter so I am unable to answer question 4.2".[224]

[220] Ibid., p. 26, Figure 5
[221] Ibid., p. 28-29
[222] CORE Response to BCUC IR1 3.1 (Ex. C7-13)
[223] CORE Response to BCUC IR1 3.4 (Ex. C7-13)
[224] CORE Response to BCUC IR1 4.2 (Ex. C7-13)

203. Dr. Héroux's evidence, as reflected above, does imply or suggest that Sonix IQ gas meters could be non-compliant with RF exposure limits in Safety Code 6 when the separation distance from the meter is 26 cm from the source. However, Dr. Héroux also readily accepts in the IR response noted above that this would only be the case if the meter was "irradiating continuously" and that this is not a "foreseen condition". In fact, FEI's evidence establishes that the meters would typically only be transmitting and creating potential RF exposure in messages that are 52.48 milliseconds in length, sent every 4 hours, plus approximately 4 weekly status messages, or a total of 0.34 seconds per day. Even at maximum duty cycle, during one-time meter startup and network connection, at a distance of 0.25 meters, outside, directly in front of the meter, as noted above, Dr. Cotts calculates the RF exposure to be 1,000 times below the Safety Code 6 limit.

204. Furthermore, the 26 cm exposure distance referenced in Dr. Héroux's evidence is not consistent with any plausible operational circumstance involving the regular use of the gas meters. Evaluation of compliance with Safety Code 6 is based upon the intended use and exposure scenarios relevant to a particular source.[225] Generally speaking, the meters will be installed on the outside of customer premises and the RF signals directed away from the premises.[226] As Dr. Cotts' report explains (and as discussed in the 2013 AMI Decision), this results in the signal strength being greatly diminished both because power transmitted backward from the meter is approximately 1/10th of the power transmitted forward and because the signal passing through walls or other building materials attenuates the power density.[227] A customer would literally have to stand less than an arm's length directly in front of the meter for 4 hours to be exposed to even 52.48 milliseconds of RF emission from the Sonix IQ gas meter.

205. FEI also submits that the evidence of CORE and its witnesses regarding the technical specifications and other performance metrics of the meters in issue is of questionable reliability. Both Dr. Héroux and Dr. Havas refer to an FCC certification document as their source of information regarding the power density and strength of the signal of a Sonix IQ gas meter with FCC ID number: SDBSONIXIQ.[228] CORE refers to this same FCC certification document in its IR responses.[229] In fact, this is an FCC certification document for an older generation Sonix IQ meter, not the Sensus product FEI proposes to use in the AMI Project – the correct meter has an FCC ID number of SDBSONIXIQV2 and an ISED Identification No. 2002A-SDBSONIXIQV2 and operates at a lower power than the meter cited in CORE's evidence.[230]

206. Neither Dr. Miller nor Dr. Havas provide any evidence on whether the Sonix IQ gas meters are compliant with Safety Code 6. As noted above, Dr. Havas candidly admitted, in response to an IR regarding Safety Code 6 compliance, that she had "no first-hand

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[225] FEI Response to CORE IR3 4.b (Ex. B-34)
[226] Ex. B-1, App. F-1, p. 16
[227] Ex. B-1, App. F-1, p. 21 and fn. 21
[228] Ex. C7-12-1, App. B (Héroux), p. 29 and App. D (Havas), p. 76
[229] See CORE Response to BCUC IR1 1.1 (Ex. C7-13), CORE Response to FEI IR1 1.1. (Ex. C7-17)
[230] Ex. B-1, App. F-1, p. 20, Table 2; Ex. B-26, Part 2, p. 6

experience regarding the emissions (average or peak) from the Sonix IQ meter so I am unable to answer".[231]

207. Dr. Havas' report does critique Exponent's RF Technology Report prepared by Dr. Cotts. However, her specific criticisms are restricted to Table 4 and Figure 5 of Dr. Cotts' report, which compare RF exposure from the Sonix IQ gas meters to other common sources of RF emissions (and were due to math errors in Dr. Havas' report).[232] Dr. Havas' main ground for asserting that the information in these parts of Dr. Cotts' report are "false and misleading" appears to be her belief that the human body and the earth do not emit RF emissions at levels that are measurable – she asserts it is "false information" for Exponent's report to state that they do.[233] She also asserts that it is "incorrect" that blackbody radiation emits at frequencies between 0.003-3,000 MHz.[234]

208. Dr. Havas appears to be basing these assertions, which are plainly wrong, on her home testing of RF emissions from various devices and people using an RF meter (the "Safe and Sound Pro II meter").[235] In her video evidence (Ex. C7-12), she suggests that her testing results show that the Earth and human bodies do not emit RF radiation.

209. Exponent's rebuttal testimony shows Dr. Havas to be wrong in all respects on these issues.

210. First, Dr. Havas herself quotes from a Wikipedia definition of blackbody radiation that contradicts her assertion that such radiation does not occur at frequencies from 0.003 to 3,000 MHz. The definition she relies on states that a "blackbody … emits <u>all</u> radiation frequencies".[236]

211. Exponent's evidence explains that any object that has a temperature above absolute zero radiates electromagnetic energy and does so at all frequencies. Because humans and earth have temperatures of approximately 300 Kelvin, most of their emitted energy is in the infrared portion of the electromagnetic spectrum, but very small portions of that energy is emitted in the radio and microwave portions of the electromagnetic spectrum.[237] Exponent's rebuttal also explains how quantum physics and statistical mechanics (both matters outside of Dr. Havas' expertise) are used to calculate emissions of such objects at any frequency, including in the RF/microwave range of 3 kHz-300 GHz.[238] Exponent further cites a peer reviewed scientific and engineering journal, as well as a publication from the International Commission of Non-Ionizing Radiation Protection (**ICNIRP**), as

[231] CORE Response to BCUC IR1 4.2 (Ex. C7-13)
[232] Ex. B-26, Part 2, p. 33-35
[233] Ex. C7-12-1, App. D, p. 69
[234] Ibid., p. 67
[235] Ibid., p. 75 (underlining added)
[236] CORE Response to FEI IR1 8.2 (Ex. C7-17)
[237] Ex. B-1, App. F-1, p. 5; Ex. B-26, Part 2, p. 27
[238] Ex. B-26, Part 2, p. 27-28

supporting the conclusion that humans emit blackbody radiation in the RF portion of the spectrum.[239]

212. Dr. Havas' purported measurements of RF emissions in her home laboratory as depicted in Exhibit C7-12 are, with respect, not credible evidence on this topic. The manual for the Safe and Sound Pro II device that Dr. Havas used for these measurements specifies that the device is not capable of measuring the vast majority of the emitted RF/microwave energy (3 kHz-300 GHz) from humans and the earth.[240] Exponent further explains that specialized instrumentation, a microwave radiometer with energy focusing elements and waveguiding components, as well as expertise in microwave engineering, are required to measure the extremely low levels of RF/microwave energy from humans or the earth.[241] Exponent also refers to an academic publication that used such equipment in its study and, in Rebuttal Evidence, reproduces an image from this publication showing RF/microwave emissions from a human body.[242] Dr. Havas does not have the necessary equipment or experience to take the required measurements and instead claims, incorrectly attributing the result to the non-existence of the phenomenon, that, "It isn't possible to measure something that does not exist".[243]

213. FEI submits that the evidence in this proceeding establishes conclusively that the Sonix IQ gas meters and other End Points to be installed as part of the AMI Project comply with the RF exposure limits in Safety Code 6. The advanced meters will, in fact, emit RF at levels that are far, far below the Safety Code 6 limits.

F. CORE's Evidence Does Not Demonstrate Any Credible Health Risks Arising from Safety Code 6

i. Summary

214. As set out above, the BCUC's 2013 AMI Decision rejected intervener arguments that Safety Code 6 is "fundamentally flawed" and instead determined that "Safety Code 6 provides protection from thermal effects, non-thermal effects and incorporates an adequate degree of precaution". Safety Code 6 has since been updated in 2015 with Health Canada stating in the new version that: "Despite the advent of numerous additional research studies on RF fields and health [i.e. since the 2009 version of Safety Code 6], the only established adverse health effects associated with RF field exposures in the frequency range from 3 kHz to 300 GHz relate to the occurrence of tissue heating and nerve stimulation (NS) from short-term (acute) exposures. At present, there is no scientific basis for the occurrence of acute, chronic and/or cumulative adverse health risks from RF field exposure at levels below the limits outlined in Safety Code 6".[244]

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[239] Ibid., p. 28-30 and Fig. 2
[240] Ibid., p. 30-31
[241] Ex. B-26, Part 2, p. 31; FEI/Exponent Response to CEC IR3 12.1
[242] Ex. B-26, Part 2, p. 30, Fig. 3
[243] CORE Response to FEI IR1 8.1 (Ex. C7-17)
[244] Safety Code 6 (2015), p. 2 **[Book of Authorities, Tab 7]**

215. FEI questions the extent to which the BCUC has jurisdiction to find, contrary to Health Canada's conclusion, that Safety Code 6 does not provide adequate protection from the health risks associated with RF exposure. Doing so is not within the BCUC's mandate under the *UCA* and the Panel in the 2012-2013 proceeding regarding the FBC AMI Project noted that, while evidence on RF and health would be included in the oral hearing, the BCUC "has no jurisdiction over regulations made by Health Canada and other agencies. Accordingly, it is not within the Commission's mandate to consider any changes to these regulations".[245] To the extent the BCUC has authority to address these matters as part of its CPCN review, FEI submits that CORE's evidence in this proceeding does not come close to meeting the high burden that would be necessary to prove that Safety Code 6 does not provide adequate protection against adverse health effects from RF exposure.

216. FEI has also filed in this proceeding, the Exponent RF Health Report prepared by Drs. Dopart and Bailey (Ex. B-1, App. F-2). The Exponent RF Health Report provides a thorough review and analysis of various comprehensive risk assessments and reviews of the scientific literature related to exposure to RF fields and health conducted by several international organizations in the last decade, as well as a review of relevant epidemiological and experimental studies on RF and health published after the most recent comprehensive international review was completed in 2015. The Exponent RF Health Report sets out that the most recent comprehensive international reviews have concluded that research does not confirm that RF fields at the levels we encounter in our everyday environment are a cause of cancer, chronic disease, or other adverse health effects.[246] Further, the more recent studies reviewed did not provide evidence in support of a causal relationship between RF field exposure and cancer or symptoms of well-being.[247]

217. CORE's intervener evidence, like certain intervener evidence in the 2012-2013 proceeding regarding the FBC AMI Project, suggests that Safety Code 6 does not adequately protect FEI's customers from potential adverse health effects of RF exposure. The main points that can be discerned from CORE's evidence in this regard appear to be that:

(a) Safety Code 6 is purportedly flawed because, as Dr. Héroux claims, its RF exposure limits are based on "avoidance of short-term tissue heating (temperature rise)".[248]

(b) Safety Code 6's RF exposure limits are also, according to Dr. Héroux and Dr. Havas, flawed because they are based on time-averaged RF exposure calculations.[249]

(c) Both Dr. Héroux and Dr. Havas also claim, incorrectly, that RF emissions from the Sonix IQ gas meters are "pulsed" and that this creates greater health risks.[250]

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[245] BCUC Order G-177-12, p. 5 [Book of Authorities, Tab 12]
[246] Ex. B-1, App. F-1, p. 119
[247] Ibid.
[248] Ex. C7-12-1, App. B, p. 3
[249] Ex. C7-12-1, App. B, p. 23-24 (Héroux) and App. D, p. 76 (Havas)
[250] Ibid., App. B, p. 18 (Héroux) and App. D p. 77 (Havas)

218. These topics are addressed in detail below.

ii. Thermal Effects and RF Cancer Risk

219. Before addressing the specific issues raised in CORE's intervener evidence it is important to recognize what, on the other hand, CORE's evidence does not say. In particular, none of CORE's expert witnesses appear to provide evidence that RF exposure from the Sonix IQ gas meters at levels far below the Safety Code 6 limits is a potential source of adverse health risks from the thermal effects (or tissue heating) associated with RF exposure. CORE's evidence instead makes generalized claims regarding the potential non-thermal effects of RF exposure and, primarily, focuses its discussion of potential risks to EHS symptoms.

220. Dr. Miller in his report states that, "I and many other scientists now believe that RFR should be categorized as a Class 1 Human Carcinogen, in the same category as cigarette smoking, asbestos exposure, and X-Rays".[251] Dr. Miller does not cite any body of evidence in support of this opinion or any opinion about the levels at which RF exposure creates actual health risks, even if it was categorized in this way. Dr. Miller likewise does not provide any actual evidence that he has performed a formal health assessment regarding any health risks associated with the advanced meters and End Points at issue in the Application.

221. As noted above, Exponent's Drs. Dopart and Bailey have conducted a thorough and rigorous assessment of recent scientific research regarding the health effects of RF exposure, with a focus on cancer and EHS. Their comprehensive report concludes that the research "does not confirm that RF fields at levels we encounter in our everyday environment are a cause of cancer, chronic disease, or other adverse health effects".[252] They similarly conclude that the research reviewed does not provide "a reliable scientific basis to conclude that the operation of FortisBC's proposed FlexNet system will cause or contribute to adverse health effects or physical symptoms in the general population".[253]

222. The health risk assessment in the Exponent RF Health report is consistent with assessments performed by numerous local and international organizations, such as: the British Columbia Centre for Disease Control (**BCCDC**), the Royal Society of Canada (**RSC**), the Advisory Group on Non-Ionising Radiation Protection (**AGNIR**), the International Agency for Research on Cancer (as defined above, IARC), the World Health Organization (**WHO**), the Scientific Committee on Emerging and Newly Identified Health Risks (**SCENIHR**), the International Commission on Non-Ionizing Radiation Protection **(**as defined above, ICNIRP), the Health Council of the Netherlands (**HCN**), the Swedish Radiation Safety Authority (**SSM**), and the United States Food and Drug Administration (**USFDA**).

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[251] Ex. C7-12-1, App. C, p. 54
[252] Ex. B-1, App. F-2, p. 119
[253] Ibid., p. 120

223. Dr. Miller states that he finds "much of this material [i.e. the Exponent RF Health Report] to be uninformative or simply wrong".[254] His two-page report provides almost no explanation for this vague opinion. To the extent he cites his own previous journal article, FEI notes it is primarily focused on RF health risks associated with cell phones and Exponent provides a compelling and comprehensive rebuttal in any event.[255] Further, Dr. Miller's report does not demonstrate that he followed a scientific health risk assessment or "weight of evidence" review process in developing his opinions. Exponent's RF Health Report describes the appropriate steps and process for conducting such assessments.[256]

iii. Non-Thermal RF Effects

224. CORE, like CSTS in the 2012-2013 FBC AMI proceeding, criticizes Safety Code 6 and other international RF standards for allegedly not addressing adverse health effects from RF other than from tissue heating. For example, Dr. Héroux begins his report by stating that, "Short-term heat cannot represent long-term health" and that "Exponent's assessment of FortisBC smart meter health impacts, based on SC6, is entirely based on heat, and is incorrect".[257] As reflected in his IR responses quoted above, Dr. Héroux also dismisses the meters' compliance with Safety Code 6 on the basis that the standard "takes only heat into account". Dr. Havas makes similar comments in describing Safety Code 6.[258]

225. FEI notes that this evidence is contrary to the BCUC's finding in the 2013 AMI Decision that Safety Code 6 does provide protection from non-thermal health effects of RF exposure. The 2015 version of Safety Code continues to state, based on Health Canada's review, that, "The exposure limits specified in Safety Code 6 have been established based upon a thorough evaluation of the scientific literature related to the thermal <u>and non-thermal health effects of RF fields</u>".[259] Further, the 2015 version of Safety Code 6 states that, despite numerous additional research studies on RF fields and health since 2009, "the only established adverse health effects" associated with RF exposure in the frequency range from 3 kHz to 300 GHz "relate to the occurrence of tissue heating and nerve stimulation (NS)" – note that "nerve stimulation" is only associated with RF exposure in the frequency range from 3 kHz to 10 MHz, which does not involve the proposed gas meters or other elements of the AMI Project.[260] Safety Code 6 further addresses potential non-thermal effects of RF exposure as follows:

> The hypotheses of other proposed adverse health effects occurring at levels below the exposure limits outlined in Safety Code 6 suffer from a lack of evidence of causality, biological plausibility and reproducibility and do not provide a credible foundation for making

[254] Ex. C7-12-1, App. C, p. 53
[255] Ex. B-26, Part 2, p. 22-26
[256] Ex. B-1, App. F-2, p. 7-17
[257] Ex. C7-12-1, App. B, p. 3
[258] CORE Response to BCUC IR1 4.2 (Ex. C7-13)
[259] Safety Code 6 (2015), p. 1 (underlining added) **[Book of Authorities, Tab 7]**
[260] Ibid., p. 2-3

> science-based recommendations for limiting human exposures to low-intensity RF fields.[261]

226. Other recognized international health standards also state that reported effects of all RF exposures have been reviewed and evaluated, including those of such low intensity that a non-thermal mechanism is unlikely; for example:[262]

(a) The IEEE International Committee for Electromagnetic Safety (ICES) Standard for Safety Levels with Respect to Human Exposure to Radio Frequency Electromagnetic Field (2019; 2020) states that:

> Review of the extensive literature on electromagnetic field (EMF) biological effects revealed that electrostimulation is the dominant effect at low frequencies and that thermal effects dominate at high frequencies. <u>Examination of the radio frequency (RF) exposure literature revealed no reproducible low-level (nonthermal) adverse health effects. Moreover, the scientific consensus is that there are no accepted theoretical mechanisms that would explain the existence of low-level adverse health effects</u>.

(b) The ICNIRP Guidelines for Limiting Exposure to Electromagnetic Fields (100 kHz to 300 GHz) (2020) states that:

> For the purpose of determining thresholds, evidence of adverse health effects arising from <u>all radiofrequency EMF exposures is considered, including those referred to as 'low-level' and 'non thermal', and including those where mechanisms have not been elucidated.</u> Similarly, as there is no evidence that continuous (e.g., sinusoidal) and discontinuous (e.g., pulsed) EMFs result in different biological effects (Kowalczuk et al. 2010; Juutilainen et al. 2011), no theoretical distinction has been made between these types of exposure (all exposures have been considered empirically in terms of whether they adversely affect health).

227. Neither Dr. Héroux nor Havas provides a similar health risk assessment.

228. FEI submits that CORE's intervener evidence fails to establish that the BCUC in its 2013 AMI Decision, Health Canada in Safety Code 6, or these other recognized international agencies were incorrect in their assessment of non-thermal effects of RF exposure.

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[261] Ibid., p. 2

[262] See Ex. B-26, Part 2, p. 12 (underlining added)

iv. Time Averaging in RF Exposure Calculation

229. CORE's intervener evidence does not provide any credible explanation why RF exposure limits based on time averaging, like in Safety Code 6, are inappropriate or create health risks for the public.

230. Dr. Héroux, in his report, asks rhetorically whether, for a "pulse[263] of radiation", "is it more likely that the maximum value of the pulse is relevant to your health, or is the average energy of the pulse over time more relevant?"[264] Dr. Héroux does not actually answer this question or give a clear opinion in his report, but instead obfuscates that, "If you choose the average, this means you are not worried about being hit by the bullet from a gun, because when averaged over 30 minutes, the impact of the bullet can barely be felt".[265] Dr. Héroux refers to averaging being appropriate for some other exposures, such as chemicals, "because the body has many buffering mechanisms to compensate" – he goes on to state without explanation or any supporting evidence that, "this is not true for a RF field penetrating the body, and reaching a threshold of damage".[266]

231. Dr. Héroux does not say clearly what form of "damage" he means, but his report then moves to a discussion of RF impacts on "sensitive" persons and the "EHS population".[267]

232. Dr. Havas describes time-averaged RF values as "falsely represent[ing]" the "actual radiation to which a person is exposed". She asserts that use of averages do not "make sense" "from a biological perspective since organisms react to extremes rather than averages".[268] Dr. Havas does not provide any scientific explanation or evidentiary support for that broad statement or how it applies to RF exposures.

233. Safety Code 6 uses time averaged reference periods of 6 minutes for the purposes of its RF exposure limits and reference levels.[269] Safety Code 6 also explicitly states that, "Where exposure is estimated in terms of power density and for exposures shorter than the reference period [i.e. 6 minutes], power density levels may exceed the reference levels provided that the time average of the power density over any time period equal to the reference shall not exceed [the power density reference level]".[270]

234. Given these express features of Safety Code 6, it is apparent that Health Canada considers a time averaged calculation of RF exposure to be the appropriate metric for assessing health

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[263] Dr. Héroux's evidence regarding "pulsation" of RF from the Sonix IQ meters is addressed separately below.
[264] Ex. C12-1-1, App. B, p. 23
[265] Ibid.
[266] Ibid.
[267] Ibid., p. 24
[268] Ex. C7-12-1, App. D, p. 76
[269] See Safety Code 6 (2015), p. 8 and Table 5
[270] Ibid., p. 9

and safety risks. Exponent explains the use of time-averaged reference periods in Safety Code 6 as follows:

> The Reference Period of 6 minutes (SC 6, Table 5) for time averaging is used in recognition of the fact that the human body has natural processes to deal with temperature increases. For instance, when a person goes for a run, the core body temperature increases. As a result, the body sweats in order to regulate the temperature increase associated with the exercise (i.e., thermoregulation). The 6-minute averaging time is therefore a reflection of the ability of the body to properly thermo-regulate itself (i.e., remove the low level of excess heat) that results from exposure to the low level of electromagnetic energy.[271]

235. Exponent further explains that, "Persons can be exposed at or below 100% of the limit indefinitely. Exposure to levels above 100% can be permitted provided the duration is sufficiently short. This is because the absorption of RF energy by the body, and therefore the effects of RF exposure, are described by an intensity x time relationship".[272]

v. "Pulsation" of RF Signals

236. Dr. Héroux includes in his report various references to the "pulsation" or "pulses" of RF emitted from the Sonix IQ gas meters or the "spurious" nature of such signals.[273] For example, he states that a figure in Exponent's RF Technology Report "does not display that the FSK signal is not continuous, but spurious, suddenly turning on and off with a duration of about 55 milliseconds (the burst is much longer that the 0.577 millisecond of GSM cell phone signals). A spurious signal increases biological activity."[274] Dr. Havas similarly claims that, "radiation from a smart meter is modulated with a carrier wave and communication frequencies. This results in a chaotic emission and chaotic radiation adversely affects the body compared with coherent emissions that can be beneficial. The difference between coherent and chaotic is like the difference between music and noise".[275]

237. Neither of these witnesses provides any evidentiary or scientific support for their claims, nor do they explain how "pulsation" of RF signals increases the risk of adverse health effects or what those effects might be. As Exponent points out, "Neither Dr. Héroux nor Dr. Havas have provided scientific evidence that would support their distinction between biological effects of sources of modulated or unmodulated RF signals".[276] Again, the only health risks from "pulsation" raised in either report relate to EHS (addressed below). Dr.

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[271] Ex. B-26, Part 2, p. 7
[272] Ibid., p. 8
[273] See e.g. Ex. C7-12-1, App. B, p. 18, 23
[274] Ex. C7-12-1, App. B, p. 18
[275] Ex. C7-12-1, App. D, p. 77
[276] Ex. B-26, Part 2, p. 9

Havas does note that "pulsed light can bring on seizure in epileptics", but gives no explanation why that would be a relevant comparison to RF from an advanced gas meter.[277]

238. More importantly, Dr. Héroux and Dr. Havas are simply wrong that the RF signals from the Sonix IQ meters and other End Points are pulsed. Exponent provides a comprehensive rebuttal on this issue, pointing out that the RF signal from the Sonix IQ gas meter "turns on and transmits a continuous frequency shift-keying (FSK) signal for 55 milliseconds and then turns off for approximately 4 hours".[278] Exponent further explains that the only real difference between the FSK signal and the AM or FM signals that Drs. Héroux and Havas appear to favour is that AM and FM signals are constantly "on" while the FSK signal from the advanced gas meter transmits only for very brief periods.[279]

vi. EHS Symptoms and RF

239. As referenced above, both Dr. Héroux and Dr. Havas raise in their reports potential effects of RF exposure on individuals suffering from EHS. Dr. Héroux alludes to potential impacts on "sensitive person[s]" and the EHS population in relation to his comments regarding the maximum value of pulsed RF energy. The conclusion section in Dr. Havas' report is primarily focused on EHS and the prevalence of individuals suffering from EHS in the population.[280]

240. Neither Dr. Héroux nor Dr. Havas provides any credible scientific evidence that would establish the BCUC's findings regarding EHS in the 2013 AMI Decision are wrong or should be re-assessed. As set out above, the Panel in that decision concluded that:

> The Panel recognizes that there are individuals who feel strongly that low-level EMF emissions will have a negative impact on their health. However based on the scientific evidence in this Proceeding, the Panel is not persuaded that there is a causal link between RF emissions and the symptoms of EHS. The Panel notes that according to the World Health Organization, there is "no scientific basis to link EHS symptoms to EMF exposure."[281]

241. FEI notes that, per Exponent's RF Health Report in this proceeding, the WHO remains of the view that, "research has not been able to provide support for a causal relationship between exposure to electromagnetic fields and self-reported symptoms, or 'electromagnetic hypersensitivity'".[282] This is the same position as adopted by various other local and international health organizations.[283] Drs. Dopart and Bailey's review of

[277] Ex. C7-12-1, App. D, p. 76
[278] Ex. B-26, Part 2, p. 9
[279] Ibid., p. 10 and Fig. 1
[280] Ex. C7-12-1, App. D, p. 78-79
[281] 2013 AMI Decision, p. 137 [Book of Authorities, Tab 14]
[282] Ex. B-1, App. F-2, p. 107-108
[283] Ibid., p. 105-108

the scientific research in this area similarly found that health and scientific agencies did not conclude that exposure to RF signals cause symptoms or disturbances to well-being and the results of recent epidemiologic studies do not change that conclusion.[284]

242. FEI notes as well that customers with concerns regard EHS will, as discussed further below, be able to avail themselves of a radio-off meter option, which would not generate any RF emissions.

PART XII – SPECIFIC APPLICATION ISSUES

A. Security and Privacy

243. FEI recognizes that due to the nature of AMI, security is an important consideration for a number of Project components. FEI treats the security of its customers' information as a high priority and the requirement for security of information was and is a key consideration throughout design, procurement, and implementation.[285]

244. To this end, FEI retained a cybersecurity expert consultant to provide a detailed analysis on mechanisms built into Sensus' AMI technology and how FEI will be using and integrating the technology with existing and new systems as part of the Project. This independent, expert analysis concluded the system will provide sufficient levels of security for its intended use and made recommendations that will inform definition and design deliverables.[286] In addition, FEI will ensure security audits are carried out by a third-party agency during implementation and on an on-going basis to verify that the AMI Project meets or exceed the security standards set out in the AMI-SEC AMI System Security Requirements, as described in Section 5.8.2 of the Application.[287]

245. Additional details from Sensus regarding the end to end security layers built into the FlexNet communication system being implemented in the AMI Project are provided in FEI's response to CORE IR2 22a.[288]

246. The AMI Project will also provide improvements to existing data security. The AMI Project will involve encryption of data from the meter to the AMI system, whereas currently the meter data is collected manually in handheld devices that are not encrypted.[289]

247. In terms of privacy, FEI respects its customers' privacy and seeks to protect their personal information. The *Personal Information Protection Act* (**PIPA**) and the federal *Personal Information Protection and Electronic Documents Act* (**PIPEDA**), as applicable, govern

[284] Ibid., p. 116-117
[285] Ibid., p. 92
[286] Ibid., p. 93
[287] Ibid., p. 92
[288] Ex. B-22
[289] FEI Response to CEC IR1 66.2 (Ex. B-8-1)

the protection of personal information in BC. FEI takes its obligation to protect its customers' personal information seriously and is committed to complying with the requirements under PIPA through, among other things, the application of its privacy policy.[290]

248. CORE's Mr. Karow raises concerns in his witness statement about the AMI Project presenting FEI with a "marketing opportunity" to sell its customers' data to third-parties without their permission and also about the prospect that data will "reside in offshore jurisdictions not subject to Canadian Laws & practices".[291] However, under FEI's Customer Privacy Policy, FEI will not sell customer information to third parties unless FEI has explicit customer consent to do so.[292] With respect to the location of data storage, FEI follows the directives set out in BCUC Order G-161-15, including annual reporting to the BCUC on data and servers located outside of Canada.[293]

249. For his part, Dr. Héroux in responding to CEC IR regarding the applicability of privacy legislation to FEI, stated that, "This legislation relies heavily on the judgment of a 'reasonable person', presumably or at least temporarily, an employee of FortisBC".[294] It is unclear what implication Dr. Héroux intended by this statement. Notwithstanding that matters of customer privacy are not within the scope of Dr. Héroux's expertise, FEI confirms that FortisBC's Privacy Officer is accountable for ensuring compliance with privacy legislation and FortisBC privacy policies.[295]

B. Customer Refusals and Opt-Outs

250. In its 2013 AMI Decision, the BCUC directed FBC to design and bring-forward an opt-out program for customers that did not wish to have a wireless transmitting meter installed on their premises. The Panel was of the view that an opt-out program could mitigate potential schedule impacts arising from protracted disputes with individual customers regarding advanced meter installation and that a properly designed opt-out program would allow individuals to decide not to accept a transmitting AMI meters while protecting FBC's other customers from the increased costs associated with the opt-out program.[296] FBC's opt-out program was subsequently approved by the BCUC pursuant to an FBC application for a Radio-Off AMI Meter Option based on principles set out in the 2013 AMI Decision.[297]

251. Consistent with the 2013 AMI Decision, FEI is proposing a similar radio-off option for customers that refuse the installation of an advanced meter due to its remote communication functions; such customers will have the option to have the advanced meter

[290] Ex. B-26, Part 1, p. 7; FEI Response to CORE IR2 27.a (Ex. B-22)
[291] Ex. C7-12-1, App. A, p. 4
[292] Ex. B-26, Part 1, p. 7
[293] Ibid.
[294] CORE Response to CEC IR1 14.1 (Ex. C7-16)
[295] Ibid.
[296] 2013 AMI Decision, p. 148 [Book of Authorities, Tab 14]
[297] BCUC Order and Decision G-220-13 **[Book of Authorities, Tab 13]**

installed with the radio turned off for a fee.[298] Because the meter in this configuration will not communicate remotely with the FlexNet base stations, customers that elect this option will be required to pay for their meters to be read manually.[299] FEI considers that this is appropriate because it ensures all customers are not negatively impacted from the costs for manual meter reading due to customers who prefer to have a radio-off advanced meter.[300] It is also consistent with the 2013 AMI Decision, which determined that the incremental cost of opting-out of the AMI program will be borne by the individual choosing to opt-out.[301]

C. Automated Seismic Shut-Off Valves

i. FEI's Investigation of and Decision Not to Incorporate Seismic Shut-Off Valves

252. One intervener in this proceeding, the Institute for Catastrophic Loss Reduction (**ICLR**), is advocating for the gas meters installed as part of the AMI Project to incorporate "automated seismic shut-off valves", also referred to as "earthquake actuated automatic gas shutoff valves" (**EGVs**).

253. In preparation for the AMI Project, FEI did explore options for seismic detection and response, including EGVs. FEI concluded that the optimal solution was to utilize the intelligent capabilities of AMI, including remote shutoff capabilities, excess flow shutoff, and leak detection, which provide most of the safety benefits of a seismic detection and response program without the risks of unnecessary shutoff.[302]

254. FEI provided a detailed explanation of its decision not to include EGVs as part of the AMI Project in its response to ICLR IR1 1.16 in this proceeding.[303] It should be emphasized that the technology ICLR advocates for FEI to include in the advanced gas meters is not commercially available. To FEI's knowledge, no North American gas meter manufacturer offers seismic-actuated shutoff valve functionality built into their meters; further, there is no Measurement Canada approved meter with an integrated seismic actuated valve that FEI can legally install to measure gas consumption for custody transfer purposes.[304] FEI's expert consultant regarding EGVs, Douglas Honegger, confirmed that there are no smart meters with this capability in the North American market and that adding such a capability to the AMI Project would require a separate research and development project to perfect the technology and subsequent partnering with a utility meter manufacturer for product development and certification.[305]

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[298] Ex. B-1, p. 94
[299] Ibid.
[300] FEI Response to RCIA IR1 45.1 (Ex. B-13)
[301] 2013 AMI Decision, p. 148 [Book of Authorities, Tab 14]
[302] FEI Response to BCUC IR1 38.1 (Ex. B-6)
[303] Ex. B-21
[304] FEI Response to ICLR IR1 1.16 (Ex. B-21)
[305] FEI Response to ICLR IRs (Ex. B-21), Attachment 1.16, p. 2

255. Even if ICLR's proposed EGVs were commercially available, FEI has considered and determined that this technology should not be implemented into gas meters installed at its customers' premises for a variety of reasons. In summary:[306]

(a) Mass outages from undesirable actuation: An earthquake event could result in minimal to no property damage, but still result in widespread customer outages due to the actuation of many thousands of EGVs.

(b) Potential for false actuations: Construction activity, large trucks, and other events causing localized vibration can cause the valves to actuate and interrupt the customer's gas supply.

(c) Automatic meter shut-off driven by unexpected gas flow is a more accurate approach: Configuring the advanced meters to automatically shut off based on high gas flow that is directly indicative of damage to downstream gas lines or appliances is a more accurate approach to ensuring customers with a safe operating gas service do not have service interrupted unnecessarily.

(d) FEI would lose control of the gas system: In an emergency, FEI would rely on its ability to control which sections of the system get shut down and when. Seismic-actuated valves that automatically shut off gas when this is not needed would interfere with this control.

(e) Utility practice has not identified benefits: separately installed (i.e., external to the gas meter) seismic-actuated valves have been available within the North American market for several decades. FEI is not aware of any major gas utility in North America that is currently installing seismic-actuated valves on their system on a mass scale.

(f) Recommendations made in publicly available studies and regulatory decisions: FEI has reviewed publicly available studies and decisions commissioned by governments, regulators, and industry working groups and none have recommended system-wide installation of seismic-actuated valves

(g) Questionable risk reduction: there appears to be no agreement, even when not considering their downsides, that seismic-actuated valves provide any meaningful improvement in safety (especially in single family homes) or a reduction in fire ignitions.

256. As noted, FEI engaged an expert consultant, Douglas Honegger of D.G. Honegger Consulting to provide a report and opinion regarding the use of EGVs. Mr. Honegger, who is a leading expert on matters related to post-earthquake fire ignitions and damage mitigation measures and strategies, concluded that, for a number of reasons "if there was an opportunity to add an EGV capability to the AMI project, the benefit would be minimal

[306] FEI Response to ICLR IR1 1.16 (Ex. B-21)

in terms of reduced safety risks and reduced post-earthquake fire ignitions".[307] In addition, Mr. Honegger was of the opinion that:

> In addition to having minimal benefit in terms of improved safety and reduced fire ignitions, universal installation of EGVs on all gas services could have serious detrimental impacts. Because it is not possible to define EGV actuation levels based upon the likelihood of damage to structures and components of customers gas systems, EGV actuation levels must be biased to the low side. For the case of universal EGV installation, this creates the potential for unnecessarily shutting off service to more than 100,000 customers for up to several months, leading to a need for many to seek temporary shelter and causing substantial business interruption losses.[308]

257. Notably, FEI conducted a presentation related to the proposed AMI Project to the Fire Chiefs Association of BC (**FCABC**) to explain the benefits of the technology and subsequently presented additional information to and conducted additional discussions with the FCABC. FEI received positive feedback related to the Project from the FCABC and the topic of EGVs was not raised by any of the attendees at these meetings.[309] FEI also engaged with the City of Vancouver's (**CoV**) Lead Seismic Policy Planner to provide an overview of the AMI Project and discuss its safety benefits. The CoV representative acknowledged the safety benefits of FEI's proposed AMI technology, including the remote and automatic shut-off capabilities. FEI also raised the topic of EGVs and the CoV representative expressed a preference toward the remote and automatic shut-off capabilities provided by the technology currently proposed by FEI as part of the AMI Project.[310]

ii. ICLR's Exhibit C12-3 Filing

258. On September 1, 2022, ICLR submitted a letter to the BCUC providing various comments on FEI's IR responses regarding EGVs and its decision not to include them as part of the AMI Project.

259. ICLR's overall position in its letter filed as Exhibit C12-3 is that, in ICLR's view, FEI "failed to respond to the fundamental question 'should the FortisBC AMI meters be equipped with a seismically actuated shut-off device'?" FEI submits that this is manifestly incorrect and that, as summarized above, FEI conducted a thorough investigation regarding the potential of EGVs, including obtaining an independent third-party expert opinion and engaging with other knowledgeable stakeholders and has concluded that FEI AMI meters <u>should not be equipped</u> with a seismically actuated shut-off device. This was stated unequivocally in FEI's IR responses.

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[307] FEI Response to ICLR IRs (Ex. B-21), Attachment 1.16, p. 1
[308] Ibid.
[309] FEI Response to ICLR IR1 1.17 (Ex. B-21)
[310] Ibid.

260. ICLR's letter also fails to provide any evidence that EGVs integrated into the meter are even a commercially available technology to include in the AMI Project. As set out above, both FEI and Douglas Honegger are unaware of any such technology being available in the North American market.

261. ICLR refers repeatedly in its filing to the use of EGVs in Japan. However, the fact that one other jurisdiction in the world has mandated the use of such devices in utility gas meters does not make this a "best practice" as ICLR claims. To the contrary, it demonstrates that industry and utility practice have rejected this as a viable or appropriate technological solution to mitigate seismic risks. ICLR also fails to provide any evidence about how the EGV technology employed in Japan operates in practice or how the technology could be implemented into FEI's system. Notably, Sensus (a North American ultrasonic meter manufacturer) in responding to an IR from ICLR stated that it has not studied the use of EGVs built into gas meters in Japan because "meters used in Japan, along with physical meter locations, differ significantly from North American applications, rendering the study not applicable".[311]

262. DG Honegger Consulting's report to FEI also describes that the use of EGVs was subject to extensive investigation and consultation in California in the early 2000s. A 2002 report of the California Seismic Safety Commission (**CSSC**) did not recommend requiring EGV installation and noted that there are a range of actions that can be taken to improve natural gas safety in earthquakes, each with advantages and disadvantages, that are best selected on a case-by-case basis by individuals and communities.[312] Subsequently, in 2005, the California Department of Housing and Community Development's Division of Codes and Standards issued Information Bulletin 2005-02 that stated there was insufficient evidence to support a statewide requirement for the installation of seismic gas shut-off devices and/or excess flow valves.[313]

263. ICLR refers to Los Angeles as a comparable location that "has for several decades required automatic shut off valves on all new construction".[314] However, ICLR fails to recognize that Los Angeles' current Municipal Code actually requires either an approved seismic gas shutoff valve <u>or</u> an excess flow shutoff valve to be installed.[315] Further, as noted in Mr. Honegger's report, such a mandate, to the extent it includes EGVs as an option, is for the valve device to be installed on the customer's gas line (i.e. on the customer side of the meter) and is not a requirement for gas utilities to include EGVs in their meters.[316] Mr. Honegger also points out that many cities in California, like Los Angeles, have passed regulations to require either an earthquake actuated or excess flow valve (similar to that

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[311] FEI Response to ICLR IR1 2.2 (Ex. B-21)
[312] FEI Response to ICLR IRs (Ex. B-21), Attachment 1.16, p. 4
[313] Ibid.
[314] Ex. C12-3, p. 3
[315] *Official City of Los Angeles Municipal Code*, Sixth Edition (Current through June 30, 2022), section 94.1217.2 (available online at: https://codelibrary.amlegal.com/codes/los_angeles/latest/lamc/0-0-0-185974#JD_C9A4D12) **[Book of Authorities, Tab 8]**
[316] FEI Response to ICLR IRs (Ex. B-21), Attachment 1.16, p. 4

included in FEI's proposed meter), essentially treating either device as equally effective in reducing the potential for natural gas to contribute to fire damage.[317]

264. ICLR's letter at Exhibit C12-3 makes a number of other comments related to FEI's emergency response arrangements and planning in the event of earthquakes and major service disruptions. FEI notes that ICLR's comments on these topics all ignore the excess gas flow shut-off capability to be employed with the AMI meters. FEI also disagrees with ICLR's characterization of its planning and processes. FEI's focus following any emergency, including a large earthquake, is the safety of its customers, employees, and the public and FEI takes these matters very seriously.[318]

265. FEI's view is that indiscriminately turning off gas service to customers through the use of EGVs following a large earthquake may result in a different emergency scenario: the unnecessary curtailment of gas supply to large numbers of customers whose service continues to operate safely.[319] If this occurred during winter months in British Columbia, (which are much colder than would typically be the case in California), the result could be significant health and safety impacts on customers and communities that did not otherwise have an actual gas emergency in their homes or facilities. Customers would be left without heat, hot water and cooking capacity and communities would find it challenging to support emergency response functions such as offering warm shelter and cooking facilities to community members in need.[320] ICLR has not addressed these significant risks associated with the widespread use of EGVs.

266. FEI submits that the proposed AMI solution provides a more sophisticated and intelligent approach for responding to a major earthquake and the potential resulting damage to some customers' gas lines and equipment and that, even if available, the use of EGVs in its gas meters would not be advisable.

PART XIII – THE PROVINCIAL GOVERNMENT ENERGY OBJECTIVES AND POLICY CONSIDERATIONS

267. As set out in Part III, above, section 46(3.1) of the *UCA* requires the BCUC, in the context of this Application, to consider:

(a) The applicable of British Columbia's energy objectives; and

(b) The most recent long-term resource plan filed by the public utility under section 44.1.

[317] Ibid.
[318] FEI Response to ICLR IR1 1.11 (Ex. B-21)
[319] Ibid.
[320] FEI Response to ICLR IR1 1.12 (Ex. B-21)

268. To similar effect, the BCUC's CPCN Guidelines require a CPCN application to address how the project is consistent with provincial government energy objectives and policy considerations.

A. Provincial Energy Objectives and Policy Considerations

269. FEI submits, as noted above, that the AMI Project is consistent with and supports the following BC energy objectives as found in section 2 of the *CEA*:

- to take demand-side measures and to conserve energy (section 2(b));
- 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 (section 2 (d));
- to reduce B.C. greenhouse gas emissions (section 2(g));
- to encourage communities to use energy efficiently (section 2(i))
- to encourage economic development and the creation and retention of jobs (section 2(k)).

270. FEI submits that the AMI technology to be implemented pursuant to the Project provides a foundation to support and enable natural gas conservation and efficiency primarily through the provision of improved natural gas consumption information for customers. Improved consumption data will support natural gas conservation by providing consumers with actionable insight on their consumption and, in turn, further enable implementation of DSM measures to reduce consumption.[321] This likewise supports the objective of encouraging communities to use energy efficiently. Further, FEI submits that reducing customer consumption of natural gas through implementation of AMI and related conservation will contribute to lowering GHG emissions in BC, which is consistent with the objective in section 2(g), as well as climate action plans described in detail in Section 8.2.2 of the Application.

271. In this vein, the AMI Project is also aligned with provincial government climate policy, in the form of the CleanBC Plan (2018), as well as FEI and FBC's combined Clean Growth Pathway to 2050. The Project supports these policies as follows:

(a) the advanced meters are compatible with certain renewable gases, such as hydrogen and biomethane;

[321] Ex. B-1, p. 140

(b) the advanced meters provide detailed usage data which can enhance energy efficiency programs and help customers to better manage their gas consumption; and

(c) the advanced meters substantially eliminate manual meter reading thereby avoiding GHG emissions associated with meter reading vehicles.[322]

272. For these reasons, FEI submits that the Project's benefits are still valid in consideration of the *Climate Change Accountability Act*, S.B.C. 2007, c. 42.[323]

273. The Project will also support the energy objective to encourage economic development and the creation and retention of jobs. The Project will support this objective by creating jobs in BC through FEI's contractors, and result in the procurement of goods and services from locally-owned and operated vendors and subcontractors.[324] FEI also anticipates an increase in the use of local services, such as dining, accommodations and other services, during deployment, which will benefit the economy.[325]

274. Further, as noted in Part III.A, above, FEI submits that the AMI Project is supportive of the BC government's "goal" stated in section 17(6) of the *CEA* of having "other advanced meters" in use with respect to "customers other than those of [BC Hydro]". Set out in full, this section of the *CEA* provides as follows:

> 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.

275. The requirements for "smart meters" within the meaning of this provision are set out in section 2 of the *Smart Meters and Smart Grid Regulation*, B.C. Reg. 368/2010. Although the prescribed requirements for "smart meters" include measurement of electricity, as explained in Section 8.2.1 and Table 8-1 of the Application, the Sonix IQ gas meters that are part of the AMI Project align with many of the regulation's other requirements. FEI submits, therefore, that the meters at issue in the Application constitute "other advanced meters" within the meaning of section 17(6) of the *CEA* and that FEI's ratepayers are customers of a public utility "other than those of the authority".

276. On this basis, the BCUC is required to consider the government energy goal of having such advanced meters implemented in BC when deciding FEI's present Application.

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[322] Ex. B-1, p. 142
[323] FEI Response to BCUC IR1 34.3.1
[324] Ex. B-1, p. 142
[325] Ibid.

B. FEI's Most Recent Long-Term Resource Plan

277. As of the time the Application was filed, FEI's most recent Long Term Gas Resource Plan was dated December 14, 2017 (**2017 LTGRP**) and approved by the BCUC pursuant to Decision and Order G-39-19.

278. In Section 2 of the 2017 LTGRP, FEI described advanced metering as a possible solution FEI was exploring for positioning natural gas services competitively within BC's energy marketplace. In Section of the 2017 LTGRP, FEI also discussed AMI as a potential solution for analyzing end use and peak demand trends given that FEI's existing exploratory peak analysis work was theoretical without direct measurement of customer end use trends. FEI also responded to a number of IRs on AMI technologies in the course of the 2017 LTRGP proceeding.[326]

279. Since the Application in this proceeding was filed, on May 9, 2022, FEI filed its 2022 Long Term Gas Resource Plan (**2022 LTGRP**).[327] The 2022 LTGRP, which the BCUC is reviewing in an ongoing proceeding, references and discusses the AMI Project in a number of resource planning areas. These include:

(a) In Section 3.2, the AMI Project is discussed as a key part of FEI's Clean Growth Pathway, as, among other things, it represents a significant opportunity for modernizing the gas infrastructure and adding additional components to support system resiliency.

(b) In Section 5.5, in addressing long term DSM impacts on peak demand, FEI describes the AMI Project as having the potential to provide FEI and customers the ability to more actively manage peak demand. The 2022 LTGRP notes that the extent to which AMI can be used for Demand Response as a DSM activity, and with respect to deferred infrastructure investments, is still being explored.

(c) In Section 7.2, in discussing regional peak demand forecasts, the 2022 LTGRP notes that the effectiveness of DSM programs on peak demand cannot be directly measured until hourly metering is deployed, but that the AMI Project would support FEI's ability to field-validate the projections of the exploratory end use peak demand forecast method and will enable FEI to improve this method in future LTGRPs.

(d) In Section 7.5, regarding FEI System Resiliency, the 2022 LTGRP states that in the medium term, FEI's AMI Project will be beneficial in enhancing FEI's Coastal Transmission System load management capabilities and is one of the key components to FEI's portfolio approach to resiliency while providing other benefits for customers.

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[326] Ibid., p. 143

[327] Available on the BCUC's website here: https://docs.bcuc.com/Documents/Proceedings/2022/DOC_66503_B-1-FEI-2022-LongTermGasResourcePlan.pdf

(e) In Section 10 of the 2022 LTGRP, the AMI Project is noted in item #6 of FEI's Action Plan as being one of the "cornerstones" of FEI's Gas System Resiliency plan (see also Appendix E).

280. Based on this review, the AMI Project is consistent with both the existing approved 2017 LTGRP and the 2022 LTGRP under BCUC review and is a key element of the more recent long term plan.

PART XIV – CONCLUSION

A. The CPCN Should be Granted

281. FEI submits that, for the reasons set out above, and based on all of the evidence FEI has filed in this proceeding, the BCUC should grant the Application and approve a CPCN for the AMI Project on the terms set out in the draft Final Order at Exhibit B-1, Appendix K-2.

B. Other Approvals

282. The Application also seeks ancillary approvals involving creation of new asset and deferral accounts pursuant to sections 59-61 of the *UCA*. Details of these proposed accounts are found in Sections 1.3.2-1.3.3 of the Application. FEI submits that BCUC should likewise grant these ancillary approvals in the terms set out in Appendix K-2 of Exhibit B-1.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

Counsel for FortisBC Energy Inc.:

Ludmila B. Herbst, K.C.

Nicholas T. Hooge

Dated: September 28, 2022

BRITISH COLUMBIA UTILITIES COMMISSION

FORTISBC ENERGY INC.

APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR APPROVAL OF THE ADVANCED METERING INFRASTRUCTURE PROJECT

PROJECT 1599211

BOOK OF AUTHORITIES

Final Argument

of

FortisBC Energy Inc.

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TAB 1

This Act is current to September 21, 2022

See the Tables of Legislative Changes for this Act's legislative history, including any changes not in force.

UTILITIES COMMISSION ACT

[RSBC 1996] CHAPTER 473

Contents

Definitions

1 (1) In this Act:

"appraisal" means appraisal by the commission;

"authority" means the British Columbia Hydro and Power Authority;

"British Columbia's energy objectives" has the same meaning as in section 1 (1) of the *Clean Energy Act*;

"commission" means the British Columbia Utilities Commission continued under this Act;

"compensation" means a rate, remuneration, gain or reward of any kind paid, payable, promised, demanded, received or expected, directly or indirectly, and includes a promise or undertaking by a public utility to provide service as consideration for, or as part of, a proposal or contract to dispose of land or any interest in it;

"costs" includes fees, counsel fees and expenses;

"demand-side measure" has the same meaning as in section 1 (1) of the *Clean Energy Act*;

(6) If the commission considers that an expenditure in an expenditure schedule was determined to be in the public interest in the course of determining that a long-term resource plan was in the public interest under section 44.1 (6),

(a) subsection (5) of this section does not apply with respect to that expenditure, and

(b) the commission must accept under subsection (3) the expenditure in the expenditure schedule.

Certificate of public convenience and necessity

45 (1) Except as otherwise provided, after September 11, 1980, a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the commission a certificate that public convenience and necessity require or will require the construction or operation.

(2) For the purposes of subsection (1), a public utility that is operating a public utility plant or system on September 11, 1980 is deemed to have received a certificate of public convenience and necessity, authorizing it

(a) to operate the plant or system, and

(b) subject to subsection (5), to construct and operate extensions to the plant or system.

(3) Nothing in subsection (2) authorizes the construction or operation of an extension that is a reviewable project under the *Environmental Assessment Act*.

(4) The commission may, by regulation, exclude a utility plant or categories of utility plants from the operation of subsection (1).

(5) If it appears to the commission that a public utility should, before constructing or operating an extension to a utility plant or system, apply for a separate certificate of public convenience and necessity, the commission may, not later than 30 days after construction of the extension is begun, order that subsection (2) does not apply in respect of the construction or operation of the extension.

(6) A public utility must file with the commission at least once each year a statement in a form prescribed by the commission of the extensions to its facilities that it plans to construct.

(6.1) and (6.2) [Repealed 2008-13-8.]

(7) Except as otherwise provided, a privilege, concession or franchise granted to a public utility by a municipality or other public authority after September 11, 1980 is not valid unless approved by the commission.

(8) The commission must not give its approval unless it determines that the privilege, concession or franchise proposed is necessary for the public convenience and properly conserves the public interest.

(9) In giving its approval, the commission

(a) must grant a certificate of public convenience and necessity, and

(b) may impose conditions about

(i) the duration and termination of the privilege, concession or franchise, or

(ii) construction, equipment, maintenance, rates or service,

as the public convenience and interest reasonably require.

Procedure on application

46 (1) An applicant for a certificate of public convenience and necessity must file with the commission information, material, evidence and documents that the commission prescribes.

(2) The commission has a discretion whether or not to hold any hearing on the application.

(3) Subject to subsections (3.1) to (3.3), the commission may, by order, issue or refuse to issue the certificate, or may issue a certificate of public convenience and necessity for the construction or operation of a part only of the proposed facility, line, plant, system or extension, or for the partial exercise only of a right or privilege, and may attach to the exercise of the right or privilege granted by the certificate, terms, including conditions about the duration of the right or privilege under this Act as, in its judgment, the public convenience or necessity may require.

(3.1) In deciding whether to issue a certificate under subsection (3) applied for by a public utility other than the authority, the commission must consider

(a) the applicable of British Columbia's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any, and

(c) the extent to which the application for the certificate is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*.

(3.2) Section (3.1) does not apply if the commission considers that the matters addressed in the application for the certificate were determined to be in the public interest in the course of considering a long-term resource plan under section 44.1.

(3.3) In deciding whether to issue a certificate under subsection (3) to the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider

(a) British Columbia's energy objectives,

(b) the most recent of the following documents:

(i) an integrated resource plan approved under section 4 of the *Clean Energy Act* before the repeal of that section;

(ii) a long-term resource plan filed by the authority under section 44.1 of this Act, and

(c) the extent to which the application for the certificate is consistent with the requirements under section 19 of the *Clean Energy Act*.

(4) If a public utility desires to exercise a right or privilege under a consent, franchise, licence, permit, vote or other authority that it proposes to obtain but that has not, at the date of the application, been granted to it, the public utility may apply to the commission for an order preliminary to the issue of the certificate.

(5) On application under subsection (4), the commission may make an order declaring that it will, on application, under rules it specifies, issue the desired certificate, on the terms it designates in the order, after the public utility has obtained the proposed consent, franchise, licence, permit, vote or other authority.

(6) On evidence satisfactory to the commission that the consent, franchise, licence, permit, vote or other authority has been secured, the commission must issue a certificate under section 45.

(7) The commission may, by order, amend a certificate previously issued, or issue a new certificate, for the purpose of renewing, extending or consolidating a certificate previously issued.

(8) A public utility to which a certificate is, or has been, issued, or to which an exemption is, or has been, granted under section 45 (4), is authorized, subject to this Act, to construct, maintain and operate the plant, system or extension authorized in the certificate or exemption.

Order to cease work

47 (1) If a public utility

(a) is engaged, or is about to engage, in the construction or operation of a plant or system, and

(b) has not secured or has not been exempted from the requirement for, or is not deemed to have received a certificate of public convenience and necessity required under this Act,

any interested person may file a complaint with the commission.

(2) The commission may, with or without notice, make an order requiring the public utility complained of to cease the construction or operation until the commission makes and files its decision on the complaint, or until further order of the commission.

(3) The commission may, after a hearing, make the order and specify the terms under this Act that it considers advisable.

(4) If the commission considers it necessary to determine whether a person is engaged or is about to engage in construction or operation of any plant or system, the commission may request that person to provide information required by it and to answer specifically all questions of the commission, and the person must comply.

Cancellation or suspension of franchises and permits

(11) A proceeding must not be brought against the commission or the government by reason of the exercise by the commission of its powers under subsection (9) or (10).

(12) An offeror who makes a take over bid for shares of a public utility must

(a) file with the commission a copy of the take over bid and all supporting or supplementary material within 5 days after the date the material is first sent to offerees, and

(b) include in or attach to the take over bid a notice setting out the provisions of this section and stating the number, without duplication, and designation of any shares of the public utility held by the offeror and the offeror's associates.

(13) Nothing in subsection (12) relieves a person from any requirement under the *Securities Act*.

Appraisal of utility property

55 (1) The commission may

(a) ascertain by appraisal the value of the property of a public utility, and

(b) inquire into every fact that, in its judgment, has a bearing on that value, including the amount of money actually and reasonably expended in the undertaking to provide service reasonably adequate to the requirements of the community served by the utility as that community exists at the time of the appraisal.

(2) In making its appraisal, the commission must have access to all records in the possession of a municipality or any ministry or board of the government.

(3) In making its appraisal under this section, the commission may order

(a) that all or part of the costs and expenses of the commission in making the appraisal must be paid by the public utility, and

(b) that the utility pay an amount as the work of appraisal proceeds.

(4) The certificate of the chair of the commission is conclusive evidence of the amounts payable under subsection (3).

(5) Expenses approved by the commission in connection with an appraisal, including expenses incurred by the public utility whose property is appraised, must be charged by the utility to the cost of operating the property as a current item of expense, and the commission may, by order, authorize or require the utility to amortize this charge over a period and in the manner the commission specifies.

Depreciation accounts and funds

56 (1) If the commission, after inquiry, considers that it is necessary and reasonable that a depreciation account should be carried by a public utility, the commission may, by order, require the utility to keep an adequate depreciation account under rules and forms of account specified by the commission.

(2) The commission must determine and, by order after a hearing, set proper and adequate rates of depreciation.

(3) The rates must be set so as to provide, in addition to the expense of maintenance, the amounts required to keep the public utility's property in a state of efficiency in accordance with technical and engineering progress in that industry of the utility.

(4) A public utility must adjust its depreciation accounts to conform to the rates set by the commission and, if ordered by the commission, must set aside out of earnings whatever money is required and carry it in a depreciation fund.

(5) Without the consent of the commission, the depreciation fund must not be expended other than for replacement, improvement, new construction, extension or addition to the property of the utility.

Reserve funds

57 (1) The commission may, by order, require a public utility to create and maintain a reserve fund for any purpose the commission considers proper, and may set the amount or rate to be charged each year in the accounts of the utility for the purpose of creating the reserve fund.

(2) The commission may order that no reserve fund other than that created and maintained as directed by the commission may be created by a public utility.

Commission may order amendment of schedules

58 (1) The commission may,

(a) on its own motion, or

(b) on complaint by a public utility or other interested person that the existing rates in effect and collected or any rates charged or attempted to be charged for service by a public utility are unjust, unreasonable, insufficient, unduly discriminatory or in contravention of this Act, the regulations or any other law,

after a hearing, determine the just, reasonable and sufficient rates to be observed and in force.

(2) If the commission makes a determination under subsection (1), it must, by order, set the rates.

(2.1) The commission must set rates for the authority in accordance with

(a) [Repealed RS1996-473-58 (2.3).]

(b) the prescribed factors and guidelines, if any.

(2.2) [Repealed RS1996-473-58 (2.3).]

(2.3) Subsections (2.1) (a) and (2.2) are repealed on March 31, 2010.

(2.4) Despite subsection (2.3), a requirement prescribed for the purposes of subsection (2.1) (a) that is in effect immediately before March 31, 2010, continues to apply after that date as though subsection (2.2) were still in force, unless the prescribed requirement is amended or repealed after that date.

(3) The public utility affected by an order under this section must

(a) amend its schedules in conformity with the order, and

(b) file amended schedules with the commission.

Rate rebalancing

58.1 (1) In this section, **"revenue-cost ratio"** means the amount determined by dividing a public utility's revenues from a class of customers during a period of time by the public utility's costs to serve that class of customers during the same period of time.

(2) This section applies despite

(a) any other provision of

(i) this Act, or

(ii) the regulations, except a regulation under section 3, or

(b) any previous decision of the commission.

(3) [Repealed 2019-24-14.]

(4) [Repealed RS1996-473-58.1 (5).]

(5) and (6) [Repealed 2019-24-14.]

(7) The commission may not set rates for a public utility for the purpose of changing the revenue-cost ratio for a class of customers except on application by the public utility.

Discrimination in rates

59 (1) A public utility must not make, demand or receive

(a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia, or

(b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

(2) A public utility must not

(a) as to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage, or

(b) extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description.

(3) The commission may, by regulation, declare the circumstances and conditions that are substantially similar for the purpose of subsection (2) (b).

(4) It is a question of fact, of which the commission is the sole judge,

(a) whether a rate is unjust or unreasonable,

(b) whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or

(c) whether a service is offered or provided under substantially similar circumstances and conditions.

(5) In this section, a rate is "unjust" or "unreasonable" if the rate is

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or

(c) unjust and unreasonable for any other reason.

Setting of rates

60 (1) In setting a rate under this Act

(a) the commission must consider all matters that it considers proper and relevant affecting the rate,

(b) the commission must have due regard to the setting of a rate that

(i) is not unjust or unreasonable within the meaning of section 59,

(ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands, and

(iii) encourages public utilities to increase efficiency, reduce costs and enhance performance,

(b.1) the commission may use any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period, and

(c) if the public utility provides more than one class of service, the commission must

(i) segregate the various kinds of service into distinct classes of service,

(ii) in setting a rate to be charged for the particular service provided, consider each distinct class of service as a self contained unit, and

(iii) set a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates set for any other unit.

(2) In setting a rate under this Act, the commission may take into account a distinct or special area served by a public utility with a view to ensuring, so far as the commission considers it advisable, that the rate applicable in each area is adequate to yield a fair and reasonable return on the appraised value of the plant or system of the public utility used, or prudently and reasonably acquired, for the purpose of providing the service in that special area.

(3) If the commission takes a special area into account under subsection (2), it must have regard to the special considerations applicable to an area that is sparsely settled or has other distinctive characteristics.

(4) For this section, the commission must exclude from the appraised value of the property of the public utility any franchise, licence, permit or concession obtained or held by the utility from a municipal or other public authority beyond the money, if any, paid to the municipality or public authority as consideration for that franchise, licence, permit or concession, together with necessary and reasonable expenses in procuring the franchise, licence, permit or concession.

Rate schedules to be filed with commission

61 (1) A public utility must file with the commission, under rules the commission specifies and within the time and in the form required by the commission, schedules showing all rates established by it and collected, charged or enforced or to be collected or enforced.

(2) A schedule filed under subsection (1) must not be rescinded or amended without the commission's consent.

(3) The rates in schedules as filed and as amended in accordance with this Act and the regulations are the only lawful, enforceable and collectable rates of the public utility filing them, and no other rate may be collected, charged or enforced.

(4) A public utility may file with the commission a new schedule of rates that the utility considers to be made necessary by a change in the price, over which the utility has no effective control, required to be paid by the public utility for its gas supplies, other energy supplied to it, or expenses and taxes, and the new schedule may be put into effect by the public utility on receiving the approval of the commission.

(5) Within 60 days after the date it approves a new schedule under subsection (4), the commission may,

(a) on complaint of a person whose interests are affected, or

(b) on its own motion,

direct an inquiry into the new schedule of rates having regard to the setting of a rate that is not unjust or unreasonable.

(6) After an inquiry under subsection (5), the commission may

(a) rescind or vary the increase and order a refund or customer credit by the utility of all or part of the money received by way of increase, or

(b) confirm the increase or part of it.

Schedules must be available to public

62 A public utility must keep a copy of the schedules filed open to and available for public inspection under commission rules.

Schedules must be observed

63 A public utility must not, without the consent of the commission, directly or indirectly, in any way charge, demand, collect or receive from any person for a regulated service provided by it, or to be provided by it, compensation that is greater than, less than or other than that specified in the subsisting schedules of the utility applicable to that service and filed under this Act.

Orders respecting contracts

64 (1) If the commission, after a hearing, finds that under a contract entered into by a public utility a person receives a regulated service at rates that are unduly preferential or discriminatory, the commission may

(a) declare the contract unenforceable, either wholly or to the extent the commission considers proper, and the contract is then unenforceable to the extent specified, or

(b) make any other order it considers advisable in the circumstances.

(2) If a contract is declared unenforceable either wholly or in part, the commission may order that rights accrued before the date of the order be preserved, and those rights may then be enforced as fully as if no proceedings had been taken under this section.

Part 3.1

Repealed

64.01-64.04 [Repealed 2010-22-69.]

Part 4 — Carriers, Purchasers and Processors

Definition

64.1 In this Part, **"sufficient notice"** means notice in the manner and form, within the period, with the content and by the person required by the commission.

Common carrier

65 (1) In this section, **"common carrier"** means a person declared to be a common carrier by the commission under subsection (2) (a).

(2) On application by an interested person and after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, the commission may

(a) issue an order, to be effective on a date determined by it, declaring a person who owns or operates a pipeline for the transportation of

(i) one or more of crude oil, natural gas and natural gas liquids, or

(ii) any other type of energy resource prescribed by the Lieutenant Governor in Council,

TAB 2

This Act is current to September 21, 2022

See the Tables of Legislative Changes for this Act's legislative history, including any changes not in force.

CLEAN ENERGY ACT

[SBC 2010] CHAPTER 22

Assented to June 3, 2010

Contents

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);

"greenhouse gas" has the same meaning as in section 1 of the *Climate Change Accountability 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) the authority's interests in the generation and storage assets identified in Schedule 1 of this Act, and

(c) the authority's interests in the equipment and facilities that are for the transmission or distribution of electricity and that are identified in Schedule 1 of this Act;

"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*.

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 *Climate Change Accountability 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) [Repealed 2019-24-2.]

Repealed

3-5 [Repealed 2019-24-2.]

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 the most recent of the following documents:

(c) an integrated resource plan approved under section 4 before its repeal;

(d) a long-term resource plan filed under section 44.1 of the *Utilities Commission Act*;

"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, by the year 2016 and each year after that, the rights to an amount of electricity that meets the electricity supply obligations solely from electricity generating facilities within the Province,

(a) assuming no more in each year than the heritage energy capability, and

(b) 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), 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.

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) [Repealed 2019-24-4.]

(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).

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).

(ii) [Repealed 2019-24-5.]

(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.

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.

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 (1) of the *Water Sustainability 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.

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).

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) 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.

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.

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.

Part 4 — Standing Offer Program

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.

Repealed

16 [Repealed 2019-24-7.]

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.

Improvement financing

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.

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.

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.

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,

(i) is issued after June 3, 2010 under the *Water Sustainability Act* or a predecessor of that Act for a power purpose, unless the licence is issued in substitution for a licence that was issued for a power purpose before that date,

(ii) is amended after June 3, 2010 under section 26 of the *Water Sustainability Act* or a predecessor of that section, whether or not a licence is issued in substitution for the licence, if

(A) the licence was issued for a power purpose, and

(B) the amendment authorizes a substantial change in works for the purpose of increasing power generation capacity, or

(iii) is amended after June 3, 2010 under section 26 of the *Water Sustainability Act* or a predecessor of that section, whether or not a licence is issued in substitution for the licence, if

(A) the licence was issued for a purpose other than a power purpose, and

(B) the amendment authorizes the use of water for a power purpose, and

(c) for which a prescribed authorization, if applicable, under an enactment respecting land is granted after this section comes into force;

"power purpose" has the same meaning as in section 2 of the *Water Sustainability Act*;

"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.

Part 7 — Transmission Corporation

Division 1 — Transfer of Property, Shares and Obligations

Definitions

21 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.

Transfer of property

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.

Transfer of obligations and liabilities

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.

Records of transferred assets and liabilities

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.

Transfer is not a default

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.

Legal proceedings

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.

Division 2 — Employees

Definitions

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*.

Transfer of employees

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.

Continuous employment

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.

Pensions

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.

Division 3 — General

Repealed

31 [Repealed 2010-22-31 (3).]

Utilities Commission Act

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.

(3) [Repealed 2010-22-32 (4).]

(4) Subsection (3) is repealed on July 1, 2011.

Designated agreements

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.

Part 8 — Regulations

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.

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) and (h) [Repealed 2019-24-7.]

(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) 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) [Repealed 2019-24-7.]

(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 fuelling or electricity charging.

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.

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 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;

(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.

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).

Part 9

Repealed

39 [Repealed 2010-22-39 (2).]

Part 10 — Consequential Amendments

Consequential Amendments

Editorial Note

Section(s)	Affected Act
40-43	*BC Hydro Public Power Legacy and Heritage Contract Act*
44	*Environmental Assessment Act*
45	*Financial Information Act*
46-51	*Forest Act*
52	*Freedom of Information and Protection of Privacy Act*
53-56	*Hydro and Power Authority Act*
57	*Transmission Corporation Act*
58-73	*Utilities Commission Act*
74-76	*Wildfire Act*

Commencement

77 The provisions of this Act referred to in column 1 of the following table come into force as set out in column 2 of the table:

Item	Column 1 **Provisions of Act**	Column 2 **Commencement**
1	Anything not elsewhere covered by this table	The date of Royal Assent
2	Sections 21 to 33	July 5, 2010
3	Section 42	July 5, 2010
4	Section 45	By regulation of the Lieutenant Governor in Council
5	Section 52	By regulation of the Lieutenant Governor in Council
6	Section 55 (d)	July 5, 2010
7	Section 57	July 5, 2010
8	Section 59	July 5, 2010
9	Section 73	July 5, 2010

Schedule 1

Heritage Assets

Those generation and storage assets commonly known as the following:

Aberfeldie

Alouette

Ash River

Bridge River

Buntzen/Coquitlam

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

Schedule 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.

TAB 3

B.C. Reg. 368/2010
M361/2010

Deposited December 15, 2010

This consolidation is current to September 20, 2022.

Link to Point in Time

Clean Energy Act

SMART METERS AND SMART GRID REGULATION

[includes amendments up to B.C. Reg. 405/2012, December 27, 2012]

Contents

Definitions

1 In this regulation:

"Act" means the *Clean Energy Act*;

"automation-enabled device" means a device that, when installed on the authority's electric system, is capable of being used by the authority, at a location remote from the device, to control the flow of electricity;

"connectivity model" means a computer model of the electric distribution system identifying all of the following:

(a) the locations at which eligible premises are connected to the electric distribution system;

(b) the locations known to the authority at which unmetered buildings, structures or equipment are connected to the electric distribution system;

(c) the locations of

(i) distribution transformers,

(ii) distribution circuit conductors,

(iii) substations,

(iv) system devices, and

(v) switches,

that are within the electric distribution system;

(d) the locations of generators connected to the electric distribution system;

(e) the phase and direction of the electricity flowing through the conductors referred to in paragraph (c);

(f) whether or which of the distribution circuit conductors connected to switches referred to in paragraph (c) are energized;

"electric distribution system" means the equipment of the authority that is energized at less than 60 kilovolts and is used by the authority to provide electricity at less than 60 kilovolts;

"electricity balance analysis" means an analysis of the electricity in a portion of the electric distribution system, including an analysis of the amount of electricity that

(a) is measured by the smart meters at all eligible premises supplied from that portion,

(b) is measured by the system devices installed on that portion,

(c) is supplied from that portion to unmetered loads known to the authority, and

(d) is lost in that portion because of resistance or another cause known to the authority;

"eligible premises" means a building, structure or equipment of a customer of the authority if the building, structure or equipment is connected to the electric distribution system and has an electricity meter, but does not include a building, structure or equipment where it is impracticable for the authority to install a smart meter;

"in-home feedback device" means a device that is capable of

(a) displaying

(i) a smart meter's measurements of electricity supplied to an eligible premises, and

(ii) the cost of the electricity measured by the smart meter, and

(b) transmitting information in digital form to and receiving information in digital form from a smart meter with which the authority has established a secure telecommunications link;

"system device" means a device, including a distribution system meter and a sensor, that, when installed on the electric distribution system, is capable of

(a) measuring and recording measurements of electricity as frequently as smart meters,

(b) transmitting and receiving information in digital form,

(c) measuring bi-directional flow of electricity, and

(d) being configured by the authority at a location either remote from or close to the device.

[am. B.C. Reg. 405/2012]

Prescribed requirements for smart meters

2 For the purposes of the definition of "smart meter" in section 17 (1) of the Act, the prescribed requirements for a meter are that it is capable of doing all of the following:

(a) measuring electricity supplied to an eligible premises;

(b) transmitting and receiving information in digital form;

(c) allowing the authority remotely to disconnect and reconnect the supply of electricity to an eligible premises, unless

(i) the point of metering for the eligible premises

(A) is greater than 240 volts,

(B) is greater than 200 amperes, or

(C) is three phase, or

(ii) the eligible premises

(A) has a bottom-connected meter,

(B) has an output or input pulse meter, or

(C) has a meter that measures maximum electricity demand in watts;

(d) recording measurements of electricity, and recording the date and time of the recording, at least as frequently as in 60-minute intervals;

(e) being configured by the authority at a location either remote from or close to the meter;

(f) measuring and recording measurements of electricity generated at the premises and supplied to the electric distribution system;

(g) transmitting information to and receiving information from an in-home feedback device, unless the point of metering for the eligible premises meets any of the criteria set out in paragraph (c) (i) or the eligible premises meets any of the criteria set out in paragraph (c) (ii).

Installation of smart meters and related equipment

3 (1) Subject to subsection (3), by the end of the 2012 calendar year, the authority must install and put into operation

(a) a smart meter for each eligible premises, and

(b) all of the following related equipment:

(i) communications infrastructure for transmitting information among smart meters and the computer hardware and software systems described in subparagraph (ii);

(ii) secure computer hardware and software systems that enable the authority to do all of the following:

(A) monitor, control and configure smart meters and the communications infrastructure referred to in subparagraph (i);

(B) store, validate, analyze and use the information measured by and received from smart meters;

(C) provide, through the internet, to a person who receives electricity from the authority secure access to information about the person's electricity consumption and generation, if any, measured by a smart meter;

(D) establish a secure telecommunications link between in-home feedback devices and smart meters that are compatible with each other;

(E) bill customers in accordance with rates that encourage the shift of the use of electricity from periods of higher demand to periods of lower demand;

(F) integrate the systems with the authority's other business systems.

(2) The communications infrastructure referred to in subsection (1) (b) (i) must include a telecommunications network that is capable of delivering two-way, digital, and secure communication.

(3) If it is impracticable because of distance, electromagnetic interference, physical obstruction or other similar cause for the authority to establish a telecommunications link between the smart meter at an eligible premises and the computer hardware and software system referred to in subsection (1) (b) (ii), the authority is not required to install or put into operation the communications infrastructure referred to in subsection (1) (b) (i) for the purpose of establishing that telecommunications link.

(4) The authority must integrate the operation of smart meters and related equipment with the authority's other operations.

Smart grid

4 (1) The program required under section 17 (4) of the Act must be established by the end of the 2015 calendar year and include the following components:

(a) the establishment and operation of a connectivity model and the installation and operation of

(i) at least 9 000 but no more than 35 000 system devices, and

(ii) computer hardware and software systems

to enable the authority to

(iii) perform electricity balance analyses for the electric distribution system, and

(iv) estimate the amount of electricity supplied from a portion of the electric distribution system to unmetered loads that are not known to the authority and to estimate the location of those loads;

(b) the acquisition of investigation devices and computer software to enable the authority to identify the location of the unmetered loads referred to in paragraph (a) (iv);

(c) the establishment and operation of telecommunications networks that

(i) have sufficient speed and bandwidth, and

(ii) enable two-way, digital, and secure communication among system devices, automation-enabled devices and the systems and equipment used by the authority for monitoring and controlling its electric system

to facilitate

(iii) the operation of the authority's electric system,

(iv) the integration, on a large scale, of distributed generation into the electric distribution system, and

(v) the provision of electricity service that allows for the large-scale use of electric vehicles by its customers.

(2) The authority must integrate the operation of the smart grid with the authority's other operations.

[Provisions relevant to the enactment of this regulation: *Clean Energy Act*, S.B.C. 2010, c. 22, section 37 (g)]

TAB 4

CANADA

CONSOLIDATION

CODIFICATION

Radiocommunication Act

Loi sur la radiocommunication

R.S.C., 1985, c. R-2

L.R.C. (1985), ch. R-2

Current to September 11, 2022

Last amended on September 21, 2017

À jour au 11 septembre 2022

Dernière modification le 21 septembre 2017

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OFFICIAL STATUS OF CONSOLIDATIONS

Subsections 31(1) and (2) of the *Legislation Revision and Consolidation Act*, in force on June 1, 2009, provide as follows:

Published consolidation is evidence

31 (1) Every copy of a consolidated statute or consolidated regulation published by the Minister under this Act in either print or electronic form is evidence of that statute or regulation and of its contents and every copy purporting to be published by the Minister is deemed to be so published, unless the contrary is shown.

Inconsistencies in Acts

(2) In the event of an inconsistency between a consolidated statute published by the Minister under this Act and the original statute or a subsequent amendment as certified by the Clerk of the Parliaments under the *Publication of Statutes Act*, the original statute or amendment prevails to the extent of the inconsistency.

CARACTÈRE OFFICIEL DES CODIFICATIONS

Les paragraphes 31(1) et (2) de la *Loi sur la révision et la codification des textes législatifs*, en vigueur le 1^er^ juin 2009, prévoient ce qui suit :

Codifications comme élément de preuve

31 (1) Tout exemplaire d'une loi codifiée ou d'un règlement codifié, publié par le ministre en vertu de la présente loi sur support papier ou sur support électronique, fait foi de cette loi ou de ce règlement et de son contenu. Tout exemplaire donné comme publié par le ministre est réputé avoir été ainsi publié, sauf preuve contraire.

Incompatibilité — lois

(2) Les dispositions de la loi d'origine avec ses modifications subséquentes par le greffier des Parlements en vertu de la *Loi sur la publication des lois* l'emportent sur les dispositions incompatibles de la loi codifiée publiée par le ministre en vertu de la présente loi.

LAYOUT

The notes that appeared in the left or right margins are now in boldface text directly above the provisions to which they relate. They form no part of the enactment, but are inserted for convenience of reference only.

MISE EN PAGE

Les notes apparaissant auparavant dans les marges de droite ou de gauche se retrouvent maintenant en caractères gras juste au-dessus de la disposition à laquelle elles se rattachent. Elles ne font pas partie du texte, n’y figurant qu’à titre de repère ou d’information.

NOTE

This consolidation is current to September 11, 2022. The last amendments came into force on September 21, 2017. Any amendments that were not in force as of September 11, 2022 are set out at the end of this document under the heading “Amendments Not in Force”.

NOTE

Cette codification est à jour au 11 septembre 2022. Les dernières modifications sont entrées en vigueur le 21 septembre 2017. Toutes modifications qui n'étaient pas en vigueur au 11 septembre 2022 sont énoncées à la fin de ce document sous le titre « Modifications non en vigueur ».

TABLE OF PROVISIONS

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R.S.C., 1985, c. R-2

An Act respecting radiocommunication in Canada

Short Title

Short title

1 This Act may be cited as the *Radiocommunication Act*.

R.S., 1985, c. R-2, s. 1; 1989, c. 17, s. 2.

Interpretation

Definitions

2 In this Act,

broadcasting means any radiocommunication in which the transmissions are intended for direct reception by the general public; (*radiodiffusion*)

broadcasting certificate means a certificate issued by the Minister under subparagraph 5(1)(a)(ii); (*certificat de radiodiffusion*)

broadcasting undertaking includes any distribution undertaking, programming undertaking and network operation to which the *Broadcasting Act* applies; (*entreprise de radiodiffusion*)

distribution undertaking has the same meaning as in the *Broadcasting Act*; (*entreprise de distribution*)

encrypted means treated electronically or otherwise for the purpose of preventing intelligible reception; (*encodage*)

harmful interference means an adverse effect of electromagnetic energy from any emission, radiation or induction that

(a) endangers the use or functioning of a safety-related radiocommunication system, or

(b) significantly degrades or obstructs, or repeatedly interrupts, the use or functioning of radio apparatus

L.R.C., 1985, ch. R-2

Loi concernant la radiocommunication au Canada

Titre abrégé

Titre abrégé

1 *Loi sur la radiocommunication*.

L.R. (1985), ch. R-2, art. 1; 1989, ch. 17, art. 2.

Définitions

Définitions

2 Les définitions qui suivent s'appliquent à la présente loi.

alimentation réseau Radiocommunication soit transmise par l'exploitant d'un réseau à ses affiliés, soit reçue par lui pour retransmission à ceux-ci, soit transmise par un distributeur légitime à une entreprise de programmation. (*network feed*)

appareil radio Dispositif ou assemblage de dispositifs destiné ou pouvant servir à la radiocommunication. (*radio apparatus*)

autorisation de radiocommunication Toute licence ou autorisation et tout certificat visés à l'alinéa 5(1)a). (*radio authorization*)

brouillage préjudiciable Effet non désiré d'une énergie électromagnétique due aux émissions, rayonnements ou inductions qui compromet le fonctionnement d'un système de radiocommunication relié à la sécurité ou qui dégrade ou entrave sérieusement ou interrompt de façon répétée le fonctionnement d'appareils radio ou de matériel radiosensible. (*harmful interference*)

brouilleur Tout dispositif ou assemblage de dispositifs qui transmet, émet ou rayonne de l'énergie électromagnétique s'il est conçu pour brouiller ou entraver la radiocommunication ou s'il est susceptible de brouiller ou d'entraver celle-ci, exception faite d'un dispositif ou d'un or radio-sensitive equipment; (*brouillage préjudiciable*)

interference-causing equipment means any device, machinery or equipment, other than radio apparatus, that causes or is capable of causing interference to radiocommunication; (*matériel brouilleur*)

jammer means any device or combination of devices that transmits, emits or radiates electromagnetic energy and that is designed to cause, causes or is capable of causing interference or obstruction to radiocommunication, other than a device or combination of devices for which standards have been established under paragraph 5(1)(d) or 6(1)(a) or for which a radio authorization has been issued. (*brouilleur*)

lawful distributor, in relation to an encrypted subscription programming signal or encrypted network feed, means a person who has the lawful right in Canada to transmit it and authorize its decoding; (*distributeur légitime*)

Minister means the Minister of Industry; (*ministre*)

network has the same meaning as in the *Broadcasting Act*; (*réseau*)

network feed means any radiocommunication that is transmitted

(a) by a network operation to its affiliates,

(b) to a network operation for retransmission by it to its affiliates, or

(c) by a lawful distributor to a programming undertaking; (*alimentation réseau*)

operator [Repealed, 1989, c. 17, s. 3]

prescribed means prescribed by regulations; (*Version anglaise seulement*)

programming undertaking has the same meaning as in the *Broadcasting Act*; (*entreprise de programmation*)

public includes persons who occupy apartments, hotel rooms or dwelling units situated in multi-unit buildings; (*public*)

public switched telephone network means a telecommunication facility the primary purpose of which is to provide a land line-based telephone service to the public for compensation; (*réseau téléphonique public commuté*)

assemblage de dispositifs pour lequel une norme technique a été fixée en application des alinéas 5(1)d) ou 6(1)a) ou pour lequel une autorisation de radiocommunication a été délivrée. (*jammer*)

certificat d’approbation technique Certificat visé au sous-alinéa 5(1)a)(iv). (*technical acceptance certificate*)

certificat de radiodiffusion Certificat visé au sous-alinéa 5(1)a)(ii). (*broadcasting certificate*)

certificat d’opérateur radio Certificat visé au sous-alinéa 5(1)a)(iii). (*radio operator certificate*)

communication radiotéléphonique S’entend de la radiocommunication faite au moyen d’un appareil servant principalement à brancher la communication à un réseau téléphonique public commuté. (*radio-based telephone communication*)

distributeur légitime La personne légitimement autorisée, au Canada, à transmettre un signal d’abonnement ou une alimentation réseau, en situation d’encodage, et à en permettre le décodage. (*lawful distributor*)

encodage Traitement électronique ou autre visant à empêcher la réception en clair. (*encrypted*)

entreprise de distribution S’entend au sens de la *Loi sur la radiodiffusion*. (*distribution undertaking*)

entreprise de programmation S’entend au sens de la *Loi sur la radiodiffusion*. (*programming undertaking*)

entreprise de radiodiffusion Sont incluses les entreprises de distribution ou de programmation et l’exploitation de réseau auxquelles s’applique la *Loi sur la radiodiffusion*. (*broadcasting undertaking*)

licence de spectre Licence visée au sous-alinéa 5(1)a)(i.1). (*spectrum licence*)

licence radio Licence visée au sous-alinéa 5(1)a)(i). (*radio licence*)

matériel brouilleur Dispositif, appareillage ou matériel — autre qu’un appareil radio — susceptible de brouiller la radiocommunication. (*interference-causing equipment*)

matériel radiosensible Dispositif, appareillage ou matériel — autre qu’un appareil radio — dont l’utilisation ou le fonctionnement est contrarié par des émissions de radiocommunication ou peut l’être. (*radio-sensitive equipment*)

radio apparatus means a device or combination of devices intended for, or capable of being used for, radiocommunication; (*appareil radio*)

radio authorization means a licence, certificate or authorization issued by the Minister under paragraph 5(1)(a); (*autorisation de radiocommunication*)

radio-based telephone communication means any radiocommunication that is made over apparatus that is used primarily for connection to a public switched telephone network; (*communication radiotéléphonique*)

radiocommunication or ***radio*** means any transmission, emission or reception of signs, signals, writing, images, sounds or intelligence of any nature by means of electromagnetic waves of frequencies lower than 3 000 GHz propagated in space without artificial guide; (*radiocommunication* ou *radio*)

radio licence means a licence issued by the Minister under subparagraph 5(1)(a)(i); (*licence radio*)

radio operator certificate means a certificate issued by the Minister under subparagraph 5(1)(a)(iii); (*certificat d'opérateur radio*)

radio-sensitive equipment means any device, machinery or equipment, other than radio apparatus, the use or functioning of which is or can be adversely affected by radiocommunication emissions; (*matériel radiosensible*)

radio station or ***station*** means a place in which radio apparatus is located; (*station de radiocommunication* ou *station*)

spectrum licence means a licence issued by the Minister under subparagraph 5(1)(a)(i.1); (*licence de spectre*)

subscription programming signal means radiocommunication that is intended for reception either directly or indirectly by the public in Canada or elsewhere on payment of a subscription fee or other charge; (*signal d'abonnement*)

technical acceptance certificate means a certificate issued by the Minister under subparagraph 5(1)(a)(iv). (*certificat d'approbation technique*)

telecommunication [Repealed, 1993, c. 38, s. 91]

R.S., 1985, c. R-2, s. 2; 1989, c. 17, s. 3; 1991, c. 11, s. 81; 1993, c. 38, s. 91, c. 40, s. 23; 1995, c. 1, s. 62; 1996, c. 18, s. 60; 2014, c. 39, s. 174.

ministre Le ministre de l'Industrie. (*Minister*)

opérateur [Abrogée, 1989, ch. 17, art. 3]

public Y sont comprises les personnes qui occupent des appartements ou des chambres d'hôtel, ainsi que des locaux d'habitation situés dans un même immeuble. (*public*)

radiocommunication ou ***radio*** Toute transmission, émission ou réception de signes, de signaux, d'écrits, d'images, de sons ou de renseignements de toute nature, au moyen d'ondes électromagnétiques de fréquences inférieures à 3 000 GHz transmises dans l'espace sans guide artificiel. (*radiocommunication* or *radio*)

radiodiffusion Toute radiocommunication dont les émissions sont destinées à être reçues directement par le public en général. (*broadcasting*)

réseau S'entend au sens de la *Loi sur la radiodiffusion*. (*network*)

réseau téléphonique public commuté Installation de télécommunication qui vise principalement à fournir au public un service téléphonique par lignes terrestres moyennant contrepartie. (*public switched telephone network*)

signal d'abonnement Radiocommunication destinée à être reçue, directement ou non, par le public au Canada ou ailleurs moyennant paiement d'un prix d'abonnement ou de toute autre forme de redevance. (*subscription programming signal*)

station de radiocommunication ou ***station*** Lieu où est situé un appareil radio. (*radio station* or *station*)

télécommunication [Abrogée, 1993, ch. 38, art. 91]

L.R. (1985), ch. R-2, art. 2; 1989, ch. 17, art. 3; 1991, ch. 11, art. 81; 1993, ch. 38, art. 91, ch. 40, art. 23; 1995, ch. 1, art. 62; 1996, ch. 18, art. 60; 2014, ch. 39, art. 174.

Application

Application to Her Majesty and Parliament

3 (1) Subject to subsection (2), this Act is binding on Her Majesty in right of Canada, on the Senate, House of Commons, Library of Parliament, office of the Senate Ethics Officer, office of the Conflict of Interest and Ethics Commissioner, Parliamentary Protective Service and office of the Parliamentary Budget Officer and on Her Majesty in right of a province.

Exemptions

(2) The Governor in Council may by order exempt Her Majesty in right of Canada, or the Senate, House of Commons, Library of Parliament, office of the Senate Ethics Officer, office of the Conflict of Interest and Ethics Commissioner, Parliamentary Protective Service or office of the Parliamentary Budget Officer, as represented by the person or persons named in the order, from any or all provisions of this Act or the regulations, and such an exemption may be

(a) in the case of an exemption of Her Majesty in right of Canada, in respect of Her Majesty in right of Canada generally, or only in respect of a department or other body named in the order;

(b) either absolute or qualified; and

(c) of either general or specific application.

Geographical application

(3) This Act applies within Canada and on board

(a) any ship, vessel or aircraft that is

(i) registered or licensed under an Act of Parliament, or

(ii) owned by, or under the direction or control of, Her Majesty in right of Canada or a province;

(b) any spacecraft that is under the direction or control of

(i) Her Majesty in right of Canada or a province,

(ii) a citizen or resident of Canada, or

(iii) a corporation incorporated or resident in Canada; and

(c) any platform, rig, structure or formation that is affixed or attached to land situated in the continental shelf of Canada.

Application

Application à Sa Majesté et au Parlement

3 (1) La présente loi lie Sa Majesté du chef du Canada et de chaque province, le Sénat, la Chambre des communes, la bibliothèque du Parlement, le bureau du conseiller sénatorial en éthique, le bureau du commissaire aux conflits d'intérêts et à l'éthique, le Service de protection parlementaire et le bureau du directeur parlementaire du budget.

Exception

(2) Le gouverneur en conseil peut toutefois, par décret, exempter Sa Majesté du chef du Canada ou tout représentant — désigné dans celui-ci — du Sénat, de la Chambre des communes, de la bibliothèque du Parlement, du bureau du conseiller sénatorial en éthique, du bureau du commissaire aux conflits d'intérêts et à l'éthique, du Service de protection parlementaire ou du bureau du directeur parlementaire du budget de l'application de toute disposition de la présente loi ou de ses règlements. L'exemption peut ou bien être générale ou relative à un ministère ou autre organisme désigné dans le décret, si elle s'applique à Sa Majesté du chef du Canada, ou bien absolue ou conditionnelle ou encore d'application générale ou spécifique.

Application géographique

(3) La présente loi s'applique au Canada et à bord :

a) d'un navire, bâtiment ou aéronef soit immatriculé ou faisant l'objet d'un permis aux termes d'une loi fédérale, soit appartenant à Sa Majesté du chef du Canada ou d'une province, ou placé sous sa responsabilité;

b) d'un véhicule spatial placé sous la responsabilité de Sa Majesté du chef du Canada ou d'une province, ou de celle d'un citoyen canadien, d'un résident du Canada ou d'une personne morale constituée ou résidant au Canada;

c) d'une plate-forme, installation, construction ou formation fixée au plateau continental canadien.

Powers, duties and functions of Minister

(4) Any power, duty or function of the Minister under this Act or the regulations may be exercised or performed by any person authorized by the Minister to do so and, if so exercised or performed, shall be deemed to have been exercised or performed by the Minister.

R.S., 1985, c. R-2, s. 3; R.S., 1985, c. 4 (3rd Supp.), s. 1; 1989, c. 17, s. 4; 1996, c. 31, s. 94; 2004, c. 7, s. 37; 2006, c. 9, s. 34; 2015, c. 36, s. 138; 2017, c. 20, s. 173.

Prohibitions

Prohibitions

4 (1) No person shall, except under and in accordance with a radio authorization, install, operate or possess radio apparatus, other than

(a) radio apparatus exempted by or under regulations made under paragraph 6(1)(m); or

(b) radio apparatus that is capable only of the reception of broadcasting and that is not a distribution undertaking.

Idem

(2) No person shall manufacture, import, distribute, lease, offer for sale or sell any radio apparatus, interference-causing equipment or radio-sensitive equipment for which a technical acceptance certificate is required under this Act, otherwise than in accordance with such a certificate.

Idem

(3) No person shall manufacture, import, distribute, lease, offer for sale or sell any radio apparatus, interference-causing equipment or radio-sensitive equipment for which technical standards have been established under paragraph 6(1)(a), unless the apparatus or equipment complies with those standards.

Other prohibitions

(4) No person shall install, use, possess, manufacture, import, distribute, lease, offer for sale or sell a jammer.

R.S., 1985, c. R-2, s. 4; 1989, c. 17, s. 4; 1991, c. 11, s. 82; 2014, c. 39, s. 175.

Minister's Powers

Minister's powers

5 (1) Subject to any regulations made under section 6, the Minister may, taking into account all matters that the Minister considers relevant for ensuring the orderly establishment or modification of radio stations and the

Pouvoirs et fonctions du ministre

(4) Les pouvoirs ou fonctions conférés au ministre par la présente loi ou ses règlements d'application peuvent être exercés par toute personne qu'il autorise à agir ainsi. Les pouvoirs ou fonctions ainsi exercés sont réputés l'avoir été par lui.

L.R. (1985), ch. R-2, art. 3; L.R. (1985), ch. 4 (3e suppl.), art. 1; 1989, ch. 17, art. 4; 1996, ch. 31, art. 94; 2004, ch. 7, art. 37; 2006, ch. 9, art. 34; 2015, ch. 36, art. 138; 2017, ch. 20, art. 173.

Interdictions

Interdictions

4 (1) Il est interdit, sans une autorisation de radiocommunication et sans en respecter les conditions, d'installer, de faire fonctionner ou de posséder un appareil radio autre :

a) qu'un appareil exempté au titre d'un règlement pris en application de l'alinéa 6(1)m);

b) qu'un appareil qui ne peut que recevoir de la radiodiffusion et n'est pas une entreprise de distribution.

Idem

(2) Il est interdit de fabriquer, d'importer, de distribuer, de louer, de mettre en vente ou de vendre tout appareil radio, matériel brouilleur ou matériel radiosensible pour lequel un certificat d'approbation technique est exigé au titre de la présente loi, si ce n'est en conformité avec celui-ci.

Idem

(3) Il est interdit d'effectuer les activités prévues au paragraphe (2) à l'égard de tout appareil ou matériel qui y est mentionné et qui n'est pas conforme aux normes techniques fixées en application de l'alinéa 6(1)a) auxquelles il est assujetti.

Autres interdictions

(4) Il est interdit d'installer, d'utiliser, de posséder, de fabriquer, d'importer, de distribuer, de louer, de mettre en vente ou de vendre un brouilleur.

L.R. (1985), ch. R-2, art. 4; 1989, ch. 17, art. 4; 1991, ch. 11, art. 82; 2014, ch. 39, art. 175.

Pouvoirs ministériels

Pouvoirs ministériels

5 (1) Sous réserve de tout règlement pris en application de l'article 6, le ministre peut, compte tenu des questions qu'il juge pertinentes afin d'assurer la constitution ou les modifications ordonnées de stations de orderly development and efficient operation of radiocommunication in Canada,

(a) issue

(i) radio licences in respect of radio apparatus,

(i.1) spectrum licences in respect of the utilization of specified radio frequencies within a defined geographic area,

(ii) broadcasting certificates in respect of radio apparatus that form part of a broadcasting undertaking,

(iii) radio operator certificates,

(iv) technical acceptance certificates in respect of radio apparatus, interference-causing equipment and radio-sensitive equipment, and

(v) any other authorization relating to radiocommunication that the Minister considers appropriate,

and may fix the terms and conditions of any such licence, certificate or authorization including, in the case of a radio licence and a spectrum licence, terms and conditions as to the services that may be provided by the holder thereof;

(b) amend the terms and conditions of any licence, certificate or authorization issued under paragraph (a);

(c) make available to the public any information set out in radio licences or broadcasting certificates;

(d) establish technical requirements and technical standards in relation to

(i) radio apparatus,

(ii) interference-causing equipment, and

(iii) radio-sensitive equipment,

or any class thereof;

(e) plan the allocation and use of the spectrum;

(f) approve each site on which radio apparatus, including antenna systems, may be located, and approve the erection of all masts, towers and other antenna-supporting structures;

(g) test radio apparatus for compliance with technical standards established under this Act;

radiocommunication ainsi que le développement ordonné et l'exploitation efficace de la radiocommunication au Canada :

a) délivrer et assortir de conditions :

(i) les licences radio à l'égard d'appareils radio, et notamment prévoir les conditions spécifiques relatives aux services pouvant être fournis par leur titulaire,

(i.1) les licences de spectre à l'égard de l'utilisation de fréquences de radiocommunication définies dans une zone géographique déterminée, et notamment prévoir les conditions spécifiques relatives aux services pouvant être fournis par leur titulaire,

(ii) les certificats de radiodiffusion à l'égard de tels appareils, dans la mesure où ceux-ci font partie d'une entreprise de radiodiffusion,

(iii) les certificats d'opérateur radio,

(iv) les certificats d'approbation technique à l'égard d'appareils radio, de matériel brouilleur ou de matériel radiosensible,

(v) toute autre autorisation relative à la radiocommunication qu'il estime indiquée;

b) modifier les conditions de toute licence ou autorisation ou de tout certificat ainsi délivrés;

c) mettre à la disposition du public tout renseignement indiqué dans les licences radio ou les certificats de radiodiffusion;

d) fixer les exigences et les normes techniques à l'égard d'appareils radio, de matériel brouilleur et de matériel radiosensible, ou de toute catégorie de ceux-ci;

e) planifier l'attribution et l'utilisation du spectre;

f) approuver l'emplacement d'appareils radio, y compris de systèmes d'antennes, ainsi que la construction de pylônes, tours et autres structures porteuses d'antennes;

g) procéder à l'essai d'appareils radio pour s'assurer de leur conformité aux normes techniques fixées sous le régime de la présente loi;

h) exiger que les demandeurs et les titulaires d'autorisations de radiocommunication lui communiquent tout renseignement qu'il estime indiqué concernant

(h) require holders of, and applicants for, radio authorizations to disclose to the Minister such information as the Minister considers appropriate respecting the present and proposed use of the radio apparatus in question and the cost of installing or maintaining it;

(i) require holders of radio authorizations to inform the Minister of any material changes in information disclosed pursuant to paragraph (h);

(j) appoint inspectors for the purposes of this Act;

(k) take such action as may be necessary to secure, by international regulation or otherwise, the rights of Her Majesty in right of Canada in telecommunication matters, and consult the Canadian Radio-television and Telecommunications Commission with respect to any matter that the Minister deems appropriate;

(l) make determinations as to the existence of harmful interference and issue orders to persons in possession or control of radio apparatus, interference-causing equipment or radio-sensitive equipment that the Minister determines to be responsible for the harmful interference to cease or modify operation of the apparatus or equipment until such time as it can be operated without causing or being affected by harmful interference;

(m) undertake, sponsor, promote or assist in research relating to radiocommunication, including the technical aspects of broadcasting; and

(n) do any other thing necessary for the effective administration of this Act.

l'utilisation — présente et future — de l'appareil radio, ainsi que son coût d'installation et d'entretien;

i) exiger que ces titulaires l'informent de toute modification importante des renseignements ainsi communiqués;

j) nommer les inspecteurs pour l'application de la présente loi;

k) prendre les mesures nécessaires pour assurer, notamment par voie de réglementation internationale, les droits de Sa Majesté du chef du Canada en matière de télécommunications et consulter le Conseil de la radiodiffusion et des télécommunications canadiennes sur les questions qui lui semblent indiquées;

l) décider de l'existence de tout brouillage préjudiciable et donner l'ordre aux personnes qui possèdent ou contrôlent tout appareil radio, matériel brouilleur ou matériel radiosensible qu'il juge responsable du brouillage de cesser ou de modifier l'exploitation de cet appareil ou de ce matériel jusqu'à ce qu'il puisse fonctionner sans causer de brouillage préjudiciable ou sans en être contrarié;

m) entreprendre, parrainer, promouvoir ou aider la recherche en matière de radiocommunication, notamment en ce qui touche les aspects techniques de la radiodiffusion;

n) prendre toute autre mesure propre à favoriser l'application efficace de la présente loi.

Canadian telecommunications policy

(1.1) In exercising the powers conferred by subsection (1), the Minister may have regard to the objectives of the Canadian telecommunications policy set out in section 7 of the *Telecommunications Act*.

Politique canadienne de télécommunication

(1.1) Dans l'exercice des pouvoirs prévus au paragraphe (1), le ministre peut aussi tenir compte de la politique canadienne de télécommunication indiquée à l'article 7 de la *Loi sur les télécommunications*.

Bidding system for radio authorizations

(1.2) In exercising the power under paragraph (1)(a) to issue radio authorizations, the Minister may use a system of competitive bidding to select the persons to whom radio authorizations will be issued.

Adjudication d'autorisations de radiocommunication

(1.2) Dans l'exercice du pouvoir qui lui est conféré par l'alinéa (1)a), le ministre peut recourir à un processus d'adjudication pour délivrer des autorisations de radiocommunication.

Payments pursuant to bids

(1.3) Where the Minister accepts a bid for a radio authorization under a system of competitive bidding, any moneys payable to Her Majesty pursuant to the bid are in lieu of any fees fixed under this or any other Act for the radio authorization.

Paiements découlant d'une enchère

(1.3) Lorsque le ministre accepte une enchère dans le cadre d'un processus d'adjudication d'une autorisation de radiocommunication, les sommes payables à Sa Majesté par suite de l'acceptation remplacent les droits fixés par la présente loi ou par toute autre loi relativement à l'autorisation.

Procedures for bidding system

(1.4) The Minister may establish procedures, standards and conditions, including, without limiting the generality of the foregoing, bidding mechanisms, minimum bids, bidders' qualifications, acceptance of bids, application fees for bidders, deposit requirements, withdrawal penalties and payment schedules, applicable in respect of a system of competitive bidding used under subsection (1.2) in selecting the person to whom a radio authorization will be issued.

Obligation

(1.5) Any person who is subject to the procedures, standards and conditions applicable in respect of a system of competitive bidding used under subsection (1.2) shall comply with all of them.

Suspension or revocation of radio authorization

(2) The Minister may suspend or revoke a radio authorization

(a) with the consent of the holder thereof;

(b) after giving written notice to the holder and giving the holder a reasonable opportunity to make representations to the Minister with respect thereto, where the Minister is satisfied that

(i) the holder has contravened this Act, the regulations or the terms or conditions of the radio authorization, or

(ii) the radio authorization was obtained through misrepresentation; or

(c) on giving written notice of suspension or revocation to the holder, without having to give the holder an opportunity to make representations to the Minister with respect thereto, where the holder has failed to comply with a request to pay fees or interest due under paragraph 6(1)(l).

R.S., 1985, c. R-2, s. 5; 1989, c. 17, s. 4; 1993, c. 38, s. 92; 1996, c. 18, s. 61; 2014, c. 39, s. 176.

Information sharing — Canada

5.1 (1) Information that has been collected or obtained by the Minister in the administration of this Act may be disclosed by the Minister to a federal department, a provincial or municipal government in Canada, or an agency of that federal, provincial or municipal government, to the extent that the disclosure is necessary for the administration of this Act.

Processus d'adjudication

(1.4) Le ministre peut établir les formalités, les normes et les modalités applicables au processus d'adjudication visé au paragraphe (1.2) et notamment fixer les mécanismes d'enchère, la mise à prix, les qualités des enchérisseurs, les modalités d'acceptation des enchères, les frais de demande exigibles des enchérisseurs, les exigences de dépôt, les pénalités pour retrait et les calendriers de paiement.

Obligation

(1.5) Toute personne qui est assujettie aux formalités, aux normes et aux modalités applicables au processus d'adjudication visé au paragraphe (1.2) est tenue de les respecter.

Suspension ou annulation de toute autorisation de radiocommunication

(2) Le ministre peut suspendre ou annuler toute autorisation de radiocommunication dans l'un ou l'autre des cas suivants :

a) avec le consentement du titulaire;

b) lorsqu'il est convaincu, après avoir donné un avis écrit au titulaire et accordé la possibilité à celui-ci de lui présenter ses observations à cet égard :

(i) soit que le titulaire a enfreint la présente loi, ses règlements d'application ou les conditions de l'autorisation,

(ii) soit que celle-ci a été obtenue sous de fausses représentations;

c) après avoir donné un avis écrit de suspension ou d'annulation au titulaire, mais sans nécessairement lui accorder la possibilité de lui présenter ses observations, lorsque le titulaire n'a pas accédé à la demande de verser les droits ou intérêts dus en vertu de l'alinéa 6(1)l).

L.R. (1985), ch. R-2, art. 5; 1989, ch. 17, art. 4; 1993, ch. 38, art. 92; 1996, ch. 18, art. 61; 2014, ch. 39, art. 176.

Communication de renseignements — Canada

5.1 (1) Le ministre peut, dans la mesure nécessaire à l'application de la présente loi, communiquer les renseignements qu'il a recueillis ou obtenus dans le cadre de l'application de celle-ci à une administration fédérale, provinciale ou municipale au Canada, ou à l'un de leurs organismes.

Information sharing — Government of foreign state and international organization

(2) The information may also be disclosed by the Minister under an agreement, a memorandum of understanding or an arrangement in writing between the Government of Canada and the government of a foreign state, an international organization of states or an international organization established by the governments of states, or any institution of that government or organization, if the Minister believes that the information may be relevant to an investigation or proceeding in respect of a contravention under this Act or of the laws of that foreign state that address conduct that is substantially similar to conduct that would be in contravention of this Act.

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(3) The agreement, memorandum of understanding or arrangement must

(a) restrict the use of the information to purposes relevant to an investigation or proceeding in respect of a contravention of the laws of the foreign state that address conduct referred to in subsection (2);

(b) stipulate that the information be treated in a confidential manner and not be further disclosed without the express consent of the person responsible for disclosing the information; and

(c) only be in respect of contraventions of the laws of a foreign state that have consequences that would not be considered penal under Canadian law.

2014, c. 39, s. 177.

Powers of Governor in Council and Others

Regulations

6 (1) The Governor in Council may make regulations

(a) respecting technical requirements and technical standards in relation to

(i) radio apparatus,

(ii) interference-causing equipment, and

(iii) radio-sensitive equipment,

or any class thereof;

(b) prescribing the eligibility of persons to whom radio authorizations, or any class thereof, may be issued, including eligibility criteria based on

Communication de renseignements — États étrangers et organisations internationales

(2) Il peut également communiquer les renseignements aux termes d'accords, d'ententes ou d'arrangements conclus par écrit entre, d'une part, le gouvernement du Canada et, d'autre part, le gouvernement d'un État étranger, une organisation internationale d'États ou une organisation internationale établie par des gouvernements, ou l'un de leurs organismes, s'il croit que les renseignements pourraient être utiles à une enquête, instance ou poursuite relative à une contravention à la présente loi ou à une loi de cet État étranger visant des comportements essentiellement semblables à ceux qui, selon lui, constitueraient des contraventions au titre de la présente loi.

Contenu

(3) Les accords, ententes ou arrangements :

a) précisent que les renseignements ne peuvent être utilisés qu'à des fins se rapportant à une enquête, instance ou poursuite relative à une contravention à une loi d'un État étranger portant sur des comportements visés au paragraphe (2);

b) prévoient que les renseignements seront traités de manière confidentielle et ne seront pas autrement communiqués sans le consentement exprès de la personne responsable de la communication;

c) ne peuvent viser que les contraventions aux lois d'un État étranger dont la sanction ne serait pas considérée comme pénale sous le régime du droit canadien.

2014, ch. 39, art. 177.

Pouvoirs du gouverneur en conseil et autres

Règlements

6 (1) Le gouverneur en conseil peut, par règlement :

a) fixer les exigences et les normes techniques à l'égard d'appareils radio, de matériel brouilleur et de matériel radiosensible, ou de toute catégorie de ceux-ci;

b) définir l'admissibilité à l'attribution d'autorisations de radiocommunication, ou de toute catégorie de celles-ci, notamment les critères d'admissibilité fondés sur :

(i) dans le cas d'une personne physique, la citoyenneté ou la résidence permanente,

(i) in the case of an individual, citizenship or permanent residence, or

(ii) in the case of a corporation, residence, ownership or control of the corporation, and the citizenship or permanent residence status of the directors and officers of the corporation;

(c) prescribing the qualifications of persons to whom radio authorizations, or any class thereof, may be issued, including examinations to be administered;

(d) prescribing the procedure governing the making of applications for radio authorizations, or any class thereof, including form and manner, and prescribing the processing and disposition of those applications and the issuing of radio authorizations by the Minister;

(e) prescribing the terms and conditions of radio authorizations, including, in the case of a radio licence, terms and conditions as to the services that may be provided by the holder thereof;

(f) prescribing conditions and restrictions applicable in respect of any prescribed radio service;

(g) prescribing radio apparatus, interference-causing equipment and radio-sensitive equipment, or classes thereof, in respect of which a technical acceptance certificate is required;

(h) respecting the inspection, testing and approval of radio apparatus, interference-causing equipment and radio-sensitive equipment in relation to technical acceptance certificates;

(i) prohibiting or regulating, in relation to

(i) interference to radiocommunication, or

(ii) adverse effects of electromagnetic energy from any emission, radiation or induction,

the manufacture, importation, installation, distribution, lease, offering for sale, sale or use of radio apparatus, interference-causing equipment and radio-sensitive equipment;

(j) prescribing the eligibility and qualifications of persons who may be appointed as inspectors, and the duties of inspectors;

(k) for giving effect to international agreements, conventions or treaties respecting radiocommunication to which Canada is a party;

(ii) dans le cas d'une personne morale, la résidence, le lien de propriété ou le pouvoir de contrôle, ainsi que le statut de citoyen ou de résident permanent de ses administrateurs et dirigeants;

c) définir les qualités requises pour l'attribution d'autorisations de radiocommunication, ou de toute catégorie de celles-ci, notamment l'examen à subir;

d) préciser la procédure applicable à la présentation des demandes d'autorisations de radiocommunication, ou de toute catégorie de celles-ci, notamment quant aux modalités de forme, au mode de traitement et au sort de ces demandes, ainsi qu'à la délivrance des autorisations par le ministre;

e) préciser les conditions des autorisations de radiocommunication et, dans le cas des licences radio, celles qui concernent les services pouvant être fournis par leur titulaire;

f) préciser les conditions et les restrictions applicables aux services radio réglementaires;

g) déterminer lesquels des appareils radio, des matériels brouilleurs et des matériels radiosensibles nécessitent un certificat d'approbation technique;

h) régir l'inspection, l'essai et l'approbation d'appareils radio, de matériel brouilleur et de matériel radiosensible en ce qui concerne les certificats d'approbation technique;

i) interdire ou régir la fabrication, l'importation, l'installation, la distribution, la location, la mise en vente, la vente ou l'utilisation d'appareils radio, de matériel brouilleur et de matériel radiosensible, relativement au brouillage de la radiocommunication ou à l'effet d'une énergie électromagnétique non désirée et due à une émission, à un rayonnement ou à une induction;

j) préciser les fonctions des inspecteurs et régir l'admissibilité et les qualités requises des personnes en vue de leur nomination à ce poste;

k) donner effet aux accords, conventions ou traités internationaux concernant la radiocommunication et auxquels le Canada est partie;

l) fixer les droits à payer — et les intérêts afférents à ceux-ci — pour :

(i) les demandes d'autorisation de radiocommunication, les examens ou les tests nécessaires à leur obtention et la délivrance des autorisations,

(l) prescribing fees

(i) for radio authorizations, applications therefor and examinations or testing in relation thereto, and

(ii) for services provided by the Department of Communications relating to spectrum management,

and respecting interest payable on unpaid fees so prescribed;

(m) prescribing radio apparatus, or any class thereof, that is exempt, either absolutely or subject to prescribed qualifications, from the application of subsection 4(1);

(n) prohibiting or regulating the further telecommunication, other than by persons operating broadcasting undertakings, of radiocommunications;

(o) for requiring, in a manner set out in the regulations, the reception or transmission of radiocommunication by any radio apparatus, or the exchange of radiocommunication by any radio apparatus with another radio apparatus;

(p) prescribing the manner in which radiocommunication is carried on in relation to any class of radio apparatus or radio service;

(q) prescribing the procedure to be followed with respect to the making of determinations under paragraph 5(1)(l), and prescribing the factors, including signal quality requirements, that the Minister shall take into account when making those determinations;

(r) prescribing maximum fines or maximum terms of imprisonment, or both, not exceeding those set out in subsection 10(1), for contravening or failing to comply with a regulation;

(s) prescribing anything that by this Act is to be prescribed; and

(t) generally for carrying out the purposes and provisions of this Act.

Incorporation by reference

(2) A regulation made under subsection (1) incorporating by reference a classification, standard, procedure or other specification may incorporate the classification, standard, procedure or specification as amended from time to time.

R.S., 1985, c. R-2, s. 6; 1989, c. 17, s. 4.

(ii) la fourniture de services de gestion du spectre par le ministère des Communications;

m) soustraire — éventuellement aux conditions qu'il fixe — certains appareils radio ou catégories de ceux-ci à l'application du paragraphe 4(1);

n) interdire ou régir la retransmission par télécommunication — sauf par les exploitants d'entreprises de radiodiffusion — d'émissions de radiocommunication;

o) exiger soit la réception ou la transmission de radiocommunication par tout appareil radio, soit l'échange de radiocommunication entre cet appareil et un autre, et en prévoir les modalités;

p) déterminer la manière dont s'effectue la radiocommunication à l'égard de toute catégorie d'appareils radio ou de services radio;

q) fixer les modalités de la décision visée à l'alinéa 5(1)l) et préciser les éléments, notamment les exigences en matière de qualité de signal, dont le ministre tient alors compte;

r) fixer les peines, n'excédant pas celles établies au paragraphe 10(1), pour contravention à un règlement;

s) prendre toute mesure d'ordre réglementaire prévue par la présente loi;

t) prendre toute autre mesure d'application de la présente loi.

Incorporation par renvoi

(2) Il peut être précisé, dans le règlement d'application du paragraphe (1) qui incorpore par renvoi des spécifications — classifications, normes ou modalités —, qu'elles sont incorporées avec leurs modifications successives.

L.R. (1985), ch. R-2, art. 6; 1989, ch. 17, art. 4.

Possession by Her Majesty

7 (1) Her Majesty may assume and, for any length of time, retain possession of any radio station and all things necessary to the sufficient working of it and may, for the same time, require the exclusive service of the operators and other persons employed in working the station.

Control by Government

(2) The person who owns or controls the station of which possession is assumed pursuant to subsection (1) shall give up possession of it and the operators and other persons employed as described in that subsection shall, during the time of possession thereunder, diligently and faithfully obey such orders, and transmit and receive such signals, calls and radiograms, as they are required to receive and transmit by any duly authorized officer of the Government of Canada.

Compensation

(3) Where the Minister and the person who owns or controls any radio station taken possession of by the Crown under this section cannot agree on the compensation to be paid by the Crown for the taking of possession, the Minister shall refer the matter to the Federal Court for adjudication and the *Expropriation Act* is, with such modifications as the circumstances require, applicable for the purpose of determining the amount of the compensation, if any, and the amount of any judgment on proceedings instituted under this subsection is payable out of the Consolidated Revenue Fund.

Exception

(4) Notwithstanding subsection (3), any dispute as to the compensation to be paid for the taking of possession of a radio station on settlement land as defined in section 2 of the *Yukon Surface Rights Board Act* or on Tetlit Gwich'in Yukon land may be heard and determined only by the Yukon Surface Rights Board under and in accordance with that Act.

Settlement land

(5) If the Yukon first nation concerned does not consent thereto, no interest in settlement land as defined in section 2 of the *Yukon Surface Rights Board Act* may be taken possession of under this section without the consent of the Governor in Council.

Tetlit Gwich'in Yukon land

(6) If the Gwich'in Tribal Council does not consent thereto, no interest in Tetlit Gwich'in Yukon land may be taken possession of under this section without the consent of the Governor in Council.

Prise de possession par Sa Majesté

7 (1) Sa Majesté peut temporairement prendre possession d'une station et de tout ce qui est nécessaire à son fonctionnement. Elle peut en outre, pendant cette période, requérir les services exclusifs des opérateurs et des autres membres du personnel de la station.

Station placée sous tutelle

(2) La personne qui possède ou contrôle la station visée au paragraphe (1) doit en abandonner la possession; les opérateurs et les autres membres du personnel sont tenus, pendant la durée de la possession par Sa Majesté, d'obéir consciencieusement et fidèlement aux ordres de tout fonctionnaire fédéral dûment autorisé à leur en donner, notamment en ce qui concerne les signaux, appels et radiogrammes qu'il leur demande de recevoir et de transmettre.

Indemnisation

(3) En cas de désaccord, entre lui et la personne qui possède ou contrôle une station dont Sa Majesté prend la possession sous le régime du présent article, sur le montant de l'indemnité à payer par celle-ci pour la prise de possession, le ministre soumet l'affaire au jugement de la Cour fédérale. La *Loi sur l'expropriation* s'applique, compte tenu des adaptations de circonstance, pour la détermination de l'indemnité éventuelle et le montant fixé par tout jugement sur des poursuites intentées aux termes du présent paragraphe est payable sur le Trésor.

Exception

(4) Par dérogation au paragraphe (3), l'Office des droits de surface du Yukon est seul à connaître, en conformité avec la *Loi sur l'Office des droits de surface du Yukon*, de tout désaccord sur le montant de l'indemnité payable par suite de la prise de possession, par Sa Majesté, d'une station située sur une terre désignée au sens de l'article 2 de cette loi ou de terres gwich'in tetlit du Yukon.

Terre désignée

(5) Sauf avec le consentement de la première nation touchée, nulle compagnie ne peut, au titre du présent article, s'approprier un droit sur une terre désignée au sens de l'article 2 de la *Loi sur l'Office des droits de surface du Yukon* sans l'agrément du gouverneur en conseil.

Terre gwich'in tetlit

(6) Sauf avec le consentement du Conseil tribal des Gwich'in, nulle compagnie ne peut, au titre du présent article, s'approprier un droit sur une terre gwich'in tetlit du Yukon sans l'agrément du gouverneur en conseil.

Notice of intention

(7) Where an interest in land referred to in subsection (5) or (6) is to be taken possession of without the consent of the Yukon first nation or Gwich'in Tribal Council, as the case may be,

(a) a public hearing in respect of the location and extent of the land to be taken possession of or occupied shall be held in accordance with the following procedure:

(i) notice of the time and place for the public hearing shall be given to the Yukon first nation or Gwich'in Tribal Council and the public,

(ii) at the time and place fixed for the public hearing, an opportunity shall be provided for the Yukon first nation or Gwich'in Tribal Council and the public to be heard,

(iii) costs incurred by any party in relation to the hearing are in the discretion of the person or body holding the hearing and may be awarded on or before the final disposition of the issue, and

(iv) a report on the hearing shall be prepared and submitted to the Minister; and

(b) notice of intention to obtain the consent of the Governor in Council shall be given to the Yukon first nation or Gwich'in Tribal Council on completion of the public hearing and submission of a report thereon to the Minister.

Definition of “Tetlit Gwich'in Yukon land”

(8) In this section, ***Tetlit Gwich'in Yukon land*** means land as described in Annex B, as amended from time to time, to Appendix C of the Comprehensive Land Claim Agreement between Her Majesty the Queen in right of Canada and the Gwich'in, as represented by the Gwich'in Tribal Council, that was approved, given effect and declared valid by the *Gwich'in Land Claim Settlement Act*.

R.S., 1985, c. R-2, s. 10; 1989, c. 17, s. 5; 1994, c. 43, s. 92.

Powers of inspectors

8 (1) An inspector who is appointed under paragraph 5(1)(j) may, subject to subsection (2),

(a) enter, at any reasonable time, any place in which they believe on reasonable grounds there is any document, information or thing relevant to the purpose of verifying compliance or preventing non-compliance

Avis d'intention

(7) L'appropriation d'un droit sur les terres visées aux paragraphes (5) ou (6) sans le consentement de la première nation ou du Conseil tribal des Gwich'in, selon le cas, ne peut avoir lieu qu'après l'observation des formalités suivantes :

a) une audience publique est tenue, en conformité avec les règles énoncées ci-après, au sujet de l'emplacement et de la superficie de la terre visée :

(i) avis des date, heure et lieu de l'audience est donné au public et, selon le cas, à la première nation ou au Conseil tribal des Gwich'in,

(ii) le public et, selon le cas, la première nation ou le Conseil tribal des Gwich'in se voient offrir l'occasion de se faire entendre à l'audience,

(iii) les frais et dépens des parties afférents à l'audience sont laissés à l'appréciation de la personne ou de l'organisme présidant l'audience, qui peut les adjuger en tout état de cause,

(iv) un procès-verbal de l'audience est dressé et remis au ministre;

b) après l'audience publique et la remise du procès-verbal de celle-ci au ministre, avis de l'intention de demander l'agrément du gouverneur en conseil est donné, selon le cas, à la première nation ou au Conseil tribal des Gwich'in.

Définition de « terre gwich'in tetlit du Yukon »

(8) Au présent article, ***terre gwich'in tetlit du Yukon*** s'entend de toute terre visée à la sous-annexe B — avec ses modifications — de l'annexe C de l'Entente sur la revendication territoriale globale des Gwich'in, conclue entre Sa Majesté la Reine du chef du Canada et les Gwich'in, représentés par le Conseil tribal des Gwich'in, approuvée, mise en vigueur et déclarée valide par la *Loi sur le règlement de la revendication territoriale des Gwich'in*.

L.R. (1985), ch. R-2, art. 10; 1989, ch. 17, art. 5; 1994, ch. 43, art. 92.

Pouvoirs des inspecteurs

8 (1) L'inspecteur nommé au titre de l'alinéa 5(1)j) peut :

a) à toute fin liée à la vérification du respect ou à la prévention du non-respect de la présente loi, entrer à toute heure convenable dans tout lieu s'il a des motifs raisonnables de croire que s'y trouvent des objets, des with this Act, and examine the document, information or thing or remove it for examination or reproduction;

(b) make use of, or cause to be made use of, any computer system at the place to examine any data contained in or available to the system;

(c) reproduce any document, or cause it to be reproduced, from the data in the form of a print-out or other intelligible output and take the print-out or other output for examination or copying; and

(d) use any copying equipment or means of communication in the place.

Certificate

(1.1) An inspector shall be provided with a certificate of appointment which is to be presented at the request of any person appearing to be in charge of any place entered by the inspector.

Dwelling-houses

(2) Where a place referred to in subsection (1) is a dwelling-house, an inspector may not enter that dwelling-house without the consent of the occupant, except

(a) under the authority of a warrant issued under subsection (3), or

(b) where, by reason of exigent circumstances, it would not be practical for the inspector to obtain a warrant

and, for the purposes of paragraph (b), exigent circumstances include circumstances in which the delay necessary to obtain a warrant would result in danger to human life or safety or the loss or destruction of evidence.

Authority to issue warrant

(3) On an *ex parte* application, a justice of the peace may issue a warrant authorizing an inspector who is named in the warrant to enter a dwelling-house, subject to any conditions specified in the warrant, if the justice is satisfied by information on oath that

(a) the dwelling-house is a place described in paragraph (1)(a);

(b) entry to the dwelling-house is necessary for the purpose of verifying compliance or preventing non-compliance with this Act; and

(c) entry has been refused by, or there are reasonable grounds to believe that entry will be refused by, or that

documents ou des renseignements, examiner ceux-ci et les emporter pour examen ou reproduction;

b) faire usage, directement ou indirectement, de tout système informatique se trouvant dans le lieu pour examiner les données qu’il contient ou auxquelles il donne accès;

c) à partir de ces données, reproduire ou faire reproduire tout document sous forme d’imprimé ou toute autre forme intelligible qu’il peut emporter pour examen ou reproduction;

d) utiliser le matériel de reproduction et les moyens de communication du lieu.

Certificat

(1.1) Il reçoit un certificat attestant sa qualité qu’il présente, sur demande, à toute personne apparemment responsable du lieu visité.

Maison d’habitation

(2) Il ne peut toutefois entrer dans une maison d’habitation sans le consentement de l’occupant que s’il est muni d’un mandat ou si l’urgence de la situation — notamment dans les cas où le temps nécessaire à l’obtention de ce dernier risquerait soit de mettre en danger des personnes, soit d’entraîner la perte ou la destruction d’éléments de preuve — rend l’obtention de celui-ci difficilement réalisable.

Délivrance du mandat

(3) Sur demande *ex parte*, le juge de paix peut décerner un mandat autorisant, sous réserve des conditions fixées, l’inspecteur qui y est nommé à entrer dans une maison d’habitation si lui-même est convaincu, sur la foi d’une dénonciation sous serment, que sont réunies les conditions suivantes :

a) il s’agit d’un lieu visé à l’alinéa (1)a);

b) l’entrée est nécessaire à toute fin liée à la vérification du respect ou à la prévention du non-respect de la présente loi;

c) soit un refus d’y entrer a été opposé, soit il y a des motifs raisonnables de croire que tel sera le cas ou consent to entry cannot be obtained from, the occupant.

Use of force

(4) In executing a warrant issued under subsection (3), an inspector shall not use force unless the inspector is accompanied by a peace officer and the use of force is specifically authorized in the warrant.

Assistance to inspectors

(5) The owner or person in charge of a place entered by an inspector shall give the inspector all reasonable assistance to enable the inspector to carry out the inspector's duties under this Act, and shall give the inspector any information that the inspector reasonably requests.

Information requirement

(5.1) An inspector who believes that a person is in possession of information that the inspector considers necessary for the purpose of verifying compliance or preventing non-compliance with this Act may, by notice, require that person to submit the information to the inspector in the form and manner and within the reasonable time that is stipulated in the notice.

Obstruction, false information

(6) Where an inspector is carrying out duties under this Act, no person shall

(a) resist or wilfully obstruct the inspector; or

(b) knowingly make a false or misleading statement, either orally or in writing, to the inspector.

1989, c. 17, s. 6; 2014, c. 39, s. 178.

Seizure

8.1 (1) An inspector may seize and detain any radio apparatus, interference-causing equipment, radio-sensitive equipment or jammer that they have reasonable grounds to believe is or was used to contravene any provision of this Act or the regulations or is related to the contravention of a provision of the Act or the regulations.

Detention

(2) Any thing that is seized under subsection (1) is not to be detained

(a) after the applicable provisions of this Act or the regulations have, in the opinion of an inspector, been complied with; or

(b) after the expiry of 60 days after the day on which the thing is seized, unless before that time

qu'il sera impossible d'obtenir le consentement de l'occupant.

Usage de la force

(4) L'inspecteur ne peut recourir à la force dans l'exécution du mandat que si celui-ci en autorise expressément l'usage et que lui-même est accompagné d'un agent de la paix.

Assistance à l'inspecteur

(5) Le propriétaire ou le responsable du lieu visé est tenu de prêter à l'inspecteur toute l'assistance possible dans l'exercice de ses fonctions et de lui donner les renseignements qu'il peut raisonnablement exiger.

Obligation de fournir des renseignements

(5.1) S'il croit qu'une personne détient des renseignements qu'il juge nécessaires pour la vérification du respect ou à la prévention du non-respect de la présente loi, l'inspecteur peut, par avis, l'obliger à les lui communiquer, selon les modalités, notamment de temps et de forme, que précise l'avis.

Entrave et fausses déclarations

(6) Il est interdit :

a) d'entraver volontairement l'action de l'inspecteur dans l'exercice de ses fonctions;

b) de sciemment lui faire, oralement ou par écrit, une déclaration fausse ou trompeuse.

1989, ch. 17, art. 6; 2014, ch. 39, art. 178.

Saisie

8.1 (1) S'il a des motifs raisonnables de croire qu'un appareil radio, brouilleur, matériel brouilleur ou matériel radiosensible sert, a servi ou est lié à la contravention d'une disposition de la présente loi ou de ses règlements, l'inspecteur peut le saisir et le retenir.

Rétention

(2) Les objets saisis ne peuvent être retenus après :

a) soit constatation par un inspecteur du respect des dispositions applicables de la présente loi ou des règlements;

b) soit l'expiration d'un délai de soixante jours suivant la date de saisie sauf si, dans ce délai, ont été prises l'une ou l'autre des mesures suivantes :

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(i) the seized thing has been forfeited under section 8.3 or 13,

(ii) proceedings have been instituted in respect of the contravention in relation to which the thing was seized, in which case it may be detained until the proceedings are concluded, or

(iii) notice of an application for an order extending the time during which the seized thing may be detained has been given in accordance with subsection 8.2(1).

(i) il y a eu confiscation, en vertu des articles 8.3 ou 13, des objets saisis,

(ii) des procédures ont été engagées pour la contravention reprochée, auquel cas les objets saisis peuvent être retenus jusqu'à la conclusion de celles-ci,

(iii) la signification d'un avis de demande d'ordonnance en vue de la prorogation du délai de rétention a été faite au titre du paragraphe 8.2(1).

Storing of seized things

(3) Any thing seized under subsection (1) may, at the option of an inspector, be kept or stored in the building or place where it was seized or may be removed to any other proper place by or at the direction of an inspector.

Lieu de rétention

(3) Les objets saisis peuvent, au choix d'un inspecteur, être gardés ou entreposés sur les lieux mêmes de leur saisie ou être transportés en tout autre lieu approprié par un inspecteur ou sur son ordre.

Prohibition

(4) No person shall, without the permission of an inspector, remove, alter or interfere in any way with any thing seized under this section.

2014, c. 39, s. 179.

Interdiction

(4) Il est interdit, sans l'autorisation d'un inspecteur, de déplacer un objet saisi et retenu par un inspecteur en vertu du présent article ou d'en modifier l'état de quelque manière que ce soit.

2014, ch. 39, art. 179.

Application to extend period of detention

8.2 (1) If proceedings have not been instituted, the Minister may, before the expiry of 60 days after the day on which the thing is seized and after giving notice to the owner of the seized thing or to the person in whose possession it was at the time of seizure, apply to any superior court of competent jurisdiction for an order extending the time during which the seized thing may be detained.

Demande de prorogation

8.2 (1) Si des procédures n'ont pas été engagées, le ministre peut, avant expiration des soixante jours suivant la date de saisie et après signification de l'avis au propriétaire ou à la dernière personne qui possède les objets saisis, demander à toute cour supérieure compétente qu'elle rende une ordonnance prorogeant le délai.

Order of extension granted

(2) If, on the hearing of an application made under subsection (1), the court is satisfied that the thing seized should continue to be detained, the court shall order that it be detained for the additional period that the court considers appropriate and that, on the expiry of that period, it be restored to the person from whom it was seized or to any other person entitled to its possession unless before the expiry of that period, subparagraph 8.1(2)(b)(i) or (ii) applies.

2014, c. 39, s. 179.

Acceptation de prorogation

(2) Si elle est convaincue, après audition de la demande, que la rétention des objets saisis devrait se poursuivre, la cour supérieure rend une ordonnance en ce sens précisant le nouveau délai qu'elle estime justifié et l'obligation, à l'expiration de celui-ci, de restituer les objets au saisi ou de les remettre à la personne ayant droit à leur possession, sauf si les mesures visées aux sous-alinéas 8.1(2)b)(i) ou (ii) sont prises entre-temps.

2014, ch. 39, art. 179.

Forfeiture on consent

8.3 The owner or the last person in lawful possession of any radio apparatus, interference-causing equipment, radio-sensitive equipment or jammer may, at any time, consent in writing to its forfeiture to Her Majesty.

2014, c. 39, s. 179.

Confiscation sur consentement

8.3 Le propriétaire de tout appareil radio, brouilleur, matériel brouilleur ou matériel radiosensible ou la dernière personne à les posséder légitimement peut consentir à tout moment, par écrit, à la confiscation de celui-ci au profit de Sa Majesté.

2014, ch. 39, art. 179.

Offences and Punishment

Prohibitions

9 (1) No person shall

(a) knowingly send, transmit or cause to be sent or transmitted any false or fraudulent distress signal, message, call or radiogram of any kind;

(b) without lawful excuse, interfere with or obstruct any radiocommunication;

(c) decode an encrypted subscription programming signal or encrypted network feed otherwise than under and in accordance with an authorization from the lawful distributor of the signal or feed;

(d) operate a radio apparatus so as to receive an encrypted subscription programming signal or encrypted network feed that has been decoded in contravention of paragraph (c); or

(e) retransmit to the public an encrypted subscription programming signal or encrypted network feed that has been decoded in contravention of paragraph (c).

Prohibition

(1.1) Except as prescribed, no person shall make use of or divulge a radio-based telephone communication

(a) if the originator of the communication or the person intended by the originator of the communication to receive it was in Canada when the communication was made; and

(b) unless the originator, or the person intended by the originator to receive the communication consents to the use or divulgence.

Idem

(2) Except as prescribed, no person shall intercept and make use of, or intercept and divulge, any radiocommunication, except as permitted by the originator of the communication or the person intended by the originator of the communication to receive it.

Exceptions

(3) Subsection (2) does not apply in respect of radiocommunication that consists of broadcasting, a subscription programming signal or a network feed.

1989, c. 17, s. 6; 1991, c. 11, s. 83; 1993, c. 40, s. 24.

Infractions et peines

Interdictions

9 (1) Il est interdit :

a) d’envoyer, d’émettre ou de faire envoyer ou émettre, sciemment, un signal de détresse ou un message, appel ou radiogramme de quelque nature, faux ou frauduleux;

b) sans excuse légitime, de gêner ou d’entraver la radiocommunication;

c) de décoder, sans l’autorisation de leur distributeur légitime ou en contravention avec celle-ci, un signal d’abonnement ou une alimentation réseau;

d) d’utiliser un appareil radio de façon à recevoir un signal d’abonnement ou une alimentation réseau ainsi décodé;

e) de transmettre au public un signal d’abonnement ou une alimentation réseau ainsi décodé.

Interdictions

(1.1) Sauf exception réglementaire, il est interdit d’utiliser ou de communiquer une communication radiotéléphonique sans l’autorisation de l’émetteur ou du destinataire, si l’un d’eux se trouvait au Canada lorsque la communication a été faite.

Idem

(2) Sauf exception réglementaire, il est interdit d’intercepter et soit d’utiliser, soit de communiquer toute radiocommunication sans l’autorisation de l’émetteur ou du destinataire.

Exceptions

(3) Les communications par radiodiffusion, alimentation réseau ou signal d’abonnement sont soustraites à l’application du paragraphe (2).

1989, ch. 17, art. 6; 1991, ch. 11, art. 83; 1993, ch. 40, art. 24.

Penalties

9.1 Every person who contravenes subsection 9(1.1) or (2) is guilty of an offence punishable on summary conviction and liable

(a) in the case of an individual, to a fine not exceeding twenty-five thousand dollars or to imprisonment for a term not exceeding one year, or to both; and

(b) in the case of a person other than an individual, to a fine not exceeding seventy-five thousand dollars.

1993, c. 40, s. 25.

Offences

10 (1) Every person who

(a) contravenes section 4 or paragraph 9(1)(a) or (b),

(b) without lawful excuse, manufactures, imports, distributes, leases, offers for sale, sells, installs, modifies, operates or possesses any equipment or device, or any component thereof, under circumstances that give rise to a reasonable inference that the equipment, device or component has been used, or is or was intended to be used, for the purpose of contravening section 9,

(c) contravenes or fails to comply with an order issued by the Minister under paragraph 5(1)(l),

(c.1) contravenes subsection 5(1.5), or

(d) contravenes or fails to comply with a regulation, where no punishment is prescribed by regulations made under paragraph 6(1)(r) for that contravention or failure to comply,

is guilty of an offence punishable on summary conviction and is liable, in the case of an individual, to a fine not exceeding five thousand dollars or to imprisonment for a term not exceeding one year, or to both, or, in the case of a corporation, to a fine not exceeding twenty-five thousand dollars.

Offences

(2) Every person is guilty of an offence punishable on summary conviction and is liable to a fine not exceeding five thousand dollars, who

(a) contravenes or fails to comply with subsection 8(5) or (6) or 8.1(4); or

(b) does not submit the information required by the inspector under subsection 8(5.1).

Peines

9.1 Quiconque contrevient aux paragraphes 9(1.1) ou (2) commet une infraction et encourt, sur déclaration de culpabilité par procédure sommaire :

a) dans le cas d’une personne physique, une amende maximale de vingt-cinq mille dollars et un emprisonnement maximal d’un an, ou l’une de ces peines;

b) dans le cas d’une personne morale, une amende maximale de soixante-quinze mille dollars.

1993, ch. 40, art. 25.

Infractions

10 (1) Commet une infraction et encourt, sur déclaration de culpabilité par procédure sommaire, dans le cas d’une personne physique, une amende maximale de cinq mille dollars et un emprisonnement maximal d’un an, ou l’une de ces peines, ou, dans le cas d’une personne morale, une amende maximale de vingt-cinq mille dollars quiconque, selon le cas :

a) contrevient à l’article 4 ou aux alinéas 9(1)a) ou b);

b) sans excuse légitime, fabrique, importe, distribue, loue, met en vente, vend, installe, modifie, exploite ou possède tout matériel ou dispositif, ou composante de celui-ci, dans des circonstances donnant à penser que l’un ou l’autre est utilisé en vue d’enfreindre l’article 9, l’a été ou est destiné à l’être;

c) contrevient à l’ordre donné par le ministre en vertu de l’alinéa 5(1)l);

c.1) contrevient au paragraphe 5(1.5);

d) à défaut de peine prévue par règlement d’application de l’alinéa 6(1)r), contrevient à un règlement.

Infractions

(2) Commet une infraction et encourt, sur déclaration de culpabilité par procédure sommaire, une amende maximale de cinq mille dollars, quiconque contrevient, selon le cas :

a) aux paragraphes 8(5) ou (6) ou 8.1(4);

b) à l’obligation que lui a imposée l’inspecteur en vertu du paragraphe 8(5.1).

Idem

(2.1) Every person who contravenes paragraph 9(1)(c) or (d) is guilty of an offence punishable on summary conviction and is liable, in the case of an individual, to a fine not exceeding ten thousand dollars or to imprisonment for a term not exceeding six months, or to both, or, in the case of a corporation, to a fine not exceeding twenty-five thousand dollars.

Idem

(2.1) Quiconque contrevient aux alinéas 9(1)c) ou d) commet une infraction et encourt, sur déclaration de culpabilité par procédure sommaire, dans le cas d'une personne physique, une amende maximale de dix mille dollars et un emprisonnement maximal de six mois, ou l'une de ces peines, dans le cas d'une personne morale, une amende maximale de vingt-cinq mille dollars.

Idem

(2.2) Every person who contravenes paragraph 9(1)(e) is guilty of an offence punishable on summary conviction and is liable, in the case of an individual, to a fine not exceeding twenty thousand dollars or to imprisonment for a term not exceeding one year, or to both, or, in the case of a corporation, to a fine not exceeding two hundred thousand dollars.

Idem

(2.2) Quiconque contrevient à l'alinéa 9(1)e) commet une infraction et encourt, sur déclaration de culpabilité par procédure sommaire, dans le cas d'une personne physique, une amende maximale de vingt mille dollars et un emprisonnement maximal d'un an, ou l'une de ces peines, dans le cas d'une personne morale, une amende maximale de deux cent mille dollars.

Exception

(2.3) No person who decodes an encrypted subscription programming signal in contravention of paragraph 9(1)(c) shall be convicted of an offence under that paragraph if the lawful distributor had the lawful right to make the signal available, on payment of a subscription fee or other charge, to persons in the area where the signal was decoded but had not made the signal readily available to those persons.

Défense

(2.3) Le fait de décoder un signal d'abonnement autrement qu'en conformité avec l'autorisation du distributeur légitime ne constitue pas une infraction à l'alinéa 9(1)c) si ce distributeur, étant légitimement autorisé à mettre, à l'endroit du décodage, le signal à la disposition des personnes ayant payé un prix d'abonnement ou une autre forme de redevance, ne l'avait pas mis à la disposition de celles-ci.

Not lawful excuse

(2.4) Nothing in subsection (2.3) shall constitute a lawful excuse for any person to manufacture, import, distribute, lease, offer for sale or sell any equipment or device, or any component thereof, in contravention of paragraph (1)(b).

Exception

(2.4) Le paragraphe (2.3) n'a pas pour effet d'accorder une défense à quiconque fabrique, importe, distribue, loue, met en vente ou vend tout matériel ou dispositif, ou composante de celui-ci, en contravention avec l'alinéa (1)b).

Due diligence

(2.5) No person shall be convicted of an offence under paragraph 9(1)(c), (d) or (e) if the person exercised all due diligence to prevent the commission of the offence.

Disculpation

(2.5) Nul ne peut être déclaré coupable de l'infraction visée aux alinéas 9(1)c), d) ou e) s'il a pris les mesures nécessaires pour l'empêcher.

Continuing offence

(3) Where an offence under this section is committed or continued on more than one day, the person who committed the offence is liable to be convicted for a separate offence for each day on which the offence is committed or continued.

Infraction continue

(3) Il est compté une infraction distincte au présent article pour chacun des jours au cours desquels se commet ou se continue l'infraction.

Injunctions

(4) Where a court of competent jurisdiction is satisfied, on application by the Minister, that an offence under paragraph (1)(a) is being or is likely to be committed, the court may grant an injunction, subject to such conditions as the court considers appropriate, ordering any person

Injonctions

(4) S'il est convaincu qu'une infraction à l'alinéa (1)a) se commet ou est sur le point d'être commise, le tribunal compétent peut, sur demande du ministre, accorder une to cease or refrain from any activity related to that offence.

injonction, sous réserve des conditions qu'il juge indiquées, ordonnant à quiconque de cesser toute activité liée à l'infraction ou de s'en abstenir.

Federal Court

(5) For the purposes of subsection (4), the Federal Court is a court of competent jurisdiction.

Cour fédérale

(5) La Cour fédérale est, pour l'application du paragraphe (4), un tribunal compétent.

Limitation

(6) A prosecution for an offence under this Act may be commenced within, but not after, three years after the day on which the subject-matter of the offence arose.

1989, c. 17, s. 6; 1991, c. 11, s. 84; 2014, c. 39, s. 180.

Prescription

(6) Les poursuites visées par la présente loi se prescrivent par trois ans à compter de la perpétration de l'infraction.

1989, ch. 17, art. 6; 1991, ch. 11, art. 84; 2014, ch. 39, art. 180.

Liability of directors, etc.

11 Where a corporation commits an offence under this Act, any officer, director or agent of the corporation who directed, authorized, assented to or acquiesced or participated in the commission of the offence is a party to and guilty of the offence, and is liable to the punishment provided for that offence in respect of an individual, whether or not the corporation has been prosecuted or convicted.

1989, c. 17, s. 6.

Responsabilité pénale : administrateurs

11 En cas de perpétration par une personne morale d'une infraction à la présente loi, ceux de ses dirigeants, administrateurs ou mandataires qui l'ont ordonnée ou autorisée, ou qui y ont consenti ou participé, sont considérés comme des coauteurs de l'infraction et encourent la peine prévue pour une personne physique, que la personne morale ait été ou non poursuivie ou déclarée coupable.

1989, ch. 17, art. 6.

Ticket offences

12 (1) The Governor in Council may make regulations designating any offence under this Act as an offence in respect of which

- **(a)** any person appointed as an inspector may issue and serve a summons by completing a ticket in the prescribed form, signing it and
  - **(i)** delivering it to the accused at the time the offence is alleged to have been committed, or
  - **(ii)** mailing it to the accused at the accused's latest known address, and
- **(b)** the information may be laid after the ticket is delivered or mailed,

and any regulations made under this section shall establish a procedure for voluntarily entering a plea of guilty and paying a fine in respect of each offence to which the regulations relate and shall prescribe the amount of the fine to be paid in respect of each such offence.

Contravention

12 (1) Le gouverneur en conseil peut, par règlement, déterminer, parmi les infractions à la présente loi, celles pour lesquelles :

- **a)** d'une part, l'inspecteur peut, pour valoir citation, remplir et signer le formulaire réglementaire de contravention et le remettre au prévenu lors de leur prétendue perpétration ou le lui signifier par la poste, à sa dernière adresse connue;
- **b)** d'autre part, la dénonciation peut être déposée après la remise ou la signification du formulaire.

Le règlement d'application du présent article fixe pour chaque infraction, d'une part, les modalités permettant au prévenu de plaider coupable et d'acquitter l'amende prévue et, d'autre part, le montant de celle-ci.

Fines

(2) A fine prescribed by regulations made under subsection (1) in respect of an offence may be lower for a first offence than for a subsequent offence, but in no case shall it be greater than one thousand dollars.

Amendes en cas de récidive

(2) Le montant des amendes prévues par règlement d'application du présent article peut être plus élevé en cas de récidive, sans jamais toutefois dépasser mille dollars par infraction.

Failure to respond to ticket

(3) Where a person to whom a ticket is delivered or mailed does not enter a plea within the prescribed time, a justice shall examine the information referred to in subsection (1) and

(a) if the information is complete and regular on its face, the justice shall enter a conviction in the person's absence and impose a fine of the prescribed amount; or

(b) if the information is not complete and regular on its face, the justice shall quash the proceedings.

1989, c. 17, s. 6.

Défaut

(3) Si la personne qui reçoit le formulaire de contravention n'y donne pas suite dans le délai réglementaire, le juge, après examen de la dénonciation :

a) si celle-ci est complète et régulière, la déclare coupable en son absence et lui impose l'amende réglementaire;

b) sinon, met fin aux procédures.

1989, ch. 17, art. 6.

Forfeiture of radio apparatus

13 (1) In the case of a conviction for an offence under paragraph 10(1)(a), any radio apparatus in relation to which or by means of which the offence was committed may be forfeited to Her Majesty in right of Canada by order of the Minister for such disposition, subject to subsections (2) to (6), as the Minister may direct.

Confiscation

13 (1) En cas de condamnation pour l'infraction visée à l'alinéa 10(1)a), l'appareil radio en cause peut être confisqué au profit de Sa Majesté du chef du Canada par arrêté du ministre pour qu'il en soit disposé, sous réserve des paragraphes (2) à (6), suivant les instructions de celui-ci.

Notice of forfeiture

(2) Where a radio apparatus is ordered to be forfeited under subsection (1), the Minister shall cause a notice of the forfeiture to be published in the *Canada Gazette*.

Avis

(2) Le ministre fait publier un avis de la confiscation dans la *Gazette du Canada*.

Application by person claiming interest

(3) Any person, other than a party to the proceedings that resulted in a forfeiture under subsection (1), who claims an interest in the apparatus as owner, mortgagee, lien holder or holder of any like interest may, within thirty days after the making of the order of forfeiture, apply to any superior court of competent jurisdiction for an order under subsection (6), whereupon the court shall fix a day for the hearing of the application.

Requête

(3) Quiconque n'est pas partie aux procédures dont résulte la confiscation et revendique un droit sur cet appareil à titre de propriétaire, de créancier hypothécaire, de détenteur de privilège ou de créancier d'un droit semblable peut, dans les trente jours suivant la prise de l'arrêté, requérir de toute cour supérieure compétente l'ordonnance visée au paragraphe (6), après quoi la cour fixe la date d'audition de la requête.

Notice

(4) An applicant for an order under subsection (6) shall, at least thirty days before the day fixed for the hearing of the application, serve a notice of the application and of the hearing on the Minister and on all other persons claiming an interest in the apparatus that is the subject-matter of the application as owner, mortgagee, lien holder or holder of any like interest of whom the applicant has knowledge.

Avis

(4) Le requérant donne avis de la requête et de la date fixée pour l'audition, au moins trente jours avant celle-ci, au ministre et à toute personne qui, au su du requérant, revendique sur l'appareil radio en cause un droit à titre de propriétaire, de créancier hypothécaire, de détenteur de privilège ou de créancier d'un droit semblable.

Notice of intervention

(5) Every person, other than the Minister, who is served with a notice under subsection (4) and who intends to appear at the hearing of the application to which the notice relates shall, at least ten days before the day fixed for the hearing, file an appropriate notice of intervention in the

Avis d'intervention

(5) À l'exception du ministre, toute personne qui reçoit signification d'un tel avis et se propose de comparaître lors de l'audition de la requête qui y est visée dépose au greffe du tribunal, au moins dix jours avant la date fixée record of the court and serve a copy thereof on the Minister and on the applicant.

Order declaring nature and extent of interests

(6) Where, on the hearing of an application under this section, the court is satisfied that the applicant, or the interveners, if any, or any of them,

(a) are innocent of any complicity and collusion in any conduct that caused the apparatus to be subject to forfeiture, and

(b) in the case of owners, exercised all reasonable care in respect of the persons permitted to obtain possession and use of the apparatus to satisfy themselves that it was not likely to be used in the commission of an offence under paragraph 10(1)(a),

any applicant or intervener in respect of whom the court is so satisfied is entitled to an order declaring that his interest is not affected by the forfeiture and declaring the nature and extent of his interest and the priority of his interest in relation to other interests recognized pursuant to this subsection, and the court may, in addition, order that the apparatus to which the interests relate be delivered to one or more of the persons found to have an interest therein, or that an amount equal to the value of each of the interests so declared be paid to the persons found to have those interests.

1989, c. 17, s. 6.

Exemptions

14 (1) The Minister may, by order, subject to any terms and conditions that he or she may specify, exempt any person, class of persons or entity from the application of subsection 4(4) or paragraph 9(1)(b), for any of the following purposes:

(a) national security;

(b) public safety, including with respect to penitentiaries and prisons;

(c) customs and immigration;

(d) national defence;

(e) international relations;

(f) the investigation or prosecution of offences in Canada, including the preservation of evidence;

(g) the protection of property, or the prevention of serious harm to any person; or

(h) for any other purpose prescribed by regulation.

pour l’audition, un avis d’intervention dont elle fait transmettre copie au ministre et au requérant.

Ordonnance

(6) Le requérant et les intervenants sont fondés à obtenir une ordonnance préservant leurs droits des effets de la confiscation et déclarant la nature, l’étendue et le rang de ceux-ci, lorsque le tribunal est convaincu, à l’issue de l’audition, de ce qui suit :

a) le requérant et les intervenants ne sont coupables ni de complicité ni de collusion à l’égard des actes qui ont rendu l’appareil radio susceptible de confiscation;

b) celles de ces personnes qui en sont propriétaires ont fait toute diligence pour s’assurer que les personnes ayant droit à la possession et à l’exploitation de l’appareil ne risquaient pas en cette qualité de perpétrer l’infraction visée à l’alinéa 10(1)a).

Le tribunal peut, dans ce cas, ordonner soit la remise de l’appareil en cause à l’une ou plusieurs des personnes dont il constate les droits, soit le versement à celles-ci d’une somme égale à la valeur de leurs droits respectifs.

1989, ch. 17, art. 6.

Exemptions

14 (1) Le ministre peut, par arrêté et aux conditions qu’il estime indiquées, exempter toute personne, individuellement ou au titre de son appartenance à telle catégorie, ou entité de l’application du paragraphe 4(4) ou de l’alinéa 9(1)b) aux fins suivantes :

a) la sécurité nationale;

b) la sécurité publique, notamment les pénitenciers et les prisons;

c) les douanes et l’immigration;

d) la défense nationale;

e) les relations internationales;

f) les enquêtes ou les poursuites relatives aux infractions au Canada, notamment la préservation des éléments de preuve;

g) la protection de biens ou la prévention de dommage grave à l’endroit d’une personne;

h) toute autre fin prévue par règlement.

Radiocommunication
Infractions et peines
Articles 14-15.11

Regulation

(2) The Governor in Council may make regulations for the purpose of paragraph (1)(h).

R.S., 1985, c. R-2, s. 14; 1989, c. 17, s. 6; 2014, c. 39, s. 181.

Règlement

(2) Le gouverneur en conseil peut prendre un règlement pour l'application de l'alinéa (1)h).

L.R. (1985), ch. R-2, art. 14; 1989, ch. 17, art. 6; 2014, ch. 39, art. 181.

Disposition of fines

15 All fines imposed by this Act or the regulations belong to Her Majesty in right of Canada and shall be paid to the Receiver General.

R.S., c. R-1, s. 13.

Versement des amendes au receveur général

15 Les amendes imposées par la présente loi ou ses règlements appartiennent à Sa Majesté du chef du Canada et sont versées au receveur général.

S.R., ch. R-1, art. 13.

Administrative Monetary Penalties

Sanctions administratives pécuniaires

Commission of violation

15.1 Every contravention of subsection 4(1), (3) or (4) or 5(1.5) constitutes a violation and the person who commits the violation is liable

(a) in the case of an individual, to an administrative monetary penalty not exceeding $25,000 and, for a subsequent contravention, a penalty not exceeding $50,000; or

(b) in any other case, to an administrative monetary penalty not exceeding $10,000,000 and, for a subsequent contravention, a penalty not exceeding $15,000,000.

2014, c. 39, s. 182.

Violation

15.1 Toute contravention aux paragraphes 4(1), (3) ou (4) ou 5(1.5) constitue une violation exposant son auteur à une pénalité dont le montant maximal est :

a) dans le cas d'une personne physique, de vingt-cinq mille dollars et de cinquante mille dollars en cas de récidive;

b) dans les autres cas, de dix millions de dollars et de quinze millions de dollars en cas de récidive.

2014, ch. 39, art. 182.

Criteria for penalty

15.11 (1) The amount of the penalty is to be determined by taking into account the following factors:

(a) the nature and scope of the violation;

(b) the history of compliance with this Act by the person who committed the violation;

(c) any benefit that the person obtained from the commission of the violation;

(d) the person's ability to pay the penalty;

(e) any factors established by the regulations; and

(f) any other relevant factor.

Détermination du montant de la pénalité

15.11 (1) Pour la détermination du montant de la pénalité, il est tenu compte des critères suivants :

a) la nature et la portée de la violation;

b) les antécédents de l'auteur de la violation en ce qui a trait au respect de la présente loi;

c) tout avantage qu'il a retiré de la commission de la violation;

d) sa capacité de payer le montant de la pénalité;

e) tout autre critère prévu par règlement;

f) tout autre critère pertinent.

Purpose of penalty

(2) The purpose of the penalty is to promote compliance with this Act and not to punish.

2014, c. 39, s. 182.

But de la pénalité

(2) L'imposition de la pénalité vise non pas à punir, mais à favoriser le respect de la présente loi.

2014, ch. 39, art. 182.

Power of Minister — violation

15.12 The Minister may

(a) designate any person, or any person who is a member of a class of persons, as being authorized to issue notices of violation or to accept undertakings; and

(b) establish, in respect of each violation, a short-form description to be used in notices of violation.

2014, c. 39, s. 182.

Entry into undertaking

15.13 (1) A person may enter into an undertaking after a notice of violation is served on them.

Contents

(2) The undertaking

(a) shall be accepted by a person who is authorized to accept an undertaking;

(b) shall identify every act or omission that constitutes a violation and that is covered by the undertaking;

(c) shall identify every provision at issue;

(d) may contain any conditions that the person who is authorized to accept an undertaking considers appropriate; and

(e) may include a requirement to pay a specified amount.

Effect of undertaking

(3) If a person enters into an undertaking, the proceeding that is commenced by the notice of violation is ended in respect of that person in connection with any act or omission referred to in the undertaking.

Failure to respect undertaking

(4) Failure to respect an undertaking constitutes a violation.

2014, c. 39, s. 182.

Issuance and service

15.14 (1) A person who is authorized to issue notices of violation and who believes, on reasonable grounds, that a person has committed a violation may issue, and shall cause to be served on the person, a notice of violation.

Pouvoir du ministre : violation

15.12 Le ministre peut :

a) désigner, individuellement ou au titre de leur appartenance à telle catégorie, les agents autorisés à dresser des procès-verbaux pour une violation ou les personnes autorisées à accepter un engagement;

b) établir pour chaque violation un sommaire la caractérisant dans les procès-verbaux.

2014, ch. 39, art. 182.

Engagement

15.13 (1) Toute personne peut contracter un engagement après qu’un procès-verbal lui a été signifié.

Contenu

(2) L’engagement :

a) doit être accepté par la personne autorisée à accepter un engagement;

b) énonce les actes ou omissions qui constituent une violation et sur lesquels il porte;

c) mentionne les dispositions en cause;

d) peut comporter les conditions que la personne autorisée à accepter un engagement estime indiquées;

e) peut prévoir l’obligation de payer une somme précise.

Effet de l’engagement

(3) Si une personne contracte un engagement, la procédure en violation prend fin à son égard en ce qui concerne les actes ou omissions mentionnés dans l’engagement.

Non-respect

(4) Le non-respect d’un engagement constitue une violation.

2014, ch. 39, art. 182.

Procès-verbal

15.14 (1) L’agent verbalisateur peut, s’il a des motifs raisonnables de croire qu’une violation a été commise, dresser un procès-verbal qu’il fait signifier à l’auteur présumé de la violation.

Contents of notice

(2) The notice of violation shall name the person who is believed to have committed the violation, identify the violation and include

(a) the penalty that the person is liable to pay;

(b) a statement as to the right of the person, within 30 days after the day on which the notice is served, or within any longer period that the Minister specifies, to pay the penalty or to make representations with respect to the violation and the penalty, and the manner for doing so; and

(c) a statement indicating that if the person does not pay the penalty or make representations in accordance with the notice, the person is deemed to have committed the violation and the penalty is to be imposed.

2014, c. 39, s. 182.

Contenu du procès-verbal

(2) Le procès-verbal mentionne, outre le nom de l'auteur présumé et les faits reprochés :

a) le montant de la pénalité à payer;

b) la faculté qu'a l'auteur présumé soit de payer la pénalité, soit de présenter des observations relativement à la violation ou à la pénalité, et ce, dans les trente jours suivant la signification du procès-verbal — ou dans le délai plus long que peut préciser le ministre —, ainsi que les autres modalités d'exercice de cette faculté;

c) le fait que le non-exercice de cette faculté vaut déclaration de responsabilité et entraîne l'imposition de la pénalité.

2014, ch. 39, art. 182.

Payment

15.15 (1) If a person who is served with a notice of violation pays the penalty proposed in the notice, the person is deemed to have committed the violation and the proceedings in respect of it are ended.

Paiement

15.15 (1) Le paiement de la pénalité prévue au procès-verbal vaut déclaration de responsabilité à l'égard de la violation et met fin à la procédure.

Representations to Minister

(2) If a person who is served with a notice of violation makes representations in accordance with the notice, the Minister shall decide, on a balance of probabilities, after considering any other representations that the Minister considers appropriate, whether the person committed the violation and may, if the Minister so decides, impose the penalty set out in the notice, a lesser penalty or no penalty.

Présentation d'observations

(2) Si des observations sont présentées, dans le délai et selon les autres modalités précisés dans le procès-verbal, le ministre décide, selon la prépondérance des probabilités, de la responsabilité de l'intéressé, et ce, après avoir examiné toutes les autres observations qu'il estime appropriées. Le cas échéant, il peut imposer la pénalité prévue au procès-verbal ou une pénalité réduite, ou encore n'en imposer aucune.

Failure to pay or make representations

(3) If a person who is served with a notice of violation neither pays the penalty nor makes representations in accordance with the notice, the person is deemed to have committed the violation and the penalty is to be imposed.

Omission de payer ou de présenter des observations

(3) Le non-exercice de la faculté mentionnée au procès-verbal, dans le délai et selon les autres modalités qui y sont précisées, vaut déclaration de responsabilité à l'égard de la violation et entraîne l'imposition de la pénalité.

Copy of decision and notice of rights

(4) The Minister shall cause a copy of any decision made under subsection (2) to be issued and served on the person together with a notice of the person's right to appeal under section 15.2.

2014, c. 39, s. 182.

Copie de la décision et droits de l'intéressé

(4) Le ministre fait signifier à l'intéressé copie de la décision prise au titre du paragraphe (2) et l'avise par la même occasion de son droit d'appel au titre de l'article 15.2.

2014, ch. 39, art. 182.

Evidence

15.16 In a proceeding in respect of a violation, a notice purporting to be served under subsection 15.14(1) or a copy of a decision purporting to be served under

Admissibilité en preuve

15.16 Dans les procédures en violation, le procès-verbal ou la copie de la décision paraissant signifié en application des paragraphes 15.14(1) ou 15.15(4), selon le cas, est subsection 15.15(4) is admissible in evidence without proof of the signature or official character of the person appearing to have signed it.

2014, c. 39, s. 182.

Defence

15.17 (1) It is a defence for a person in a proceeding in relation to a violation to establish that they exercised due diligence to prevent the violation.

Common law principles

(2) Every rule and principle of the common law that renders any circumstance a justification or excuse in relation to a charge for an offence under this Act applies in respect of a violation to the extent that it is not inconsistent with this Act.

2014, c. 39, s. 182.

Vicarious liability — acts of employees and agents and mandataries

15.18 A person is liable for a violation that is committed by an employee of the person acting in the course of the employee's employment, or by an agent or mandatary of the person acting within the scope of the agent's or mandatary's authority, whether or not the employee or agent or mandatary who actually committed the violation is identified or proceeded against.

2014, c. 39, s. 182.

Officer, director or agent or mandatary of corporations

15.19 An officer, director or agent or mandatary of a corporation that commits a violation is liable for the violation if they directed, authorized, assented to, acquiesced in or participated in the commission of the violation, whether or not the corporation is proceeded against.

2014, c. 39, s. 182.

Appeal to Federal Court

15.2 (1) Subject to subsection (2), an appeal may be brought in the Federal Court from a decision made under subsection 15.15(2) within 30 days after the day on which the decision is made.

Appeal on question of fact

(2) An appeal on a question of fact may be brought only with the leave of the Federal Court, an application for which shall be made within 30 days after the day on which the decision is made. The appeal may not be brought later than 30 days after the day on which leave to appeal is granted.

2014, c. 39, s. 182.

admissible en preuve sans qu'il soit nécessaire de prouver l'authenticité de la signature qui y est apposée ni la qualité officielle du signataire.

2014, ch. 39, art. 182.

Moyens de défense

15.17 (1) L'auteur présumé de la violation peut invoquer en défense dans le cadre de toute procédure en violation qu'il a pris les précautions voulues.

Principes de la common law

(2) Les règles et principes de la common law qui font d'une circonstance une justification ou une excuse dans le cadre d'une poursuite pour infraction à la présente loi s'appliquent à l'égard de toute violation, sauf dans la mesure où ils sont incompatibles avec la présente loi.

2014, ch. 39, art. 182.

Responsabilité indirecte : employeurs et mandants

15.18 L'employeur ou le mandant est responsable de la violation commise par son employé ou son mandataire dans le cadre de son emploi ou de son mandat, selon le cas, que l'auteur de la violation fasse ou non l'objet de procédures en violation.

2014, ch. 39, art. 182.

Administrateurs, dirigeants et mandataires de personnes morales

15.19 En cas de commission par une personne morale d'une violation, ceux de ses dirigeants, administrateurs ou mandataires qui l'ont ordonnée ou autorisée, ou qui y ont consenti ou participé, sont responsables de la violation, que la personne morale fasse ou non l'objet de procédures en violation.

2014, ch. 39, art. 182.

Appel à la Cour fédérale

15.2 (1) Sous réserve du paragraphe (2), il peut être interjeté appel à la Cour fédérale d'une décision rendue au titre du paragraphe 15.15(2) dans les trente jours suivant la date de la décision.

Questions de fait

(2) Un tel appel, s'il porte sur une question de fait, est subordonné à l'autorisation de la Cour fédérale. La demande d'autorisation doit être présentée dans les trente jours suivant la date de la décision, et l'appel doit être interjeté dans les trente jours suivant la date de l'autorisation.

2014, ch. 39, art. 182.

Debts due to Her Majesty

15.21 (1) The following amounts are debts due to Her Majesty in right of Canada that may be recovered in the Federal Court:

(a) the amount payable under an undertaking entered into under subsection 15.13(1), beginning on the day specified in the undertaking or, if no day is specified, beginning on the day on which the undertaking is entered into;

(b) the amount of the penalty set out in a notice of violation, beginning on the day on which it is required to be paid in accordance with the notice, unless representations are made in accordance with the notice;

(c) if representations are made, either the amount of the penalty that is imposed by the Minister or on appeal, as the case may be, beginning on the day specified by the Minister or the court or, if no day is specified, beginning on the day on which the decision is made; and

(d) the amount of any reasonable expenses incurred in attempting to recover an amount referred to in any of paragraphs (a) to (c).

Time limit or prescription

(2) A proceeding to recover such a debt may not be commenced later than five years after the day on which the debt becomes payable.

Receiver General

(3) A penalty paid or recovered in relation to a violation is payable to the Receiver General.

2014, c. 39, s. 182.

Certificate of default

15.22 (1) The Minister may issue a certificate for the unpaid amount of any debt referred to in subsection 15.21(1).

Effect of registration

(2) Registration of a certificate in the Federal Court has the same effect as a judgment of that Court for a debt of the amount set out in the certificate and all related registration costs.

2014, c. 39, s. 182.

Time limit or prescription

15.23 (1) A proceeding in respect of a violation may not be commenced later than three years after the day on which the subject-matter of the proceedings becomes known to the Minister.

Créance de Sa Majesté

15.21 (1) Constituent une créance de Sa Majesté du chef du Canada, dont le recouvrement peut être poursuivi à ce titre devant la Cour fédérale :

a) la somme à payer aux termes de l’engagement contracté en vertu du paragraphe 15.13(1), à compter de la date à laquelle l’engagement a été contracté ou, s’il y a lieu, de la date qui y est précisée;

b) le montant de la pénalité mentionné dans le procès-verbal, à compter de la date de paiement qui y est précisée, sauf en cas de présentation d’observations selon les modalités qui y sont prévues;

c) s’il y a présentation d’observations, le montant de la pénalité imposée par le ministre ou lors d’un appel, selon le cas, à compter de la date précisée par le ministre dans sa décision ou le tribunal ou, dans le cas où aucune date n’est précisée, à compter de la date de la décision du ministre;

d) les frais raisonnables faits en vue du recouvrement d’une somme ou d’un montant visé à l’un ou l’autre des alinéas a) à c).

Prescription

(2) Le recouvrement de la créance se prescrit par cinq ans à compter de la date à laquelle elle est devenue exigible.

Receveur général

(3) Toute pénalité perçue au titre d’une violation est versée au receveur général.

2014, ch. 39, art. 182.

Certificat de non-paiement

15.22 (1) Le ministre peut établir un certificat de non-paiement pour la partie impayée de toute créance visée au paragraphe 15.21(1).

Effet de l’enregistrement

(2) L’enregistrement à la Cour fédérale confère au certificat la valeur de jugement de cette juridiction pour la somme visée et les frais afférents.

2014, ch. 39, art. 182.

Prescription

15.23 (1) Les procédures en violation se prescrivent par trois ans à compter de la date où le ministre a eu connaissance des éléments constitutifs de la violation.

Certificate of Minister

(2) A document appearing to have been issued by the Minister, certifying the day on which the subject-matter of any proceedings became known to him or her, is admissible in evidence without proof of the signature or official character of the person appearing to have signed the document and is, in the absence of evidence to the contrary, proof of the matter asserted in it.

2014, c. 39, s. 182.

Publication

15.24 The Minister may make public

(a) the name of a person who committed a violation, the nature of the violation including the acts or omissions, or the provisions at issue and the amount of the penalty; and

(b) the name of a person who enters into an undertaking, the nature of the undertaking including the acts or omissions, or the provisions at issue, the conditions included in the undertaking and, if applicable, the amount of the penalty.

2014, c. 39, s. 182.

How act or omission may be proceeded with

15.25 If an act or omission may be proceeded with either as a violation or as an offence, proceeding in one manner precludes proceeding in the other.

2014, c. 39, s. 182.

For greater certainty

15.26 For greater certainty, a violation is not an offence and, accordingly, section 126 of the *Criminal Code* does not apply.

2014, c. 39, s. 182.

Regulations

15.27 The Governor in Council may make regulations

(a) designating provisions of this Act whose contravention constitutes a separate violation in respect of each day during which it continues;

(b) for the purpose of paragraph 15.11(1)(e), establishing other factors to be considered in determining the amount of the penalty; and

(c) respecting undertakings entered into under section 15.13.

2014, c. 39, s. 182.

Certificat du ministre

(2) Tout document apparemment délivré par le ministre et attestant la date où les éléments constitutifs sont parvenus à sa connaissance fait foi de cette date, en l’absence de preuve contraire, sans qu’il soit nécessaire de prouver l’authenticité de la signature qui y est apposée ni la qualité officielle du signataire.

2014, ch. 39, art. 182.

Publication

15.24 Le ministre peut rendre publics :

a) le nom de l’auteur de la violation, la nature de la violation, notamment les actes ou omissions et les dispositions en cause, et le montant de la pénalité;

b) le nom de la personne qui a contracté un engagement, la nature de celui-ci, notamment les actes ou omissions et les dispositions en cause, les conditions qu’il comporte et, le cas échéant, le montant de la pénalité.

2014, ch. 39, art. 182.

Cumul interdit

15.25 S’agissant d’un acte ou d’une omission qualifiable à la fois de violation et d’infraction, la procédure en violation et la procédure pénale s’excluent l’une l’autre.

2014, ch. 39, art. 182.

Précision

15.26 Il est entendu que les violations ne sont pas des infractions; en conséquence, nul ne peut être poursuivi à ce titre sur le fondement de l’article 126 du *Code criminel*.

2014, ch. 39, art. 182.

Règlements

15.27 Le gouverneur en conseil peut, par règlement :

a) désigner les dispositions de la présente loi dont la contravention constitue une violation distincte pour chacun des jours au cours desquels la contravention se continue;

b) pour l’application de l’alinéa 15.11(1)e), établir d’autres critères applicables à la détermination du montant de la pénalité;

c) régir les engagements visés à l’article 15.13.

2014, ch. 39, art. 182.

General

Certificates or reports of inspectors

16 (1) In any proceeding under this Act, or in any other proceeding to which the legislative jurisdiction of Parliament extends, a certificate or report purporting to have been given by an inspector who did an inspection or test pursuant to this Act and to have been signed by that inspector is admissible in evidence and, in the absence of any evidence to the contrary, is proof of the matters stated therein relating to the inspection or test, without proof of the signature, official character or capacity of the person appearing to have signed the certificate or report.

No admissibility without notice

(2) No certificate or report shall be received in evidence pursuant to subsection (1) unless the party who intends to produce it has given to the party against whom it is intended to be produced reasonable notice of that intention, together with a copy of the certificate or report.

Attendance of inspector

(3) A party who receives notice under subsection (2) may, with leave of the court, require the attendance of the inspector for the purposes of cross-examination.

R.S., 1985, c. R-2, s. 16; 1989, c. 17, s. 7.

Protection from personal liability

17 (1) No action or other proceeding for damages lies or may be instituted against a Minister, servant or agent of the Crown for or in respect of anything done or omitted to be done, or purported to be done or omitted to be done, in good faith under this Act or any order or regulation issued or made under this Act.

Crown not relieved of liability

(2) Subsection (1) does not relieve the Crown of liability for the acts or omissions described therein, and the Crown is liable under the *Crown Liability Act* or any other law as if that subsection had not been enacted.

1989, c. 17, s. 7.

Civil Action

Right of civil action

18 (1) Any person who

(a) holds an interest in the content of a subscription programming signal or network feed, by virtue of copyright ownership or a licence granted by a copyright owner,

Dispositions générales

Certificats ou rapports des inspecteurs

16 (1) Dans les poursuites sous le régime de la présente loi et dans toute autre procédure relevant de l'autorité législative du Parlement, les certificats ou les rapports censés délivrés et signés par l'inspecteur qui a fait l'inspection ou l'essai en question sont admissibles en preuve et, sauf preuve contraire, font foi de leur contenu sans qu'il soit nécessaire de prouver l'authenticité de la signature qui y est apposée ou la qualité officielle du signataire.

Préavis

(2) Les certificats et rapports ne sont reçus en preuve que si la partie qui a l'intention de les produire contre une autre donne à celle-ci un préavis suffisant accompagné d'une copie de ces documents.

Comparution de l'inspecteur

(3) Le destinataire du préavis peut, avec l'autorisation du tribunal, exiger la présence de l'inspecteur pour contre-interrogatoire.

L.R. (1985), ch. R-2, art. 16; 1989, ch. 17, art. 7.

Exclusion de la responsabilité personnelle

17 (1) Aucune action ni autre procédure pour dommages-intérêts ne peut être intentée contre un ministre, un préposé ou un mandataire de l'État pour un fait — acte ou omission — accompli, ou censé l'avoir été, de bonne foi en application de la présente loi ou des décrets, arrêtés ou règlements pris sous son régime.

Responsabilité de l'État

(2) Le paragraphe (1) ne dégage pas l'État de sa responsabilité pour les faits qui y sont visés et celui-ci demeure responsable, en application de la *Loi sur la responsabilité de l'État* et de toute autre loi, indépendamment de ce paragraphe.

1989, ch. 17, art. 7.

Recours civil

Recours civil

18 (1) Peut former, devant tout tribunal compétent, un recours civil à l'encontre du contrevenant quiconque a subi une perte ou des dommages par suite d'une contravention aux alinéas 9(1)c), d) ou e) ou 10(1)b) et :

a) soit détient, à titre de titulaire du droit d'auteur ou d'une licence accordée par ce dernier, un droit dans le

(b) is authorized by the lawful distributor of a subscription programming signal or network feed to communicate the signal or feed to the public,

(c) holds a licence to carry on a broadcasting undertaking issued by the Canadian Radio-television and Telecommunications Commission under the *Broadcasting Act*, or

(d) develops a system or technology, or manufactures or supplies to a lawful distributor equipment, for the purpose of encrypting a subscription programming signal or network feed, or manufactures, supplies or sells decoders, to enable authorized persons to decode an encrypted subscription programming signal or encrypted network feed

may, where the person has suffered loss or damage as a result of conduct that is contrary to paragraph 9(1)(c), (d) or (e) or 10(1)(b), in any court of competent jurisdiction, sue for and recover damages from the person who engaged in the conduct, or obtain such other remedy, by way of injunction, accounting or otherwise, as the court considers appropriate.

Rules applicable

(2) In an action under subsection (1) against a person,

(a) a monetary judgment may not exceed one thousand dollars where the person is an individual and the conduct engaged in by the person is neither contrary to paragraph 9(1)(e) or 10(1)(b) nor engaged in for commercial gain; and

(b) the costs of the parties are in the discretion of the court.

Evidence of prior proceedings

(3) In an action under subsection (1) against a person, the record of proceedings in any court in which that person was convicted of an offence under paragraph 9(1)(c), (d) or (e) or 10(1)(b) is, in the absence of any evidence to the contrary, proof that the person against whom the action is brought engaged in conduct that was contrary to that paragraph, and any evidence given in those proceedings as to the effect of that conduct on the person bringing the action is evidence thereof in the action.

Jurisdiction of Federal Court

(4) For the purposes of an action under subsection (1), the Federal Court is a court of competent jurisdiction.

contenu d'un signal d'abonnement ou d'une alimentation réseau;

b) soit est autorisé, par le distributeur légitime de celui-ci, à le communiquer au public;

c) soit est titulaire d'une licence attribuée, au titre de la *Loi sur la radiodiffusion*, par le Conseil de la radiodiffusion et des télécommunications canadiennes et l'autorisant à exploiter une entreprise de radiodiffusion;

d) soit encore élabore un système ou une technique ou fabrique un équipement destinés à l'encodage de signaux d'abonnement ou d'alimentations réseau, les fournit à un distributeur légitime, ou fabrique, vend ou fournit des décodeurs permettant à des personnes autorisées à cet effet de décoder de tels signaux ou alimentations.

Cette personne est admise à exercer tous recours, notamment par voie de dommages-intérêts, d'injonction ou de reddition de compte, selon ce que le tribunal estime indiqué.

Règles applicables

(2) Le plafond des dommages-intérêts accordés, au terme d'un tel recours, à l'encontre d'une personne physique n'ayant pas contrevenu aux alinéas 9(1)e) ou 10(1)b) et n'ayant pas posé les actes en cause dans un but lucratif est de mille dollars; les frais des parties sont laissés à la discrétion du tribunal.

Preuve de procédures antérieures

(3) Dans tout recours visé au paragraphe (1) et intenté contre une personne, les procès-verbaux relatifs aux procédures engagées devant tout tribunal qui a déclaré celle-ci coupable d'une infraction aux alinéas 9(1)c), d) ou e) ou 10(1)b) constituent, sauf preuve contraire, la preuve que cette personne a eu un comportement allant à l'encontre de ces dispositions; toute preuve fournie lors de ces procédures quant à l'effet de l'infraction sur la personne qui intente le recours constitue une preuve à cet égard.

Cour fédérale

(4) La Cour fédérale est, pour l'application du paragraphe (1), un tribunal compétent.

Limitation

(5) An action under subsection (1) may be commenced within, but not after, three years after the conduct giving rise to the action was engaged in.

Copyright Act

(6) Nothing in this section affects any right or remedy that an aggrieved person may have under the *Copyright Act*.

1991, c. 11, s. 85.

Right of civil action

19 (1) Any person who has made or received a radio-based telephone communication that the person believes on reasonable grounds will be or has been divulged or will be used or has been made use of contrary to subsection 9(1.1) may, in any court of competent jurisdiction, bring an action to prevent the divulgence or use of or to recover damages from the person who will divulge or has divulged or who will make use of or has made use of the radio-based telephone communication, and in any such action the court may grant any remedy, by way of injunction, damages, accounting or otherwise, as the court considers appropriate.

Evidence of prior proceedings

(2) In an action under subsection (1) against a person, the record of proceedings in any court in which that person was convicted of an offence under subsection 9(1.1) is, in the absence of any evidence to the contrary, proof that the person against whom the action is brought divulged or made use of the radio-based telephone communication and any evidence given in those proceedings as to the effect of the divulgence or use on the person bringing the action is evidence thereof in the action.

Jurisdiction of Federal Court

(3) For the purposes of an action under subsection (1), the Federal Court is a court of competent jurisdiction.

Limitation

(4) An action under subsection (1) may be commenced within, but not after, three years after the conduct giving rise to the action was engaged in.

Remedies not affected

(5) Nothing in this section affects any other right or remedy that an aggrieved person might otherwise have.

1993, c. 40, s. 26.

Prescription

(5) Les recours visés au paragraphe (1) se prescrivent dans les trois ans suivant la date de l'infraction en cause.

Loi sur le droit d'auteur

(6) Le présent article ne porte pas atteinte aux droits ou aux recours prévus par la *Loi sur le droit d'auteur*.

1991, ch. 11, art. 85.

Recours civil

19 (1) Quiconque a fait ou reçu une communication radiotéléphonique et a des motifs raisonnables de croire que cette communication a été ou sera communiquée ou utilisée en contravention au paragraphe 9(1.1) peut former, devant tout tribunal compétent, un recours civil pour empêcher une telle utilisation ou une telle communication, ou pour recouvrer des dommages du contrevenant. Cette personne est admise à exercer tous recours, notamment par voie de dommages-intérêts, d'injonction ou de reddition de compte, selon ce que le tribunal estime indiqué.

Preuve de procédures antérieures

(2) Dans tout recours visé au paragraphe (1) et intenté contre une personne, les procès-verbaux relatifs aux procédures engagées devant tout tribunal qui a déclaré celle-ci coupable d'une infraction au paragraphe 9(1.1) constituent, sauf preuve contraire, la preuve que cette personne a communiqué ou utilisé la communication radiotéléphonique; toute preuve fournie lors de ces procédures quant à l'effet de l'infraction sur la personne qui intente le recours constitue une preuve à cet égard.

Cour fédérale

(3) La Cour fédérale est, pour l'application du paragraphe (1), un tribunal compétent.

Prescription

(4) Les recours visés au paragraphe (1) se prescrivent dans les trois ans suivant la date de l'infraction en cause.

Autres recours

(5) Le présent article ne porte pas atteinte à tout autre droit ou recours que pourrait avoir la personne lésée.

1993, ch. 40, art. 26.

RELATED PROVISIONS

— 1989, c. 17, s. 16

Radio licences, etc.

16 Radio licences, technical construction and operating certificates and radio operator certificates that were in force under the *Radio Act* immediately before this Act comes into force continue in force thereafter as if they had been issued in accordance with the *Radio Act* as amended by this Act.

— 1995, c. 1, s. 62(4)

Idem

62 (4) Every reference to the Minister of Communications in any order, regulation or other instrument made under the *Radiocommunication Act* or the *Telecommunications Act* shall, unless the context otherwise requires, be read as a reference to the Minister of Industry.

DISPOSITIONS CONNEXES

— 1989, ch. 17, art. 16

Licences radio et certificats

16 Les licences radio, les certificats techniques de construction et de fonctionnement et les certificats d'opérateur radio en vigueur avant l'entrée en vigueur de la présente loi le demeurent comme si leur prise avait été autorisée par la *Loi sur la radio* dans sa version modifiée par la présente loi.

— 1995, ch. 1, par. 62(4)

Idem

62 (4) Dans les textes d'application de la *Loi sur la radiocommunication* ou de la *Loi sur les télécommunications*, la mention du ministre des Communications vaut mention, sauf indication contraire du contexte, du ministre de l'Industrie.

AMENDMENTS NOT IN FORCE

— 1992, c. 47, s. 84 (Sch., s. 14)

1989, c. 17, s. 6

14 Section 12 is repealed.

— 2002, c. 7, s. 233

1994, c. 43, s. 92

233 Subsections 7(4) and (5) of the *Radiocommunication Act* are replaced by the following:

Exception

(4) Notwithstanding subsection (3), any dispute as to the compensation to be paid for the taking of possession of a radio station on settlement land as defined in section 2 of the *Yukon First Nations Land Claims Settlement Act*, land identified as such in a self-government agreement as defined in the *Yukon First Nations Self-Government Act* or on Tetlit Gwich'in Yukon land may be heard and determined only by the body established under the laws of the Legislature of Yukon having jurisdiction with respect to surface rights and in accordance with those laws.

Settlement land

(5) If the Yukon first nation concerned does not consent to it, no interest in settlement land as defined in section 2 of the *Yukon First Nations Land Claims Settlement Act* or identified as such in a self-government agreement as defined in the *Yukon First Nations Self-Government Act* may be taken possession of under this section without the consent of the Governor in Council.

MODIFICATIONS NON EN VIGUEUR

— 1992, ch. 47, art. 84 (ann., art. 14)

1989, ch. 17, art. 6

14 L'article 12 est abrogé.

— 2002, ch. 7, art. 233

1994, ch. 43, art. 92

233 Les paragraphes 7(4) et (5) de la *Loi sur la radiocommunication* sont remplacés par ce qui suit :

Exception

(4) Par dérogation au paragraphe (3), l'organisme établi par les lois de la Législature du Yukon et compétent en matière de droits de surface est seul à connaître, en conformité avec ces lois, de tout désaccord sur le montant de l'indemnité payable par suite de la prise de possession, par Sa Majesté, d'une station située sur une terre désignée au sens de l'article 2 de la *Loi sur le règlement des revendications territoriales des premières nations du Yukon*, sur une terre tenue pour telle aux termes d'un accord au sens de la *Loi sur l'autonomie gouvernementale des premières nations du Yukon* ou sur des terres gwich'in tetlit du Yukon.

Terre désignée

(5) Sauf avec le consentement de la première nation touchée, nulle compagnie ne peut, sans l'agrément du gouverneur en conseil, s'approprier au titre du présent article un droit sur une terre désignée au sens de l'article 2 de la *Loi sur le règlement des revendications territoriales des premières nations du Yukon* ou sur une terre tenue pour telle aux termes d'un accord au sens de la *Loi sur l'autonomie gouvernementale des premières nations du Yukon*.

TAB 5

CANADA

CONSOLIDATION

Radiocommunication Regulations

SOR/96-484

CODIFICATION

Règlement sur la radiocommunication

DORS/96-484

Current to September 11, 2022

Last amended on April 1, 2021

À jour au 11 septembre 2022

Dernière modification le 1 avril 2021

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OFFICIAL STATUS OF CONSOLIDATIONS

Subsections 31(1) and (3) of the *Legislation Revision and Consolidation Act*, in force on June 1, 2009, provide as follows:

Published consolidation is evidence

31 (1) Every copy of a consolidated statute or consolidated regulation published by the Minister under this Act in either print or electronic form is evidence of that statute or regulation and of its contents and every copy purporting to be published by the Minister is deemed to be so published, unless the contrary is shown.

...

Inconsistencies in regulations

(3) In the event of an inconsistency between a consolidated regulation published by the Minister under this Act and the original regulation or a subsequent amendment as registered by the Clerk of the Privy Council under the *Statutory Instruments Act*, the original regulation or amendment prevails to the extent of the inconsistency.

LAYOUT

The notes that appeared in the left or right margins are now in boldface text directly above the provisions to which they relate. They form no part of the enactment, but are inserted for convenience of reference only.

NOTE

This consolidation is current to September 11, 2022. The last amendments came into force on April 1, 2021. Any amendments that were not in force as of September 11, 2022 are set out at the end of this document under the heading “Amendments Not in Force”.

CARACTÈRE OFFICIEL DES CODIFICATIONS

Les paragraphes 31(1) et (3) de la *Loi sur la révision et la codification des textes législatifs*, en vigueur le 1er juin 2009, prévoient ce qui suit :

Codifications comme élément de preuve

31 (1) Tout exemplaire d'une loi codifiée ou d'un règlement codifié, publié par le ministre en vertu de la présente loi sur support papier ou sur support électronique, fait foi de cette loi ou de ce règlement et de son contenu. Tout exemplaire donné comme publié par le ministre est réputé avoir été ainsi publié, sauf preuve contraire.

[...]

Incompatibilité — règlements

(3) Les dispositions du règlement d'origine avec ses modifications subséquentes enregistrées par le greffier du Conseil privé en vertu de la *Loi sur les textes réglementaires* l'emportent sur les dispositions incompatibles du règlement codifié publié par le ministre en vertu de la présente loi.

MISE EN PAGE

Les notes apparaissant auparavant dans les marges de droite ou de gauche se retrouvent maintenant en caractères gras juste au-dessus de la disposition à laquelle elles se rattachent. Elles ne font pas partie du texte, n’y figurant qu’à titre de repère ou d’information.

NOTE

Cette codification est à jour au 11 septembre 2022. Les dernières modifications sont entrées en vigueur le 1 avril 2021. Toutes modifications qui n'étaient pas en vigueur au 11 septembre 2022 sont énoncées à la fin de ce document sous le titre « Modifications non en vigueur ».

TABLE OF PROVISIONS

Radiocommunication Regulations

TABLE ANALYTIQUE

Règlement sur la radiocommunication

Registration
SOR/96-484 November 5, 1996

RADIOCOMMUNICATION ACT
FINANCIAL ADMINISTRATION ACT

Radiocommunication Regulations

P.C. 1996-1679 November 5, 1996

His Excellency the Governor General in Council, on the recommendation of the Minister of Industry and of the Treasury Board, pursuant to section 6[a] of the *Radiocommunication Act*[b] and section 19.1[c] of the *Financial Administration Act*, is pleased hereby to repeal the *General Radio Regulations*, Part I, C.R.C., c. 1371, the *General Radio Regulations*, Part II, C.R.C., c. 1372, the *Interference-causing Equipment Regulations*, made by Order in Council P.C. 1993-408 of March 9, 1993[d], and the *Radio Operators' Certificate Regulations*, made on March 9, 1978[e], and to make the annexed *Regulations respecting radiocommunication, radio authorizations, exemptions from authorizations and the operation of radio apparatus, radio-sensitive equipment and interference-causing equipment* in substitution therefor, effective on the date of publication in the *Canada Gazette* Part II.

Enregistrement
DORS/96-484 Le 5 novembre 1996

LOI SUR LA RADIOCOMMUNICATION
LOI SUR LA GESTION DES FINANCES PUBLIQUES

Règlement sur la radiocommunication

C.P. 1996-1679 Le 5 novembre 1996

Sur recommandation du ministre de l'Industrie et du Conseil du Trésor, et en vertu de l'article 6[a] de la *Loi sur la radiocommunication*[b] et de l'article 19.1[c] de la *Loi sur la gestion des finances publiques*, il plaît à Son Excellence le Gouverneur général en conseil d'abroger le *Règlement général sur la radio*, Partie I, C.R.C., ch. 1371, le *Règlement général sur la radio*, Partie II, C.R.C., ch. 1372, le *Règlement sur le matériel brouilleur*, pris par le décret C.P. 1993-408 du 9 mars 1993[d], et le *Règlement sur les certificats d'opérateur radio*, pris le 9 mars 1978[e], et de prendre en remplacement le *Règlement concernant la radiocommunication, les autorisations de radiocommunication, les exemptions d'autorisation et l'utilisation des appareils radio, du matériel radiosensible et du matériel brouilleur*, ci-après, lequel entre en vigueur à la date de sa publication dans la *Gazette du Canada* Partie II.

[a] S.C. 1989, c. 17, s. 4
[b] S.C. 1989, c. 17, s. 2
[c] S.C. 1991, c. 24, s. 6
[d] SOR/93-113, Canada Gazette, Part II, 1993, p. 1162
[e] SOR/78-244, Canada Gazette, Part II, 1978, p. 1049

[a] L.C. 1989, ch. 17, art. 4
[b] L.C. 1989, ch. 17, art. 2
[c] L.C. 1991, ch. 24, art. 6
[d] DORS/93-113, Gazette du Canada Partie II, 1993, p. 1162
[e] DORS/78-244, Gazette du Canada Partie II, 1978, p. 1049

1 [Repealed, SOR/2021-40, s. 2]

Interpretation

2 In these Regulations,

Act means the *Radiocommunication Act*; (*loi*)

aeronautical service means a radiocommunication service that provides for the safety and navigation and other operations of aircraft, and that may also include the exchange of air-to-ground messages on behalf of the public; (*service aéronautique*)

amateur radio service means a radiocommunication service in which radio apparatus are used for the purpose of self-training, intercommunication or technical investigation by individuals who are interested in radio technique solely with a personal aim and without pecuniary interest; (*service de radioamateur*)

applicable standard [Repealed, SOR/2001-533, s. 1]

developmental service means a radiocommunication service that provides for research and development, experimentation or demonstration of radio apparatus, or the assessment of the marketability of radio apparatus, new technology or telecommunication services; (*service de développement*)

equipment means radio apparatus, interference-causing equipment and radio-sensitive equipment; (*matériel*)

fixed point-to-point service means a radiocommunication service that provides for communications on radio frequencies above 30 MHz between two fixed stations that are each authorized to operate at a specific point, other than fixed stations that also operate within the land mobile service on the same radio frequency as the one assigned to the land mobile service; (*service point à point fixe*)

fixed service means a radiocommunication service that provides for communications between fixed stations or between fixed stations and space stations; (*service fixe*)

fixed station means a radio station authorized to operate at a fixed point; (*station fixe*)

interconnected radio-based transmission facility means any radio apparatus that is used for the

1 [Abrogé, DORS/2021-40, art. 2]

Définitions

2 Les définitions qui suivent s'appliquent au présent règlement.

CAT Certificat d'approbation technique. (*TAC*)

coentreprise Association de personnes dans le cas où leurs rapports ne constituent pas, en vertu des lois canadiennes, une personne morale, une société de personnes ou une fiducie et si les droits de participation indivise à la propriété des actifs du fournisseur de services radio ou de l'usager radio ou des intérêts avec droit de vote du fournisseur de services radio ou de l'usager radio appartiennent ou appartiendront à celles-ci. (*joint venture*)

fabricant Selon le cas :

a) la personne désignée comme le fabricant dans la norme applicable;

b) lorsqu'il n'existe pas de norme applicable ou que le fabricant n'est désigné dans aucune norme applicable, la personne, autre que celle dont l'unique fonction est d'installer le matériel, qui :

(i) dans le cas d'un appareil radio ou de matériel brouilleur, effectue l'assemblage final ou la dernière modification du modèle du matériel pouvant influer sur sa capacité de brouiller la radiocommunication,

(ii) dans le cas de matériel radiosensible, effectue l'assemblage final ou la dernière modification du modèle du matériel pouvant influer sur sa sensibilité à l'énergie électromagnétique. (*manufacturer*)

fournisseur de services radio Personne qui fait fonctionner un appareil radio au moyen duquel elle ou une autre personne fournit des services de radiocommunication moyennant contrepartie. (*radiocommunication service provider*)

installation de transmission radio d'interconnexion Appareil radio utilisé pour la transmission d'information à tout point d'un réseau public commuté ou pour la réception d'information en provenance de ce point. (*interconnected radio-based transmission facility*) transmission or reception of intelligence to or from anywhere on a public switched network; (*installation de transmission radio d'interconnexion*)

intersatellite service means a radiocommunication service that provides for communications between space stations; (*service intersatellite*)

joint venture means an association of two or more persons, if the relationship among those associated persons does not, under the laws in Canada, constitute a corporation, a partnership or a trust, and if all the undivided ownership interests in the assets of the radiocommunication user and radiocommunication service provider or in the voting interests of the radiocommunication user and radiocommunication service provider are or will be owned by all the persons that are so associated; (*coentreprise*)

land mobile service means a radiocommunication service that provides for communications between mobile stations and

(a) fixed stations,

(b) space stations, or

(c) other mobile stations; (*service mobile terrestre*)

manufacturer means

(a) the person specified as the manufacturer in the applicable standard, or

(b) where no applicable standard exists or where the manufacturer is not specified in any applicable standard, the person, other than a person whose function is solely to install equipment, who

(i) with respect to radio apparatus and interference-causing equipment, carries out the last assembly of or last modification to the model of equipment which could affect its capacity to cause interference to radiocommunication, or

(ii) with respect to radio-sensitive equipment, carries out the last assembly of or last modification to the model of equipment which could affect its sensitivity to electromagnetic energy; (*fabricant*)

maritime service means a radiocommunication service that provides for the safety and navigation and other operations of ships or vessels, and that may also include the exchange of ship-to-shore messages on behalf of the public; (*service maritime*)

Minister [Repealed, SOR/2021-40, s. 3]

licence radio renouvelable Licence radio qui est délivrée pour une période d'un an ou moins, qui expire le 31 mars et qui peut être renouvelée pour une période d'un an. (*renewable radio licence*)

licence radio temporaire Licence radio qui est délivrée pour une période de onze mois ou moins et qui ne peut être renouvelée. (*temporary radio licence*)

Loi La *Loi sur la radiocommunication*. (*Act*)

matériel Appareil radio, matériel brouilleur ou matériel radiosensible. (*equipment*)

ministre [Abrogée, DORS/2021-40, art. 3]

modèle Matériel désigné par une marque, une appellation commerciale, un symbole ou un logo uniques et un code d'identification composé de lettres, de chiffres ou d'une combinaison des deux, lesquels figurent en permanence sur le matériel. (*model*)

norme applicable [Abrogée, DORS/2001-533, art. 1]

personne Vise notamment une personne morale, une société de personnes, une fiducie et une coentreprise. (*person*)

service aéronautique Service de radiocommunication qui sert à la sécurité et à la navigation et autres activités des aéronefs, et qui peut servir également à l'échange de messages air-sol pour le compte du public. (*aeronautical service*)

service de développement Service de radiocommunication qui sert à la recherche et au développement, à l'expérimentation ou à la démonstration d'appareils radio, ou à l'évaluation des possibilités de commercialisation d'appareils radio, de nouvelles technologies ou de services de télécommunication. (*developmental service*)

service de radioamateur Service de radiocommunication qui a pour objet l'utilisation d'appareils radio pour la formation personnelle, l'intercommunication ou les recherches techniques par des individus qui s'intéressent à la radiotechnique uniquement à des fins personnelles et sans but lucratif. (*amateur radio service*)

service de radiorepérage Service de radiocommunication qui sert à la détermination de la position, de la vitesse ou d'autres caractéristiques d'un objet ou d'un phénomène physique, ou à l'obtention de renseignements relatifs à ces paramètres, grâce aux propriétés de propagation des ondes radio. (*radiodetermination service*)

mobile station means a radio station intended to be used while in motion and during stops; (*station mobile*)

model means equipment identified by, and permanently marked with, a unique brand, trade name, symbol or logo and an identification code, comprised of letters, numbers or a combination thereof; (*modèle*)

person includes a corporation, partnership, trust and joint venture; (*personne*)

public information service means a radiocommunication service that provides for communications in which the transmissions are intended for the public, but does not include transmissions by a broadcasting undertaking; (*service d'information publique*)

radiocommunication carrier [Repealed, SOR/2014-34, s. 1]

radiocommunication service provider means a person who operates radio apparatus used by that person or another person to provide radiocommunication services for compensation; (*fournisseur de services radio*)

radiocommunication user means a person who operates radio apparatus for personal or government use or for a business other than the business of a radiocommunication service provider; (*usager radio*)

radiodetermination service means a radiocommunication service that provides for the determination of the position, velocity or other characteristics of an object or physical phenomenon, or for the obtaining of information relating to these parameters, by means of the propagation properties of radio waves; (*service de radiorepérage*)

renewable radio licence means a radio licence that is issued for a period of one year or less, that expires on March 31 and that can be renewed for a period of one year; (*licence radio renouvelable*)

space station means a radio station where radio apparatus that is used for any radiocommunication service is installed in a place located outside the major portion of the earth's atmosphere or is intended to travel beyond the major portion of the earth's atmosphere; (*station spatiale*)

TAC means a technical acceptance certificate; (*CAT*)

temporary radio licence means a radio licence that is issued for a period of 11 months or less and that cannot be renewed. (*licence radio temporaire*)

SOR/2001-533, s. 1; SOR/2014-34, s. 1; SOR/2021-40, s. 3.

service d'information publique Service de radiocommunication qui sert à l'émission de communications destinées au public. Sont exclues de la présente définition les émissions d'une entreprise de radiodiffusion. (*public information service*)

service fixe Service de radiocommunication qui sert à assurer les communications entre des stations fixes ou entre des stations fixes et des stations spatiales. (*fixed service*)

service intersatellite Service de radiocommunication qui sert à assurer les communications entre des stations spatiales. (*intersatellite service*)

service maritime Service de radiocommunication qui sert à la sécurité et à la navigation et autres activités des navires et bâtiments, et qui peut servir également à l'échange de messages navire-terre pour le compte du public. (*maritime service*)

service mobile terrestre Service de radiocommunication qui sert à assurer les communications entre des stations mobiles et :

a) soit des stations fixes;

b) soit des stations spatiales;

c) soit d'autres stations mobiles. (*land mobile service*)

service point à point fixe Service de radiocommunication qui sert à assurer les communications, sur des radiofréquences supérieures à 30 MHz, entre deux stations fixes qui sont chacune autorisée à être exploitée à un endroit précis, à l'exception de stations également utilisées pour le service mobile terrestre sur la même radiofréquence que celle assignée au service mobile terrestre. (*fixed point-to-point service*)

station fixe Station de radiocommunication qui est autorisée à être exploitée à un endroit fixe. (*fixed station*)

station mobile Station de radiocommunication qui est utilisée pendant qu'elle est en mouvement ou lors d'arrêts. (*mobile station*)

station spatiale Station de radiocommunication dont l'appareil radio utilisé pour tout service de radiocommunication est installé au-delà de la partie principale de l'atmosphère terrestre ou est destiné à se déplacer au-delà de la partie principale de l'atmosphère terrestre. (*space station*)

transporteur de radiocommunications [Abrogée, DORS/2014-34, art. 1]

usager radio La personne qui fait fonctionner un appareil radio à des fins personnelles ou gouvernementales, ou pour une entreprise autre que celle d'un fournisseur de services radio. (*radiocommunication user*)

DORS/2001-533, art. 1; DORS/2014-34, art. 1; DORS/2021-40, art. 3.

Applicable Standards

2.1 The applicable standards for equipment or any class of equipment are those established by the Minister pursuant to paragraph 5(1)(d) of the Act and that are set out in the *Category I Equipment Standards List*, as amended from time to time, and the *Category II Equipment Standards List*, as amended from time to time, both published by the Department of Industry.

SOR/2001-533, s. 2.

Normes applicables

2.1 Les normes applicables au matériel ou à toute catégorie de celui-ci sont les normes que le ministre fixe aux termes de l'alinéa 5(1)d) de la Loi et qui sont publiées par le ministère de l'Industrie dans la *Liste des normes applicables au matériel de catégorie I* et dans la *Liste des normes applicables au matériel de catégorie II*, avec leurs modifications successives.

DORS/2001-533, art. 2.

PART I

Radio Licences

Radiocommunication Services and Stations

3 It is a term of a radio licence that the holder of the licence may

(a) install, operate or possess radio apparatus to perform any of the following services, as authorized by the radio licence, namely,

(i) aeronautical service,

(ii) amateur radio service,

(iii) public information service,

(iv) developmental service,

(v) fixed service,

(vi) intersatellite service,

(vii) land mobile service,

(viii) maritime service,

(ix) radiodetermination service, and

(x) fixed point-to-point service; and

PARTIE I

Licences radio

Services et stations de radiocommunication

3 La licence radio prévoit que le titulaire peut :

a) installer, faire fonctionner ou posséder un appareil radio en vue de fournir ceux des services suivants qu'autorise la licence :

(i) service aéronautique,

(ii) service de radioamateur,

(iii) service d'information publique,

(iv) service de développement,

(v) service fixe,

(vi) service intersatellite,

(vii) service mobile terrestre,

(viii) service maritime,

(ix) service de radiorepérage,

(x) service point à point fixe;

(b) install, operate or possess radio apparatus at a fixed station, mobile station or space station as authorized by the radio licence.

SOR/2021-40, s. 4.

Restriction Relating to Holders of Radio Licences

4 It is a term of a radio licence that the holder of the radio licence shall restrict the activities of the station to those radiocommunication services referred to in paragraph 3(a) that are specified in the licence.

5 It is a term of a radio licence that the holder of the radio licence who is a radiocommunication service provider shall provide its radiocommunication services without unjust discrimination.

Restrictions Relating to the Aeronautical Service

6 Use of radio apparatus in the aeronautical service is restricted to communications relating to

(a) the safety and navigation of aircraft;

(b) the general operation of aircraft; and

(c) the exchange of messages on behalf of the public.

SOR/2011-47, s. 1.

Restrictions Relating to the Developmental Service

7 Use of radio apparatus licensed in the developmental service is restricted to experiments, tests, research or demonstrations being carried out in relation to that service.

Restrictions Relating to the Maritime Service

8 Use of radio apparatus in the maritime service is restricted to communications relating to

(a) the safety and navigation of ships or vessels;

(b) the general operation of ships or vessels; and

(c) the exchange of messages on behalf of the public.

SOR/2011-47, s. 2.

b) installer, faire fonctionner ou posséder un appareil radio dans une station fixe, une station mobile ou une station spatiale, selon ce qu’autorise la licence.

DORS/2021-40, art. 4.

Restrictions applicables au titulaire de la licence radio

4 La licence radio prévoit que le titulaire doit limiter les activités de la station aux services de radiocommunication, visés à l’alinéa 3a), qui sont indiqués sur la licence.

5 La licence radio prévoit que le titulaire qui est fournisseur de services radio doit fournir des services de radiocommunication sans distinction injuste.

Restrictions concernant le service aéronautique

6 L’utilisation d’un appareil radio autorisé aux fins du service aéronautique se limite aux communications relatives à ce qui suit :

a) la sécurité et la navigation des aéronefs;

b) l’ensemble des activités des aéronefs;

c) l’échange de messages pour le compte du public.

DORS/2011-47, art. 1.

Restrictions concernant le service de développement

7 L’utilisation d’un appareil radio autorisé par licence radio aux fins du service de développement se limite aux expériences, aux essais, à la recherche ou aux démonstrations qui en font partie.

Restrictions concernant le service maritime

8 L’utilisation d’un appareil radio autorisé aux fins du service maritime se limite aux communications relatives à ce qui suit :

a) la sécurité et la navigation des navires et bâtiments;

b) l’ensemble des activités des navires et bâtiments;

c) l’échange de messages pour le compte du public.

DORS/2011-47, art. 2.

Eligibility

9 (1) The following persons are eligible to be issued radio licences or spectrum licences as radiocommunication users or radiocommunication service providers in all services except the amateur radio service:

(a) an individual who is

(i) a citizen within the meaning of subsection 2(1) of the *Citizenship Act*,

(ii) a permanent resident within the meaning of subsection 2(1) of the *Immigration Act*, or

(iii) a non-resident who has been issued an employment authorization under the *Immigration and Refugee Protection Act*;

(b) a corporation that is incorporated or continued under the laws of Canada or a province;

(c) a partnership, joint venture or trust if each partner, co-venturer or trustee is eligible to be issued a radio licence under this subsection;

(d) a Canadian government, whether federal, provincial or local, or an agency thereof;

(e) the Government of a country other than Canada, which is a signatory to the *Vienna Convention on Diplomatic Relations*, done at Vienna, April 18, 1961;

(f) any person who is the registered owner of an aircraft that is registered in Canada, for the establishment and operation of a station on board the aircraft;

(g) any person who is the registered or licensed owner of a ship or vessel that is registered under the *Canada Shipping Act* or licensed under the *Coasting Trade Act*, for the establishment and operation of a station on board the ship or vessel; and

(h) any person who is a resident of a country other than Canada, who

(i) seeks to establish and operate a radio station designed for interconnection with a public switched network, or

(ii) requires a radio licence for radio apparatus used for a special event of a limited duration.

Admissibilité

9 (1) Pour tous les services sauf le service de radioamateur, sont admissibles à l’attribution d’une licence radio ou d’une licence de spectre à titre d’usager radio ou de fournisseur de services radio :

a) la personne physique qui est :

(i) soit un citoyen au sens du paragraphe 2(1) de la *Loi sur la citoyenneté*,

(ii) soit un résident permanent au sens du paragraphe 2(1) de la *Loi sur l’immigration*,

(iii) soit un non-résident qui a obtenu une autorisation d’emploi sous le régime de la *Loi sur l’immigration et la protection des réfugiés*;

b) la personne morale qui est constituée ou prorogée sous le régime des lois fédérales ou provinciales;

c) la société de personnes, la coentreprise ou la fiducie dont chaque associé, coentrepreneur ou fiduciaire est admissible à l’attribution d’une licence radio en vertu du présent paragraphe;

d) le gouvernement fédéral, un gouvernement provincial ou une administration locale au Canada, ou un organisme de l’un d’eux;

e) le gouvernement d’un pays étranger qui est signataire de la *Convention de Vienne sur les relations diplomatiques*, conclue à Vienne le 18 avril 1961;

f) la personne qui est le propriétaire enregistré d’un aéronef immatriculé au Canada, en vue de l’établissement et de l’exploitation d’une station à bord de l’aéronef;

g) la personne qui est le propriétaire enregistré — ou titulaire d’un permis — d’un navire ou d’un bâtiment immatriculé aux termes de la *Loi sur la marine marchande du Canada* ou faisant l’objet d’une licence délivrée en vertu de la *Loi sur le cabotage*, en vue de l’établissement et de l’exploitation d’une station à bord du navire ou du bâtiment;

h) la personne qui est résidente d’un pays étranger et qui :

(i) ou bien veut établir et exploiter une station radio conçue pour l’interconnexion avec un réseau commuté public,

(ii) ou bien veut obtenir une licence radio pour un appareil radio qui servira à un événement spécial d'une durée limitée.

(2) [Repealed, SOR/2000-78, s. 1]

SOR/2000-78, s. 1; 2001, c. 27, s. 273; SOR/2014-34, s. 2.

(2) [Abrogé, DORS/2000-78, art. 1]

DORS/2000-78, art. 1; 2001, ch. 27, art. 273; DORS/2014-34, art. 2.

10 [Repealed, SOR/2014-34, s. 3]

10 [Abrogé, DORS/2014-34, art. 3]

10.1 [Repealed, SOR/2014-34, s. 3]

10.1 [Abrogé, DORS/2014-34, art. 3]

Non-Assignability of Radio Licences

11 It is a term of a radio licence that the licence not be transferred or assigned without the authorization of the Minister.

Incessibilité de la licence radio

11 La licence radio prévoit qu'elle ne peut être ni transférée ni cédée sans l'autorisation du ministre.

Stations Licensed or Exempted in Another Country

12 Radio apparatus used in a mobile station that is licensed or exempted by the responsible administration of another country is exempt from the application of subsection 4(1) of the Act if the mobile station is used for communications with stations licensed or exempted in Canada or that other country and if

(a) the operator is a citizen of that other country; and

(b) a reciprocal agreement that allows similar privileges to Canadians exists between that other country and Canada.

Stations autorisées par licence ou exemptées à l'étranger

12 L'appareil radio d'une station mobile qui est autorisée ou exemptée par l'administration compétente d'un pays étranger est soustrait à l'application du paragraphe 4(1) de la Loi si la station mobile est utilisée pour communiquer avec des stations autorisées par licence radio ou exemptées de licence au Canada ou dans le pays étranger, et si les conditions suivantes sont réunies :

a) l'opérateur est un citoyen du pays étranger;

b) un accord de réciprocité accordant les mêmes privilèges aux Canadiens existe entre ce pays et le Canada.

Radio Licences of Radiocommunication Service Providers

13 (1) It is a term of a radio licence of a radiocommunication service provider that a subscriber to the services or a lessee of radio apparatus of the radiocommunication service provider may install, operate or possess radio apparatus to communicate with other radio apparatus to which that licence applies.

(2) Use of the services or radio apparatus of a radiocommunication service provider is restricted to communications with radio apparatus to which the radio licence referred to in subsection (1) applies.

14 (1) Every radiocommunication service provider shall provide to each of its subscribers and lessees of its radio apparatus a copy of the terms and conditions of its radio

Licence radio du fournisseur de services radio

13 (1) La licence radio du fournisseur de services radio prévoit que l'abonné des services ou le preneur à bail d'appareils radio du fournisseur peut installer, faire fonctionner ou posséder un appareil radio pour communiquer avec tout autre appareil radio visé par cette licence.

(2) L'utilisation des services ou des appareils radio du fournisseur de services radio se limite aux communications avec les appareils radio visés par la licence radio de celui-ci.

14 (1) Le fournisseur de services radio fournit à chaque abonné de ses services et à chaque preneur à bail de ses licence that are applicable to those subscribers or lessees, as the case may be.

(2) [Repealed, SOR/2011-47, s. 3]

SOR/2011-47, s. 3.

Exemption

15 Radio apparatus that is set out in and meets a standard set out in the *Licence-exempt Radio Apparatus Standards List,* April 2020 is exempt from the application of subsection 4(1) of the Act in respect of a radio licence.

SOR/2001-533, s. 3; SOR/2011-47, s. 4; SOR/2014-34, s. 4; SOR/2020-278, s. 1.

Exemption of Radio Apparatus on Board an Aircraft

15.1 (1) This section applies in respect of an aircraft that is

(a) registered or licensed under an Act of Parliament; or

(b) owned by, or under the direction or control of, Her Majesty in right of Canada or a province.

(2) A radio apparatus that is operated on board an aircraft in the performance of the aeronautical service or the radiodetermination service is exempt from subsection 4(1) of the Act, in respect of a radio licence, if

(a) the operation of the radio apparatus occurs when

(i) the aircraft is within Canada,

(ii) the aircraft is outside Canada and the territory of another country, or

(iii) the aircraft is in the territory of another country with which Canada has entered into a reciprocal agreement that confers similar privileges on Canadians; and

(b) the operation of the radio apparatus is in accordance with the technical requirements for mobile stations operating in the aeronautical service that are specified in section 34.1.

(c) [Repealed, SOR/2011-47, s. 5]

SOR/99-107, s. 1; SOR/2011-47, s. 5.

appareils radio une copie des conditions de la licence radio auxquelles ils sont assujettis.

(2) [Abrogé, DORS/2011-47, art. 3]

DORS/2011-47, art. 3.

Exemption

15 Tout appareil radio visé par une norme figurant dans la *Liste des normes applicables au matériel radio exempté de licence*, avril 2020, et qui satisfait à cette norme est soustrait à l'application du paragraphe 4(1) de la Loi en ce qui concerne la licence radio.

DORS/2001-533, art. 3; DORS/2011-47, art. 4; DORS/2014-34, art. 4; DORS/2020-278, art. 1.

Exemption des appareils radio à bord des aéronefs

15.1 (1) Le présent article s'applique à tout aéronef qui, selon le cas, :

a) est immatriculé ou fait l'objet d'un permis aux termes d'une loi fédérale;

b) appartient à Sa Majesté du chef du Canada ou d'une province, ou est placé sous sa responsabilité.

(2) L'appareil radio utilisé à bord d'un aéronef aux fins du service aéronautique ou du service de radiorepérage est soustrait à l'application du paragraphe 4(1) de la Loi, en ce qui concerne la licence radio, lorsque les conditions suivantes sont réunies :

a) il est utilisé lorsque l'aéronef est :

(i) au Canada,

(ii) à l'extérieur du Canada et du territoire de tout autre pays,

(iii) dans le territoire d'un autre pays qui a conclu avec le Canada un accord de réciprocité accordant les mêmes privilèges aux Canadiens;

b) son utilisation est conforme aux exigences techniques applicables aux stations mobiles fonctionnant dans le cadre du service aéronautique et visées à l'article 34.1.

c) [Abrogé, DORS/2011-47, art. 5]

DORS/99-107, art. 1; DORS/2011-47, art. 5.

Exemption of Radio Apparatus on Board a Ship or Vessel

15.2 (1) This section applies in respect of a ship or vessel that is

(a) registered or licensed under an Act of Parliament; or

(b) owned by, or under the direction or control of, Her Majesty in right of Canada or a province.

(2) A radio apparatus that is operated on board a ship or vessel in the performance of the maritime service or the radiodetermination service is exempt from subsection 4(1) of the Act, in respect of a radio licence, if

(a) the operation of the radio apparatus occurs when

(i) the ship or vessel is within Canada,

(ii) the ship or vessel is outside Canada and the territory of another country, or

(iii) the ship or vessel is in the territory of another country with which Canada has entered into a reciprocal agreement that confers similar privileges on Canadians; and

(b) the operation of the radio apparatus is in accordance with the technical requirements for mobile stations operating in the maritime service specified in section 34.2.

(c) [Repealed, SOR/2011-47, s. 6]

SOR/99-107, s. 1; SOR/2011-47, s. 6.

Exemption des appareils radio à bord des navires ou bâtiments

15.2 (1) Le présent article s'applique à tout navire ou bâtiment qui, selon le cas :

a) est immatriculé ou fait l'objet d'un permis aux termes d'une loi fédérale;

b) soit appartient à Sa Majesté du chef du Canada ou d'une province, ou est placé sous sa responsabilité.

(2) L'appareil radio utilisé à bord d'un navire ou d'un bâtiment aux fins du service maritime ou du service de radiorepérage est soustrait à l'application du paragraphe 4(1) de la Loi, en ce qui concerne la licence radio, lorsque les conditions suivantes sont réunies :

a) il est utilisé lorsque le navire ou le bâtiment est :

(i) au Canada,

(ii) à l'extérieur du Canada et du territoire de tout autre pays,

(iii) dans le territoire d'un autre pays qui a conclu avec le Canada un accord de réciprocité accordant les mêmes privilèges aux Canadiens;

b) son utilisation est conforme aux exigences techniques applicables aux stations mobiles fonctionnant dans le cadre du service maritime et visées à l'article 34.2.

c) [Abrogé, DORS/2011-47, art. 6]

DORS/99-107, art. 1; DORS/2011-47, art. 6.

Exemption of Radio Apparatus Operated in the Amateur Radio Service

15.3 A radio apparatus that is operated in the amateur radio service at a mobile or fixed station is exempt from subsection 4(1) of the Act, in respect of a radio licence, if

(a) a person who operates the radio apparatus is an individual who is the holder of one or more of the certificates or licences referred to in section 42; and

(b) the operation of the radio apparatus in the amateur radio service is in accordance with the technical requirements referred to in section 45.

SOR/2000-78, s. 2.

Exemption des appareils radio du service de radioamateur

15.3 Tout appareil radio du service de radioamateur qui est utilisé dans une station mobile ou une station fixe est soustrait à l'application du paragraphe 4(1) de la Loi en ce qui concerne la licence radio, lorsque les conditions suivantes sont réunies :

a) l'utilisateur est titulaire de l'un ou plusieurs des documents mentionnés à l'article 42;

b) l'utilisation de l'appareil radio est conforme aux exigences techniques visées à l'article 45.

DORS/2000-78, art. 2.

PART II

Broadcasting Undertakings

Certificate Exemption

16 Radio apparatus that is set out in and meets a standard set out in the *Broadcasting Certificate-exempt Radio Apparatus List, October 2010* is exempt from the application of subsection 4(1) of the Act in respect of a broadcasting certificate.

SOR/2001-533, s. 4; SOR/2011-47, s. 7.

17 [Repealed, SOR/2011-47, s. 7]

Identification

18 The holder of a broadcasting certificate shall identify the broadcasting station in accordance with the *Technical Requirements Respecting Identification of Broadcasting Stations*, issued by the Minister, as amended from time to time.

PART III

Technical Acceptance Certification and Compliance with Applicable Standards

Interpretation

19 The following definitions apply in this Part.

Category I equipment means equipment that is described in subsection 21(1). (*matériel de catégorie I*)

Category II equipment means equipment that is described in subsection 21(5). (*matériel de catégorie II*)

SOR/2001-533, s. 5.

20 [Repealed, SOR/2001-533, s. 6]

Requirements for Certification

[SOR/2001-533, s. 7]

21 (1) All equipment that is listed and classified as Category I equipment in the *Category I Equipment Standards List*, as amended from time to time, published by

PARTIE II

Entreprises de radiodiffusion

Exemption de certificat

16 Tout appareil radio qui fait l’objet d’une norme figurant dans la *Liste des normes applicables aux appareils radio exemptés d’un certificat de radiodiffusion, octobre 2010*, et qui satisfait à cette norme est soustrait à l’application du paragraphe 4(1) de la Loi en ce qui concerne le certificat de radiodiffusion.

DORS/2001-533, art. 4; DORS/2011-47, art. 7.

17 [Abrogé, DORS/2011-47, art. 7]

Identification

18 Le titulaire d’un certificat de radiodiffusion procède à l’identification de sa station de radiodiffusion de la manière prévue dans les *Exigences techniques concernant l’identification des stations de radiodiffusion*, publiées par le ministre, compte tenu de leurs modifications successives.

PARTIE III

Certificats d’approbation technique et conformité aux normes applicables

Définitions

19 Les définitions qui suivent s’appliquent à la présente partie :

matériel de catégorie I Le matériel visé au paragraphe 21(1). (*Category I equipment*)

matériel de catégorie II Le matériel visé au paragraphe 21(5). (*Category II equipment*)

DORS/2001-533, art. 5.

20 [Abrogé, DORS/2001-533, art. 6]

Certificats

[DORS/2001-533, art. 7]

21 (1) Le matériel figurant dans la *Liste des normes applicables au matériel de catégorie I* publiée par le ministère de l’Industrie, avec ses modifications successives, et the Department of Industry, and that is classified as Category I equipment in the applicable standard, requires a TAC unless it is

(a) the subject of a certificate issued by the Minister before the coming into force of these Regulations;

(b) the subject of a certificate issued by a foreign certification body that is designated under an international agreement, convention or treaty to which Canada is a party and that is recognized by Canada under that agreement, convention or treaty as competent to certify equipment, to the effect that the equipment complies with the applicable standards; or

(c) the subject of a certificate issued by a Canadian certification body that meets the requirements set out in the *Requirements for Certification Bodies*, as amended from time to time, published by the Department of Industry, to the effect that the equipment complies with the applicable standards.

(2) The Minister may issue a TAC for a specific model of Category I equipment or for several models of Category I equipment that possess similar technical characteristics.

(3) An applicant for a TAC shall demonstrate to the Minister that the model or models of Category I equipment comply with all applicable standards.

(4) A TAC may only be issued where the Minister determines that the model or models of Category I equipment comply with all applicable standards.

(5) Equipment that is listed and classified as Category II equipment in the *Category II Equipment Standards List*, as amended from time to time, published by the Department of Industry, and that is classified as Category II equipment in the applicable standard, does not require a TAC.

SOR/2001-533, s. 8.

Compliance with Standards

22 (1) No person shall use the authority of a TAC or a certificate referred to in paragraphs 21(1)(a) to (c) to manufacture, import, distribute, lease, offer for sale or sell any Category I equipment, other than the specific model or models for which the TAC or certificate referred to in any of paragraphs 21(1)(a) to (c) was issued.

(2) If Category I equipment is modified in such a way as to affect any parameter specified in the applicable standard under which the TAC or a certificate referred to in any of paragraphs 21(1)(a) to (c) was issued, the modified

classé dans la norme applicable comme du matériel de catégorie I, est assujetti au CAT sauf s'il fait l'objet, selon le cas :

a) d'un certificat d'homologation délivré avant l'entrée en vigueur du présent règlement;

b) d'un certificat de conformité aux normes applicables délivré par un organisme étranger de certification désigné dans un accord, une convention ou un traité international auquel le Canada est partie et reconnu aux termes de cet accord, cette convention ou ce traité par le Canada comme étant compétent pour délivrer de tels certificats;

c) d'un certificat de conformité aux normes applicables délivré par un organisme canadien de certification qui répond aux exigences prévues au document intitulé *Critères applicables aux organismes de certification*, avec ses modifications successives, publié par le ministère de l'Industrie.

(2) Le ministre peut délivrer un CAT soit pour un modèle particulier de matériel de catégorie I, soit pour plusieurs modèles de ce matériel possédant des caractéristiques techniques similaires.

(3) La personne qui demande un CAT démontre au ministre que le modèle ou les modèles de matériel de catégorie I sont conformes aux normes applicables.

(4) Le ministre ne délivre un CAT que s'il détermine que le modèle ou les modèles de matériel de catégorie I sont conformes aux normes applicables.

(5) Le matériel figurant dans la *Liste des normes applicables au matériel de catégorie II* publiée par le ministère de l'Industrie avec ses modifications successives, et classé dans la norme applicable comme du matériel de catégorie II n'est pas soumis à un CAT.

DORS/2001-533, art. 8.

Conformité aux normes

22 (1) Il est interdit de se prévaloir d'un CAT ou de l'un des certificats mentionnés aux alinéas 21(1)a) à c) pour fabriquer, importer, distribuer, louer, mettre en vente ou vendre du matériel de catégorie I qui n'est pas du même modèle que celui visé par le CAT ou l'un des certificats mentionnés aux alinéas 21(1)a) à c).

(2) Lorsque du matériel de catégorie I est modifié à un point tel qu'il n'est plus conforme à l'un ou l'autre des paramètres précisés dans la norme applicable en fonction de laquelle le CAT ou l'un des certificats mentionnés aux equipment is no longer considered to be certified and requires testing in accordance with section 24.

SOR/98-437, s. 1; SOR/2001-533, s. 9.

23 [Repealed, SOR/2001-533, s. 9]

Testing

24 (1) For the purposes of testing a model of Category I or Category II equipment to obtain certification or to ensure compliance with the applicable standards,

(a) the number of units of equipment required to satisfy the testing requirements of the applicable standards is one or, where the number is specified in the applicable standards, that number; and

(b) the maximum number of units of equipment that may be manufactured or imported without a TAC, without a certificate referred to in any of paragraphs 21(a) to (c) or not in compliance with the applicable standards shall be one more than the applicable number of units referred to in paragraph (a).

(2) At any time during the life cycle of Category I or Category II equipment, the Minister may test or, with the agreement of the manufacturer or importer, have the manufacturer or importer test the Category I or Category II equipment in order to ensure compliance with applicable standards.

(3) Any person whose Category I or Category II equipment is subject to testing pursuant to subsection (2), shall test the equipment in accordance with the Minister's instructions or, at the Minister's request, make the equipment available for testing by the Minister at a place and time designated by the Minister.

(4) When the testing done under subsection (3) shows that the Category I or Category II equipment tested does not comply with the applicable standard, the Minister shall give notice of the test results to those persons who are likely to be affected by them.

(5) [Repealed, SOR/2011-47, s. 8]

SOR/98-437, s. 2; SOR/2001-533, s. 10; SOR/2011-47, s. 8.

Labelling

25 (1) Subject to subsections (2) and (7), no person shall mark or label Category I or Category II equipment contrary to the requirements set out in the applicable standards.

alinéas 21(1)a) à c) a été délivré, le matériel modifié est considéré comme n'étant pas approuvé et doit être mis à l'essai conformément à l'article 24.

DORS/98-437, art. 1; DORS/2001-533, art. 9.

23 [Abrogé, DORS/2001-533, art. 9]

Essais

24 (1) Lors de la mise à l'essai d'un modèle de matériel de catégorie I ou de catégorie II aux fins de l'obtention d'un CAT ou de la vérification de sa conformité aux normes applicables :

a) le nombre d'unités de ce matériel à mettre à l'essai pour satisfaire aux exigences d'essai de ces normes est le nombre indiqué dans celles-ci ou, à défaut d'une telle indication, une seule unité;

b) le nombre maximum d'unités de ce matériel qui peuvent être fabriquées ou importées sans un CAT, sans l'un des certificats mentionnés aux alinéas 21(1)a) à c) ou sans être conformes aux normes applicables est le nombre d'unités applicable mentionné à l'alinéa a) plus un.

(2) Le ministre peut, au cours de la durée de vie du matériel de catégorie I ou de catégorie II, procéder à la mise à l'essai du matériel ou charger le fabricant ou l'importateur de le faire, avec son accord, afin d'en assurer la conformité aux normes applicables.

(3) La personne dont le matériel de catégorie I ou de catégorie II doit être mis à l'essai en application du paragraphe (2) en fait l'essai conformément aux instructions du ministre ou, à la demande de celui-ci, met le matériel à sa disposition pour qu'il en fasse l'essai aux date, heure et lieu fixés par lui.

(4) Lorsque l'essai effectué conformément au paragraphe (3) démontre que le matériel de catégorie I ou de catégorie II n'est pas conforme aux normes applicables, le ministre communique les résultats de l'essai aux intéressés.

(5) [Abrogé, DORS/2011-47, art. 8]

DORS/98-437, art. 2; DORS/2001-533, art. 10; DORS/2011-47, art. 8.

Étiquetage

25 (1) Sous réserve des paragraphes (2) et (7), il est interdit de marquer ou d'étiqueter du matériel de catégorie I ou de catégorie II d'une façon contraire aux exigences énoncées dans les normes applicables.

(2) Subsection (1) does not preclude labelling for purposes unrelated to this Part or pursuant to other legislation.

(3) No person shall remove, replace or alter a label that has been affixed in accordance with applicable standards.

(4) No person shall mark, label or otherwise indicate that Category I or Category II equipment complies with applicable standards, unless that equipment complies with those standards.

(5) No person shall mark, label or otherwise indicate that Category I or Category II equipment has been certified as complying with applicable standards unless a TAC or a certificate referred to in any of paragraphs 21(1)(a) to (c) has been issued in respect of the equipment and the equipment complies with the standards under which the TAC or certificate was issued.

(6) No person shall mark, label or otherwise indicate how to modify Category I or Category II equipment so that it will not comply with applicable standards.

(7) Subsections (1) to (6) do not apply to equipment that was labelled before the coming into force of these Regulations.

SOR/2001-533, s. 11.

(2) Le paragraphe (1) n'a pas pour effet d'interdire l'étiquetage à des fins autres que celles visées par la présente partie ou l'étiquetage prévu par d'autres lois.

(3) Il est interdit d'enlever, de remplacer ou de modifier une étiquette qui a été apposée conformément aux normes applicables.

(4) Il est interdit d'indiquer, notamment par une marque ou une étiquette, que le matériel de catégorie I ou de catégorie II est conforme aux normes applicables, à moins qu'il ne soit conforme à ces normes.

(5) Il est interdit d'indiquer, notamment par une marque ou une étiquette, que le matériel de catégorie I ou de catégorie II est reconnu comme étant conforme aux normes applicables, à moins qu'il ne fasse l'objet d'un CAT ou de l'un des certificats mentionnés aux alinéas 21(1)a) à c) et qu'il ne soit conforme aux normes applicables en fonction desquelles le CAT ou l'un des certificats mentionnés aux alinéas 21(1)a) à c) a été délivré.

(6) Il est interdit d'indiquer, notamment par une marque ou une étiquette, la façon de faire pour modifier du matériel de catégorie I ou de catégorie II de sorte qu'il ne soit plus conforme aux normes applicables.

(7) Les paragraphes (1) à (6) ne s'appliquent pas au matériel étiqueté avant l'entrée en vigueur du présent règlement.

DORS/2001-533, art. 11.

PART IV

Radio Operator Certificates

Application

26 (1) This Part applies in respect of radio operator certificates set out in this subsection and in Schedule I:

(a) Restricted Operator Certificate with one or more of the following qualifications:

(i) Aeronautical Qualification, and

(ii) [Repealed, SOR/2020-278, s. 2]

(iii) Maritime Qualification;

(b) General Operator Certificate; and

(c) [Repealed, SOR/2020-278, s. 2]

(d) [Repealed, SOR/2020-278, s. 2]

PARTIE IV

Certificats d'opérateur radio

Application

26 (1) La présente partie s'applique aux certificats d'opérateur radio mentionnés dans le présent paragraphe et à l'annexe I :

a) certificat restreint d'opérateur radio avec une ou plusieurs des compétences suivantes :

(i) compétence aéronautique,

(ii) [Abrogé, DORS/2020-278, art. 2]

(iii) compétence maritime;

b) certificat général d'opérateur radio;

c) [Abrogé, DORS/2020-278, art. 2]

d) [Abrogé, DORS/2020-278, art. 2]

(e) Amateur Radio Operator Certificate with one or more of the following qualifications:

(i) Basic Qualification,

(ii) Morse Code (5 w.p.m.) Qualification,

(iii) Basic Qualification with Honours, and

(iv) Advanced Qualification.

(2) A radio operator certificate set out in column I of an item of Schedule I is equivalent to the radio operator certificate set out in column II of that item.

(3) For the purposes of this Part, an Amateur Radio Operator Certificate with a Morse Code (12 w.p.m.) Qualification is equivalent to an Amateur Radio Operator Certificate with a Basic Qualification with Honours.

SOR/2020-278, s. 2.

Eligibility for Radio Operator Certificates

27 The following persons are eligible to be issued a radio operator certificate set out in subsection 26(1):

(a) an individual who has passed the examinations set by the Minister in respect of the radio operator certificate being applied for;

(b) an individual who has met reissuance requirements or the requirements for the issuance of an equivalent certificate, set out in section 28; or

(c) an individual who is a citizen of a country other than Canada if

(i) the individual is the holder of an authorization that is issued by the responsible administration of that country and that corresponds with the applicable radio operator certificate set out in subsection 26(1), and

(ii) a reciprocal arrangement that establishes correspondence between radio operator certificates is in effect between the responsible administrations of Canada and that country.

e) certificat d'opérateur radioamateur avec une ou plusieurs des compétences suivantes :

(i) compétence de base,

(ii) compétence en morse (5 mots/min),

(iii) compétence de base avec distinction,

(iv) compétence supérieure.

(2) Tout certificat d'opérateur radio mentionné à la colonne I de l'annexe I équivaut au certificat d'opérateur radio visé à la colonne II.

(3) Pour l'application de la présente partie, le certificat d'opérateur radioamateur avec compétence en morse (12 mots/min) est équivalent au certificat d'opérateur radioamateur avec compétence de base avec distinction.

DORS/2020-278, art. 2.

Admissibilité aux certificats d'opérateur radio

27 Sont admissibles aux certificats d'opérateur radio mentionnés au paragraphe 26(1) les personnes physiques suivantes :

a) celle qui a réussi les examens prescrits par le ministre pour l'obtention du certificat demandé;

b) celle qui satisfait aux exigences prévues à l'article 28 pour la délivrance d'un nouveau certificat ou d'un certificat équivalent;

c) celle qui est un citoyen d'un pays étranger, lorsque les conditions suivantes sont réunies :

(i) elle détient une autorisation, délivrée par l'administration compétente de ce pays, équivalente au certificat d'opérateur radio applicable mentionné au paragraphe 26(1),

(ii) un accord de réciprocité établissant l'équivalence entre les certificats d'opérateur radio existe entre les administrations compétentes du Canada et de ce pays.

Requirements for Reissuance of Certificates and Issuance of Equivalent Certificates

28 If a radio operator certificate set out in paragraph 26(1)(b) or items 4 and 5 of Schedule I in column I has expired or is about to expire, the holder may apply to the Minister for the reissuance of the radio operator certificate or the issuance of an equivalent certificate, and the Minister shall reissue or issue the certificate if the holder

(a) has accumulated, during the preceding five years, at least one year of service as

(i) a radio operator holding a radio operator certificate, and is engaged in radiocommunications at the level commensurate with that certificate, or

(ii) a radio technician engaged in the maintenance of modern radio apparatus; or

(b) has passed the examinations set by the Minister in respect of the certificate being applied for.

SOR/2020-278, s. 3.

29 [Repealed, SOR/2011-47, s. 9]

PART V

Requirements for the Operation of Radio Apparatus

Operation of Radio Apparatus

30 [Repealed, SOR/2011-47, s. 10]

31 A person may operate or permit the operation of radio apparatus only where the apparatus is maintained within the tolerances set out in the applicable standards.

32 [Repealed, SOR/2011-47, s. 11]

33 A person may operate radio apparatus in the aeronautical service, maritime service or amateur radio service only where the person holds an appropriate radio operator certificate as set out in column I of any of items 1 and 3 to 15 of Schedule II.

34 (1) A person who holds a radio licence authorizing the operation of any radio apparatus in the aeronautical service or maritime service may permit another person to operate the radio apparatus only if the other person

Délivrance de nouveaux certificats ou de certificats équivalents

28 Lorsqu'un certificat d'opérateur radio mentionné à l'alinéa 26(1)b) ou à la colonne I de l'annexe I, aux articles 4 et 5, est expiré ou sur le point de l'être, le titulaire peut demander au ministre de lui délivrer un nouveau certificat ou un certificat équivalent. Le ministre délivre le certificat si le titulaire :

a) ou bien a acquis, au cours des cinq années précédentes, au moins un an d'expérience à titre :

(i) soit d'opérateur radio titulaire d'un certificat d'opérateur radio et est chargé des radiocommunications à un niveau qui correspond à ce certificat,

(ii) soit de technicien radio chargé de l'entretien d'appareils radio modernes;

b) ou bien a réussi les examens prescrits par le ministre pour l'obtention du certificat demandé.

DORS/2020-278, art. 3.

29 [Abrogé, DORS/2011-47, art. 9]

PARTIE V

Exigences concernant l'utilisation des appareils radio

Utilisation des appareils radio

30 [Abrogé, DORS/2011-47, art. 10]

31 Une personne ne peut faire fonctionner ou permettre de faire fonctionner un appareil radio que dans les limites des tolérances prévues dans les normes applicables.

32 [Abrogé, DORS/2011-47, art. 11]

33 Une personne ne peut faire fonctionner un appareil radio dans le cadre du service aéronautique, du service maritime ou du service de radioamateur que si elle est titulaire du certificat d'opérateur radio applicable mentionné à la colonne I des articles 1 et 3 à 15 de l'annexe II.

34 (1) Le titulaire d'une licence radio autorisant l'utilisation d'un appareil radio aux fins du service aéronautique ou du service maritime ne peut permettre à nul autre que le titulaire du certificat d'opérateur radio holds the appropriate radio operator certificate set out in column I of any of items 1 and 3 to 14 of Schedule II.

(2) A person who operates any radio apparatus that is exempt from licensing in accordance with section 15.1 in the case of the aeronautical service, or section 15.2 in the case of the maritime service, may permit another person to operate the radio apparatus only if the other person holds the appropriate radio operator certificate set out in column I of any of items 1 and 3 to 14 of Schedule II.

SOR/99-107, s. 2.

Operation in the Aeronautical Service

34.1 A person shall operate any radio apparatus on board an aircraft in the aeronautical service in accordance with the *Technical Requirements for the Operation of Mobile Stations in the Aeronautical Service*, issued by the Minister, as amended from time to time.

SOR/99-107, s. 2.

Operation in the Maritime Service

34.2 A person shall operate any radio apparatus on board a ship or vessel in the maritime service in accordance with the *Technical Requirements for the Operation of Mobile Stations in the Maritime Service*, issued by the Minister, as amended from time to time.

SOR/99-107, s. 2.

35 The holder of a radio operator certificate set out in column I of an item of Schedule I has the same operating privileges as the holder of a radio operator certificate set out in column II of that item.

36 The holder of a radio operator certificate set out in column I of an item of Schedule II may operate radio apparatus that forms part of a radio station set out in column II of that item.

37 [Repealed, SOR/2014-34, s. 5]

Proof of Radio Authorization

38 The holder of a radio authorization shall, at the request of an inspector appointed pursuant to the Act, show the radio authorization or a copy thereof to the inspector within 48 hours after the request.

applicable mentionné à la colonne I d'un des articles 1 et 3 à 14 de l'annexe II de faire fonctionner cet appareil.

(2) La personne qui utilise un appareil radio exempté d'une licence en vertu de l'article 15.1 en ce qui concerne le service aéronautique ou de l'article 15.2 en ce qui concerne le service maritime ne peut permettre à nul autre que le titulaire du certificat d'opérateur radio applicable mentionné à la colonne I d'un des articles 1 et 3 à 14 de l'annexe II de faire fonctionner cet appareil.

DORS/99-107, art. 2.

Utilisation dans le cadre du service aéronautique

34.1 La personne qui utilise un appareil radio à bord d'un aéronef aux fins du service aéronautique se conforme aux *Exigences techniques pour l'exploitation des stations mobiles dans le service aéronautique*, publiées par le ministre, compte tenu de leurs modifications successives.

DORS/99-107, art. 2.

Utilisation dans le cadre du service maritime

34.2 La personne qui utilise un appareil radio à bord d'un navire ou bâtiment aux fins du service maritime se conforme aux *Exigences techniques pour l'exploitation des stations mobiles dans le service maritime*, publiées par le ministre, compte tenu de leurs modifications successives.

DORS/99-107, art. 2.

35 Le titulaire d'un certificat d'opérateur radio mentionné à la colonne I de l'annexe I jouit des mêmes privilèges d'utilisation que le titulaire du certificat d'opérateur radio visé à la colonne II.

36 Le titulaire d'un certificat d'opérateur radio mentionné à la colonne I de l'annexe II peut faire fonctionner un appareil radio qui fait partie d'une station radio visée à la colonne II.

37 [Abrogé, DORS/2014-34, art. 5]

Preuve de l'autorisation de radiocommunication

38 Le titulaire d'une autorisation de radiocommunication présente, dans les 48 heures suivant la demande de l'inspecteur nommé en vertu de la Loi, l'original ou une copie de son autorisation.

Operation, Repair and Maintenance of Radio Apparatus on behalf of Another Person

39 A person may install, place in operation, modify, repair, maintain or permit the operation of radio apparatus on behalf of another person only where, if a radio licence is required,

(a) that other person has obtained a radio licence; and

(b) the person does so in accordance with the terms of the radio licence.

Assignment of Frequencies

40 The assignment of a frequency or frequencies to a holder of a radio authorization does not confer a monopoly on the use of the frequency or frequencies, nor shall a radio authorization be construed as conferring any right of continuing tenure in respect of the frequency or frequencies.

Identification

41 The holder of a radio licence shall identify the radio station in respect of which the licence was issued in accordance with the *Technical Requirements Respecting Identification of Radio Stations*, issued by the Minister, as amended from time to time.

Operation in the Amateur Radio Service

Operating Qualifications

42 An individual may operate radio apparatus in the amateur radio service if the individual is the holder of one or more of the following certificates or licences:

(a) an Amateur Radio Operator Certificate with Basic Qualification;

(b) [Repealed, SOR/2020-278, s. 4]

(c) [Repealed, SOR/2020-278, s. 4]

(d) [Repealed, SOR/2020-278, s. 4]

(e) a Radiotelephone Operator's General Certificate (Aeronautical);

Utilisation, réparation et entretien d'un appareil radio pour le compte d'une autre personne

39 Une personne ne peut installer, mettre en service, modifier, réparer, entretenir ou permettre de faire fonctionner un appareil radio pour le compte d'une autre personne que si, dans le cas où une licence radio est obligatoire :

a) cette autre personne a obtenu la licence radio;

b) la personne respecte les conditions de cette licence.

Assignation de fréquences

40 L'assignation d'une ou de plusieurs fréquences au titulaire d'une autorisation de radiocommunication ne lui en confère pas le monopole d'usage et cette autorisation n'entraîne pas l'octroi d'un droit permanent à l'égard de ces fréquences.

Identification

41 Le titulaire d'une licence radio procède à l'identification de la station radio visée par la licence de la manière prévue dans les *Exigences techniques concernant l'identification des stations radio*, publiées par le ministre, compte tenu de leurs modifications successives.

Service de radioamateur

Qualités requises de l'opérateur

42 Est habilitée à faire fonctionner un appareil radio du service de radioamateur la personne physique qui est titulaire de l'un ou plusieurs des documents suivants :

a) certificat d'opérateur radioamateur avec compétence de base;

b) [Abrogé, DORS/2020-278, art. 4]

c) [Abrogé, DORS/2020-278, art. 4]

d) [Abrogé, DORS/2020-278, art. 4]

e) certificat général de radiotéléphoniste (service aéronautique);

(f) a Radiotelephone Operator's General Certificate (Maritime);

(g) a Radiotelephone Operator's General Certificate (Land);

(h) [Repealed, SOR/2020-278, s. 4]

(i) a radio licence in the amateur radio service and an amateur radio operator authorization, issued by the responsible administration of a country other than Canada, if

(i) the individual is a citizen of that country, and

(ii) a reciprocal arrangement that allows similar privileges to Canadians exists between that other country and Canada; and

(j) a radio licence for a radio station in the amateur radio service issued to a citizen of the United States by the Government of the United States.

SOR/2000-78, s. 3; SOR/2020-278, s. 4.

Installation and Operating Restrictions

43 [Repealed, SOR/2000-78, s. 4]

44 A person who operates radio apparatus in the amateur radio service must hold an Amateur Radio Operator Certificate with Advanced Qualification in order to

(a) install or operate a transmitter or a radio frequency amplifier that is not commercially manufactured, for use in the amateur radio service; or

(b) install any radio apparatus to be used specifically

(i) for receiving and automatically retransmitting radiotelephone communications within the same frequency band, or

(ii) for an amateur radio club station.

SOR/2000-78, s. 5.

f) certificat général de radiotéléphoniste (service maritime);

g) certificat général de radiotéléphoniste (service terrestre);

h) [Abrogé, DORS/2020-278, art. 4]

i) licence radio du service de radioamateur et autorisation d'opérateur radioamateur, délivrées par l'administration compétente d'un pays étranger, lorsque les conditions suivantes sont réunies :

(i) la personne est un citoyen de ce pays,

(ii) un accord de réciprocité accordant les mêmes privilèges aux Canadiens existe entre ce pays et le Canada;

j) licence radio pour une station de radiocommunication du service de radioamateur délivrée à un citoyen des États-Unis par le gouvernement de ce pays.

DORS/2000-78, art. 3; DORS/2020-278, art. 4.

Restrictions visant l'installation et l'utilisation

43 [Abrogé, DORS/2000-78, art. 4]

44 La personne qui fait fonctionner un appareil radio du service de radioamateur doit être titulaire d'un certificat d'opérateur radioamateur avec compétence supérieure pour :

a) installer ou faire fonctionner un émetteur ou un amplificateur radioélectrique, de fabrication non commerciale, destiné à servir aux fins du service de radioamateur;

b) installer un appareil radio destiné à être utilisé expressément :

(i) pour la réception et la retransmission automatique, dans la même bande de fréquences, des communications téléphoniques transmises par ondes radio,

(ii) comme station de club de radioamateurs.

DORS/2000-78, art. 5.

Technical Requirements

45 A person shall operate radio apparatus in the amateur radio service in accordance with the technical requirements set out in the *Standards for the Operation of Radio Stations in the Amateur Radio Service*, issued by the Minister, as amended from time to time.

SOR/2000-78, s. 6.

Participation in Communications

46 (1) Any person may participate in the operation of radio apparatus in the amateur radio service under the supervision and in the presence of an individual referred to in section 42.

(2) A holder of a certificate or licence referred to in section 42 may

(a) permit any person who does not hold such a certificate or licence to operate radio apparatus, subject to compliance with the terms and conditions of that holder's certificate or licence; and

(b) permit the participation in the operation referred to in paragraph (a) by any person only in accordance with subsection (1).

SOR/2000-78, s. 7.

Communications with Radio Apparatus in the Amateur Radio Service

[SOR/2000-78, s. 8]

47 A person who operates radio apparatus in the amateur radio service may only

(a) communicate with a radio station that operates in the amateur radio service;

(b) use a code or cipher that is not secret; and

(c) be engaged in communication that does not include the transmission of

(i) music,

(ii) commercially recorded material,

(iii) programming that originates from a broadcasting undertaking, or

(iv) radiocommunications in support of industrial, business or professional activities.

SOR/2000-78, s. 9.

Exigences techniques

45 La personne qui fait fonctionner un appareil radio du service de radioamateur se conforme aux exigences techniques prévues dans les *Normes sur l'exploitation de stations radio du service de radioamateur*, publiées par le ministre, compte tenu de leurs modifications successives.

DORS/2000-78, art. 6.

Participation aux communications

46 (1) Toute personne peut aider à faire fonctionner un appareil radio du service de radioamateur, à condition qu'elle soit sous la supervision et en présence d'une personne visée à l'article 42.

(2) Le titulaire d'un document mentionné à l'article 42 peut :

a) sous réserve du respect des conditions de ce document, permettre à une personne qui n'est pas titulaire d'un tel document de faire fonctionner un appareil radio;

b) permettre la participation de toute personne à l'activité visée à l'alinéa a), pourvu que les conditions prévues au paragraphe (1) soient respectées.

DORS/2000-78, art. 7.

Communications avec des appareils radio du service de radioamateur

[DORS/2000-78, art. 8]

47 La personne qui fait fonctionner un appareil radio du service de radioamateur peut seulement :

a) communiquer avec une station du service de radioamateur;

b) utiliser des codes ou des messages chiffrés qui ne sont pas secrets;

c) participer à des communications ne comportant pas l'émission de ce qui suit :

(i) musique,

(ii) enregistrements commerciaux,

(iii) émissions provenant d'une entreprise de radiodiffusion,

(iv) radiocommunications relatives à des activités industrielles, commerciales ou professionnelles.

DORS/2000-78, art. 9.

Emergency Communications

48 In a real or simulated emergency, a person operating radio apparatus in the amateur radio service may only communicate with a radio station that is in the amateur radio service in order to transmit a message that relates to the real or simulated emergency on behalf of a person, government or relief organization.

SOR/2000-78, s. 10.

Communications en cas d'urgence

48 En situation d'urgence réelle ou simulée, la personne qui fait fonctionner un appareil radio du service de radioamateur peut communiquer seulement avec une station du service de radioamateur afin de transmettre un message concernant la situation d'urgence pour le compte d'une personne, d'un gouvernement ou d'un organisme de secours.

DORS/2000-78, art. 10.

Remuneration

49 A person who operates radio apparatus in the amateur radio service shall do so without demanding or accepting remuneration in any form in respect of a radiocommunication that the person transmits or receives.

SOR/2000-78, s. 11.

Rétribution

49 La personne qui fait fonctionner un appareil radio du service de radioamateur ne peut exiger ni accepter quelque rétribution que ce soit pour les radiocommunications qu'elle transmet ou reçoit.

DORS/2000-78, art. 11.

PART VI

Interference

Determination of Interference for a Model of Equipment

50 (1) This section applies to

(a) equipment whether or not it complies with applicable standards; and

(b) equipment for which no applicable standard exists.

(2) Where the Minister, taking into account the factors mentioned in subsection (5), determines that a model or several models of equipment cause or are likely to cause interference to radiocommunication or suffer from or are likely to suffer from adverse effects of electromagnetic energy, the Minister shall give notice of the determination to persons who are likely to be affected thereby.

(3) No person shall manufacture, import, distribute, lease, offer for sale, sell, install or use equipment in respect of which a notice referred to in subsection (2) has been given.

(4) Subsection (3) does not apply in respect of equipment that is manufactured or imported solely for export purposes.

(5) A determination pursuant to subsection (2) shall include the consideration of the following factors:

PARTIE VI

Brouillage

Détermination de l'existence de brouillage pour un modèle de matériel

50 (1) Le présent article s'applique :

a) au matériel, qu'il soit ou non conforme aux normes applicables;

b) au matériel pour lequel il n'existe pas de norme applicable.

(2) Lorsque le ministre décide, en tenant compte des facteurs mentionnés au paragraphe (5), qu'un ou plusieurs modèles de matériel brouillent ou sont susceptibles de brouiller la radiocommunication, ou subissent ou risquent de subir l'effet non désiré d'une énergie électromagnétique, il en donne avis aux intéressés.

(3) Il est interdit de fabriquer, d'importer, de distribuer, de louer, de mettre en vente, de vendre, d'installer ou d'utiliser du matériel au sujet duquel un avis a été donné aux termes du paragraphe (2).

(4) Le matériel fabriqué ou importé aux seules fins d'exportation est soustrait à l'application du paragraphe (3).

(5) La décision visée au paragraphe (2) tient compte des facteurs suivants :

(a) the electromagnetic environment in which the equipment is being used;

(b) the circumstances under which it is being used;

(c) the technical characteristics of the devices being interfered with or being adversely affected by electromagnetic energy; and

(d) the technical characteristics of the devices causing interference or the adverse effects of electromagnetic energy.

51 A determination under section 50 does not apply to a determination under paragraph 5(1)(l) of the Act.

Determination of Interference other than Harmful Interference

52 (1) If the Minister, taking into account the factors referred to in subsection (2), determines that a radio apparatus causes or suffers from interference other than harmful interference or adverse effects of electromagnetic energy, the Minister shall, if it is necessary for the purpose of ensuring the orderly development and efficient operation of radiocommunication in Canada, order the persons in possession or control of the radio apparatus to cease or modify operation of the radio apparatus until it can be operated without causing or being affected by that interference or those adverse effects.

(2) A determination pursuant to subsection (1) shall consider the following factors:

(a) the electromagnetic environment in which the radio apparatus is being used;

(b) the circumstances under which it is being used;

(c) the technical characteristics of the devices being interfered with or being adversely affected by electromagnetic energy; and

(d) the technical characteristics of the devices causing interference or the adverse effects of electromagnetic energy.

SOR/2014-34, s. 6; SOR/2020-278, s. 5.

53 (1) A determination under section 52 does not apply to a determination under paragraph 5(1)(l) of the Act.

a) l’environnement électromagnétique dans lequel le matériel est utilisé;

b) les circonstances dans lesquelles le matériel est utilisé;

c) les caractéristiques techniques des dispositifs dont le fonctionnement est contrarié par du brouillage ou par l’effet non désiré d’une énergie électromagnétique;

d) les caractéristiques techniques des dispositifs causant du brouillage ou l’effet non désiré d’une énergie électromagnétique.

51 La décision prise aux termes de l’article 50 ne s’applique pas à la décision prise en vertu de l’alinéa 5(1)l) de la Loi.

Détermination de l’existence de brouillage autre que le brouillage préjudiciable

52 (1) Lorsque le ministre décide, en tenant compte des facteurs mentionnés au paragraphe (2), qu’un appareil radio cause ou subit du brouillage autre que du brouillage préjudiciable ou l’effet non désiré d’une énergie électromagnétique, il ordonne, lorsque cela est nécessaire pour assurer le développement ordonné et le fonctionnement efficace de la radiocommunication au Canada, aux personnes qui possèdent ou contrôlent l’appareil radio d’en cesser ou d’en modifier l’utilisation jusqu’à ce que celui-ci puisse fonctionner sans causer ce brouillage ou cet effet ou sans en être contrarié.

(2) La décision visée au paragraphe (1) tient compte des facteurs suivants :

a) l’environnement électromagnétique dans lequel l’appareil radio est utilisé;

b) les circonstances dans lesquelles l’appareil radio est utilisé;

c) les caractéristiques techniques des dispositifs dont le fonctionnement est contrarié par du brouillage ou par l’effet non désiré d’une énergie électromagnétique;

d) les caractéristiques techniques des dispositifs causant du brouillage ou l’effet non désiré d’une énergie électromagnétique.

DORS/2014-34, art. 6; DORS/2020-278, art. 5.

53 (1) La décision prise aux termes de l’article 52 ne s’applique pas à la décision prise en vertu de l’alinéa 5(1)l) de la Loi.

(2) No person shall operate radio apparatus contrary to an order made under subsection 52(1).

PART VII

Privacy of Communications

Prescribed Exceptions

54 (1) The exceptions set out in subsection (2) apply to

(a) a person who makes use of or divulges a radio-based telephone communication; and

(b) a person who intercepts and makes use of or intercepts and divulges any radiocommunication.

(2) The persons referred to in subsection (1) are excepted from the prohibitions set out in subsections 9(1.1) and (2) of the Act where the use or divulgation, or interception and use or interception and divulgation, as the case may be, is made

(a) for the purpose of preserving or protecting any property, or the prevention of serious harm to any person, including the bringing of emergency assistance to any person;

(b) in the course of or for the purposes of giving evidence in any criminal or civil proceeding or in any other proceeding in which the persons may be required to give evidence on oath;

(c) by a peace officer, prosecutor, officer of the court or other public official, or by a person who discloses the communication to such an official, for the purpose of the investigation or prosecution of an alleged contravention of any law of Canada or a province or in the interests of the administration of justice; or

(d) on behalf of Her Majesty in right of Canada for the purposes of international affairs or national defence or security.

(3) In addition to being excepted where appropriate under the circumstances referred to in subsection (2), the following persons are also excepted from the prohibitions referred to in that subsection in the following circumstances:

(2) Il est interdit de faire fonctionner un appareil radio contrairement à l'ordre donné en vertu du paragraphe 52(1).

PARTIE VII

Caractère privé des communications

Exceptions

54 (1) Les exceptions prévues au paragraphe (2) s'appliquent aux personnes suivantes :

a) la personne qui utilise ou communique une communication radiotéléphonique;

b) la personne qui intercepte et soit utilise, soit communique une radiocommunication.

(2) Les personnes visées au paragraphe (1) sont soustraites aux interdictions prévues aux paragraphes 9(1.1) et (2) de la Loi lorsqu'elles se livrent aux activités mentionnées à ce paragraphe :

a) soit dans le but de protéger des biens ou d'empêcher qu'un dommage grave soit causé à une personne, notamment lui prêter assistance en cas d'urgence;

b) soit au cours ou dans le cadre d'une déposition lors de poursuites civiles ou pénales ou de toute autre procédure dans laquelle elles peuvent avoir à déposer sous serment;

c) soit, dans le cas d'un agent de la paix, d'un poursuivant, d'un fonctionnaire d'un tribunal ou de tout autre fonctionnaire — que le fonctionnaire soit l'exécutant des activités ou le destinataire de la communication —, dans le cadre d'une enquête ou d'une poursuite relative à une infraction à une loi fédérale ou provinciale, ou dans l'intérêt de l'administration de la justice;

d) soit au nom de Sa Majesté du chef du Canada pour les besoins des affaires internationales ou de la défense ou de la sécurité nationales.

(3) Outre les exceptions prévues au paragraphe (2), les personnes suivantes sont également soustraites aux interdictions visées à ce paragraphe dans les circonstances mentionnées ci-après :

a) un fonctionnaire ou un préposé de Sa Majesté du chef du Canada lorsqu'il utilise ou communique une

(a) an officer or servant of Her Majesty in right of Canada, where the officer or servant makes use of or divulges a radio-based telephone communication, or intercepts and makes use of, or intercepts and divulges, a radiocommunication, as the case may be, in the course of radio frequency spectrum management for the purpose of identifying, isolating or preventing an unauthorized or interfering use of a frequency or of a transmission; or

(b) an officer or servant of Her Majesty in right of Canada or a person providing a communication service, where the officer, servant or person makes use of or divulges a radio-based telephone communication, intercepts and makes use of, or intercepts and divulges, a radiocommunication, as the case may be, in the course of monitoring radiocommunications for the purpose of ensuring the security and integrity of communications and communication systems.

communication radiotéléphonique, ou intercepte et soit utilise, soit communique une radiocommunication, selon le cas, dans le cadre de la gestion du spectre des fréquences de radiocommunication, en vue d'identifier, d'isoler ou d'empêcher l'utilisation non autorisée ou importune d'une fréquence ou d'une transmission;

b) un fonctionnaire ou un préposé de Sa Majesté du chef du Canada, ou une personne qui fournit un service de communication, lorsqu'il utilise ou communique une communication radiotéléphonique, ou intercepte et soit utilise, soit communique une radiocommunication, selon le cas, dans le cadre de la surveillance des radiocommunications, en vue d'assurer la sécurité et l'intégrité des communications et des systèmes de communication.

PART VIII

Fees

Interpretation

55 For the purposes of this Part,

broadband personal communications services radio frequencies [Repealed, SOR/2021-40, s. 5]

cellular mobile radio frequencies [Repealed, SOR/2021-40, s. 5]

congestion zone means the geographical area where a station is located and is described as a low congestion zone, a medium congestion zone or a high congestion zone; (*zone d'encombrement*)

coverage area means the geographic area over which a radio signal is propagated as is determined by the terrain, antenna height, effective radiated power, frequency, or other technical characteristics that may affect the path or field strength level of the signal; (*zone de couverture*)

high congestion zone means, in respect of a regional area set out in column I of an item of Schedule V, the area bounded by the geographical coordinates set out in columns II to X of that item; (*zone d'encombrement intense*)

link means the spectrum dedicated to an assigned radio frequency that is used to communicate between two stations; (*liaison*)

PARTIE VIII

Droits

Définitions

55 Les définitions qui suivent s'appliquent à la présente partie.

autre région Région du Canada autre qu'une région métropolitaine. (*other area*)

droit de licence radio [Abrogée, DORS/2014-34, art. 7]

largeur de bande nécessaire Largeur de bande de fréquences à utiliser pour assurer la précision de la transmission de l'information et les conditions optimales à cette fin. (*necessary bandwidth*)

liaison Spectre dédié à une radiofréquence assignée qui est utilisée pour la communication entre deux stations. (*link*)

radiofréquences des services de communications personnelles à large bande [Abrogée, DORS/2021-40, art. 5]

radiofréquences des services de communications personnelles à bande étroite Les fréquences d'émission et de réception comprises dans les bandes de radiofréquences de 901 MHz à 902 MHz, de 930 MHz à 931 MHz et de 940 MHz à 941 MHz. (*narrowband personal communications services radio frequencies*)

low congestion zone means any area that is not a medium congestion zone or a high congestion zone; (*zone d'encombrement faible*)

medium congestion zone means, in respect of a regional area set out in column I of an item of Schedule VI, the area bounded by the geographical coordinates set out in columns II to XI of that item, but does not include any area that is included in a high congestion zone; (*zone d'encombrement moyen*)

metropolitan area means, in respect of a metropolitan area set out in column I of an item of Schedule IV, the geographical area bounded by the north latitude in the range between the limits set out in columns II and III of that item and the west longitude in the range between the limits set out in columns IV and V of that item; (*région métropolitaine*)

narrowband personal communications services radio frequencies means the transmit and receive frequencies in the radio frequency bands 901 MHz to 902 MHz, 930 MHz to 931 MHz and 940 MHz to 941 MHz; (*radiofréquences des services de communications personnelles à bande étroite*)

necessary bandwidth means the width of a radio frequency band required to ensure accurate and optimum transmission of information; (*largeur de bande nécessaire*)

other area means a geographical area in Canada other than a metropolitan area; (*autre région*)

public cordless telephone radio frequencies [Repealed, SOR/2014-34, s. 7]

radio licence fee [Repealed, SOR/2014-34, s. 7]

remote area means any area not identified as an "Urban area" or "Rural area" on the *Map of Radiocommunication Areas*, published by the Department of Industry in February, 2021; (*région éloignée*)

rural area means any area identified as a "Rural area" on the *Map of Radiocommunication Areas*, published by the Department of Industry in February, 2021; (*région rurale*)

urban area means any area identified as an "Urban area" on the *Map of Radiocommunication Areas*, published by the Department of Industry in February, 2021. (*région urbaine*)

Err.(F), Vol. 140, No. 12; SOR/2014-34, s. 7; SOR/2021-40, s. 5.

radiofréquences du service mobile cellulaire [Abrogée, DORS/2021-40, art. 5]

radiofréquences du service téléphonique public sans cordon [Abrogée, DORS/2014-34, art. 7]

région éloignée Région qui n'est pas délimitée en tant que « région urbaine » ou « région rurale » sur la *Carte des régions de radiocommunication* publiée par le ministère de l'Industrie en février 2021. (*remote area*)

région métropolitaine Région mentionnée à la colonne I de l'annexe IV, dont la latitude se trouve entre les limites indiquées aux colonnes II et III et la longitude, entre les limites indiquées aux colonnes IV et V. (*metropolitan area*)

région rurale Région délimitée en tant que « région rurale » sur la *Carte des régions de radiocommunication* publiée par le ministère de l'Industrie en février 2021. (*rural area*)

région urbaine Région délimitée en tant que « région urbaine » sur la *Carte des régions de radiocommunication* publiée par le ministère de l'Industrie en février 2021. (*urban area*)

zone de couverture Région à l'intérieur de laquelle un signal radio est propagé suivant le terrain, la hauteur de l'antenne, la puissance apparente rayonnée, la fréquence ou d'autres caractéristiques techniques pouvant influer sur le parcours ou l'intensité de champ du signal. (*coverage area*)

zone d'encombrement Étendue géographique dans laquelle une station est située, qui est soit une zone d'encombrement faible, soit une zone d'encombrement moyen, soit une zone d'encombrement intense. (*congestion zone*)

zone d'encombrement faible Étendue qui n'est ni une zone d'encombrement moyen ni une zone d'encombrement intense. (*low congestion zone*)

zone d'encombrement intense À l'égard d'une zone régionale mentionnée à la colonne I de l'annexe V, étendue délimitée par les coordonnées géographiques indiquées aux colonnes II à X. (*high congestion zone*)

zone d'encombrement moyen À l'égard d'une zone régionale mentionnée à la colonne I de l'annexe VI, étendue délimitée par les coordonnées géographiques indiquées aux colonnes II à XI, à l'exclusion de toute partie comprise dans une zone d'encombrement intense. (*medium congestion zone*)

Err.(F), Vol. 140, nº 12; DORS/2014-34, art. 7; DORS/2021-40, art. 5.

General

56 The radio licence fee payable in respect of a radio licence that is issued in respect of radio apparatus installed in a station and that authorizes the use of certain frequencies is

(a) in the case of a renewable radio licence, the annual fee for the period from April 1 to March 31 of the following year, that is payable in advance on March 31 of each year and that is the fee set out in section 61.1 or 65.1 or in column IV of Parts I to IV, V and VI of Schedule III;

(b) in the case of either a renewable radio licence or a temporary radio licence that is valid for a period of more than 30 days, the monthly fee set out in section 61.1 or 65.1 or in column III of Parts I to IV, V and VI of Schedule III multiplied by the number of months for which the licence is valid; or

(c) in the case of either a renewable radio licence or a temporary radio licence that is valid for a period of 30 days or less, the monthly fee set out in section 61.1 or 65.1 or in column III of Parts I to IV, V and VI of Schedule III.

SOR/2014-34, s. 8; SOR/2021-40, s. 6.

Dispositions générales

56 Le droit à payer pour une licence radio visant un appareil radio installé dans une station et autorisant l'utilisation de certaines fréquences correspond :

a) s'agissant d'une licence radio renouvelable, au droit annuel qui est payable d'avance le 31 mars, pour la période du 1er avril au 31 mars de l'année suivante, et dont le montant est prévu aux articles 61.1 ou 65.1 ou figure à la colonne IV des parties I à IV, V et VI de l'annexe III;

b) s'agissant d'une licence radio renouvelable ou d'une licence radio temporaire dont la période de validité est de plus de trente jours, au droit mensuel dont le montant est prévu aux articles 61.1 ou 65.1 ou figure à la colonne III des parties I à IV, V et VI de l'annexe III multiplié par le nombre de mois pour lequel la licence est valide;

c) s'agissant d'une licence radio renouvelable ou d'une licence radio temporaire dont la période de validité est d'au plus trente jours, au droit mensuel dont le montant est prévu aux articles 61.1 ou 65.1 ou figure à la colonne III des parties I à IV, V et VI de l'annexe III.

DORS/2014-34, art. 8; DORS/2021-40, art. 6.

Radio Licence Fee Exemption for Foreign Governments

57 The radio licence fees do not apply in respect of a radio licence issued to a foreign government that grants a reciprocal radio licence fee exemption to Her Majesty in right of Canada.

Exemption des droits de licence radio accordée à des gouvernements étrangers

57 Les droits de licence radio ne s'appliquent pas à la licence radio délivrée à un gouvernement étranger qui accorde une exemption réciproque de droits de licence radio à Sa Majesté du chef du Canada.

Telephone Channel Equivalencies

58 For the purpose of calculating the radio licence fees payable for a radio licence authorizing operation on certain frequencies for radio apparatus installed in a fixed station or space station referred to in section 61 or 65 or 73,

(a) one television channel, including the associated sound channels,

(i) where the necessary bandwidth is 6 MHz or less, is equivalent to 300 telephone channels,

Nombre équivalent de voies téléphoniques

58 Aux fins du calcul des droits de licence radio à payer pour une licence radio autorisant l'utilisation, sur certaines fréquences, d'un appareil radio installé dans une station fixe ou une station spatiale visée aux articles 61, 65 ou 73 :

a) un canal de télévision, y compris les voies son associées :

(i) dans le cas où la largeur de bande nécessaire est égale ou inférieure à 6 MHz, équivaut à 300 voies téléphoniques,

(ii) where the necessary bandwidth is greater than 6 MHz and less than or equal to 12.7 MHz, is equivalent to 600 telephone channels, and

(iii) where the necessary bandwidth is greater than 12.7 MHz, is equivalent to 960 telephone channels;

(b) one sound channel is equivalent to three telephone channels; and

(c) one digitally modulated channel is equivalent to the number of telephone channels calculated by dividing the modulation bit rate by 64 kilobits per second.

59 [Repealed, SOR/2000-78, s. 12]

Mobile Stations

60 (1) The radio licence fee payable in respect of radio apparatus installed in a mobile station that operates in the aeronautical service or maritime service is the applicable fee set out in item 2 of Part I of Schedule III for all authorized transmit and receive frequencies.

(2) The radio licence fee payable in respect of radio apparatus installed in a mobile station that operates in the public information service is the applicable fee set out in item 3 of Part I of Schedule III for all authorized transmit and receive frequencies.

(3) The radio licence fee payable in respect of radio apparatus installed in a mobile station that operates in the developmental service or radiodetermination service is the applicable fee set out in item 4 of Part I of Schedule III for all authorized transmit and receive frequencies.

(4) The radio licence fee payable in respect of radio apparatus installed in a mobile station that operates in the land mobile service is the applicable fee set out in item 5 of Part I of Schedule III for all authorized transmit and receive frequencies.

(5) In addition to any applicable fee prescribed pursuant to subsection (1), (2), (3) or (4), the radio licence fee payable in respect of radio apparatus installed in a mobile station that communicates with a space station is the applicable fee set out in item 6 of Part I of Schedule III for all authorized transmit and receive frequencies.

(6) The radio licence fee payable in respect of radio apparatus installed in a mobile station, other than a mobile

(ii) dans le cas où la largeur de bande nécessaire est supérieure à 6 MHz et égale ou inférieure à 12,7 MHz, équivaut à 600 voies téléphoniques,

(iii) dans le cas où la largeur de bande nécessaire est supérieure à 12,7 MHz, équivaut à 960 voies téléphoniques;

b) une voie son équivaut à trois voies téléphoniques;

c) une voie à modulation numérique équivaut au nombre de voies téléphoniques calculé par la division du débit binaire par 64 kilobits par seconde.

59 [Abrogé, DORS/2000-78, art. 12]

Stations mobiles

60 (1) Le droit de licence radio à payer à l'égard d'un appareil radio installé dans une station mobile du service aéronautique ou du service maritime est le droit applicable prévu à l'article 2 de la partie I de l'annexe III pour toutes les fréquences d'émission et de réception autorisées.

(2) Le droit de licence radio à payer à l'égard d'un appareil radio installé dans une station mobile du service d'information publique est le droit applicable prévu à l'article 3 de la partie I de l'annexe III pour toutes les fréquences d'émission et de réception autorisées.

(3) Le droit de licence radio à payer à l'égard d'un appareil radio installé dans une station mobile du service de développement ou du service de radiorepérage est le droit applicable prévu à l'article 4 de la partie I de l'annexe III pour toutes les fréquences d'émission et de réception autorisées.

(4) Le droit de licence radio à payer à l'égard d'un appareil radio installé dans une station mobile du service mobile terrestre est le droit applicable prévu à l'article 5 de la partie I de l'annexe III pour toutes les fréquences d'émission et de réception autorisées.

(5) Outre le droit applicable visé aux paragraphes (1), (2), (3) ou (4), le droit de licence radio à payer à l'égard d'un appareil radio installé dans une station mobile qui communique avec une station spatiale est le droit applicable prévu à l'article 6 de la partie I de l'annexe III pour toutes les fréquences d'émission et de réception autorisées.

(6) Le droit de licence radio à payer à l'égard d'un appareil radio installé dans une station mobile non visée aux station referred to in subsections (1) to (5), is the applicable fee set out in item 7 of Part I of Schedule III for all authorized transmit and receive frequencies.

paragraphes (1) à (5) est le droit applicable prévu à l'article 7 de la partie I de l'annexe III pour toutes les fréquences d'émission et de réception autorisées.

Fixed Stations — Radiocommunication Users

Stations fixes — Usagers radio

Fixed Stations Communicating with other Fixed Stations or Space Stations

Stations fixes communiquant avec d'autres stations fixes ou des stations spatiales

61 (1) Subject to subsection (2), the radio licence fee payable by a radiocommunication user in respect of radio apparatus installed in a fixed station, other than a fixed station that operates in the land mobile service or a fixed station described in section 61.1 or 62, is for each transmitter and each receiver installed at the station the sum of the applicable fees set out in Part II of Schedule III that corresponds to the number of telephone channels per radio frequency assigned to that transmitter or receiver.

61 (1) Sous réserve du paragraphe (2), le droit de licence radio à payer par l'usager radio à l'égard d'un appareil radio installé dans une station fixe, autre qu'une station fixe du service mobile terrestre ou une station fixe visée aux articles 61.1 ou 62, est, pour chaque émetteur et chaque récepteur de la station, la somme des droits applicables prévus à la partie II de l'annexe III, établis en fonction du nombre de voies téléphoniques par radiofréquence assignée à l'émetteur ou au récepteur.

(2) If a fixed station, other than a fixed station described in section 61.1, 62 or 63, communicates solely on one transmit radio frequency and one receive radio frequency that are not manually selected with another fixed station, other than a fixed station in the land mobile service, operated for the automatic reception and retransmission of radiocommunications within a communication system that does not accept traffic from or deliver traffic to external points by means other than radio, the radio licence fee payable is the sum of

(a) in respect of all assigned transmit radio frequencies, the applicable radio licence fee for the assigned transmit radio frequency with the greatest number of telephone channels set out in Part II of Schedule III, and

(b) in respect of all assigned receive radio frequencies, the applicable radio licence fee for the assigned receive radio frequency with the greatest number of telephone channels set out in Part II of Schedule III.

SOR/2021-40, s. 7.

(2) Lorsqu'une station fixe, autre qu'une station fixe visée aux articles 61.1, 62 ou 63, communique exclusivement sur une seule radiofréquence d'émission et une seule radiofréquence de réception, syntonisées de façon automatique, avec une autre station fixe, autre qu'une station fixe du service mobile terrestre, qui est exploitée pour la réception et la retransmission automatiques de radiocommunications au sein d'un système de communication et qui n'accepte pas de trafic en provenance ou à destination de points extérieurs autrement que par radio, le droit de licence radio à payer est la somme des droits suivants :

a) pour toutes les radiofréquences d'émission assignées, le droit de licence radio applicable prévu à la partie II de l'annexe III pour la radiofréquence d'émission assignée qui utilise le nombre le plus élevé de voies téléphoniques;

b) pour toutes les radiofréquences de réception assignées, le droit de licence radio applicable prévu à la partie II de l'annexe III pour la radiofréquence de réception assignée qui utilise le nombre le plus élevé de voies téléphoniques.

DORS/2021-40, art. 7.

Fixed Point-to-Point Service

Service point à point fixe

61.1 (1) The radio licence fee payable by a radiocommunication user in respect of radio apparatus installed in a fixed station that is part of the fixed point-to-point service consisting of two stations located in an urban area or

61.1 (1) Le droit de licence radio à payer par l'usager radio à l'égard d'un appareil radio installé dans une station fixe faisant partie du service point à point fixe dont les deux stations sont situées en région urbaine ou dont one station located in an urban area and another in a rural area is, for each link authorized by the licence, the applicable base rate set out in item 1 of Part IV.1 of Schedule III multiplied by the assigned spectrum, in MHz, that is set out in the licence.

(2) The radio licence fee payable by a radiocommunication user in respect of radio apparatus installed in a fixed station that is part of the fixed point-to-point service consisting of two stations located in a rural area is, for each link authorized by the licence, the applicable base rate set out in item 2 of Part IV.1 of Schedule III multiplied by the assigned spectrum, in MHz, that is set out in the licence.

(3) The radio licence fee payable by a radiocommunication user in respect of radio apparatus installed in a fixed station that is part of the fixed point-to-point service consisting of at least one station located in a remote area is, for each link authorized by the licence, the applicable base rate set out in item 3 of Part IV.1 of Schedule III multiplied by the assigned spectrum, in MHz, that is set out in the licence.

(4) The minimum radio licence fee payable by a radiocommunication user in respect of radio apparatus installed in a fixed station that is part of the fixed point-to-point service is, for each link authorized by the licence,

(a) if the two stations are located in an urban area or one station is located in an urban area and the other is located in a rural area, the applicable fee set out in item 1 of Part IV.2 of Schedule III;

(b) if the two stations are located in a rural area, the applicable fee set out in item 2 of Part IV.2 of Schedule III; and

(c) if at least one station is located in a remote area, the applicable fee set out in item 3 of Part IV.2 of Schedule III.

SOR/2021-40, s. 8.

une station est située en région urbaine et l’autre en région rurale est, pour chaque liaison autorisée par la licence, le taux de référence applicable prévu à l’article 1 de la partie IV.1 de l’annexe III, multiplié par le spectre assigné prévu par la licence, en MHz.

(2) Le droit de licence radio à payer par l’usager radio à l’égard d’un appareil radio installé dans une station fixe faisant partie du service point à point fixe dont les deux stations sont situées en région rurale est, pour chaque liaison autorisée par la licence, le taux de référence applicable prévu à l’article 2 de la partie IV.1 de l’annexe III, multiplié par le spectre assigné prévu par la licence, en MHz.

(3) Le droit de licence radio à payer par l’usager radio à l’égard d’un appareil radio installé dans une station fixe faisant partie du service point à point fixe dont au moins une station est située en région éloignée est, pour chaque liaison autorisée par la licence, le taux de référence applicable prévu à l’article 3 de la partie IV.1 de l’annexe III, multiplié par le spectre assigné prévu par la licence, en MHz.

(4) Le droit de licence radio minimum à payer par l’usager radio à l’égard d’un appareil radio installé dans une station fixe faisant partie du service point à point fixe est, pour chaque liaison autorisée par la licence :

a) lorsque les deux stations sont situées en région urbaine ou lorsqu’une station est située en région urbaine et l’autre en région rurale, le droit applicable prévu à l’article 1 de la partie IV.2 de l’annexe III;

b) lorsque les deux stations sont situées en région rurale, le droit applicable prévu à l’article 2 de la partie IV.2 de l’annexe III;

c) lorsqu’au moins une station est située en région éloignée, le droit applicable prévu à l’article 3 de la partie IV.2 de l’annexe III.

DORS/2021-40, art. 8.

Fixed Stations Operated in Certain Services

62 (1) The applicable radio licence fee set out in item 1 of Part III of Schedule III for all authorized transmit and receive frequencies is payable by a radiocommunication user in respect of radio apparatus installed in a fixed station to

(a) operate in any of the following services

(i) aeronautical service,

Stations fixes de certains services

62 (1) Le droit de licence radio à payer par l’usager radio à l’égard d’un appareil radio installé dans une station fixe à l’une des fins suivantes est le droit applicable prévu à l’article 1 de la partie III de l’annexe III pour toutes les fréquences d’émission et de réception autorisées :

a) utilisation pour l’un des services suivants :

(i) service aéronautique,

(ii) developmental service,

(iii) maritime service, and

(iv) radiodetermination service;

(b) communicate on radio frequencies at or below 30 MHz; or

(c) communicate on radio frequencies assigned to a radiocommunication service provider and for which the radiocommunication user does not come under the authority of the radiocommunication service provider's licence as a subscriber.

(2) The applicable radio licence fee set out in item 2 of Part III of Schedule III for all authorized transmit and receive frequencies is payable by a radiocommunication user in respect of radio apparatus installed in a fixed station to operate in the public information service.

SOR/2021-40, s. 9.

Land Mobile Service

63 Subject to section 64, the radio licence fee payable by a radiocommunication user in respect of radio apparatus installed in a fixed station to operate in the land mobile service is the fee, for the applicable metropolitan or other area, set out in Part IV of Schedule III for each assigned transmit or receive frequency.

Electronic News Gathering

64 The radio licence fee payable by a radiocommunication user in respect of radio apparatus installed in a fixed station to operate in the land mobile service and to communicate with a mobile station for the purpose of electronic news gathering is the sum of

(a) in respect of all assigned transmit radio frequencies, the fee, for the applicable metropolitan or other area, set out in item 1 of Part IV of Schedule III for one assigned transmit radio frequency, and

(b) in respect of all assigned receive radio frequencies, the fee, for the applicable metropolitan or other area, set out in item 1 of Part IV of Schedule III for one assigned receive radio frequency.

SOR/2014-34, s. 9(F).

(ii) service de développement,

(iii) service maritime,

(iv) service de radiorepérage;

b) communication sur des radiofréquences inférieures ou égales à 30 MHz;

c) communication sur des radiofréquences assignées à un fournisseur de services radio et pour lesquelles l'usager radio, en tant qu'abonné, n'est pas assujetti à la licence de ce fournisseur.

(2) Le droit de licence radio à payer par l'usager radio à l'égard d'un appareil radio installé dans une station fixe du service d'information publique est le droit applicable prévu à l'article 2 de la partie III de l'annexe III pour toutes les fréquences d'émission et de réception autorisées.

DORS/2021-40, art. 9.

Service mobile terrestre

63 Sous réserve de l'article 64, le droit de licence radio à payer par l'usager radio à l'égard d'un appareil radio installé dans une station fixe du service mobile terrestre est le droit applicable prévu à la partie IV de l'annexe III pour chaque fréquence d'émission ou de réception assignée, selon la région métropolitaine ou autre visée.

Journalisme électronique

64 Le droit de licence radio à payer par l'usager radio à l'égard d'un appareil radio installé dans une station fixe du service mobile terrestre et qui sert à communiquer avec une station mobile à des fins de journalisme électronique est la somme des droits suivants :

a) pour toutes les radiofréquences d'émission assignées, le droit prévu à l'article 1 de la partie IV de l'annexe III pour une seule radiofréquence d'émission assignée, selon la région métropolitaine ou autre visée;

b) pour toutes les radiofréquences de réception assignées, le droit prévu à l'article 1 de la partie IV de l'annexe III pour une seule radiofréquence de réception assignée, selon la région métropolitaine ou autre visée.

DORS/2014-34, art. 9(F).

Fixed Stations — Radiocommunication Service Providers

Fixed Stations Communicating with other Fixed Stations or Space Stations

65 The radio licence fee payable by a radiocommunication service provider in respect of radio apparatus installed in a fixed station, other than a fixed station referred to in any of sections 65.1 to 71, is for each transmitter and each receiver installed at the station the sum of the applicable fees set out in Part II of Schedule III that corresponds to the number of telephone channels per radio frequency assigned to that transmitter or receiver.

SOR/2021-40, s. 10.

Fixed Point-to-Point Service

65.1 (1) The radio licence fee payable by a radiocommunication service provider in respect of radio apparatus installed in a fixed station that is part of the fixed point-to-point service consisting of two stations located in an urban area or one station located in an urban area and another in a rural area is, for each link authorized by the licence, the applicable base rate set out in item 1 of Part IV.1 of Schedule III multiplied by the assigned spectrum, in MHz, that is set out in the licence.

(2) The radio licence fee payable by a radiocommunication service provider in respect of radio apparatus installed in a fixed station that is part of the fixed point-to-point service consisting of two stations located in a rural area is, for each link authorized by the licence, the applicable base rate set out in item 2 of Part IV.1 of Schedule III multiplied by the assigned spectrum, in MHz, that is set out in the licence.

(3) The radio licence fee payable by a radiocommunication service provider in respect of radio apparatus installed in a fixed station that is part of the fixed point-to-point service consisting of at least one station located in a remote area is, for each link authorized by the licence, the applicable base rate set out in item 3 of Part IV.1 of Schedule III multiplied by the assigned spectrum, in MHz, that is set out in the licence.

(4) The minimum radio licence fee payable by a radiocommunication service provider in respect of radio apparatus installed in a fixed station that is part of the fixed

Stations fixes — Fournisseurs de services radio

Stations fixes communiquant avec d'autres stations fixes ou des stations spatiales

65 Le droit de licence radio à payer par le fournisseur de services radio à l'égard d'un appareil radio installé dans une station fixe, autre qu'une station fixe visée aux articles 65.1 à 71, est, pour chaque émetteur et chaque récepteur de la station, la somme des droits applicables prévus à la partie II de l'annexe III, établis en fonction du nombre de voies téléphoniques par radiofréquence assignée à l'émetteur ou au récepteur.

DORS/2021-40, art. 10.

Service point à point fixe

65.1 (1) Le droit de licence radio à payer par le fournisseur de services radio à l'égard d'un appareil radio installé dans une station fixe faisant partie du service point à point fixe dont les deux stations sont situées en région urbaine ou dont une station est située en région urbaine et l'autre en région rurale est, pour chaque liaison autorisée par la licence, le taux de référence applicable prévu à l'article 1 de la partie IV.1 de l'annexe III, multiplié par le spectre assigné prévu par la licence, en MHz.

(2) Le droit de licence radio à payer par le fournisseur de services radio à l'égard d'un appareil radio installé dans une station fixe faisant partie du service point à point fixe dont les deux stations sont situées en région rurale est, pour chaque liaison autorisée par la licence, le taux de référence applicable prévu à l'article 2 de la partie IV.1 de l'annexe III, multiplié par le spectre assigné prévu par la licence, en MHz.

(3) Le droit de licence radio à payer par le fournisseur de services radio à l'égard d'un appareil radio installé dans une station fixe faisant partie du service point à point fixe dont au moins une station est située en région éloignée est, pour chaque liaison autorisée par la licence, le taux de référence applicable prévu à l'article 3 de la partie IV.1 de l'annexe III, multiplié par le spectre assigné prévu par la licence, en MHz.

(4) Le droit de licence radio minimum à payer par le fournisseur de services radio à l'égard d'un appareil radio installé dans une station fixe faisant partie du service point-to-point service is, for each link authorized by the licence,

(a) if the two stations are located in an urban area or one station is located in an urban area and the other is located in a rural area, the applicable fee set out in item 1 of Part IV.2 of Schedule III;

(b) if the two stations are located in a rural area, the applicable fee set out in item 2 of Part IV.2 of Schedule III; and

(c) if at least one station is located in a remote area, the applicable fee set out in item 3 of Part IV.2 of Schedule III.

SOR/2021-40, s. 10.

Land Mobile Service

66 Subject to sections 67 to 71, the radio licence fee payable by a radiocommunication service provider in respect of radio apparatus installed in a fixed station to operate in the land mobile service is the fee, for the applicable metropolitan or other area, set out in item 1 of Part V of Schedule III for each assigned transmit or receive frequency.

Dispatch

67 The radio licence fee payable by a radiocommunication service provider in respect of radio apparatus installed in a fixed station for the purpose of dispatch and to communicate with a mobile station in the land mobile service is the applicable congestion zone fee set out in item 2 of Part V of Schedule III for each assigned transmit or receive frequency.

Paging

68 The radio licence fee payable by a radiocommunication service provider in respect of radio apparatus installed in a fixed station in the land mobile service for the purpose of paging is the applicable congestion zone fee set out in item 3 of Part V of Schedule III for each assigned transmit or receive frequency.

69 [Repealed, SOR/2021-40, s. 11]

70 [Repealed, SOR/2021-40, s. 11]

point à point fixe est, pour chaque liaison autorisée par la licence :

a) lorsque les deux stations sont situées en région urbaine ou lorsqu'une station est située en région urbaine et l'autre en région rurale, le droit applicable prévu à l'article 1 de la partie IV.2 de l'annexe III;

b) lorsque les deux stations sont situées en région rurale, le droit applicable prévu à l'article 2 de la partie IV.2 de l'annexe III;

c) lorsqu'au moins une station est située en région éloignée, le droit applicable prévu à l'article 3 de la partie IV.2 de l'annexe III.

DORS/2021-40, art. 10.

Service mobile terrestre

66 Sous réserve des articles 67 à 71, le droit de licence radio à payer par le fournisseur de services radio à l'égard d'un appareil radio installé dans une station fixe du service mobile terrestre est le droit applicable prévu à l'article 1 de la partie V de l'annexe III pour chaque fréquence d'émission ou de réception assignée, selon la région métropolitaine ou autre visée.

Dépêche

67 Le droit de licence radio à payer par le fournisseur de services radio à l'égard d'un appareil radio installé dans une station fixe aux fins de dépêche et de communication avec une station mobile du service mobile terrestre est le droit applicable prévu à l'article 2 de la partie V de l'annexe III pour chaque fréquence d'émission ou de réception assignée, selon la zone d'encombrement visée.

Téléappel

68 Le droit de licence radio à payer par le fournisseur de services radio à l'égard d'un appareil radio installé dans une station fixe du service mobile terrestre aux fins de téléappel est le droit applicable prévu à l'article 3 de la partie V de l'annexe III pour chaque fréquence d'émission ou de réception assignée, selon la zone d'encombrement visée.

69 [Abrogé, DORS/2021-40, art. 11]

70 [Abrogé, DORS/2021-40, art. 11]

Narrowband Personal Communications Services Radio Frequencies

71 The radio licence fee payable by a radiocommunication service provider in respect of radio apparatus installed in a fixed station that communicates on narrowband personal communications services radio frequencies is the applicable fee set out in item 6 of Part V of Schedule III for each 12.5 kHz assigned block of transmit or receive frequencies.

Radiofréquences des services de communications personnelles à bande étroite

71 Le droit de licence radio à payer par le fournisseur de services radio à l'égard d'un appareil radio installé dans une station fixe qui communique sur les radiofréquences des services de communications personnelles à bande étroite est le droit applicable prévu à l'article 6 de la partie V de l'annexe III pour chaque bloc assigné de 12,5 kHz de fréquences d'émission ou de réception.

Fixed Station Communicating with a Station not Otherwise Described

[SOR/97-266, s. 2]

72 The radio licence fee payable in respect of radio apparatus installed in a fixed station other than a fixed station referred to in sections 61 to 71 is the applicable fee set out in item 1 of Part III of Schedule III for all authorized transmit and receive frequencies.

Station fixe communiquant avec une station non visée ailleurs

[DORS/97-266, art. 2]

72 Le droit de licence radio à payer à l'égard d'un appareil radio installé dans une station fixe, autre qu'une station fixe visée aux articles 61 à 71, est le droit applicable prévu à l'article 1 de la partie III de l'annexe III pour toutes les fréquences d'émission et de réception autorisées.

Space Station

73 The radio licence fee payable in respect of radio apparatus installed in a space station that communicates with a fixed station or space station is, for each transmitter and each receiver installed at the station, the sum of the applicable fees set out in Part VI of Schedule III that corresponds to the number of telephone channels per radio frequency assigned to that transmitter or receiver.

Station spatiale

73 Le droit de licence radio à payer à l'égard d'un appareil radio installé dans une station spatiale qui communique avec une station fixe ou une station spatiale est, pour chaque émetteur et chaque récepteur de la station, la somme des droits applicables prévus à la partie VI de l'annexe III, établis en fonction du nombre de voies téléphoniques par radiofréquence assignée à l'émetteur ou au récepteur.

74 [Repealed, SOR/2021-40, s. 12]

74 [Abrogé, DORS/2021-40, art. 12]

Radio Licence Amendments

75 Where a licensee requests an amendment to a radio licence that results in a higher fee, the radio licence fee payable is the difference between the existing fee and the new fee.

Modification de la licence radio

75 Lorsque le titulaire d'une licence radio demande une modification de sa licence qui entraîne des droits plus élevés, le droit de licence radio à payer correspond à la différence entre le nouveau droit et le droit existant.

Additional Radio Frequency

76 Where a licensee operates on an additional radio frequency for which a fee is prescribed, the radio licence fee payable is the difference between the existing fee and the new fee.

Radiofréquence supplémentaire

76 Lorsque le titulaire d'une licence radio utilise une radiofréquence supplémentaire pour laquelle des droits sont prévus, le droit de licence radio à payer correspond à la différence entre le nouveau droit et le droit existant.

Increase in the Number of Telephone Channels per Radio Frequency

77 Where a licensee increases the number of telephone channels of a radio frequency assigned to a transmitter or receiver installed at a fixed station or space station described in section 61, 65 or 73, the radio licence fee payable in respect of that amendment is the difference between

(a) the new fee for the amended total number of telephone channels per radio frequency assigned to that transmitter or receiver, and

(b) the existing fee for the total number of telephone channels per radio frequency assigned to that transmitter or receiver.

Relocation of a Station

78 Where a fixed station referred to in section 67 or 68 is relocated into a congestion zone where the radio licence fee is higher, the radio licence fee payable is, for each assigned transmit or receive radio frequency, the difference between the new fee in the congestion zone to which the station is relocated and the corresponding existing fee applicable in the congestion zone in which the station was previously located.

79 Where a fixed station referred to in section 63 or 66 is relocated from an area into a metropolitan area, the radio licence fee payable is, for each assigned transmit or receive radio frequency, the difference between the new fee in the metropolitan area to which the station is relocated and the corresponding existing fee applicable in the area in which the station was previously located.

80 [Repealed, SOR/2020-278, s. 6]

81 [Repealed, SOR/2020-278, s. 6]

Augmentation du nombre de voies téléphoniques d'une radiofréquence

77 Lorsque le titulaire d'une licence radio augmente le nombre de voies téléphoniques d'une radiofréquence assignée à un émetteur ou à un récepteur d'une station fixe ou d'une station spatiale visée à l'un des articles 61, 65 ou 73, le droit de licence radio à payer pour cette modification correspond à la différence entre les droits suivants :

a) le nouveau droit à payer pour le nombre total, après augmentation, de voies téléphoniques par radiofréquence assignée à l'émetteur ou au récepteur;

b) le droit existant à payer pour le nombre total de voies téléphoniques par radiofréquence assignée à l'émetteur ou au récepteur.

Déplacement d'une station

78 Lorsqu'une station fixe visée aux articles 67 ou 68 est déplacée vers une zone d'encombrement où le droit de licence radio est plus élevé, le droit de licence radio à payer correspond, pour chaque radiofréquence d'émission ou de réception assignée, à la différence entre le nouveau droit applicable à cette zone et le droit existant applicable à la zone d'encombrement où la station était située.

79 Lorsqu'une station fixe visée aux articles 63 ou 66 est déplacée vers une région métropolitaine, le droit de licence radio à payer correspond, pour chaque radiofréquence d'émission ou de réception assignée, à la différence entre le nouveau droit applicable à cette région et le droit existant applicable à la région où la station était située.

80 [Abrogé, DORS/2020-278, art. 6]

81 [Abrogé, DORS/2020-278, art. 6]

SCHEDULE I

(Sections 26, 28 and 35)

Certificate Equivalencies

Item	Column I Certificates Issued Under the Repealed *Radio Operator's Certificate Regulations*	Column II Certificates Issued Under the *Radiocommunication Regulations*
1	[Repealed, SOR/2020-278, s. 7]	
2	[Repealed, SOR/2020-278, s. 7]	
3	[Repealed, SOR/2020-278, s. 7]	
4	General Operator's Certificate (issued after January 4, 1995)	General Operator Certificate
5	Radiotelephone Operator's General Certificate (Aeronautical)	Restricted Operator Certificate with Aeronautical Qualification
6	[Repealed, SOR/2020-278, s. 7]	
7	Radiotelephone Operator's Restricted Certificate (Aeronautical)	Restricted Operator Certificate with Aeronautical Qualification
8	[Repealed, SOR/2020-278, s. 7]	
9	Amateur Radio Operator's Advanced Certificate	Amateur Radio Operator Certificate with (a) Basic Qualification; (b) Basic Qualification with Honours; and (c) Advanced Qualification
10	Amateur Radio Operator's Certificate	Amateur Radio Operator Certificate with (a) Basic Qualification; (b) Basic Qualification with Honours; and (c) Advanced Qualification
11	Amateur Digital Radio Operator's Certificate	Amateur Radio Operator Certificate with (a) Basic Qualification; and (b) Advanced Qualification
12	Amateur Operator's Certificate with (a) Basic Qualification; (b) Morse Code (5 w.p.m.) Qualification; (c) Basic Qualification with Honours; and (d) Advanced Qualification	Amateur Radio Operator Certificate with (a) Basic Qualification; (b) Morse Code (5 w.p.m.) Qualification; (c) Basic Qualification with Honours; and (d) Advanced Qualification

SOR/98-189, ss. 1(F), 2, 3, 4(E); SOR/2011-47, s. 12; SOR/2020-278, s. 7; SOR/2020-278, s. 8.

ANNEXE I

(articles 26, 28 et 35)

Équivalence des certificats

Article	Colonne I Certificats délivrés en vertu de l'ancien *Règlement sur les certificats d'opérateur radio*	Colonne II Certificats délivrés en vertu du *Règlement sur la radiocommunication*
1	[Abrogé, DORS/2020-278, art. 7]	
2	[Abrogé, DORS/2020-278, art. 7]	
3	[Abrogé, DORS/2020-278, art. 7]	
4	Certificat général d'opérateur (délivré après le 4 janvier 1995)	Certificat général d'opérateur radio
5	Certificat général de radiotéléphoniste (service aéronautique)	Certificat restreint d'opérateur radio (compétence aéronautique)
6	[Abrogé, DORS/2020-278, art. 7]	
7	Certificat restreint de radiotéléphoniste (service aéronautique)	Certificat restreint d'opérateur radio (compétence aéronautique)
8	[Abrogé, DORS/2020-278, art. 7]	
9	Certificat supérieur de radioamateur	Certificat d'opérateur radioamateur avec : a) compétence de base b) compétence de base avec distinction c) compétence supérieure
10	Certificat de radioamateur	Certificat d'opérateur radioamateur avec : a) compétence de base b) compétence de base avec distinction c) compétence supérieure
11	Certificat numérique de radioamateur	Certificat d'opérateur radioamateur avec : a) compétence de base b) compétence supérieure
12	Certificat de radioamateur avec : a) compétence de base b) compétence en morse (5 mots/min) c) compétence de base avec distinction d) compétence supérieure	Certificat d'opérateur radioamateur avec : a) compétence de base b) compétence en morse (5 mots/min) c) compétence de base avec distinction d) compétence supérieure

DORS/98-189, art. 1(F), 2, 3 et 4(A); DORS/2011-47, art. 12; DORS/2020-278, art. 7; DORS/2020-278, art. 8.

SCHEDULE II

(Sections 33, 34 and 36)

Operation of Radio Stations

	Column I	Column II
Item	Radio Operator Certificates	Radio Stations
1	Restricted Operator Certificate with Aeronautical Qualification	Radio installations that form part of any station authorized in the aeronautical service
2	[Repealed, SOR/2020-278, s. 9]	
3	Restricted Operator Certificate with Maritime Qualification	Radio installations that form part of any authorized station on board a ship that is voluntarily fitted with those installations, or radiotelephone installations that form part of any authorized station on board a ship that is compulsorily fitted with those installations in accordance with the *Ship Station Radio Regulations* and is not capable of digital selective calling or is a ship earth station
4	General Operator Certificate	Radio installations that form part of any authorized station on board a ship that is voluntarily fitted with those installations or compulsorily fitted with those installations in accordance with the *Ship Station Radio Regulations*
5	First-Class Radioelectronic Certificate	Radio installations that form part of any authorized station on board a ship that is voluntarily fitted with those installations or compulsorily fitted with those installations in accordance with the *Ship Station Radio Regulations*
6	[Repealed, SOR/2020-278, s. 9]	
7 and 8	[Repealed, SOR/97-266, s. 5]	
9	General Operator's Certificate (issued prior or on January 4, 1995)	Radio installations that form part of any authorized station on board a ship that is voluntarily fitted with those installations or radiotelephone installations that form part of any authorized station on board a ship that is compulsorily fitted with those installations in accordance with the *Ship Station Radio Regulations* and is not capable of digital selective calling or is a ship earth station
10	Coast Guard Radiotelegraph Operator's Certificate	Radio installations that form part of any authorized station on board a ship that is voluntarily fitted with those installations or radiotelephone installations that form part of any authorized station on board a ship that is compulsorily fitted with those installations in accordance with the *Ship Station Radio Regulations* and is not capable of digital selective calling or is a ship earth station

ANNEXE II

(articles 33, 34 et 36)

Exploitation des stations

	Colonne I	Colonne II
Article	Certificats d'opérateur radio	Stations
1	Certificat restreint d'opérateur radio (compétence aéronautique)	Installations radio faisant partie d'une station autorisée quelconque du service aéronautique
2	[Abrogé, DORS/2020-278, art. 9]	
3	Certificat restreint d'opérateur radio (compétence maritime)	Installations radio faisant partie d'une station autorisée quelconque à bord d'un navire volontairement muni d'installations radio ou installations de radiotéléphonie faisant partie d'une station autorisée quelconque à bord d'un navire obligatoirement muni, conformément au *Règlement sur les stations radio de navires,* et qui est incapable d'effectuer un appel sélectif numérique ou qui constitue une station terrienne de navire
4	Certificat général d'opérateur radio	Installations radio faisant partie d'une station autorisée quelconque à bord d'un navire volontairement ou obligatoirement muni, conformément au *Règlement sur les stations radio de navires*
5	Certificat de radioélectronicien de première classe	Installations radio faisant partie d'une station autorisée quelconque à bord d'un navire volontairement ou obligatoirement muni, conformément au *Règlement sur les stations radio de navires*
6	[Abrogé, DORS/2020-278, art. 9]	
7 et 8	[Abrogés, DORS/97-266, art. 5]	
9	Certificat général d'opérateur (délivré au plus tard le 4 janvier 1995)	Installations radio faisant partie d'une station autorisée quelconque à bord d'un navire volontairement muni ou installations de radiotéléphonie faisant partie d'une station autorisée quelconque à bord d'un navire obligatoirement muni, conformément au *Règlement sur les stations radio de navires*, et qui est incapable d'effectuer un appel sélectif numérique ou qui constitue une station terrienne de navire
10	Certificat de radiotélégraphiste de la Garde côtière	Installations radio faisant partie d'une station autorisée quelconque à bord d'un navire volontairement muni ou installations de radiotéléphonie faisant partie d'une station autorisée quelconque à bord d'un navire obligatoirement muni, conformément au *Règlement sur les stations radio de navires*, et qui est incapable d'effectuer un appel sélectif numérique ou qui constitue une station terrienne de navire

Item	Column I Radio Operator Certificates	Column II Radio Stations
11	Coast Guard Radiotelephone Operator’s Certificate	Radio installations that form part of any authorized station on board a ship that is voluntarily fitted with those installations or radiotelephone installations that form part of any authorized station on board a ship that is compulsorily fitted with those installations in accordance with the *Ship Station Radio Regulations* and is not capable of digital selective calling or is a ship earth station
12	Restricted Operator’s Certificate	Radio installations that form part of any authorized station on board a ship that is voluntarily fitted with those installations or radio installations that form part of any authorized station on board a small fishing vessel that is compulsorily fitted with those installations in accordance with the *Ship Station Radio Regulations* or radiotelephone installations and VHF digital selective calling equipment that form part of any authorized station on board a ship, other than a small fishing vessel, that is compulsorily fitted with those installations in accordance with those Regulations
13	Radiotelephone Operator’s General Certificate (Maritime)	Radio installations that form part of any authorized station on board a ship that is voluntarily fitted with those installations or radiotelephone installations that form part of any authorized station on board a ship that is compulsorily fitted with those installations in accordance with the *Ship Station Radio Regulations* and is not capable of digital selective calling or is a ship earth station
14	Radiotelephone Operator’s Restricted Certificate (Maritime)	Radio installations that form part of any authorized station on board a ship that is voluntarily fitted with those installations or radiotelephone installations that form part of any authorized station on board a ship that is compulsorily fitted with those installations in accordance with the *Ship Station Radio Regulations* and is not capable of digital selective calling or is a ship earth station
15	Amateur Radio Operator Certificate with Basic Qualification	Radio installations that form part of any station authorized in the amateur radio service

SOR/97-266, ss. 3(F), 4 to 6; SOR/98-189, ss. 5, 6, 7(F); SOR/2001-533, ss. 12, 13; SOR/2020-278, s. 9.

Article	Colonne I Certificats d’opérateur radio	Colonne II Stations
11	Certificat de radiotéléphoniste de la Garde côtière	Installations radio faisant partie d’une station autorisée quelconque à bord d’un navire volontairement muni ou installations de radiotéléphonie faisant partie d’une station autorisée quelconque à bord d’un navire obligatoirement muni, conformément au *Règlement sur les stations radio de navires*, et qui est incapable d’effectuer un appel sélectif numérique ou qui constitue une station terrienne de navire
12	Certificat restreint d’opérateur	Installations radio faisant partie d’une station autorisée quelconque à bord d’un navire volontairement muni ou installations radio faisant partie d’une station autorisée quelconque à bord d’un petit navire de pêche obligatoirement muni, conformément au *Règlement sur les stations radio de navires*, ou installations de radiotéléphonie et équipement d’appel sélectif numérique VHF faisant partie d’une station autorisée quelconque à bord d’un navire autre qu’un petit navire de pêche, obligatoirement muni, conformément au *Règlement sur les stations radio de navires*
13	Certificat général de radiotéléphoniste (service maritime)	Installations radio faisant partie d’une station autorisée quelconque à bord d’un navire volontairement muni ou installations de radiotéléphonie faisant partie d’une station autorisée quelconque à bord d’un navire obligatoirement muni, conformément au *Règlement sur les stations radio de navires*, et qui est incapable d’effectuer un appel sélectif numérique ou qui constitue une station terrienne de navire
14	Certificat restreint de radiotéléphoniste (service maritime)	Installations radio faisant partie d’une station autorisée quelconque à bord d’un navire volontairement muni ou installations de radiotéléphonie faisant partie d’une station autorisée quelconque à bord d’un navire obligatoirement muni, conformément au *Règlement sur les stations radio de navires*, et qui est incapable d’effectuer un appel sélectif numérique ou qui constitue une station terrienne de navire
15	Certificat d’opérateur radioamateur avec compétence de base	Installations radio faisant partie d’une station autorisée quelconque du service de radioamateur

DORS/97-266, art. 3(F) et 4 à 6; DORS/98-189, art. 5, 6 et 7(F); DORS/2001-533, art. 12 et 13; DORS/2020-278, art. 9.

SCHEDULE III

PART I

(Sections 56 and 60)

Fee Schedule Applicable for a Mobile Station in any Service other than the Amateur Radio Service

Item	Column I Type of Station, for all Authorized Transmit and Receive Frequencies	Column II [Repealed, SOR/2014-34, s. 10]	Column III Monthly Fee	Column IV Annual Fee	Columns V and VI [Repealed, SOR/2014-34, s. 10]
1	[Repealed, SOR/2000-78, s. 14]				
2	Mobile station in the aeronautical or maritime services		3.00	36.00	
3	Mobile station in the public information service		3.00	36.00	
4	Mobile station in the developmental or radiodetermination service		3.40	41.00	
5	Mobile station in the land mobile service		3.40	41.00	
6	Mobile station communicating with a space station		3.40	41.00	
7	Other mobile station		3.40	41.00	

PART II

(Sections 56, 58, 61 and 65)

Fee Schedule Applicable for Fixed Stations that Communicate with other Fixed Stations or Space Stations

Item	Column I Number of Telephone Channels per Radio Frequency Assigned to each Transmitter or Receiver	Column II [Repealed, SOR/2014-34, s. 10]	Column III Monthly Fee	Column IV Annual Fee	Columns V and VI [Repealed, SOR/2014-34, s. 10]
1	From 1 to 24		$ 2.80	$ 34.00	
2	From 25 to 60		3.50	42.00	
3	From 61 to 120		4.20	50.00	
4	From 121 to 300		7.60	91.00	
5	From 301 to 600		12.60	151.00	
6	From 601 to 960		17.80	213.00	
7	From 961 to 1,200		23.10	277.00	
8	1,201 or more		$23.10, plus $5.30 per 300 telephone channels or portion thereof in excess of 1,200	$277.00, plus $63.00 per 300 telephone channels or portion thereof in excess of 1,200	

PART III

(Sections 56, 62 and 72)

Fee Schedule Applicable to Radiocommunication Users for Fixed Stations Operating in Certain Services

Item	Column I Type of Station, for all Authorized Transmit and Receive Frequencies	Column II [Repealed, SOR/2014-34, s. 10]	Column III Monthly Fee	Column IV Annual Fee	Columns V and VI [Repealed, SOR/2014-34, s. 10]
1	Fixed station referred to in subsection 62(1) or section 72 of these Regulations		$3.40	$41.00	
2	Fixed station in the public information service		3.00	36.00	

PART IV

(Sections 55, 56, 63 and 64)

Fee Schedule Applicable to Radiocommunication Users for Fixed Stations in the Land Mobile Service

Item	Column I For each Assigned Transmit or Receive Frequency	Column II [Repealed, SOR/2014-34, s. 10]	Column III Monthly Fee	Column IV Annual Fee	Columns V and VI [Repealed, SOR/2014-34, s. 10]
1	(a) Metropolitan Area		$9.70	$116.00	
	(b) Other Area		4.40	53.00	

PART IV.1

(Subsections 61.1(1) to (3) and 65.1(1) to (3))

Fee Schedule Applicable for Stations in the Fixed Point-to-Point Service

Item	Column I Area and Assigned Radio Frequency	Column II Monthly Base Rate ($/MHz)	Column III Annual Base Rate ($/MHz)
1	Urban Area		
	(a) ≤ 890 MHz	229.17	2,750.00
	(b) > 890 and ≤ 960 MHz	11.50	138.00
	(c) > 960 and ≤ 4200 MHz	3.75	45.00
	(d) > 4.2 and ≤ 8.5 GHz	2.83	34.00
	(e) > 8.5 and ≤ 15.35 GHz	2.00	24.00
	(f) > 15.35 and ≤ 24.25 GHz	1.33	16.00
	(g) > 24.25 and ≤ 52.6 GHz	0.83	10.00
	(h) > 52.6 GHz	0.04	0.50
2	Rural Area		
	(a) ≤ 890 MHz	183.33	2,200.00
	(b) > 890 and ≤ 960 MHz	9.20	110.40
	(c) > 960 and ≤ 4200 MHz	3.00	36.00

Item	Column I Area and Assigned Radio Frequency	Column II Monthly Base Rate ($/MHz)	Column III Annual Base Rate ($/MHz)
	(d) > 4.2 and ≤ 8.5 GHz	2.27	27.20
	(e) > 8.5 and ≤ 15.35 GHz	1.60	19.20
	(f) > 15.35 and ≤ 24.25 GHz	1.07	12.80
	(g) > 24.25 and ≤ 52.6 GHz	0.67	8.00
	(h) > 52.6 GHz	0.03	0.40
3	Remote Area		
	(a) ≤ 890 MHz	114.58	1,375.00
	(b) > 890 and ≤ 960 MHz	5.75	69.00
	(c) > 960 and ≤ 4200 MHz	1.88	22.50
	(d) > 4.2 and ≤ 8.5 GHz	1.42	17.00
	(e) > 8.5 and ≤ 15.35 GHz	1.00	12.00
	(f) > 15.35 and ≤ 24.25 GHz	0.67	8.00
	(g) > 24.25 and ≤ 52.6 GHz	0.42	5.00
	(h) > 52.6 GHz	0.02	0.25

PART IV.2

(Subsections 61.1(4) and 65.1(4))

Minimum Fee Schedule Applicable for Stations in the Fixed Point-to-Point Service

Item	Column I Area	Column II Minimum Monthly Fee ($)	Column III Minimum Annual Fee ($)
1	Urban Area	5.83	70.00
2	Rural Area	4.67	56.00
3	Remote Area	2.92	35.00

PART V

(Sections 55, 56 and 66 to 71)

Fee Schedule Applicable to Radiocommunication Service Providers for Fixed Stations in The Land Mobile Service

Item	Column I Type of Operation, and Area, Congestion Zone or Coverage Area	Column II [Repealed, SOR/2014-34, s. 10]	Column III Monthly Fee	Column IV Annual Fee	Columns V and VI [Repealed, SOR/2014-34, s. 10]
1	For each assigned transmit or receive frequency				
	(a) Metropolitan Area		$9.70	$116.00	
	(b) Other Area		4.40	53.00	
2	Dispatch				
	For each assigned transmit or receive frequency				

Item	Column I Type of Operation, and Area, Congestion Zone or Coverage Area	Column II [Repealed, SOR/2014-34, s. 10]	Column III Monthly Fee	Column IV Annual Fee	Columns V and VI [Repealed, SOR/2014-34, s. 10]
	(a) High Congestion Zone		87.60	1,051.00	
	(b) Medium Congestion Zone		43.80	526.00	
	(c) Low Congestion Zone		21.80	262.00	
3	Paging				
	For each assigned transmit or receive frequency				
	(a) High Congestion Zone		30.70	368.00	
	(b) Medium Congestion Zone		26.30	316.00	
	(c) Low Congestion Zone		21.80	262.00	
4	[Repealed, SOR/2021-40, s. 15]				
5	[Repealed, SOR/2021-40, s. 15]				
6	Narrowband Personal Communications Services Radio Frequencies				
	For each 12.5 kHz assigned block of transmit or receive frequencies		43.80	525.00	

PART VI

(Sections 56, 58 and 73)

Fee Schedule Applicable for Space Stations that Communicate with Fixed Stations or Space Stations

Item	Column I Number of Telephone Channels per Radio Frequency Assigned to each Transmitter or Receiver	Column II [Repealed, SOR/2014-34, s. 10]	Column III Monthly Fee	Column IV Annual Fee	Columns V and VI [Repealed, SOR/2014-34, s. 10]
1	From 1 to 24		$ 98.10	$1,177.00	
2	From 25 to 60		122.60	1,471.00	
3	From 61 to 120		147.10	1,765.00	
4	From 121 to 300		262.70	3,152.00	
5	From 301 to 600		446.60	5,359.00	
6	From 601 to 960		630.30	7,564.00	
7	From 961 to 1,200		814.30	9,771.00	
8	1,201 or more		$814.30, plus $183.90 per 300 telephone channels or portion thereof in excess of 1,200	$9,771.00, plus $2,207.00 per 300 telephone channels or portion thereof in excess of 1,200	

PART VII

[Repealed, SOR/2021-40, s. 16]

SOR/2000-78, ss. 13, 14; SOR/2014-34, ss. 10 to 16; SOR/2021-40, s. 13; SOR/2021-40, s. 14; SOR/2021-40, s. 15; SOR/2021-40, s. 16.

ANNEXE III

PARTIE I

(articles 56 et 60)

Droits applicables pour une station mobile de tout service autre que le service de radioamateur

Article	Colonne I Type de station, pour toutes les fréquences d'émission et de réception autorisées	Colonne II [Abrogée, DORS/2014-34, art. 10]	Colonne III Droit mensuel	Colonne IV Droit annuel	Colonnes V et VI [Abrogées, DORS/2014-34, art. 10]
1	[Abrogé, DORS/2000-78, art. 14]				
2	Station mobile des services aéronautique ou maritime		3,00	36,00	
3	Station mobile du service d'information publique		3,00	36,00	
4	Station mobile des services de développement ou de radiorepérage		3,40	41,00	
5	Station mobile du service mobile terrestre		3,40	41,00	
6	Station mobile communiquant avec une station spatiale		3,40	41,00	
7	Autre station mobile		3,40	41,00	

PARTIE II

(articles 56, 58, 61 et 65)

Droits applicables pour les stations fixes communiquant avec d'autres stations fixes ou des stations spatiales

Article	Colonne I Nombre de voies téléphoniques par radiofréquence assignée à chaque émetteur ou récepteur	Colonne II [Abrogée, DORS/2014-34, art. 10]	Colonne III Droit mensuel	Colonne IV Droit annuel	Colonnes V et VI [Abrogées, DORS/2014-34, art. 10]
1	De 1 à 24		2,80 $	34,00 $	
2	De 25 à 60		3,50	42,00	
3	De 61 à 120		4,20	50,00	
4	De 121 à 300		7,60	91,00	
5	De 301 à 600		12,60	151,00	
6	De 601 à 960		17,80	213,00	
7	De 961 à 1 200		23,10	277,00	
8	1 201 ou plus		23,10 $, plus 5,30 $ par groupe de 300 voies téléphoniques ou moins excédant 1 200	277,00 $, plus 63,00 $ par groupe de 300 voies téléphoniques ou moins excédant 1 200	

PARTIE III

(articles 56, 62 et 72)

Droits applicables aux usagers radio pour les stations fixes de certains services

Article	Colonne I Type de station, pour toutes les fréquences d'émission et de réception autorisées	Colonne II [Abrogée, DORS/2014-34, art. 10]	Colonne III Droit mensuel	Colonne IV Droit annuel	Colonnes V et VI [Abrogées, DORS/2014-34, art. 10]
1	Station fixe visée au paragraphe 62(1) ou à l'article 72 du présent règlement		3,40 $	41,00 $	
2	Station fixe du service d'information publique		3,00	36,00	

PARTIE IV

(articles 55, 56, 63 et 64)

Droits applicables aux usagers radio pour les stations fixes du service mobile terrestre

Article	Colonne I Pour chaque fréquence d'émission ou de réception assignée	Colonne II [Abrogée, DORS/2014-34, art. 10]	Colonne III Droit mensuel	Colonne IV Droit annuel	Colonnes V et VI [Abrogées, DORS/2014-34, art. 10]
1	a) Région métropolitaine		9,70 $	116,00 $	
	b) Autre région		4,40	53,00	

PARTIE IV.1

(paragraphes 61.1(1) à (3) et 65.1(1) à (3))

Droits applicables pour les stations du service point à point fixe

Article	Colonne I Région et radiofréquences assignées	Colonne II Taux de référence mensuel ($/MHz)	Colonne III Taux de référence annuel ($/MHz)
1	Région urbaine		
	a) ≤ 890 MHz	229,17	2 750,00
	b) > 890 et ≤ 960 MHz	11,50	138,00
	c) > 960 et ≤ 4200 MHz	3,75	45,00
	d) > 4,2 et ≤ 8,5 GHz	2,83	34,00
	e) > 8,5 et ≤ 15,35 GHz	2,00	24,00
	f) > 15,35 et ≤ 24,25 GHz	1,33	16,00
	g) > 24,25 et ≤ 52,6 GHz	0,83	10,00
	h) > 52,6 GHz	0,04	0,50
2	Région rurale		
	a) ≤ 890 MHz	183,33	2 200,00
	b) > 890 et ≤ 960 MHz	9,20	110,40
	c) > 960 et ≤ 4200 MHz	3,00	36,00
	d) > 4,2 et ≤ 8,5 GHz	2,27	27,20
	e) > 8,5 et ≤ 15,35 GHz	1,60	19,20
	f) > 15,35 et ≤ 24,25 GHz	1,07	12,80

Article	Colonne I Région et radiofréquences assignées	Colonne II Taux de référence mensuel ($/MHz)	Colonne III Taux de référence annuel ($/MHz)
	g) > 24,25 et ≤ 52,6 GHz	0,67	8,00
	h) > 52,6 GHz	0,03	0,40
3	Région éloignée		
	a) ≤ 890 MHz	114,58	1 375,00
	b) > 890 et ≤ 960 MHz	5,75	69,00
	c) > 960 et ≤ 4200 MHz	1,88	22,50
	d) > 4,2 et ≤ 8,5 GHz	1,42	17,00
	e) > 8,5 et ≤ 15,35 GHz	1,00	12,00
	f) > 15,35 et ≤ 24,25 GHz	0,67	8,00
	g) > 24,25 et ≤ 52,6 GHz	0,42	5,00
	h) > 52,6 GHz	0,02	0,25

PARTIE IV.2

(paragraphes 61.1(4) et 65.1(4))

Droits minimums applicables pour les stations du service point à point fixe

Article	Colonne I Région	Colonne II Droit mensuel minimum ($)	Colonne III Droit annuel minimum ($)
1	Région urbaine	5,83	70,00
2	Région rurale	4,67	56,00
3	Région éloignée	2,92	35,00

PARTIE V

(articles 55, 56 et 66 à 71)

Droits applicables aux fournisseurs de services de radiocommunications pour les stations fixes du service mobile terrestre

Article	Colonne I Type d’installation, selon la région, la zone d’encombrement ou la zone de couverture	Colonne II [Abrogée, DORS/2014-34, art. 10]	Colonne III Droit mensuel	Colonne IV Droit annuel	Colonnes V et VI [Abrogées, DORS/2014-34, art. 10]
1	Pour chaque fréquence d’émission ou de réception assignée				
	a) Région métropolitaine		9,70 $	116,00 $	
	b) Autre région		4,40	53,00	
2	Dépêche				
	Pour chaque fréquence d’émission ou de réception assignée				
	a) Zone d’encombrement intense		87,60	1 051,00	
	b) Zone d’encombrement moyen		43,80	526,00	
	c) Zone d’encombrement faible		21,80	262,00	

Article	Colonne I Type d’installation, selon la région, la zone d’encombrement ou la zone de couverture	Colonne II [Abrogée, DORS/2014-34, art. 10]	Colonne III Droit mensuel	Colonne IV Droit annuel	Colonnes V et VI [Abrogées, DORS/2014-34, art. 10]
3	Téléappel				
	Pour chaque fréquence d’émission ou de réception assignée				
	a) Zone d’encombrement intense		30,70	368,00	
	b) Zone d’encombrement moyen		26,30	316,00	
	c) Zone d’encombrement faible		21,80	262,00	
4	[Abrogé, DORS/2021-40, art. 15]				
5	[Abrogé, DORS/2021-40, art. 15]				
6	Radiofréquences des services de communications personnelles à bande étroite				
	Pour chaque bloc assigné de 12,5 kHz de fréquences d’émission ou de réception		43,80	525,00	

PARTIE VI

(articles 56, 58 et 73)

Droits applicables aux stations spatiales communiquant avec des stations fixes ou des stations spatiales

Article	Colonne I Nombre de voies téléphoniques par radiofréquence assignée à chaque émetteur ou récepteur	Colonne II [Abrogée, DORS/2014-34, art. 10]	Colonne III Droit mensuel	Colonne IV Droit annuel	Colonnes V et VI [Abrogées, DORS/2014-34, art. 10]
1	De 1 à 24		98,10 $	1 177,00 $	
2	De 25 à 60		122,60	1 471,00	
3	De 61 à 120		147,10	1 765,00	
4	De 121 à 300		262,70	3 152,00	
5	De 301 à 600		446,60	5 359,00	
6	De 601 à 960		630,30	7 564,00	
7	De 961 à 1 200		814,30	9 771,00	
8	1 201 ou plus		814,30 $, plus 183,90 $ par groupe de 300 voies téléphoniques ou moins excédant 1 200	9 771,00 $, plus 2 207,00 $ par groupe de 300 voies téléphoniques ou moins excédant 1 200	

PARTIE VII

[Abrogée, DORS/2021-40, art. 16]

DORS/2000-78, art. 13 et 14; DORS/2014-34, art. 10 à 16; DORS/2021-40, art. 13; DORS/2021-40, art. 14; DORS/2021-40, art. 15; DORS/2021-40, art. 16.

SCHEDULE IV

(Sections 55, 63, 66 and 79)

Metropolitan Areas

	Column I	Column II	Column III	Column IV	Column V
Item	Metropolitan Area	North Latitude		West Longitude	
1	Calgary, Alta.	50° 51′	51° 13′	113° 50′	114° 18′
2	Chicoutimi-Jonquière, Que.	48° 22′	48° 27′	70° 55′	71° 13′
3	Edmonton, Alta.	53° 19′	53° 45′	113° 10′	113° 45′
4	Halifax, N.S.	44° 35′	44° 43′	63° 29′	63° 40′
5	Hamilton, Ont.	43° 09′	43° 24′	79° 43′	80° 00′
6	Kitchener, Ont.	43° 20′	43° 32′	80° 16′	80° 36′
7	London, Ont.	42° 54′	43° 03′	81° 08′	81° 21′
8	Montréal, Que.	45° 21′	45° 45′	73° 18′	74° 00′
9	Oshawa, Ont.	43° 50′	43° 57′	78° 45′	78° 55′
10	Ottawa-Hull, Ont., Que.	45° 17′	45° 30′	75° 30′	75° 55′
11	Québec, Que.	46° 41′	46° 52′	71° 06′	71° 25′
12	Regina, Sask.	50° 22′	50° 33′	104° 29′	104° 43′
13	Saint John, N.B.	45° 13′	45° 18′	66° 00′	66° 10′
14	Saskatoon, Sask.	52° 04′	52° 15′	106° 23′	106° 47′
15	St. Catharines-Niagara, Ont.	43° 03′	43° 17′	79° 02′	79° 20′
16	St. John’s, Nfld.	47° 30′	47° 38′	52° 32′	52° 48′
17	Sudbury, Ont.	46° 25′	46° 34′	80° 46′	81° 02′
18	Thunder Bay, Ont.	48° 18′	48° 29′	89° 09′	89° 20′
19	Toronto, Ont.	43° 24′	43° 55′	78° 55′	79° 43′
20	Vancouver, B.C.	49° 00′	49° 23′	122° 31′	123° 17′
21	Victoria, B.C.	48° 24′	48° 45′	123° 15′	123° 32′
22	Windsor, Ont.	42° 13′	42° 21′	82° 50′	83° 07′
23	Winnipeg, Man.	49° 42′	50° 00′	96° 57′	97° 30′

ANNEXE IV

(articles 55, 63, 66 et 79)

Régions métropolitaines

	Colonne I	Colonne II	Colonne III	Colonne IV	Colonne V
Poste	Région métropolitaine	Latitude nord		Longitude ouest	
1	Calgary (Alb.)	50° 51′	51° 13′	113° 50′	114° 18′
2	Chicoutimi-Jonquière (QC)	48° 22′	48° 27′	70° 55′	71° 13′
3	Edmonton (Alb.)	53° 19′	53° 45′	113° 10′	113° 45′
4	Halifax (N.-É.)	44° 35′	44° 43′	63° 29′	63° 40′
5	Hamilton (Ont.)	43° 09′	43° 24′	79° 43′	80° 00′
6	Kitchener (Ont.)	43° 20′	43° 32′	80° 16′	80° 36′
7	London (Ont.)	42° 54′	43° 03′	81° 08′	81° 21′
8	Montréal (QC)	45° 21′	45° 45′	73° 18′	74° 00′
9	Oshawa (Ont.)	43° 50′	43° 57′	78° 45′	78° 55′
10	Ottawa-Hull (Ont.), (QC)	45° 17′	45° 30′	75° 30′	75° 55′
11	Québec (QC)	46° 41′	46° 52′	71° 06′	71° 25′
12	Regina (Sask.)	50° 22′	50° 33′	104° 29′	104° 43′
13	Saint John (N.-B.)	45° 13′	45° 18′	66° 00′	66° 10′
14	Saskatoon (Sask.)	52° 04′	52° 15′	106° 23′	106° 47′
15	St. Catharines-Niagara (Ont.)	43° 03′	43° 17′	79° 02′	79° 20′
16	St. John’s (T.-N.)	47° 30′	47° 38′	52° 32′	52° 48′
17	Sudbury (Ont.)	46° 25′	46° 34′	80° 46′	81° 02′
18	Thunder Bay (Ont.)	48° 18′	48° 29′	89° 09′	89° 20′
19	Toronto (Ont.)	43° 24′	43° 55′	78° 55′	79° 43′
20	Vancouver (C.-B.)	49° 00′	49° 23′	122° 31′	123° 17′
21	Victoria (C.-B.)	48° 24′	48° 45′	123° 15′	123° 32′
22	Windsor (Ont.)	42° 13′	42° 21′	82° 50′	83° 07′
23	Winnipeg (Man.)	49° 42′	50° 00′	96° 57′	97° 30′

SCHEDULE V

(Sections 55, 67, 68 and 78)

High Congestion Zones

	Column I	Column II		Column III		Column IV		Column V		Column VI		Column VII		Column VIII		Column IX		Column X	
		Geographical Coordinates		Geographical Coordinates		Geographical Coordinates		Geographical Coordinates		Geographical Coordinates		Geographical Coordinates		Geographical Coordinates		Geographical Coordinates		Geographical Coordinates	
Item	Regional Area	North Lat.	West Long.	North Lat..	West Long.	North Lat.	West Long.	North Lat.	West Long.	North Lat.	West Long.	North Lat.	West Long.	North Lat.	West Long.	North Lat.	West Long.	North Lat.	West Long.
1	Calgary, Alta.	51° 06′	114° 13′	51° 06′	113° 58′	50° 57′	113° 58′	50° 57′	114° 13′	-	-	-	-	-	-	-	-	-	-
2	Edmonton, Alta.	53° 36′	113° 37′	53° 36′	113° 23′	53° 28′	113° 23′	53° 28′	113° 37′	-	-	-	-	-	-	-	-	-	-
3	Montréal, Que.	45° 24′	74° 00′	45° 41′	73° 44′	45° 42′	73° 27′	45° 31′	73° 24′	45° 24′	73° 27′	-	-	-	-	-	-	-	-
4	Toronto, Ont.	44° 08′	79° 40′	44° 00′	78° 45′	43° 02′	78° 45′	43° 02′	79° 30′	43° 10′	80° 00′	43° 40′	80° 00′	-	-	-	-	-	-
5	Vancouver, B.C.	49° 23′	123° 25′	49° 23′	122° 08′	49° 00′	122° 08′	49° 00′	123° 20′	49° 19′	123° 25′	-	-	-	-	-	-	-	-
6	Victoria, B.C.	49° 20′	124° 30′	49° 20′	124° 00′	48° 50′	123° 00′	48° 18′	123° 15′	48° 18′	123° 45′	48° 35′	123° 45′	-	-	-	-	-	-

ANNEXE V

(articles 55, 67, 68 et 78)

Zones d’encombrement intense

	Colonne I	Colonne II		Colonne III		Colonne IV		Colonne V		Colonne VI		Colonne VII		Colonne VIII		Colonne IX		Colonne X	
		Coordonnées géographiques		Coordonnées géographiques		Coordonnées géographiques		Coordonnées géographiques		Coordonnées géographiques		Coordonnées géographiques		Coordonnées géographiques		Coordonnées géographiques		Coordonnées géographiques	
Article	Zone régionale	Lat. nord	Long. ouest	Lat. nord	Long. ouest	Lat. nord	Long. ouest	Lat. nord	Long. ouest	Lat. nord	Long. ouest	Lat. nord	Long. ouest	Lat. nord	Long. ouest	Lat. nord	Long. ouest	Lat. nord	Long. ouest
1	Calgary (Alb.)	51° 06′	114° 13′	51° 06′	113° 58′	50° 57′	113° 58′	50° 57′	114° 13′	-	-	-	-	-	-	-	-	-	-
2	Edmonton (Alb.)	53° 36′	113° 37′	53° 36′	113° 23′	53° 28′	113° 23′	53° 28′	113° 37′	-	-	-	-	-	-	-	-	-	-
3	Montréal(QC)	45° 24′	74° 00′	45° 41′	73° 44′	45° 42′	73° 27′	45° 31′	73° 24′	45° 24′	73° 27′	-	-	-	-	-	-	-	-
4	Toronto (Ont.)	44° 08′	79° 40′	44° 00′	78° 45′	43° 02′	78° 45′	43° 02′	79° 30′	43° 10′	80° 00′	43° 40′	80° 00′	-	-	-	-	-	-
5	Vancouver (C.-B.)	49° 23′	123° 25′	49° 23′	122° 08′	49° 00′	122° 08′	49° 00′	123° 20′	49° 19′	123° 25′	-	-	-	-	-	-	-	-
6	Victoria (C.-B.)	49° 20′	124° 30′	49° 20′	124° 00′	48° 50′	123° 00′	48° 18′	123° 15′	48° 18′	123° 45′	48° 35′	123° 45′	-	-	-	-	-	-

SCHEDULE VI

(Sections 55, 67, 68 and 78)

Medium Congestion Zone

	Column I	Column II		Column III		Column IV		Column V		Column VI		Column VII		Column VIII		Column IX		Column X		Column XI	
		Geographical Coordinates		Geographical Coordinates		Geographical Coordinates		Geographical Coordinates		Geographical Coordinates		Geographical Coordinates		Geographical Coordinates		Geographical Coordinates		Geographical Coordinates		Geographical Coordinates	
Item	Regional Area	North Lat.	West Long.	North Lat..	West Long.	North Lat.	West Long.	North Lat.	West Long.	North Lat.	West Long.	North Lat.	West Long.	North Lat.	West Long.	North Lat.	West Long.	North Lat.	West Long.	North Lat.	West Long.
1	Calgary, Alta.	51°13′	114°18′	51°13′	113° 50′	50°51′	113°50′	50°51′	114°18′	-	-	-	-	-	-	-	-	-	-	-	-
2	Chicoutimi, Que.	48° 23′	71° 18′	48° 28′	71° 18′	48° 38′	70° 48′	48° 33′	70° 48′	48° 23′	71° 00′	-	-	-	-	-	-	-	-	-	-
3	Chilliwack, B.C.	49°23′	122°08′	49° 23′	121° 30′	49° 00′	121°30′	49° 00′	122°08′	-	-	-	-	-	-	-	-	-	-	-	-
4	Edmonton, Alta.	53° 45′	113°45′	53° 45′	113° 10′	53° 19′	113°10′	53° 19′	113°45′	-	-	-	-	-	-	-	-	-	-	-	-
5	Halifax, N.S.	44° 48′	63° 46′	44° 48′	63° 25′	44° 33′	63° 25′	44° 33′	63° 46′	-	-	-	-	-	-	-	-	-	-	-	-
6	London, Ont.	43°08′	81° 26′	43° 08′	81° 03′	42° 54′	81° 03′	42° 54′	81° 26′	-	-	-	-	-	-	-	-	-	-	-	-
7	Montréal, Que.	45°36′	74° 31′	46° 03′	73° 28′	46° 03′	73° 04′	45° 32′	72° 52′	45° 21′	72° 10′	45° 30′	71° 45′	45°20′	71°45′	45°12′	72°10′	45°12′	74°07′	-	-
8	Ottawa, Ont.	45° 35′	76° 00′	45° 35′	75° 25′	45° 12′	75° 25′	45° 12′	76° 00′	-	-	-	-	-	-	-	-	-	-	-	-
9	Québec, Que.	46°49′	71° 32′	46° 40′	71° 22′	46° 40′	71° 13′	46° 49′	71° 06′	46° 55′	71° 10′	46°55′	71° 20′	-	-	-	-	-	-	-	-
10	Regina, Sask.	50°33′	104°43′	50° 33′	104° 29′	50° 22′	104°29′	50° 22′	104°43′	-	-	-	-	-	-	-	-	-	-	-	-
11	Saint John, N.B.	45°18′	66° 12′	45° 24′	66° 00′	45° 10′	66° 00′	45° 10′	66° 12′	-	-	-	-	-	-	-	-	-	-	-	-
12	Saskatoon, Sask.	52° 12′	106°45′	52° 12′	106° 23′	52° 05′	106°23′	52° 05′	106°45′	-	-	-	-	-	-	-	-	-	-	-	-
13	St. John’s, Nfld.	47°38′	52° 50′	47° 38′	52° 36′	47° 29′	52° 36′	47° 29′	52° 50′	-	-	-	-	-	-	-	-	-	-	-	-
14	Sudbury, Ont.	46° 36′	81° 07′	46° 36′	80° 46′	46° 25′	80° 46′	46° 25′	81° 07′	-	-	-	-	-	-	-	-	-	-	-	-
15	Thunder Bay, Ont.	48° 29′	89° 20′	48° 29′	89° 09′	48°18′	89° 09′	48° 18′	89° 20′	-	-	-	-	-	-	-	-	-	-	-	-
16	Toronto, Ont.	44°16′	79° 20′	44° 07′	78° 30′	42° 53′	78° 30′	42° 53′	80° 00′	43° 20′	80° 45′	43°40′	80°45′	43°40′	80°22′	44°02′	80°00′	44° 40′	80°00′	44°40′	79° 20′
17	Trois-Rivières, Que.	46°32′	72° 42′	46° 32′	72° 35′	46° 23′	72° 27′	46° 18′	72° 35′	-	-	-	-	-	-	-	-	-	-	-	-
18	Vancouver, B.C.	49° 50′	124°50′	50° 00′	124° 30′	49° 23′	123°10′	49° 23′	123°25′	49° 19′	123°25′	49°00′	123°20′	49°20′	124° 00′	-	-	-	-	-	-
19	Victoria, B.C.	49°50′	125°20′	49°50′	124° 50′	49°20′	124°00′	49°20′	124°30′	48°35′	123°45′	48°18′	123°45′	49°20′	125° 20′	-	-	-	-	-	-
20	Windsor, Ont.	42°21′	83° 07′	42° 21′	82° 45′	42° 05′	82° 45′	42° 05′	83° 07′	-	-	-	-	-	-	-	-	-	-	-	-
21	Winnipeg, Man.	50°02′	97° 22′	50° 02′	96° 51′	49° 44′	96° 51′	49° 44′	97° 22′	-	-	-	-	-	-	-	-	-	-	-	-

SOR/2011-47, s. 13.

ANNEXE VI

(articles 55, 67, 68 et 78)

Zones d’encombrement moyen

	Colonne I	Colonne II		Colonne III		Colonne IV		Colonne V		Colonne VI		Colonne VII		Colonne VIII		Colonne IX		Colonne X		Colonne XI	
		Coordonnées géographiques		Coordonnées géographiques		Coordonnées géographiques		Coordonnées géographiques		Coordonnées géographiques		Coordonnées géographiques		Coordonnées géographiques		Coordonnées géographiques		Coordonnées géographiques		Coordonnées géographiques	
Article	Zone régionale	Lat. nord	Long. ouest	Lat. nord	Long. ouest	Lat. nord	Long. ouest	Lat. nord	Long. ouest	Lat. nord	Long. ouest	Lat. nord	Long. ouest	Lat. nord	Long. ouest	Lat. nord	Long. ouest	Lat. nord	Long. ouest	Lat. nord	Long. ouest
1	Calgary (Alb.)	51°13′	114°18′	51°13′	113° 50′	50°51′	113°50′	50°51′	114°18′	-	-	-	-	-	-	-	-	-	-	-	-
2	Chicoutimi (QC)	48° 23′	71° 18′	48° 28′	71° 18′	48° 38′	70° 48′	48° 33′	70° 48′	48° 23′	71° 00′	-	-	-	-	-	-	-	-	-	-
3	Chilliwack (C.-B.)	49°23′	122°08′	49° 23′	121° 30′	49° 00′	121°30′	49° 00′	122°08′	-	-	-	-	-	-	-	-	-	-	-	-
4	Edmonton (Alb.)	53° 45′	113°45′	53° 45′	113° 10′	53° 19′	113°10′	53° 19′	113°45′	-	-	-	-	-	-	-	-	-	-	-	-
5	Halifax (N.-É.)	44° 48′	63° 46′	44° 48′	63° 25′	44° 33′	63° 25′	44° 33′	63° 46′	-	-	-	-	-	-	-	-	-	-	-	-
6	London (Ont.)	43°08′	81° 26′	43° 08′	81° 03′	42° 54′	81° 03′	42° 54′	81° 26′	-	-	-	-	-	-	-	-	-	-	-	-
7	Montréal (QC)	45°36′	74° 31′	46° 03′	73° 28′	46° 03′	73° 04′	45° 32′	72° 52′	45° 21′	72° 10′	45° 30′	71° 45′	45°20′	71°45′	45°12′	72°10′	45°12′	74°07′	-	-
8	Ottawa (Ont.)	45° 35′	76° 00′	45° 35′	75° 25′	45° 12′	75° 25′	45° 12′	76° 00′	-	-	-	-	-	-	-	-	-	-	-	-
9	Québec (QC)	46°49′	71° 32′	46° 40′	71° 22′	46° 40′	71° 13′	46° 49′	71° 06′	46° 55′	71° 10′	46°55′	71° 20′	-	-	-	-	-	-	-	-
10	Regina (Sask.)	50°33′	104°43′	50° 33′	104° 29′	50° 22′	104°29′	50° 22′	104°43′	-	-	-	-	-	-	-	-	-	-	-	-
11	Saint-John (N.-B.)	45°18′	66° 12′	45° 24′	66° 00′	45° 10′	66° 00′	45° 10′	66° 12′	-	-	-	-	-	-	-	-	-	-	-	-
12	Saskatoon (Sask.)	52° 12′	106°45′	52° 12′	106° 23′	52° 05′	106°23′	52° 05′	106°45′	-	-	-	-	-	-	-	-	-	-	-	-
13	St. John’s (T.-N.)	47°38′	52° 50′	47° 38′	52° 36′	47° 29′	52° 36′	47° 29′	52° 50′	-	-	-	-	-	-	-	-	-	-	-	-
14	Sudbury (Ont.)	46° 36′	81° 07′	46° 36′	80° 46′	46° 25′	80° 46′	46° 25′	81° 07′	-	-	-	-	-	-	-	-	-	-	-	-
15	Thunder Bay (Ont.)	48° 29′	89° 20′	48° 29′	89° 09′	48°18′	89° 09′	48° 18′	89° 20′	-	-	-	-	-	-	-	-	-	-	-	-
16	Toronto (Ont.)	44°16′	79° 20′	44° 07′	78° 30′	42° 53′	78° 30′	42° 53′	80° 00′	43° 20′	80° 45′	43°40′	80°45′	43°40′	80°22′	44°02′	80°00′	44° 40′	80°00′	44°40′	79° 20′
17	Trois-Rivières (QC)	46°32′	72° 42′	46° 32′	72° 35′	46° 23′	72° 27′	46° 18′	72° 35′	-	-	-	-	-	-	-	-	-	-	-	-
18	Vancouver (C.-B.)	49° 50′	124°50′	50° 00′	124° 30′	49° 23′	123°10′	49° 23′	123°25′	49° 19′	123°25′	49°00′	123°20′	49°20′	124° 00′	-	-	-	-	-	-
19	Victoria (C.-B.)	49°50′	125°20′	49°50′	124° 50′	49°20′	124°00′	49°20′	124°30′	48°35′	123°45′	48°18′	123°45′	49°20′	125° 20′	-	-	-	-	-	-
20	Windsor (Ont.)	42°21′	83° 07′	42° 21′	82° 45′	42° 05′	82° 45′	42° 05′	83° 07′	-	-	-	-	-	-	-	-	-	-	-	-
21	Winnipeg (Man.)	50°02′	97° 22′	50° 02′	96° 51′	49° 44′	96° 51′	49° 44′	97° 22′	-	-	-	-	-	-	-	-	-	-	-	-

DORS/2011-47, art. 13.

TAB 6

Industry Canada Industrie Canada

RSS-102
Issue 5
March 2015

Spectrum Management and Telecommunications

Radio Standards Specification

Radio Frequency (RF) Exposure Compliance of Radiocommunication Apparatus (All Frequency Bands)

Amendment 1 (February 2, 2021)

The localized power density limits (basic restrictions and reference levels) for exposure duration $t \geq 6$ min published by Health Canada in *Notice: Localized human exposure limits for radiofrequency fields in the range of 6 GHz to 300 GHz* are effective immediately. These limits only affect radiocommunication apparatus operating in the 6 GHz to 300 GHz frequency range.

Aussi disponible en français − CNR-102

Canada

Preface

Radio Standards Specification 102, *Radio Frequency (RF) Exposure Compliance of Radiocommunication Apparatus (All Frequency Bands)*, sets out the requirements and measurement techniques used to evaluate radio frequency (RF) exposure compliance of radiocommunication apparatus designed to be used within the vicinity of the human body.

RSS-102, Issue 5, will be in force immediately for the purposes of certifying new equipment. All devices currently certified that are manufactured, imported or sold in Canada must be in compliance with the revised standard 180 days after its publication on the Industry Canada website — no matter when they were originally certified. Some requirements will not be in force immediately as outlined in Notice 2015-DRS001 available at http://www.ic.gc.ca/eic/site/ceb-bhst.nsf/eng/h_tt00080.html.

Changes:

(1) **Section 1:** Clarification related to the scope of the standard has been made.

(2) **Section 1.1:** The definitions of *limb-worn devices* and *separation distance* have been added, and the definition of *RF exposure evaluation* and *controlled use* has been revised.

(3) **Section 2.2:** Clarification related to the RF exposure technical brief has been made.

(4) **Section 2.5.1:** Exemption limits for routine evaluation -SAR evaluation have been revised.

(5) **Section 2.5.2:** Exemption limits for routine evaluation -RF exposure evaluation have been added.

(6) **Section 2.6:** Clarification related to the user manual has been made.

(7) **Section 3:** Clarification on test reduction and fast SAR methods and on the priority list of documents has been made.

(8) **Section 3.1:** Clarification on the following items has been made: devices with push-to-talk capability; on the test distance for certain types of devices; for devices with a very low transmission duty factor; and on the test channel to first be tested in a SAR evaluation.

(9) **Section 3.1.1:** The SAR measurement method for body-worn devices has been revised.

(10) **Section 3.1.2:** The SAR Measurement of Devices Containing Multiple Transmitters has been revised.

(11) **Section 3.1.3:** Clarification has been made on the SAR measurement for specific technology and other types of devices.

(12) **Section 4:** The Safety Code 6 limits have been revised and clarification on the averaging time for SAR evaluation has been made.

(13**)** **Annex A:** Clarification has been made related to the standard(s) and/or procedure(s) used for the evaluation and an addition of the Industry Canada (IC) Certification Number and the name of the SAR/RF exposure testing laboratory has been entered.

(14) **Annex B:** A revision has been made to add the Product Marketing Name (PMN), Hardware Version Identification Number (HVIN), Firmware Version Identification Number (FVIN), Host Marketing Number (HMN) and the IC Certification Number.

(15) **Annex C:** A revision has been made to add the Product Marketing Name (PMN), Hardware Version Identification Number (HVIN), Firmware Version Identification Number (FVIN), Host Marketing Number (HMN) and the IC Certification Number; clarification has been made related to the submission.

(16) **Annex E:** Clarification has been made related to operating tolerance and the local SAR measurement; additional reporting requirements for test reduction and fast SAR methods were added.

Issued under the authority of
the Minister of Industry

____
DANIEL DUGUAY
Acting Director General
Engineering, Planning and Standards Branch

Contents

1. Scope

This Radio Standards Specification (RSS) sets out the requirements and measurement techniques used to evaluate RF exposure compliance of radiocommunication apparatus (Category I and Category II equipment) that are designed to be used within the vicinity of the human body. This standard applies to radiocommunication apparatus having an integral antenna, systems requiring licensing with detachable antennas sold with the transmitters or licence-exempt transmitters with detachable antennas, as defined in RSS-Gen.

This standard shall be used in conjunction with other applicable RSSs. Before the equipment certificate is granted by Industry Canada or by a recognized Certification Body (CB), the applicant shall demonstrate compliance with all applicable departmental standards.

It is the responsibility of proponents[1] and operators of antenna system installations to ensure that all radiocommunication and broadcasting installations comply at all times with Health Canada's Safety Code 6, including the consideration of combined effects of nearby installations within the local radio environment. These requirements are specified in Client Procedures Circular CPC-2-0-03, *Radiocommunication and Broadcasting Antenna Systems*.

1.1 Definitions

The following terms and definitions apply to this standard:

Body-supported device is a device whose intended use includes transmitting with any portion of the device being held directly against a user's body.[2]

Body-worn (or body-mount) radio is a wireless transceiver that is normally operated (or intended to be used) while it is placed in the pocket of a garment, or is maintained close to the body by means of a belt clip, holster, pouch, lanyard or similar mechanism.

Controlled use is the type of approval given to a device that is intended to be used by persons who are fully aware of, and can exercise control over, their exposure. Controlled use devices are typically installed in non-public areas and are not intended for use by members of the general public.

Controlled use limit refers to the SAR and RF field strength limits that apply to devices approved for controlled use (controlled environment).

Device refers to a sample unit, representative of the equipment for which certification is sought.

1 "Proponent" is defined as anyone who is planning to install or modify an antenna system, regardless of the type of installation or service. This includes, among other services, Personal Communications Services (PCS) and cellular, fixed wireless, broadcasting, land-mobile, licence-exempt and amateur radio services.

2 This differs from a body-worn or body-mount radio in that it is not attached to a user's body by means of a carry accessory. A portable computer with an external antenna plug-in radio card (e.g. PCMCIA card) and a portable computer with an antenna located in the screen section are examples of body-supported devices.

General public limit refers to the SAR and RF field strength limits that apply to devices approved for general public use (uncontrolled environment).

General public use is the type of approval given to a device that can be used by the general public.

Limb-Worn Device refers to a device[3] containing one or more wireless transmitters or transceivers that is designed or intended for use on or to be operated only by the limbs. It includes being strapped to the arm or leg of the user while transmitting (except in idle mode).

RF exposure evaluation is the method used to evaluate the RF field strength levels generated by a device. RF exposure evaluation is required if the separation distance between the user or bystander and the device is greater than 20 cm.

RF field strength limit refers to the limit pertaining to an electric field, a magnetic field or a power density that applies to the RF exposure evaluation.

Separation distance (per the power exemption limits) refers to the minimum test separation distance based on the smallest distance between the antenna and radiating structures or the outer surface of the device, according to the most conservative exposure condition for the applicable module or host platform test procedure requirements, to any part of the body or extremity of a user or bystander (refer to Table 1).

Specific absorption rate (SAR) evaluation is the method used to evaluate the SAR levels from a device by physical measurement or computational modelling techniques. SAR evaluation is required if the separation distance between the user or bystanders and the device is less than or equal to 20 cm.

Specific absorption rate (SAR) limit is the limit pertaining to the rate of RF energy absorbed in tissue, per unit mass, and which applies to the SAR evaluation.

2. Certification Requirements

2.1 Application for Certification

Compliance with this RSS shall be evaluated in the context of an application for certification submitted under the RSS(s) applicable to the frequency band and/or technology that pertains to the equipment for which certification is sought.

2.2 RF Exposure Technical Brief

The applicant shall prepare an RF exposure technical brief that contains information related to the SAR evaluation (see Annex E) or RF exposure evaluation of the device, including the exact test configuration(s), equipment calibrations, equipment and measurement/computational uncertainty budgets, system validation/system check, tissue dielectric parameters, maximum output power or single point SAR measured before and after each SAR measurement (drift), test reduction and fast SAR

3 The localized limb limits are typically applicable to limb-worn devices.

techniques, as well as all other relevant technical information. Device test positions shall be documented, including graphical representations showing separation distances and tilt angles used during the evaluation. The rationale for the selection of the separation distance(s) between the device and
the phantom shall be included in the RF exposure technical brief. Close-up photos of the actual device in the various test positions shall also be included. The reported SAR or field strength/power density values shall be scaled to the maximum tune-up tolerance of the device.

The RF exposure technical brief shall demonstrate that the requirements of this standard have been met and that the appropriate measurement methods, evaluation methodologies or calculations have been used.

For devices approved for controlled use, the RF exposure technical brief shall also include device operational guidelines that meet the requirements of Section 2.6 for user exposure awareness and control.

2.3 RF Technical Brief Cover Sheet

The information found in the RF technical brief cover sheet (see Annex A) shall be taken from the RF exposure technical brief. The information provided therein shall clearly support the compliance claim.

2.4 Approval Process

To obtain approval under this standard, the above-mentioned application for certification shall be accompanied by the duly completed RF technical brief cover sheet (see Annex A) and a properly signed declaration of compliance (see Annex B). However, if the device in question meets the exemption from routine evaluation limits of sections 2.5.1 or 2.5.2, only a signed declaration of compliance needs to be submitted (see Annex C).

In addition, submission of the RF exposure technical brief is now required for certification. It shall be accompanied by the completed RF technical brief cover sheet.

2.5 Exemption Limits for Routine Evaluation

All transmitters are exempt from routine SAR and RF exposure evaluations provided that they comply with the requirements of sections 2.5.1 or 2.5.2. If the equipment under test (EUT) meets the requirements of sections 2.5.1 or 2.5.2, applicants are only required to submit a properly signed declaration of compliance (see Annex C). The information contained in the RF exposure technical brief may be limited to the value(s) of the maximum output power, the information that demonstrates how the maximum output power of the transmitter was derived and the rationale for the separation distances applied (see Table 1), which must be based on the most conservative exposure condition for the applicable module or host platform test procedure requirements.

If the EUT does not meet the appropriate exemption limit, a complete SAR or RF exposure evaluation shall be performed. However, the power exemption limits in Table 1 can be applied to reduce the number of test configurations (e.g. testing of a tablet edge). The RF exposure technical brief (see Section 2.2) must include a rationale for the separation distances applied based on the applicable module or host platform test procedure requirements.

It must be emphasized that the above exemption from routine evaluation is **not** an exemption from compliance.

2.5.1 Exemption Limits for Routine Evaluation – SAR Evaluation

SAR evaluation is required if the separation distance between the user and/or bystander and the antenna and/or radiating element of the device is less than or equal to 20 cm, except when the device operates at or below the applicable output power level (adjusted for tune-up tolerance) for the specified separation distance defined in Table 1.

Table 1: SAR evaluation – Exemption limits for routine evaluation based on frequency and separation distance[4,5]

Frequency (MHz)	Exemption Limits (mW)				
	At separation distance of ≤5 mm	At separation distance of 10 mm	At separation distance of 15 mm	At separation distance of 20 mm	At separation distance of 25 mm
≤300	71 mW	101 mW	132 mW	162 mW	193 mW
450	52 mW	70 mW	88 mW	106 mW	123 mW
835	17 mW	30 mW	42 mW	55 mW	67 mW
1900	7 mW	10 mW	18 mW	34 mW	60 mW
2450	4 mW	7 mW	15 mW	30 mW	52 mW
3500	2 mW	6 mW	16 mW	32 mW	55 mW
5800	1 mW	6 mW	15 mW	27 mW	41 mW

Frequency (MHz)	Exemption Limits (mW)				
	At separation distance of 30 mm	At separation distance of 35 mm	At separation distance of 40 mm	At separation distance of 45 mm	At separation distance of ≥50 mm
≤300	223 mW	254 mW	284 mW	315 mW	345 mW
450	141 mW	159 mW	177 mW	195 mW	213 mW
835	80 mW	92 mW	105 mW	117 mW	130 mW
1900	99 mW	153 mW	225 mW	316 mW	431 mW
2450	83 mW	123 mW	173 mW	235 mW	309 mW
3500	86 mW	124 mW	170 mW	225 mW	290 mW
5800	56 mW	71 mW	85 mW	97 mW	106 mW

Output power level shall be the higher of the maximum conducted or equivalent isotropically radiated power (e.i.r.p.) source-based, time-averaged output power. For controlled use devices where the 8 W/kg for 1 gram of tissue applies, the exemption limits for routine evaluation in Table 1 are multiplied by a

4 The exemption limits in Table 1 are based on measurements and simulations of half-wave dipole antennas at separation distances of 5 mm to 25 mm from a flat phantom, providing a SAR value of approximately 0.4 W/kg for 1 g of tissue. For low frequencies (300 MHz to 835 MHz), the exemption limits are derived from a linear fit. For high frequencies (1900 MHz and above), the exemption limits are derived from a third order polynomial fit.

5 Transmitters operating between 0.003-10 MHz, meeting the exemption from routine SAR evaluation, shall demonstrate compliance to the instantaneous limits in Section 4.

factor of 5. For limb-worn devices where the 10 gram value applies, the exemption limits for routine evaluation in Table 1 are multiplied by a factor of 2.5. If the operating frequency of the device is between two frequencies located in Table 1, linear interpolation shall be applied for the applicable separation distance. For test separation distance less than 5 mm, the exemption limits for a separation distance of 5 mm can be applied to determine if a routine evaluation is required.

For medical implants devices, the exemption limit for routine evaluation is set at 1 mW. The output power of a medical implants device is defined as the higher of the conducted or e.i.r.p to determine whether the device is exempt from the SAR evaluation.

2.5.2 Exemption Limits for Routine Evaluation – RF Exposure Evaluation

RF exposure evaluation is required if the separation distance between the user and/or bystander and the device's radiating element is greater than 20 cm, except when the device operates as follows:

- below 20 MHz[6] and the source-based, time-averaged maximum e.i.r.p. of the device is equal to or less than 1 W (adjusted for tune-up tolerance);
- at or above 20 MHz and below 48 MHz and the source-based, time-averaged maximum e.i.r.p. of the device is equal to or less than $4.49/f^{0.5}$ W (adjusted for tune-up tolerance), where f is in MHz;
- at or above 48 MHz and below 300 MHz and the source-based, time-averaged maximum e.i.r.p. of the device is equal to or less than 0.6 W (adjusted for tune-up tolerance);
- at or above 300 MHz and below 6 GHz and the source-based, time-averaged maximum e.i.r.p. of the device is equal to or less than $1.31 \times 10^{-2} f^{0.6834}$ W (adjusted for tune-up tolerance), where f is in MHz;
- at or above 6 GHz and the source-based, time-averaged maximum e.i.r.p. of the device is equal to or less than 5 W (adjusted for tune-up tolerance).

In these cases, the information contained in the RF exposure technical brief may be limited to information that demonstrates how the e.i.r.p. was derived.

2.6 User Manual Requirements

The applicant is responsible for providing proper instructions to the user of the radio device, and any usage restrictions, including limits of exposure durations. The user manual shall provide installation and operation instructions,[7] as well as any special usage conditions (e.g. proper accessory required, including the proper orientation of the device in the accessory, maximum antenna gain in the case of detachable antenna), in order to ensure compliance with SAR and/or RF field strength limits. For instance, compliance distance shall be clearly stated in the user manual.

The user manual of devices intended for controlled use shall also include information relating to the operating characteristics of the device; the operating instructions to ensure compliance with SAR and/or

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[6] Transmitters operating between 0.003-10 MHz, meeting the exemption from routine RF Exposure evaluation, shall demonstrate compliance to the instantaneous limits in Section 4.

[7] All device operating instructions and installations shall be supported by the test configurations and the test results. Applying instructions as a substitute for providing test results is unacceptable. Caution statements or warning labels are only acceptable for alerting users from certain unintended use conditions that are not required for normal operations.

RF field strength limits; information on the installation and operation of accessories to ensure compliance with SAR and/or RF field strength limits; and contact information where the user can obtain Canadian information on RF exposure and compliance. Other related information may also be included.

2.7 Quality Control and Post-Certification Investigations/Audits

Industry Canada will conduct market surveillance compliance audits and compliance investigations from time to time, after certification, of radiocommunication apparatus intended for sale in Canada. In the event of an investigation of non-compliance, the certificate holder will be asked to provide to Industry Canada records of the quality control process and any relevant information that would help identify issues related to compliance. It is expected that all certificate holders will be able to demonstrate a quality control process used for production inspection and testing in accordance with good engineering practices.

3. Evaluation Methods

Devices that have a radiating element normally operating at or below 6 GHz, with a separation distance of up to 20 cm between the user and/or bystander and the device, shall undergo a SAR evaluation. Devices that have a radiating element normally operating at or below 6 GHz, with a separation distance greater than 20 cm between the user and/or bystander and the device shall undergo an RF exposure evaluation. However, a SAR evaluation may be performed in lieu of an RF exposure evaluation for devices operating below 6 GHz with a separation distance of greater than 20 cm between the user and/or bystander and the device. Devices operating above 6 GHz regardless of the separation distance shall undergo an RF exposure evaluation.

SAR evaluations shall be made in accordance with the latest version of IEEE 1528[8] and/or IEC 62209.[9] However, the applicant shall consult with Industry Canada prior to initiating the certification process if the sections on test reductions[10] and fast SAR evaluations[11] within IEC 62209 are to be applied for the determination of regulatory compliance of the radiocommunication apparatus.

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8 IEEE 1528: *Recommended Practice for Determining the Peak Spatial-Average Specific Absorption Rate (SAR) in the Human Head from Wireless Communications Devices: Measurement Techniques*.

9 IEC 62209: *Human exposure to radio frequency fields from hand-held and body-mounted wireless communication devices – Human models, instrumentation, and procedures*.

10 The applicant is not required to consult with Industry Canada if the test reductions or fast SAR methods are based on the normative sections of the IEEE 1528 standard. The applicant is not required to consult with Industry Canada if the test reductions are based on the Federal Communications Commission (FCC) Knowledge Database (KDB) procedures referenced in this standard.

11 *Ibid.*

For SAR probe calibration and system verification for measurements between 100 MHz and 300 MHz, the procedures[12] established by the U.S. Federal Communications Commission (FCC) can be used as an interim measure until IEEE 1528 and IEC 62209 have incorporated the extended frequency range.

RF exposure evaluation shall be made in accordance with the latest version of IEEE C95.3.[13]

Note: The applicant must follow the applicable test methods based on the priority list of documents. The priority list[14] is as follows:

(1) RSS-102,
(2) IEC and IEEE standards referenced in this document, and
(3) Other recognized procedures, such as the FCC RF exposure KDB procedures referenced in this document.

3.1 SAR Measurements

In addition to the above-mentioned SAR standards, the following provisions shall apply when performing a SAR evaluation:

- If a device has push-to-talk capability,[15] a minimum duty cycle of 50% (on-time) shall be used in the evaluation. A duty cycle lower than 50% is permitted only if the transmission duty cycle is an inherent property of the technology or of the design of the equipment and is not under user control. Proof of the various on-off durations and a detailed method of calculation of the average power shall be included in the RF exposure technical brief. Maximum average power levels shall be used to determine compliance.

- For devices without push-to-talk capability, the duty cycle used in the evaluation shall be based on the inherent property of the transmission technology or of the design of the equipment.

- If the device is designed to operate in front of the mouth, such as PTT radio, it shall be evaluated with the front of the device positioned at 2.5 cm from a flat phantom. For wristwatch and wrist–worn transmitters in speaker mode for voice communication, evaluations shall be conducted with the front of the devices positioned at 1.0 cm from the flat phantom. If the device is also designed to operate when placed next to the cheek and ear, it shall also be tested against the SAM phantom.

- For low transmission duty factor devices (e.g. point-of–sale (POS) devices, black and white e-readers, and location trackers) that only transmit intermittently in data mode, without voice capability, an

12 List of accepted FCC RF exposure KDB procedures, other applicable procedures and notices related to SAR measurements can be found at the following link: http://www.ic.gc.ca/eic/site/ceb-bhst.nsf/eng/h_tt00080.html.

13 IEEE C95.3-2002: *IEEE recommended practice for measurements and computations of radio frequency electromagnetic fields with respect to human exposure to such fields, 100 kHz-300 GHz*.

14 The applicant can consult with Industry Canada if guidance on the priority list of documents is required for the type of radiocommunication apparatus for which regulatory compliance is sought.

15 List of accepted FCC RF exposure KDB procedures, other applicable procedures and notices related to SAR measurements can be found at the following link: http://www.ic.gc.ca/eic/site/ceb-bhst.nsf/eng/h_tt00080.html.

exemption from routine SAR evaluation is deemed acceptable if the exemption limits from routine evaluation (Table 1) are met by applying the worst-case or most conservative transmission duty factor. The supporting details for determining the duty factor with respect to the design, implementation, operating configurations and exposure conditions of the devices must be fully documented in the RF exposure brief.

- SAR evaluation of medical implants (e.g. Medical Implant Communication Systems (MICS) and Medical Implant Telemetry System (MITS)) devices shall be performed by physical measurement or by computational modelling.

- The mid-channel of a transmission band shall first be tested in the SAR evaluation. However, if the variation of the maximum output power across the required test channels is more than 0.5 dB above the output power of the mid-channel, the channel with the highest output power shall first be tested (if different from the mid-channel). The method for determining the maximum output power, as well as the value of each channel, shall be documented in the RF exposure technical brief.

3.1.1 SAR Measurement of Body-Worn Devices

In addition to the SAR standards mentioned in Section 3, the following provisions shall apply when performing SAR measurements for body-worn devices:

- Body-worn accessories (e.g. belt clips and holsters) shall be attached to the device and positioned against the flat phantom in normal use configurations.

- When multiple accessories supplied with the device or made available by the manufacturer for the device contain no metallic component, the device shall be tested with the accessory that provides the shortest separation distance between the device and the body.

- When multiple accessories supplied with the device or made available by the manufacturer for the device contain metallic components, the device shall be tested with each accessory containing a unique metallic component. If multiple accessories share the same metallic component, only the accessory providing the shortest separation distance between the device and the body shall be tested.

- If accessories are neither supplied nor made available by the manufacturer, a conservative minimum separation distance based on off-the-shelf body-worn accessories should be used to test body-worn devices. A separation distance of 15 mm or less between the device and the phantom is required. The device shall be positioned with either its back surface or front surface toward the phantom, whichever will result in the higher SAR value. If this cannot be determined, both positions shall be tested and the higher of the two SAR values shall be included in the RF technical brief cover sheet. The selected separation distance shall be clearly explained in the RF exposure technical brief to support the body-worn accessory test configurations.

- Body-worn devices that are designed to operate on the body using lanyards or straps shall be tested using a test separation distance of 5 mm or less.

- The head or body tissue equivalent liquid (see Annex D) for SAR measurement of body-worn devices shall be used. Information related to the tissue equivalent liquid shall be included in the RF exposure technical brief.

3.1.2 SAR Measurement of Devices Containing Multiple Transmitters

Compliance of devices with multiple transmitters capable of simultaneous transmission shall be assessed in accordance with the latest version of IEEE 1528. However, other recognized methods — such as the procedures[16] published by the FCC proven to provide a conservative estimate of the SAR value — can also be used. Applicants shall include in the RF exposure technical brief all information relevant to the exact test methodology used.

3.1.3 Other SAR Measurement Procedures Related to Specific Technologies and Types of Devices

SAR measurement procedures related to specific technology (e.g. 3G and other technologies, such as CDMA2000, Ev-Do, WCDMA and LTE), 802.11 a/b/g transmitters, 802.16e/WiMAX devices, and different types of devices (such as tablets, notebooks, netbooks and laptop computers with built-in antennas on display screens or located within the chassis), as well as licensed and licence-exempt modular transmitters, are not covered by the current international standards in Section 3. Until these standards contain the measurement procedures for these specific technologies and types of devices, the FCC's published procedures can be used as an interim measure. A complete list of accepted FCC's KDB procedures related to SAR measurements can be found on Industry Canada's Certification and Engineering Bureau website.[17] In addition, other recognized methods can be used, if deemed acceptable by Industry Canada, prior to initiating the certification process. Applicants shall include all information relevant to the exact method used in the RF exposure technical brief.

3.2 RF Exposure Evaluation of Devices

A device requiring an RF exposure evaluation shall be made in accordance with the latest version of IEEE C95.3.

If the device is designed such that more than one antenna can functionally transmit at the same time, the RF exposure evaluation shall be conducted while all antennas are transmitting. The individual exposure level ratios shall be totalled and used for compliance purposes.

If the device has more than one antenna, but is not designed to have more than one antenna functionally transmit at the same time, the RF exposure evaluation of the device shall be performed for each of the individually transmitting antennas. The maximum RF field strength value shall be recorded and used for compliance purposes.

If the device combines groups of simultaneous and non-simultaneous transmitting antennas, the worst-case of the above scenarios applies.

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16 List of accepted FCC RF exposure KDB procedures, other applicable procedures and notices related to SAR measurements can be found at the following link: http://www.ic.gc.ca/eic/site/ceb-bhst.nsf/eng/h_tt00080.html.

17 *Ibid.*

3.3 Computational Modelling

Computational modelling, such as finite-difference-time-domain (FDTD), may be used to demonstrate compliance with SAR and/or RF field strength limits. However, the applicant shall consult with Industry Canada to determine if computational modelling is deemed acceptable for the type of radiocommunication apparatus for which regulatory compliance is sought, prior to initiating the certification process. The applicant shall submit all information (see Annex E) relevant to the modelling, including an electronic copy of the simulation and modelling information necessary to reproduce the results. The applicant is responsible for compliance with the limits specified in this RSS, regardless of the computational model used.

Refer to IEEE C95.3-2002 for general information on computational modelling.

4. Exposure Limits

For the purpose of this standard, Industry Canada has adopted the SAR and RF field strength limits established in Health Canada's RF exposure guideline, Safety Code 6.[18]

Table 2: Internal Electric Field Strength Basic Restrictions (3 kHz-10 MHz)

Condition[19]	**Internal Electric Field Strength* (V/m) (any part of the body)**
Controlled Environment	$2.7 \times 10^{-4} f$
Uncontrolled Environment	$1.35 \times 10^{-4} f$
Note: f is frequency in Hz. *Instantaneous, RMS values apply.	

18 Health Canada's Safety Code 6: *Limits of Human Exposure to Radiofrequency Electromagnetic Energy in the Frequency Range from 3 kHz to 300 GHz* (http://www.hc-sc.gc.ca/ewh-semt/pubs/radiation/radio_guide-lignes_direct/index-eng.php).

19 For provisions related to instantaneous nerve stimulation measurements see Notice 2015-DRS001.

Table 3: SAR Limits for Devices Used by the General Public (Uncontrolled Environment)

Body Region	Average SAR (W/kg)	Averaging Time (minutes)[20]	Mass Average (g)
Whole Body	0.08	6	Whole Body
Localized Head, Neck and Trunk	1.6	6	1
Localized Limbs	4	6	10

Table 4: RF Field Strength Limits for Devices Used by the General Public (Uncontrolled Environment)

Frequency Range (MHz)	Electric Field (V/m rms)	Magnetic Field (A/m rms)	Power Density (W/m^2)	Reference Period (minutes)
0.003-10[21]	83	90	-	Instantaneous*
0.1-10	-	$0.73/f$	-	6**
1.1-10	$87/f^{0.5}$	-	-	6**
10-20	27.46	0.0728	2	6
20-48	$58.07/f^{0.25}$	$0.1540/f^{0.25}$	$8.944/f^{0.5}$	6
48-300	22.06	0.05852	1.291	6
300-6000	$3.142 f^{0.3417}$	$0.008335 f^{0.3417}$	$0.02619 f^{0.6834}$	6
6000-15000	61.4	0.163	10	6
15000-150000	61.4	0.163	10	$616000/f^{1.2}$
150000-300000	$0.158 f^{0.5}$	$4.21 \times 10^{-4} f^{0.5}$	$6.67 \times 10^{-5} f$	$616000/f^{1.2}$

Note: f is frequency in MHz.
*Based on nerve stimulation (NS).
** Based on specific absorption rate (SAR).

Table 5: SAR Limits for Controlled Use Devices (Controlled Environment)

20 Compliance measurements are carried out while the device under test is generally configured to continuously transmit at its highest output power. In addition, the SAR measurement procedures adopted within this standard ensure that the exposure intensity variations are within the standardized power fluctuation requirements. Therefore, the six-minute time-averaging is not required when demonstrating compliance with the applicable localized SAR limits for the device under test.

21 For provisions related to instantaneous nerve stimulation measurements see Notice 2015-DRS001.

Body Region	Average SAR (W/kg)	Averaging Time (minutes) [22]	Mass Average (g)
Whole Body	0.4	6	Whole Body
Localized Head, Neck and Trunk	8	6	1
Localized Limbs	20	6	10

Table 6: RF Field Strength Limits for Controlled Use Devices (Controlled Environment)

Frequency Range (MHz)	Electric Field (V/m rms)	Magnetic Field (A/m rms)	Power Density (W/m^2)	Reference Period (minutes)
0.003-10[23]	170	180	-	Instantaneous*
0.1-10	-	$1.6/f$	-	6**
1.29-10	$193/f^{0.5}$	-	-	6**
10-20	61.4	0.163	10	6
20-48	$129.8/f^{0.25}$	$0.3444/f^{0.25}$	$44.72/f^{0.5}$	6
48-100	49.33	0.1309	6.455	6
100-6000	$15.60 f^{0.25}$	$0.04138 f^{0.25}$	$0.6455 f^{0.5}$	6
6000-15000	137	0.364	50	6
15000-150000	137	0.364	50	$616000/f^{1.2}$
150000-300000	$0.354 f^{0.5}$	$9.40 \times 10^{-4} f^{0.5}$	$3.33 \times 10^{-4} f$	$616000/f^{1.2}$

Note: f is frequency in MHz.
*Based on nerve stimulation (NS).
** Based on specific absorption rate (SAR).

22 Compliance measurements are carried out while the device under test is generally configured to continuously transmit at its highest output power. In addition, the SAR measurement procedures adopted within this standard ensure that the exposure intensity variations are within the standardized power fluctuation requirements. Therefore, the six-minute time-averaging is not required when demonstrating compliance with the applicable localized SAR limits for the device under test.

23 For provisions related to instantaneous nerve stimulation measurements see Notice 2015-DRS001.

Annex A — RF Technical Brief Cover Sheet

All fields must be completed with the requested information or the following codes:
N/A for Not Applicable, N/P for Not Performed or N/V for Not Available.
Where applicable, check appropriate box.

1. COMPANY NUMBER: ____

2. PRODUCT MARKETING NAME (PMN):______________________________________

3. HARDWARE VERSION IDENTIFICATION NO. (HVIN): _______________________

4. FIRMWARE VERSION IDENTIFICATION NO. (FVIN):________________________

5. HOST MARKETING NAME (HMN):____

6. IC CERTIFICATION NUMBER:____

7. APPLICANT: ____

8. SAR/RF EXPOSURE TEST LABORATORY:__ ___________________________________

9. TYPE OF EVALUATION: (Complete the applicable sections: (a) SAR Evaluation: Device Used in the Vicinity of the Human Head; (b) SAR Evaluation: Body-Worn Device/Body-Supported Device; (c) SAR Evaluation: Limb-Worn Device; (d) RF Exposure Evaluation).

Note: The worst-case scenario (i.e. highest measured value obtained) shall be reported.

(a) SAR Evaluation: Device Used in the Vicinity of the Human Head

- **Multiple transmitters: Yes ☐ No ☐**
- **Evaluated against exposure limits: General Public Use ☐ Controlled Use ☐**
- **Duty cycle used in evaluation: __________%**
- **Standard(s)/Procedure(s) used for evaluation (e.g. IEEE 1528, KDB 447498):____**
- **SAR value: __________W/kg Measured ☐ Computed ☐ Calculated ☐**

(b) SAR Evaluation: Body-Worn Device and Body-Supported Device

- **Multiple transmitters: Yes ☐ No ☐**
- **Evaluated against exposure limits: General Public Use ☐ Controlled Use ☐**
- **Duty cycle used in evaluation: __________%**
- **Standard(s)/Procedure(s) used for evaluation (e.g. IEC62209-2):_________________**
- **SAR value: __________W/kg Measured ☐ Computed ☐ Calculated ☐**

(c) SAR Evaluation: Limb-Worn Device

- **Multiple transmitters: Yes ☐ No ☐**
- **Evaluated against exposure limits: General Public Use ☐ Controlled Use ☐**
- **Duty cycle used in evaluation: __________%**
- **Standard(s)/Procedure(s) used for evaluation (e.g. IEC62209-2):_________________**
- **SAR value: __________W/kg Measured ☐ Computed ☐ Calculated ☐**

(d) RF Exposure Evaluation

- **Evaluated against exposure limits: General Public Use ☐ Controlled Use ☐**
- **Duty cycle used in evaluation: __________%**
- **Standard(s)/Procedure(s) used for evaluation (e.g. IEEE C95.3):________________**
- **Measurement distance: ___________ m**
- **RF field strength value: ____________ V/m ☐ A/m ☐ W/m² ☐**

Measured ☐ Computed ☐ Calculated ☐

Annex B — Declaration of RF Exposure Compliance

ATTESTATION: I attest that the information provided in Annex A is correct; that the Technical Brief was prepared and the information contained therein is correct; that the device evaluation was performed or supervised by me; that applicable measurement methods and evaluation methodologies have been followed; and that the device meets the SAR and/or RF field strength limits of RSS-102.

Signature: ____ Date: __________________

NAME (Please print or type): ____

TITLE (Please print or type): ____

COMPANY (Please print or type): ____

PRODUCT MARKETING NAME (PMN)
(Please print or type): ____

HARDWARE VERSION IDENTIFICATION NO. (HVIN)
(Please print or type):____

FIRMWARE VERSION IDENTIFICATION NO. (FVIN)
(Please print or type): ____

HOST MARKETING NAME (HMN)
(Please print or type): ____

IC CERTIFICATION NUMBER (Please print or type):______________________________

Annex C — Declaration of RF Exposure Compliance for Exemption from Routine Evaluation Limits

ATTESTATION: I attest that the radiocommunication apparatus meets the exemption from the routine evaluation limits in Section 2.5 of this standard; that the Technical Brief was prepared and the information contained therein is correct; that the device evaluation was performed or supervised by me; that applicable measurement methods and evaluation methodologies have been followed; and that the device meets the SAR and/or RF field strength limits of RSS-102.

Signature: ____ Date: __________________

NAME (Please print or type): ____

TITLE (Please print or type): ____

COMPANY (Please print or type): ____

PRODUCT MARKETING NAME (PMN)
(Please print or type): ____

HARDWARE VERSION IDENTIFICATION NO. (HVIN)
(Please print or type):____

FIRMWARE VERSION IDENTIFICATION NO. (FVIN)
(Please print or type): ____

HOST MARKETING NAME (HMN)
(Please print or type): ____

IC CERTIFICATION NUMBER (Please print or type): ______________________________

Note: The submission of Annex C is only required if the device meets the exemption limits for the routine evaluation in Section 2.5 of this standard.

Annex D — Body Tissue Equivalent Liquid

Target Frequency (MHz)	Body	
	ε_r	σ (S/m)
150	61.9	0.8
300	58.2	0.92
450	56.7	0.94
835	55.2	0.97
900	55.0	1.05
915	55.0	1.06
1450	54.0	1.30
1610	53.8	1.40
1800-2000	53.3	1.52
2450	52.7	1.95
3000	52.0	2.73
5800	48.2	6.00

(ε_r= relative permittivity, σ= conductivity and $\rho = 1000$ kg/m^3)

Annex E — Information to be Included in the RF Exposure Technical Brief, as applicable, to Document SAR Compliance

INFORMATION ON THE TEST DEVICE AND EXPOSURE CATEGORY

(1) General information
IC Certification ID
Product Marketing Name (PMN)
Hardware Version Identification Number (HVIN)
Firmware Version Identification Number (FVIN)
Host Marketing Name (HMN)
RF exposure environment (General Public/Controlled Use)
(2) Device operating configurations and test conditions
Test device is a production unit or an *identical* prototype
Brief description of the test device operating configurations, including: - illustration(s) of the antenna position(s) relative to the device under test, including dimensions and separation distances (for multiple transmitters/antennas), as applicable - operating modes and operating frequency range(s) - maximum output power of the device for each operating mode and frequency range - maximum tune-up tolerances (e.g. variation in output power of the applicable test channels) - antenna type with gain and operating positions - applicable head, body-worn or body-supported configurations - battery options that could affect the SAR results
Procedures used to establish the test signals
Detailed description of the communication protocols used during the evaluation
Applicable source-based time-averaging duty factor and the duty factor used in the tests
Maximum output power or local SAR measured before and after each SAR test

SPECIFIC INFORMATION FOR SAR MEASUREMENTS
(1) Measurement system and site description
Brief description of the SAR measurement system
Brief description of the test setup
(2) Electric field probe calibration
Description of the probe, its dimensions and sensor offset, etc.
Description of the probe measurement errors
Most recent calibration date
(3) SAR measurement system check
Description of system check procedure, including any non-standardized methods/calculations used to determine the system check target value(s).
Brief description of the RF radiating source used to verify the SAR system performance within the operating frequency range of the test device
List of the tissue dielectric parameters, ambient and tissue temperatures, output power, peak and one-gram averaged SAR for the measured and expected target test configurations
List of the error components contributing to the total measurement uncertainty
(4) Phantom description
Description of the head and/or body phantoms used in the tests, including shell thickness and other tolerances
(5) Tissue dielectric property
Composition of ingredients for the tissue material used in the SAR tests
Tissue dielectric parameters measured at the low, middle and high frequency of each operating frequency range of the test device
Temperature range and operating conditions of the tissue material during each SAR measurement

(6) Device positioning
Description of the dielectric holder or similar mechanisms used to position the test device in the specific test configurations
Description of the positioning procedures used to evaluate the highest exposure expected under normal operating configurations
Sketches and illustrations showing the device positions with respect to the phantom, including separation distances and angles, as appropriate
Description of the antenna operating positions — extended, retracted or stowed, etc., and the configurations tested in the SAR evaluation
(7) Peak SAR locations
Description of the coarse resolution, surface or area scan procedures used to search for all possible peak SAR locations within the phantom
Description of the interpolation procedures applied to the measured points to identify the peak SAR locations at a finer spatial resolution
Description, illustration and SAR distribution plots showing the peak SAR locations with respect to the phantom and the test device
Identifying the peak SAR locations used to evaluate the highest one-gram averaged SAR
(8) One-gram averaged SAR
Description of the fine resolution, volume or zoom scan procedures used to determine the highest one-gram averaged SAR in the shape of a cube
Description of the extrapolation procedures used to estimate the SAR value of points close to the phantom surface that are not measurable
Description of the interpolation procedures applied to the measured and extrapolated points to obtain SAR values at a finer spatial resolution within the zoom scan volume
Description of the integration procedures applied to the interpolated SAR values within the zoom scan volume to determine the highest one-gram SAR in the shape of a cube
(9) Total measurement uncertainty
Tabulated list of the error components and uncertainty values contributing to the total measurement uncertainty
Combined standard uncertainty and expanded uncertainty (for $k \geq 2$) of each measurement
If the expanded measurement uncertainty is greater than the target value per the referenced standard (e.g. IEEE 1528), an explanation of the procedures that have been used to reduce the measurement uncertainty shall be provided
(10) Test Reduction
All information, including description (with drawings and photograph, if required) and rationale, related to specific test reduction procedures
(11) Fast SAR Techniques
Description of measurement system main components and software; equipment list of the test equipment and accessories used to perform fast SAR measurements and used to verify the fast SAR system, as well as to characterize the tissue dielectric parameters.
Detailed calibration data relevant to critical fast SAR measurement system components
Description of the interpolations and extrapolations algorithms used in the area scans and zoom scans
Description of the fast SAR method validation, including results of the computations and measurements to validate the fast SAR method. Radiating source description and SAR distribution for each frequency band, SAR tolerance and details of any modifications to post-processing algorithms.
Results of the system check for each frequency band, deviation from target value and radiating source

description.
Measurement uncertainty budget for each frequency band, system validation uncertainty evaluation, and system check uncertainty evaluation, including any other relevant information pertaining to measurement uncertainty.
Tabulated list of all frequency bands, modulation, test configurations testing using a fast SAR method with SAR results. Tabulated and graphical results for the highest fast SAR measurement for each frequency band and modulation.
Results of all full SAR tests performed, which include the peak spatial-average SAR value for each required test and graphical representation of the scans with respect to the device.
A systematic rationale for excluding full SAR measurements.
(12) Test results for determining SAR compliance
If the channels tested for each configuration (left, right, cheek, tilt/ear, extended, retracted, etc.) have similar SAR distributions, a plot of the highest SAR for each test configuration should be sufficient; otherwise, additional plots should be included to document the differences.
All of the measured SAR values should be documented in a tabulated format with respect to the test configurations. The reported SAR shall be scaled to the maximum tune-up tolerance of the device.

SPECIFIC INFORMATION FOR SAR COMPUTATIONAL MODELLING
(1) Computational resources
Summary of the computational resources required to perform the SAR computations for the test transmitter and phantom configurations
Summary of the computational requirements with respect to modelling and computing parameters for determining the highest exposure expected for normal device operation, such as minimal computational requirements and those used in the computation
(2) FDTD algorithm implementation and validation
Summary of the basic algorithm implementation applicable to the particular SAR evaluation, including absorbing boundary conditions, source excitation methods, certain standard algorithms for handling thin metallic wires, sheets or dielectric materials, etc.
Descriptions of the procedures used to validate the basic computing algorithms and analysis of the computing accuracy based on these algorithms for the particular SAR evaluation
(3) Computational parameters
Tabulated list of computational parameters such as cell size, domain size, time-step size, tissue and device model separation from the absorbing boundaries, and other essential parameters relating to the computational setup requirements for the SAR evaluation
Description of the procedures used to handle computation efficiency and modelling accuracy for the phantom and the test device
(4) Phantom model implementation and validation
Identify the source of the phantom model, its original resolution and the procedures used to code and assign tissue dielectric parameters for the SAR evaluation
Verify that the phantom model is appropriate for determining the highest exposure expected for normal device operation
Describe procedures used to verify that the particular phantom model has been correctly constructed for making SAR computations, such as comparing computed and measured SAR results of a dipole source
(5) Tissue dielectric parameters
Description of the types of tissues used in the phantom models and the sources of tissue dielectric parameters used in the computations
Verify that the tissue types and dielectric parameters used in the SAR computation are appropriate for determining the highest exposure expected for normal device operation
Tabulated list of the dielectric parameters used in the device and phantom models
(6) Transmitter model implementation and validation
Description of the essential features that must be modelled correctly for the particular test device model to be valid
Descriptions and illustrations showing the correspondence between the modelled test device and the actual device with respect to shape, size, dimensions and near-field radiating characteristics
Verify that the test device model is equivalent to the actual device for predicting the SAR distributions
Verify the SAR distribution at the high, middle and low channels, similar to those considered in SAR measurements for determining the highest SAR

(7) Test device positioning
Description of the device test positions (left, right, cheek, tilt/ear, extended and retracted, etc.) used in the SAR computations
Illustrations showing the separation distances between the test device and the phantom for the tested configurations, similar to the reporting procedures used in SAR measurements
(8) Steady state termination procedures
Description of the criteria and procedures used to determine that sinusoidal steady state conditions have been reached throughout the computational domain for terminating the computations
Reporting the number of time steps or sinusoidal cycles executed to reach steady state
Description of the expected error margin provided by the termination procedures
(9) Computing peak SAR from field components
Description of the procedures used to compute the sinusoidal steady total electric field with selected field components at each tissue location
Description of the expected error margin provided by the algorithms used to compute the SAR at each tissue location according to the selected field components and tissue dielectric parameter
(10) One-gram averaged SAR procedures
Description of the procedures used to search for the highest one-gram averaged SAR, including the procedures for handling inhomogeneous tissues within the one-gram cube
Specify the weight and dimensions of the one-gram cube of tissue
Description of the expected error margin provided by the algorithms used in computing the one-gram SAR
(11) Total computational uncertainty
Description of the expected error and computational uncertainty for the test device and tissue models, test configurations and numerical algorithms, etc.
(12) Test results for determining SAR compliance
Illustrations showing the SAR distribution of dominant peak locations produced by the test transmitter with respect to the phantom and the test device, similar to those reported in SAR measurements
Description of how the maximum device output rating is determined and used to normalize the SAR values for each test configuration
Description of the procedures used to compute source-based time-averaged SAR

TAB 7

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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 (2015)

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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 (2009).

The purpose of this code is to establish safety limits for human exposure to radiofrequency (RF) fields 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 equipment certification and RF field exposure compliance specifications outlined in Industry Canada's regulatory documents (1–3), that govern the use of wireless devices in Canada, such as cell phones, cell towers (base stations) and broadcast antennas. 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 exposure scenarios 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 RF energy and how it interacts with the human body. This code is periodically revised to reflect new knowledge in the scientific literature and the exposure limits may be modified, if deemed necessary.

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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) fields fall within 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 electromagnetic fields. RF fields are 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.

A number of biological effects and established adverse health effects from acute exposure to RF fields have been documented (4–9). These effects relate to localized heating or stimulation of excitable tissue. The specific biological responses to RF fields are generally related to the rate of energy absorbed or the strength of internal electric fields (voltage gradients) and currents. The rate and distribution of RF energy absorption depend strongly on the frequency, strength and orientation of the incident fields as well as the body size and its constitutive electrical properties (dielectric constant and conductivity). Absorption of RF energy 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 scientific knowledge, national and international exposure limits have been established to protect the general public against all adverse effects associated with RF field exposures (10–14).

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 non-thermal health effects of RF fields. 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 exposure to RF fields. This approach takes into account 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. those with 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 any scientifically established adverse health effect occurs. Safety margins have been incorporated into the exposure limits to ensure that even worst-case exposures remain far below the threshold for harm. 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 (15–16). As such, the basic restrictions in Safety Code 6 are similar to those adopted by most other nations, since all science-based, standard-setting bodies use the same scientific data. It must be stressed that Safety Code 6 is based upon established adverse health effects 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 PURPOSE OF THE CODE

The purpose of this code is to specify maximum levels of human exposure to RF fields at frequencies between 3 kHz and 300 GHz, to prevent adverse human health effects in both controlled and uncontrolled environments.

In 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 or calculation,

(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 fields in their environment and,

(c) the exposure is incurred by persons who are aware of the potential health risks associated with RF field exposures and can control their risk using mitigation strategies.

Situations that do not meet all the specifications above are considered to be uncontrolled environments. Uncontrolled environments are defined as areas where either insufficient assessment of RF fields has been conducted or where persons who are allowed access to these areas have not received proper RF field awareness/safety training and have no means to assess or, if required, to mitigate their exposure to RF fields.

2. MAXIMUM EXPOSURE LIMITS

The scientific literature with respect to possible biological effects of RF fields has been monitored by Health Canada scientists on an ongoing basis. Since the last version of Safety Code 6 was published (2009), a significant number of new studies have evaluated the potential for acute and chronic RF field exposures to elicit possible effects on a wide range of biological endpoints including: human cancers; 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 among others. Numerous authoritative reviews have summarized the current literature (4–8, 17–40).

Despite the advent of numerous additional research studies on RF fields and health, the only established adverse health effects associated with RF field exposures in the frequency range from 3 kHz to 300 GHz relate to the occurrence of tissue heating and nerve stimulation (NS) from short-term (acute) exposures. At present, there is no scientific basis for the occurrence of acute, chronic and/or cumulative adverse health risks from RF field exposure at levels below the limits outlined in Safety Code 6. The hypotheses of other proposed adverse health effects occurring at levels below the exposure limits outlined in Safety Code 6 suffer from a lack of evidence of causality, biological plausibility and reproducibility and do not provide a credible foundation for making science-based recommendations for limiting human exposures to low-intensity RF fields.

This safety code provides guidance for the avoidance of adverse human health effects resulting from exposure to RF fields, in terms of basic restrictions and/or reference levels. Basic restrictions are exposure indices within the body that should not be exceeded. These exposure indices are directly linked to established adverse health effects. The basic restrictions in this safety code are specified in terms of: a) internal electric field strength; and b) the rate of RF energy absorption (SAR). Since measurements of the SAR or internal electric field strength are often difficult to perform, reference levels for maximum human exposure to RF fields have also been specified in this safety code. The reference levels are specified in terms of unperturbed, externally applied electric- and magnetic-field strength, power density and in terms of electric currents in the body occurring from either induction or contact with energized metallic objects. They were established using dosimetric analyses that determined the levels of externally applied field strengths that would produce the basic restrictions within the body. While compliance with the basic restrictions is required, non-compliance with the reference levels does not necessarily mean that the basic restrictions are not respected. In such cases, additional measurements or calculations may be required to assess compliance.

For frequencies from 3 kHz to 10 MHz, NS from induced electric fields within the body must be avoided. Experimental studies have demonstrated that electric and magnetic field exposures can induce internal electric fields (voltage gradients) within biological tissue which, if sufficiently intense, can alter the “resting” membrane potential of excitable tissues resulting in spontaneous depolarization of the membrane and the generation of spurious action potentials (5, 10, 11, 13, 14, 35, 41). Basic restrictions for the avoidance of NS are specified in this safety code in terms of maximum internal electric field strength within the body.

For frequencies from 100 kHz to 300 GHz, tissue heating can occur and must be limited. Basic restrictions have been specified in this safety code for RF field exposures in the 100 kHz to 6 GHz frequency range, in terms of maximum whole-body SAR (averaged over the whole-body) and peak spatially-averaged SAR, (averaged over a small cubical volume). For frequencies above 6 GHz, RF energy absorption occurs predominantly in surface tissues (e.g. upper layers of skin) and the use of maximum SAR limits, either whole-body or averaged over a cubical volume, is not appropriate. In lieu of basic restrictions, reference levels are specified for maximum unperturbed, externally applied electric- and magnetic-field strengths and in terms of power density, for the avoidance of thermal effects.

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 (5–8, 11, 12, 14, 36). Thermoregulatory studies in human volunteers exposed to RF fields under a variety of exposure scenarios have provided supporting information on RF field induced thermal responses in humans (42). This information forms the scientific basis for the basic restrictions on whole-body average SAR in Safety Code 6. To ensure that thermal effects are avoided, safety factors have been incorporated into the exposure limits, resulting in whole-body-averaged SAR limits of 0.08 and 0.4 W/kg in uncontrolled- and controlled-environments, respectively.

Basic restrictions on peak spatially-averaged SAR have also been established in Safety Code 6 to avoid adverse thermal effects in localized human tissues (hot-spots). The peak spatially-averaged SAR limits reflect the highly heterogeneous nature of typical RF field exposures and the differing thermoregulatory properties of various body tissues. The peak spatially-averaged SAR limits pertain to discrete tissue volumes (1 or 10 g, in the shape of a cube), where thermoregulation can efficiently dissipate heat and avoid changes in body temperature that are greater than 1^{o}C.

As such, the peak spatially-averaged 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 spatially-averaged SAR limits are 4.0 W/kg for the limbs and 1.6 W/kg for the head, neck and trunk.

For frequencies from 100 kHz to 10 MHz, since either NS or thermal effects could occur, depending upon the exposure conditions (frequency, duty cycle, orientation), basic restrictions for both internal electric field strength and SAR (whole-body and peak spatially-averaged) must be simultaneously respected. Safety Code 6 also specifies reference levels in the 3 kHz to 110 MHz frequency range, in terms of induced- or contact-currents (mA), for the avoidance of perception (nerve stimulation), shocks or burns (4, 6).

While the biological basis for the basic restrictions specified in this safety code has not changed since the previous version (2009), the reference levels have been updated to either account for dosimetric refinements in recent years (43–64) or where feasible, to harmonize with those of ICNIRP (10–11).

To determine whether the maximum exposure levels are exceeded, full consideration shall be given to such factors as:

(a) nature of the exposure environment (controlled or uncontrolled environment);
(b) temporal characteristics of the RF source (including ON/OFF times, duty factors, direction and sweep time of the beam, etc.);
(c) spatial characteristics between the exposure source and target (i.e. near-field exposures, whole body or parts thereof);
(d) uniformity of the exposure field (i.e. spatial averaging).

Where comparison is to be made to the SAR-based basic restrictions and/or reference levels at frequencies in the 100 kHz–300 GHz range, higher exposure levels may be permitted for short durations of time under certain circumstances. For these situations, the field strengths, power densities and body currents averaged over any one tenth-hour reference period (6 minutes) shall not exceed the limits outlined in Sections 2.1 and 2.2.

SI units are used throughout this document unless specified otherwise.

2.1 BASIC RESTRICTIONS

2.1.1 Internal Electric Field Strength Limits (3 kHz–10 MHz)

Limits for internal electric field strength are intended to prevent the occurrence of NS. At frequencies between 3 kHz and 10 MHz, basic restrictions for internal electric field strength in excitable tissues (Table 1) shall not be exceeded. For conditions where the determination of internal electric field strength is not possible or practical (e.g. by measurement or modelling), external unperturbed field strength assessment shall be carried out and the reference levels outlined in Section 2.2 shall be respected.

TABLE 1: Internal Electric Field Strength Basic Restrictions (3 kHz–10 MHz)

CONDITION	Internal Electric Field Strength (V/m) (in any excitable tissue)
Controlled Environment	$2.7 \times 10^{-4} f$
Uncontrolled Environment	$1.35 \times 10^{-4} f$

Frequency, f, is in Hz. Instantaneous, root mean square (RMS) values apply. In the case of RF fields with amplitude modulation, then RMS values during the maximum of the modulation envelope shall apply.

2.1.2 Specific Absorption Rate Limits (100 kHz–6 GHz)

The SAR is a measure of the rate at which electromagnetic energy is absorbed in the body. Basic restrictions for SAR are intended to prevent the occurrence of thermal effects from RF energy exposure on the body. At frequencies between 100 kHz and 6 GHz, the SAR limits (Table 2) take precedence over field strength and power density reference levels (Section 2.2) 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 all cases, the values in Table 2 shall not be exceeded. For conditions where SAR determination is impractical, external unperturbed field strength or power density measurements shall be carried out and the limits outlined in Section 2.2 shall be respected.

TABLE 2: Specific Absorption Rate Basic Restrictions (100 kHz–6 GHz)

CONDITION	SAR Basic Restriction (W/kg)**	
	Uncontrolled Environment	Controlled Environment
The SAR averaged over the whole body mass.	0.08	0.4
The peak spatially-averaged SAR for the head, neck and trunk, averaged over any 1 g of tissue*	1.6	8
The peak spatially-averaged SAR in the limbs, averaged over any 10 g of tissue*	4	20

* Defined as a tissue volume in the shape of a cube.

** Averaged over any 6 minute reference period.

2.1.3 Frequencies from 6 GHz–300 GHz

For frequencies above 6 GHz, energy deposition occurs predominantly in the uppermost layers of superficial tissues (e.g. skin, cornea). In this case, power density is a more appropriate exposure limit metric. Therefore, for the frequency range from 6 GHz to 300 GHz, the incident unperturbed power density and its derived electric- and magnetic-field strengths (assuming a free-space impedance of 377 ohms) form the basic restriction in this safety code (Section 2.2.2) and shall not be exceeded.

2.2 REFERENCE LEVELS

In practice, direct measurements of internal electric fields or SAR are often only feasible under laboratory conditions. Therefore, reference levels are specified in this safety code in terms of external unperturbed electric and magnetic field strength, power density, as well as induced and contact currents. In the far-field zone of an electromagnetic source, 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 reference levels in this code.

2.2.1 Electric and Magnetic Field Strength (3 kHz–10 MHz)

To ensure compliance with the basic restrictions outlined in Section 2.1, at frequencies between 0.003 MHz and 10 MHz, both the NS- and SAR-based reference levels for electric- and magnetic-field strength must be complied with simultaneously at frequencies where reference levels for both apply.

TABLE 3: Electric Field Strength Reference Levels

Frequency (MHz)	Reference Level Basis	Reference Level (E_{RL}), (V/m, RMS)		Reference Period
		Uncontrolled Environment	Controlled Environment	
0.003–10	NS	83	170	Instantaneous*
1.0–10	SAR	$87 / f^{0.5}$	$193 / f^{0.5}$	6 minutes**

Frequency, f, is in MHz. The precise frequencies at which SAR-based electric field strength reference levels for Uncontrolled and Controlled Environments begin are 1.10 MHz and 1.29 MHz, respectively.

TABLE 4: Magnetic Field Strength Reference Levels

Frequency (MHz)	Reference Level Basis	Reference Level (H_{RL}), (A/m, RMS)		Reference Period
		Uncontrolled Environment	Controlled Environment	
0.003–10	NS	90	180	Instantaneous*
0.1–10	SAR	$0.73 / f$	$1.6 / f$	6 minutes**

Frequency, f, is in MHz.

NOTES FOR TABLES 3 AND 4:

1. * At no point in time shall the RMS values for electric- and magnetic-fields exceed the reference levels with an instantaneous reference period in Tables 3 and 4. In the case of RF fields with amplitude modulation, the RMS value during the maximum of the modulation envelope shall be compared to the reference level.

2. ** For exposures shorter than the reference period, field strengths may exceed the reference levels, provided that the time average of the squared value of the electric or magnetic field strength over any time period equal to the reference period shall not exceed E_{RL}^2 or H_{RL}^2, respectively. For exposures longer than the reference period, including indefinite exposures, the time average of the squared value of the electric or magnetic field strength over any time period equal to the reference period shall not exceed E_{RL}^2 or H_{RL}^2, respectively.
3. Where external electric (at all applicable frequencies) or magnetic (at frequencies at or above 100 kHz) field strengths are spatially non-uniform, comparison to the reference levels shall be made after spatially averaging the field strengths over the vertical extent of the human body. Where comparison is to be made to the reference levels based on NS in Tables 3 and 4, spatial averaging is with respect to the sample values of the field strengths. Where comparison is to be made to the reference levels based on SAR in Tables 3 and 4, spatial averaging is with respect to the square of the sample values of the field strengths.
4. Where external magnetic field strengths are spatially non-uniform and are below 100 kHz, the spatial peak magnetic field strength over the vertical extent of the human body shall be compared to the reference levels in Table 4 (i.e. magnetic field strengths shall not be spatially-averaged at frequencies below 100 kHz).
5. For simultaneous exposure to multiple frequencies and where comparison is to be made to the reference level based on NS, each of the field strength frequency component amplitudes shall be divided by the corresponding field strength reference level for that frequency, and the sum of all these ratios shall not exceed unity. This may be expressed as $\sum (E_i/E_{RL}) \leq 1$ for electric field strength or $\sum (H_i/H_{RL}) \leq 1$ for magnetic field strength.
6. For simultaneous exposure to multiple frequencies and where comparison is to be made to the reference level based on SAR, each of the squares of the field strength frequency component amplitudes shall be divided by the square of the corresponding field strength reference level for that frequency, and the sum of all these ratios shall not exceed unity. This may be expressed as $\sum (E_i/E_{RL})^2 \leq 1$ for electric field strength or $\sum (H_i/H_{RL})^2 \leq 1$ for magnetic field strength.
7. For localized exposure of the limbs, the reference levels for magnetic field strength may be exceeded provided that the basic restrictions in Table 1 are respected within the limbs.

2.2.2 Electric Field Strength, Magnetic Field Strength and Power Density (10 MHz–300 GHz)

To ensure compliance with the basic restrictions outlined in Section 2.1, at frequencies between 10 MHz and 300 GHz, the reference levels for electric- and magnetic-field strength and power density must be complied with.

TABLE 5: Reference Levels for Electric Field Strength, Magnetic Field Strength and Power Density in Uncontrolled Environments

Frequency (MHz)	Electric Field Strength (E_{RL}), (V/m, RMS)	Magnetic Field Strength (H_{RL}), (A/m, RMS)	Power Density (S_{RL}), (W/m²)	Reference Period (minutes)
10–20	27.46	0.0728	2	6
20–48	$58.07 / f^{0.25}$	$0.1540 / f^{0.25}$	$8.944 / f^{0.5}$	6
48–300	22.06	0.05852	1.291	6
300–6000	$3.142\ f^{0.3417}$	$0.008335\ f^{0.3417}$	$0.02619\ f^{0.6834}$	6
6000–15000	61.4	0.163	10	6
15000–150000	61.4	0.163	10	$616000 / f^{1.2}$
150000–300000	$0.158\ f^{0.5}$	$4.21\text{x}10^{-4}\ f^{0.5}$	$6.67\text{x}10^{-5}\ f$	$616000 / f^{1.2}$

Frequency, f, is in MHz.

TABLE 6: Reference Levels for Electric Field Strength, Magnetic Field Strength and Power Density in Controlled Environments

Frequency (MHz)	Electric Field Strength (E_{RL}), (V/m, RMS)	Magnetic Field Strength (H_{RL}), (A/m, RMS)	Power Density, (S_{RL}), (W/m²)	Reference Period (minutes)
10–20	61.4	0.163	10	6
20–48	$129.8 / f^{0.25}$	$0.3444 / f^{0.25}$	$44.72 / f^{0.5}$	6
48–100	49.33	0.1309	6.455	6
100–6000	$15.60\ f^{0.25}$	$0.04138\ f^{0.25}$	$0.6455\ f^{0.5}$	6
6000–15000	137	0.364	50	6
15000–150000	137	0.364	50	$616000 / f^{1.2}$
150000–300000	$0.354\ f^{0.5}$	$9.40\text{x}10^{-4}\ f^{0.5}$	$3.33\text{x}10^{-4}\ f$	$616000 / f^{1.2}$

Frequency, f, is in MHz.

NOTES FOR TABLES 5 AND 6:

1. For exposures shorter than the reference period, field strengths may exceed the reference levels, provided that the time average of the squared value of the electric or magnetic field strength over any time period equal to the reference period shall not exceed E_{RL}^2 or H_{RL}^2, respectively. For exposures longer than the reference period, including indefinite exposures, the time average of the squared value of the electric or magnetic field strength over any time period equal to the reference period shall not exceed E_{RL}^2 or H_{RL}^2, respectively.

2. Where exposure is estimated in terms of power density and for exposures shorter than the reference period, power density levels may exceed the reference levels provided that the time average of the power density over any time period equal to the reference period shall not exceed S_{RL}. For exposures longer than the reference period, including indefinite exposures, the time average of the power density over any time period equal to the reference period shall not exceed S_{RL}.
3. Spatially non-uniform external field strengths or power density can be spatially averaged, provided the sampling scheme applied ensures that none of the basic restrictions are exceeded at spatially-averaged exposures equal to the reference level. If spatial averaging is not applied, the spatial peak field strength shall be compared to the reference levels. In the case of field strengths, spatial averaging is with respect to the squared values of the field strength samples while for power density, spatial averaging is with respect to the power density samples.
4. For simultaneous exposure to multiple frequencies and where exposure is estimated in terms of power density, each of the power density frequency component amplitudes shall be divided by the corresponding reference level for that frequency, and the sum of all these ratios shall not exceed unity. This may be expressed as: $\sum (S_i/S_{RL}) \leq 1$.
5. For simultaneous exposure to multiple frequencies and where exposure is estimated in terms of field strength, each of the squares of the field strength frequency component amplitudes shall be divided by the square of the corresponding field strength reference level for that frequency, and the sum of all these ratios shall not exceed unity. This may be expressed as $\sum (E_i/E_{RL})^2 \leq 1$ for electric field strength or $\sum (H_i/H_{RL})^2 \leq 1$ for magnetic field strength.
6. For pulsed RF field exposures estimated in terms of power density, the time-averaged power density, averaged over any time period equal to the reference period, shall not exceed S_{RL} and the power density, as averaged over the pulse width, shall not exceed 1000 times the reference level, S_{RL}.
7. For pulsed RF field exposures estimated in terms of field strength, the time average of the squared value of the electric or magnetic field strength over any time period equal to the reference period shall not exceed E_{RL}^2 or H_{RL}^2. In addition, the time average of the squared value of the electric or magnetic field strength, as averaged over the pulse width, shall not exceed 1000 times E_{RL}^2 or H_{RL}^2, respectively. Therefore, the RMS electric or magnetic field strength, determined over the pulse, shall not exceed 32 times E_{RL} or H_{RL}, respectively.

2.2.3 Induced and Contact Current (3 kHz–110 MHz)

Induced current is defined as the current flowing through a single foot to ground in a free-standing body (no contact with conductive objects) exposed to an electric field. Where assessment is made of the current flowing through both feet, the result shall be compared to twice the reference level for a single foot.

Contact current is defined as the total current flowing through the body to ground resulting from finger-touch contact with a conductive object insulated from the ground that has been energized in an electric field. Conversely, it can be defined as the total current flowing in an insulated body that has been energized in an electric field and is in finger-touch contact with a grounded conductive object. The current path in the body is from point of touch to ground through the feet. The total current can be assessed anywhere along the path of flow.

TABLE 7: Induced Current Reference Levels

Frequency (MHz)	Reference Level Basis	Reference Level (I_{RL}) through a single foot, (mA, RMS)		Reference Period
		Uncontrolled Environment	**Controlled Environment**	
0.003–0.4	NS	100 f	225 f	Instantaneous*
0.4–110	SAR	40	90	6 minutes**

Frequency, f, is in MHz.

TABLE 8: Contact Current Reference Levels

Frequency (MHz)	Reference Level Basis	Reference Level (I_{RL}), (MA, RMS)		Reference Period
		Uncontrolled Environment	**Controlled Environment**	
0.003–0.10	NS	200 f	400 f	Instantaneous*
0.1–10	SAR	20	40	Instantaneous*
10–110	SAR	20	40	6 minutes**

Frequency, f, is in MHz.

NOTES FOR TABLES 7 AND 8:

1. * At no point in time shall the RMS values for induced and contact currents exceed the reference levels with an instantaneous reference period in Tables 7 and 8. In the case of currents with amplitude modulation, the RMS value during the maximum of the modulation envelope shall be compared to the reference level.
2. ** For exposures shorter than the reference period, currents may exceed the reference levels, provided that the time average of the squared value of the current over any time period equal to the reference period shall not exceed I_{RL}^2. For exposures longer than the reference period, including indefinite exposures, the time average of the squared value of the current over any time period equal to the reference period shall not exceed I_{RL}^2.

3. For simultaneous exposure to multiple frequencies and where comparison is to be made to the reference level based on NS, each of the induced- or contact-current frequency component amplitudes shall be divided by the corresponding reference level for that frequency, and the sum of all these ratios shall not exceed unity. This may be expressed as $\sum (I_i/I_{RL}) \leq 1$.
4. For simultaneous exposure to multiple frequencies and where comparison is to be made to the reference level based on SAR, each of the squares of the induced- or contact-current frequency component amplitudes shall be divided by the square of the corresponding reference level for that frequency, and the sum of all these ratios shall not exceed unity. This may be expressed as $\sum (I_i/I_{RL})^2 \leq 1$.
5. For pulsed induced- or contact-currents where a 6 minute reference period applies, the time average of the squared value of the induced- or contact-currents over any time period equal to the reference period shall not exceed I_{RL}^2. In addition, the time average of the squared value of the induced- or contact-current, as averaged over the pulse width, shall not exceed 1000 times the reference level I_{RL}^2. Therefore the RMS value of the induced- or contact-current, determined over the pulse, shall not exceed 32 times the reference level I_{RL}.

ABBREVIATIONS

A	ampere
EEG	electroencephalogram
$\mathbf{E_i}$	electric field strength frequency component amplitude (RMS)
$\mathbf{E_{RL}}$	electric field strength reference level
g	gram
GHz	gigahertz
$\mathbf{H_i}$	magnetic field strength frequency component amplitude (RMS)
$\mathbf{H_{RL}}$	magnetic field strength reference level
ICNIRP	International Commission on Non-Ionizing Radiation Protection
$\mathbf{I_i}$	current frequency component amplitude (RMS)
$\mathbf{I_{RL}}$	current reference level
kg	kilogram
kHz	kilohertz
m	meter
mA	milliampere
MHz	megahertz
mm	millimeter
NS	nerve stimulation
RMS	root mean square
RF	radiofrequency
SAR	specific absorption rate
SI	International System of Units
$\mathbf{S_i}$	power density frequency component amplitude
$\mathbf{S_{RL}}$	power density reference level
V	volt
W	watt

DEFINITIONS

basic restrictions—Maximum allowable internal electrical quantities in the body, arising from exposure to incident external fields, that prevent the occurrence of all established adverse health effects.

contact current—The total current flowing through the body to ground resulting from finger-touch contact with an insulated conductive object that has been energized in an electric field, or from an insulated body that has been energized in an electric field and is in finger-touch contact with a grounded conductive object.

controlled environment—An area where the RF field intensities have been adequately characterized by means of measurement or calculation and exposure is incurred by persons who are: aware of the potential for RF field exposure, cognizant of the intensity of the RF fields in their environment, aware of the potential health risks associated with RF field exposure and able to control their risk using mitigation strategies.

electric field—A vector quantity assigned to any point in space where the magnitude and direction of the force that would be experienced by a hypothetical test charge, is defined.

electromagnetic radiation—A form of energy emitted by accelerating electric charges, that exhibits wave-like behavior as it travels through space.

far-field zone—The space beyond an imaginary boundary around an antenna, where the angular field distribution begins to be 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 cycles in the variation of the amplitude of an electromagnetic wave within one second, 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—The current flowing through one foot to ground in a free-standing human body (no contact with a conductive object) exposed to an electric field.

limbs—Extremities distal from the shoulder and hip joints, which do not include the gonads.

magnetic field—A vector quantity assigned to any point in space where the magnitude and direction of the force that would be experienced by a hypothetical test charge-in-motion, is defined. A magnetic field exerts a force on charges only if they are in motion, and charges produce magnetic fields only when they are in motion.

near-field zone—A volume of space 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 at the same distance from the source.

non-thermal effects—Biological effects resulting from exposure to RF fields, that are not due to tissue heating.

power density—The rate of flow of electromagnetic energy per unit area usually expressed in W/m^2 or mW/cm^2 or $\mu W/cm^2$.

radiofrequency (RF)—A rate of oscillation in the range of about 3 kHz to 300 GHz, which corresponds to the frequency of radio waves typically used in radio communications.

reference level—An easily measured or calculated quantity (i.e. externally applied electric field strength, magnetic field strength and power density or resulting body current), that when respected, ensures compliance with the underlying basic restrictions in Safety Code 6.

reference period—A time period used for averaging temporally non-uniform RF field exposures, for comparison with the exposure limits in Safety Code 6. The reference periods specified in Safety Code 6 are based upon the established adverse health effects to be avoided and the time required for those responses to occur. The reference period is not a maximum exposure time.

RMS (root mean square)—As applied to a set of data, it is the square root of the average of the square of the data values.

safety—The absence of established adverse health effects caused by RF field exposure.

specific absorption rate (SAR)—A measure of the rate at which energy is absorbed by the body (or a discrete tissue volume) when exposed to a radiofrequency (RF) field. SAR is expressed in units of watts per kilogram (W/kg), and can be calculated from the product of the tissue conductivity (S/m) and the square of the RMS electric field strength induced in the tissue (V/m), divided by the mass density (kg/m^3) of the tissue.

thermal effects—Biological effects resulting from heating of the whole body or of a localized region due to exposure to RF fields, where a sufficient temperature increase has occurred that results in a physiologically significant effect.

uncontrolled environment—An area where any of the criteria defining the controlled environment are not met.

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TAB 8

OFFICIAL
CITY OF LOS ANGELES
MUNICIPAL CODE ™

Sixth Edition

www.lacity.org

Ordinance No. 77,000

Effective November 12, 1936

Current through June 30, 2022

(plus Ord. No. 187,586, Eff. 9/18/22)

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FOREWORD

The First Edition of the Municipal Code of the City of Los Angeles, enacted by adoption of Ordinance No. 77,000, codified the regulatory and penal ordinances of the City. It became effective November 12, 1936. The Second Edition amended the Code through September 10, 1945. From 1955 to 1958, a Third Edition was published in loose-leaf form. This format made possible the continual page-for-page revision system that has been retained in subsequent editions. A Fourth Edition was published November 30, 1973. The Fifth Edition initially updated the Code through June 30, 1989. This Sixth Edition is current upon publication through September 30, 2002, and will be maintained up-to-date by the incorporation of subsequently published revision packages. The Sixth Edition is copyrighted by the City of Los Angeles. The City intends to register its copyright upon publication.

This newly published Sixth Edition represents a thorough modernization of the Los Angeles Municipal Code. The Sixth Edition retains the loose-leaf format of prior editions but, for the first time, the Code is presented on standard-sized 8½" × 11" paper. In addition to greatly simplifying the process of printing the Code (and subsequent revisions), the new size brings a number of advantages to the Code user. The standard size is more compatible with office equipment such as copiers and facsimile machines. The larger page size allows the implementation of a completely new dual-column layout that dramatically improves the readability of the Code's text. The new size substantially reduces the overall number of pages of the Code. The increase in the amount of text per page will also tend to reduce the number of pages that the Code user will have to replace in each revision cycle.

The Sixth Edition incorporates a number of other improvements not directly related to the new standard size. The Code has been divided into a larger number of volumes. This change, in combination with the overall page reduction described above, allows each new volume to contain far fewer pages than the unwieldy volumes of the previous edition. Chapter contents are more logically presented in this edition, with each Chapter beginning with a list of its constituent Articles, and each Article beginning with a thorough summary of its Sections (or Divisions, as the case may be). This edition also includes two new features that make navigation through the Code easier. Page headers now selectively include subdivision references which will assist the user in finding specific subdivisions in lengthy multi-page sections. Additionally, the headers of alternating pages now specifically identify the page's Chapter and Article by both name and number.

This Sixth Edition of the Los Angeles Municipal Code will assist City offices, departments and other governmental agencies in their functions, and will serve the people as the official source of information regarding the regulations enacted by the City of Los Angeles for the preservation of the public peace, health and safety.

DIVISION 12

FUEL GAS PIPING

SEC. 94.1200.0. BASIC PROVISIONS.

(Amended by Ord. No. 186,488, Eff. 12/27/19.)

Chapter 12 of the 2019 CPC is adopted by reference and LAMC Section 94.1217.0 is added.

SEC. 94.1217.0. SEISMIC GAS SHUTOFF VALVES.

(Amended by Ord. No. 182,847, Eff. 1/3/14.)

94.1217.1. Definitions. For purposes of this section, certain terms shall be defined as follows:

Downstream of the Gas Utility Meter shall refer to all customer owned gas piping, downstream of the bypass valve, as specified by the public gas utility company.

Excess Flow Shutoff Valve shall mean a shutoff system activated by significant gas leaks or overpressure surges downstream of the valves.

Residential Building shall mean any single-family dwelling, duplex, apartment building, condominium, townhouse, lodging house, congregate residence, hotel or motel.

Seismic Gas Shutoff Valve shall mean a system consisting of a seismic sensing means and actuating means designed to automatically actuate a companion gas shutoff means installed in a gas piping system in order to shutoff the gas downstream of the location of the gas shutoff means in the event of a severe seismic disturbance. The system may consist of separable components or may incorporate all functions in a single body. The terms "Seismically Activated Gas Shutoff Valves" and "Earthquake Sensitive Gas Shutoff Valves" are synonymous.

Upstream of the Gas Utility Meter shall refer to all gas piping installed by the utility up to and including the meter and the utility's bypass tee at the connection to the customer owned piping.

94.1217.2. Scope. An approved seismic gas shutoff valve or excess flow shutoff valve shall be installed downstream of the gas utility meter on each fuel gas line where the gas line serves the following buildings or structures:

94.1217.2.1. A building or structure containing fuel gas piping for which a building permit was first issued on or after September 1, 1995.

94.1217.2.2. An existing building or structure which is altered or added to; and

94.1217.2.2.1. That building or structure has fuel gas piping supplying the existing building or structure or the addition to the building or structure; and

94.1217.2.2.2. The alteration or addition is valued at more than $10,000 and a building permit for the work in commercial buildings was first issued on or after September 1, 1995. Alterations or additions to individual units or tenant spaces shall require a seismic gas shutoff valve or excess flow shutoff valve to be installed for all gas piping serving that individual unit or tenant space; or

94.1217.2.2.3. The alteration or addition is valued at more than $10,000 and a building permit for the work in residential buildings, including condominium units, is first issued on or after January 10, 1998. Alterations or additions to an individual condominium unit shall require a seismic gas shutoff valve or excess flow shutoff valve to be installed for all gas piping serving that individual condominium unit; or

94.1217.2.2.4. The alteration or addition is to the fuel gas piping system and involves the alteration or replacement of the gas meter.

94.1217.2.3. Prior to entering into an agreement of sale, or prior to the close of escrow when an escrow agreement has been executed in connection with the sale,

1. Buildings or structures which contain fuel gas piping shall have a seismic gas shutoff valve or excess flow shutoff valve installed.

2. The sale of an individual condominium unit in a building shall require the installation of a seismic gas shutoff valve or excess flow shutoff valve for all gas piping serving that individual unit.

EXCEPTIONS:

(a) Seismic gas shutoff valves or excess flow shutoff valve may be installed upstream of a gas utility meter provided they meet the requirements of this section.

(b) Seismic gas shutoff valves or excess flow shutoff valve installed on a building or structure prior to September 1, 1995, are exempt from the requirements of this section provided they remain installed on the building or structure and are maintained for the life of the building or structure.

(c) Notwithstanding LAMC Subdivisions 94.1217.2.1, 94.1217.2.2 and 94.1217.2.3 above, these provisions shall not apply to a building or structure if the Department determines that a building or structure satisfies all three of the following criteria: **(Amended by Ord. No. 185,587, Eff. 7/16/18.)**

(i) That the building or structure is owned, operated, and maintained by a governmental entity or public utility; or that the building or structure is owned by a private concern and provides a public benefit, such as a co-generation facility which shares its excess power with a public utility or with a large industrial facility which has governmental contracts;

(ii) That the building or structure has available 24-hour, year round maintenance staffing; and

(iii) That the gas piping system contained in the building or structure is designed to withstand seismic effects of earthquakes.

(d) A single seismic gas shutoff valve or excess flow shutoff valve may be installed upstream of the gas utility meter at the discretion of the gas utility.

94.1217.3. General Requirements. (Amended by Ord. No. 185,587, Eff. 7/16/18.) Seismic gas shutoff valves or excess flow shutoff valves installed either in compliance with LAMC Subsection 94.1217.2, *et seq.*, or voluntarily with a permit issued on or after September 1, 1995, shall comply with the following requirements:

94.1217.3.1. Seismic gas shutoff valves or excess flow shutoff valve shall be installed by a contractor licensed in the appropriate classification by the State of California.

EXCEPTIONS:

(a) A person who has been determined by the Department to meet the qualifications of a Qualified Installer pursuant to the definition of a Qualified Installer set forth in Article 4, Chapter IX of the LAMC may install a seismic gas shutoff valve or excess flow shutoff valve to a single-family dwelling which is or is intended to be occupied by the Qualified Installer. **(Amended by Ord. No. 185,587, Eff. 7/16/18.)**

(b) Seismic gas shutoff valves or excess flow shutoff valve may be installed, without a permit, by a gas utility or a contractor authorized by the gas utility when the valves are installed upstream of the gas utility meter and the valves are installed and approved in accordance with this section.

94.1217.3.2. Seismic gas shutoff valves or excess flow shutoff valve shall be mounted rigidly to the exterior, or other approved location, of the building or structure containing the fuel gas piping.

EXCEPTION: If the Department determines that the seismic gas shutoff valve or excess flow shutoff valve has been tested and listed for an alternate method of installation, then a seismic gas shutoff valve or excess flow shutoff valve need not be mounted rigidly to the exterior of the building or structure containing the fuel gas piping.

94.1217.3.3. Be certified by the Office of the State Architect.

94.1217.3.4. Be approved by the Department of Building and Safety, Mechanical Testing Laboratory.

94.1217.3.5. Have a thirty (30) year warranty which warrants that the valve is free from defects and will continue to properly operate for thirty (30) years from the date of installation.

94.1217.3.6. Where seismic gas shutoff valves or excess flow shutoff valve are installed as required by this section, they shall be maintained for the life of the building or structure or be replaced with a valve complying with the requirements of this section.

94.1217.3.7. Seismic gas shutoff valves must be in compliance with all requirements of California Referenced Standard 12-16-1, at Part 12, Title 24, of the California Code of Regulations (CCR). **(Amended by Ord. No. 185,587, Eff. 7/16/18.)**

94.1217.3.8. Excess flow shutoff valves must be in compliance with all requirements of California Referenced Standard 12-16-2. (Part 12, Title 24, of the CCR). **(Amended by Ord. No. 185,587, Eff. 7/16/18.)**

DIVISION 13

HEALTH CARE FACILITIES AND MEDICAL GAS AND VACUUM SYSTEMS

SEC. 94.1300.0. BASIC PROVISIONS.

(Amended by Ord. No. 186,488, Eff. 12/27/19.)
Chapter 13 of the 2019 CPC is not adopted.

DIVISION 14

FIRESTOP PROTECTION

(Title Amended by Ord. No. 184,692, Eff. 12/30/16.)

SEC. 94.1400.0. BASIC PROVISIONS.

(Amended by Ord. No. 186,488, Eff. 12/27/19.)

Chapter 14 of the 2019 CPC is not adopted.

DIVISION 15

ALTERNATE WATER SOURCES FOR NONPOTABLE APPLICATIONS

(Title Amended by Ord. No. 184,692, Eff. 12/30/16.)

TAB 9

1958 *Feb. 3, 4 Apr. 22

MEMORIAL GARDENS ASSOCIATION (CANADA) LIMITED ..... APPELLANT;

AND

COLWOOD CEMETERY COMPANY, BOARD OF CEMETERY TRUSTEES OF GREATER VICTORIA, CORPORATION OF THE DISTRICT OF SAANICH, THE CORPORATION OF THE CITY OF VICTORIA, EDWIN J. FREEMAN, HELEN J. FREEMAN, A. C. KINNERSLEY, LOLA KINNERSLEY, H. M. PALSSON, JEAN LABAN, C. J. LABAN, SHIRLEY R. CROCKETT, B. I. CROCKETT, F. A. KINNERSLEY, VERNICE ROCKWELL, PETER C. SHARP, L. H. SHARP AND ALEXANDER HORBATUK AND PUBLIC UTILITIES COMMISSION .... RESPONDENTS.

ON APPEAL FROM THE COURT OF APPEAL FOR BRITISH COLUMBIA

Public utilities—"Public convenience and necessity"—Meaning of phrase—Review of decision of Commission—The Public Utilities Act, R.S.B.C. 1948, c. 277, ss. 58, 72, 75, 100—The Cemeteries Act, R.S.B.C. 1948, c. 41, ss. 2, 3, as enacted by 1955, c. 7, s. 3.

Per Kerwin C.J. and Taschereau, Cartwright and Abbott JJ.: It is impracticable and undesirable to attempt a precise definition of the phrase "public convenience and necessity". It is clear from the American decisions that the word "necessity" as here used does not bear its strict dictionary meaning. Its meaning must be ascertained in each case by reference to the context and to the objects and purpose of the statute in which it is found; in particular, it has been held that the word is not restricted to present needs but includes provision for the future. *Wabash, C. & W. Ry. Co. v. Commerce Commission* (1923), 141 N.E. 212, referred to.

The Public Utilities Commission of British Columbia granted a certificate of public convenience and necessity to the appellant company for the operation, through a subsidiary company, of a cemetery on Vancouver Island. This certificate was set aside by the Court of Appeal.

Held: The judgment of the Court of Appeal should be set aside and the certificate should be restored.

Per Kerwin C.J. and Taschereau, Cartwright and Abbott JJ.: The Commission's decision that public convenience and necessity required the establishment of a new cemetery was not one of fact but was predominantly the formulation of an opinion based upon the facts established before the Commission. There was evidence to support

*PRESENT: Kerwin C.J. and Taschereau, Locke, Cartwright and Abbott JJ.

1958

MEM. GARDENS ASSN. LTD. v. COLWOOD CEMETERY Co. *et al.*

the findings of fact made by the Commission and its exercise of administrative discretion based on those findings should not be interfered with by the Courts. *Union Gas Company of Canada Limited v. Sydenham Gas and Petroleum Company Limited,* [1957] S.C.R. 185, applied.

Subsidiary grounds of attack on the Commission's decision should be disposed of as follows: (1) the fact that the appellant proposed to operate the cemetery by means of a subsidiary company to which the Commission agreed to grant a second certificate on incorporation was not an objection to the grant of the certificate to the appellant; (2) the fact that the appellant held only an option on the lands in question was not a ground for refusing the certificate, since the option, assuming it to be enforceable, made the appellant an "owner" within the meaning of the statute; (3) there was no ground, in the circumstances of the case, for saying that the Commission had unjustifiably received evidence without permitting the respondents to see it, thus preventing cross-examination and violating the rule *audi alteram partem. Toronto Newspaper Guild v. Globe Printing Company,* [1953] 2 S.C.R. 18, distinguished.

Per Locke J.: The option was produced for examination by the Commission with the express consent of counsel for the parties who now objected, and they should not now be heard to allege that the proceedings were invalidated by this circumstance. *Scott v. The Fernie Lumber Company, Limited* (1904), 11 B.C.R. 91 at 96, approved and applied. In other respects, the appeal failed for the reasons given by Sheppard J.A. in his dissenting judgment in the Court of Appeal.

APPEAL from a judgment of the Court of Appeal for British Columbia[1], setting aside a certificate of public convenience and necessity granted by the Public Utilities Commission. Appeal allowed.

Alan B. MacFarlane and *E. A. Popham,* for the appellant.

D. M. Gordon, Q.C., for the respondents.

The judgment of Kerwin C.J. and Taschereau, Cartwright and Abbott JJ. was delivered by

ABBOTT J.:—The question raised on this appeal is whether a certificate of public convenience and necessity issued by the Public Utilities Commission of British Columbia, under the provisions of the *Public Utilities Act,* R.S.B.C. 1948, c. 277, as amended, was authorized in law.

By the *Cemeteries Act Amendment Act, 1955* (B.C.), c. 7, cemeteries in British Columbia were brought under the jurisdiction of the Public Utilities Commission as constituted under the *Public Utilities Act,* the relevant

[1] (1957), 22 W.W.R. 348, 9 D.L.R. (2d) 653, 75 C.R.T.C. 292.

sections of the *Cemeteries Act,* R.S.B.C. 1948, c. 41, as enacted by s. 3 of the 1955 statute, reading as follows:

Regulation of Cemeteries, Crematoria, and Columbaria.

2. A cemetery shall not be established or enlarged until the Minister of Health and Welfare has approved of the site of the cemetery as a fit and proper place for the interment of the dead and the owner thereof has obtained from the Commission a certificate of public convenience and necessity under the "Public Utilities Act."

3. (1) The Commission shall have jurisdiction over all cemeteries, columbaria, and crematoria, and the owners thereof, and shall exercise with respect thereto all the powers, duties, and functions relating to public utilities conferred or imposed by the "Public Utilities Act" on the Commission, to the extent to which such powers, duties, and functions are exercisable, and the provisions of the "Public Utilities Act" (other than Part IV thereof), so far as appropriate, shall aply to cemeteries, columbaria, crematoria, and the owners thereof.

(2) Without limiting the generality of subsection (1) and notwithstanding the provisions of the "Cemetery Companies Act," the "Cremation Act," or the "Municipal Cemeteries Act," the Commission may, with the approval of the Lieutenant-Governor in Council, make regulations:

(*a*) Respecting the burial, disinterment, removal, and disposal of the bodies or other remains of deceased persons;

(*b*) Respecting the plans, survey, arrangement, condition, care, sale, and conveyancing of lots, plots, and other cemetery grounds and property;

(*c*) Respecting the erection, arrangement, and removal of tombs, vaults, monuments, gravestones, markers, copings, fences, hedges, shrubs, plants, and trees in cemeteries;

(*d*) Respecting charges for the sale and care of lots and plots;

(*e*) Respecting the collection, amounts to be collected, and investment of funds for perpetual care and maintenance of cemeteries;

(*f*) Requiring the filing or registration of plans of cemeteries and prescribing the contents and details of such plans, and requiring that burials be made in accordance with such plans;

and such regulations may be general in their application or may be made applicable specially to any particular locality or cemetery.

(3) Every person who fails or refuses to obey a regulation of the Commission made under this section is guilty of an offence and liable, on summary conviction, to a penalty of not less than ten dollars and not more than five hundred dollars.

The appellant proposed to establish and operate a new cemetery in the vicinity of Victoria and, as required by the statute, applied to the Public Utilities Commission for a certificate of public convenience and necessity. There were at the time two cemeteries in the area, one, the Colwood Cemetery, operated by a privately-owned company, the other, the Royal Oak Cemetery, a municipally-operated cemetery controlled by the City of Victoria and the Municipality of Saanich. Appellant's application was

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opposed by those in control of the two existing cemeteries and by certain owners of property adjoining the site of the proposed new cemetery.

After a hearing at which evidence was taken as to the need for cemeteries in the Victoria area, both present and future, the Commission issued the certificate requested. Under s. 100 of the *Public Utilities Act* an appeal from a decision of the Commission lies to the Court of Appeal, by leave, only upon a question of law or as to the jurisdiction of the Commission. Appeal was taken to the Court of Appeal for British Columbia and by a majority decision the Court of Appeal[1] allowed the appeal and held that the certificate should be set aside. The present appeal is from that judgment. Sheppard J. A., while dissenting on the main issues raised, would have referred the matter back to the Commission for a rehearing on one matter.

The term "public convenience and necessity" appears to have been brought into the statute law in Canada from the United States and a great many decisions were cited to us indicating the meaning given to the term in that country. It is clear from these decisions that the word "necessity" as contained in these American statutes cannot be given its dictionary meaning in the strict sense: *Canton-East Liverpool Coach Co. et al. v. Public Utilities Commission of Ohio*[2]; *Wisconsin Telephone Co. v. Railroad Commission of Wisconsin et al.*[3]; *Wabash, C. & W. Ry. Co. v. Commerce Commission*[4]; *San Diego & Coronado Ferry Co. v. Railroad Commission of California et al.*[5] The meaning in a given case must be ascertained by reference to the context and to the objects and purposes of the statute in which it is found.

The term "necessity" has also been held to be not restricted to present needs but to include provision for the future: *Wabash, C. & W. Ry. Co. v. Commerce Commission, supra,* at p. 215, and this indeed would seem to follow from s. 12 of the *Public Utilities Act,* which provides that the certificate may issue where public convenience and necessity "require or *will require*" such construction or operation.

[1] (1957), 22 W.W.R. 348, 9 D.L.R. (2d) 653, 75 C.R.T.C. 292.

[2] (1930), 174 N.E. 244.

[3] (1916), 156 N.W. 615.

[4] (1923), 141 N.E. 212 at 214.

[5] (1930), 292 P. 640 at 643.

It is obvious I think, that the phrase "public convenience and necessity" when applied to cemeteries cannot be given precisely the same connotation as when it is applied to those operations more commonly looked upon as public utilities, such as electric power services, water-distribution systems, railway lines and the like, and this is borne out both by the terms of the statute which I have quoted and by the decisions of the American Courts to which we were referred.

The phrase also appears in *The Municipal Franchises Act,* R.S.O. 1950, c. 249 (considered by this Court in *Union Gas Company of Canada Limited v. Sydenham Gas and Petroleum Company Limited*[1]), in the *Aeronautics Act,* R.S.C. 1952, c. 2, and I have no doubt in other provincial and federal statutes, and it would, I think, be both impracticable and undesirable to attempt a precise definition of general application of what constitutes public convenience and necessity. As has been frequently pointed out in the American decisions, the meaning in a given case should be ascertained by reference to the context and to the objects and purposes of the statute in which it is found.

As this Court held in the *Union Gas* case, *supra,* the question whether public convenience and necessity requires a certain action is not one of fact. It is predominantly the formulation of an opinion. Facts must, of course, be established to justify a decision by the Commission but that decision is one which cannot be made without a substantial exercise of administrative discretion. In delegating this administrative discretion to the Commission the Legislature has delegated to that body the responsibility of deciding, in the public interest, the need and desirability of additional cemetery facilities, and in reaching that decision the degree of need and of desirability is left to the discretion of the Commission.

The findings of fact made by the Commission have been concisely set forth by Sheppard J.A. in his reasons[2], and are in part as follows:

(1) That there are two established cemeteries in the district in question, namely, Royal Oak and Colwood, and these have vacant space adequate for immediate needs;

[1] [1957] S.C.R. 185, 7 D.L.R. (2d) 65, 75 C.R.T.C. 1.
[2] 22 W.W.R. at p. 362.

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(2) That the services proposed by the appellant company are similar to those now available at Royal Oak; that Colwood is not a modern, but an older, type of cemetery; that Colwood has proposed modernizing but that may be reconsidered if the respondent [now appellant] company is permitted to establish a cemetery;

(3) That the established cemeteries, Royal Oak and Colwood, are not adequate for the future; that the available space at Royal Oak will be filled in 10 to 15 years; that the need for the future is recognized by both these cemeteries in that both are presently negotiating for additional land;

(4) That vacant cemetery spaces will be needed for the future; that the modern-type cemetery may, by reducing the public demand for cremation, increase the rate at which the available space will be filled.

There was evidence before the Commission upon which it could make the findings of fact which it did. In my opinion the majority of the Court of Appeal in holding that in law the Commission could not find necessity upon the facts recited in its judgment was merely substituting its opinion for that of the Commission. As this Court held in the *Union Gas* case, *supra*, this is not a question of law upon which an appeal is given, and the Court below was therefore without jurisdiction. It would have been otherwise if it had been shown that the Commission had given a meaning to the words of the statute which as a matter of law they could not bear.

Three subsidiary points were raised by respondents. As set out in their factum these are as follows:

1. The Commission went beyond the authority given by the statute by granting the appellant a certificate, though the appellant was not meant to establish or operate the cemetery itself, but to form a subsidiary to do that, to which the Commission bound themselves to give a second certificate;

2. The appellant had no basis for its application for a certificate except an option to buy a site, and the statute required it to be an "owner";

3. The Commission unjustifiably received evidence of the option without permitting the respondents to see it, thus preventing cross-examination and infringing the *audi alteram partem* rule.

As to points 1 and 2, I agree with the views expressed by Sheppard J.A. that the certificate appears to be within the powers conferred by the statute and that the option held by appellant, assuming it to be enforceable, did enable appellant to obtain and assert a control sufficient to constitute appellant an owner within the meaning of the statute.

As to the third point, at the hearing before the Commission appellant called as witnesses the persons from whom the option referred to had been obtained, and the option itself was filed with the Commission. Appellant was apparently unwilling to exhibit the document to respondents at that time since this would have involved disclosing the purchase-price and the transcript of evidence on this point reads in part as follows:

Mr. GORDON: Just one point, since the option itself has been the subject-matter of considerable discussion. I wonder if it might be produced for examination by the Commission? There have been certain representations regarding it as to detail, as to length of time and certain questions have now arisen. Could the Commission have it produced, merely to verify statements that have been made?

Mr. MACFARLANE: I am prepared to produce it to the Commission but not to my learned friends. Now, I state that that option has been executed by these people, Mr. and Mrs. Turner. These people have sworn under oath here to-day that they executed such an option. I state that the option is in favor of James H. Edwards, the President of Memorial Gardens Association of Canada Limited. They swear the property that it covers and they swear the expiry date. I have the option here but I am not going to tell my learned friends the price that Memorial Gardens Association Limited is paying for this property, which they would dearly like to know and which is Mr. and Mrs. Turner's private business. The company doesn't care if everybody knows but Mr. and Mrs. Turner are selling it for a price, it is up to them.

Mr. GORDON: It is essential to the jurisprudence to produce the document about which you are discussing. It is the document, the very basis of the matter which we are dealing with. Simply to make an oath on something when—

The CHAIRMAN: I think the document should be produced to the Commission, whose officers are under oath not to disclose confidential information, but if the document itself does contain certain information that is confidential, it needn't be disclosed to the public.

Mr. MACFARLANE: That is my point. I am quite happy to disclose the information to the Commission but I don't feel it is such that should be disclosed—

Mr. GORDON: May I just simply add this, that in respect to this option, certain statements were made as to when it was entered into, as to what period it was extended to, asking the Commission to make a hurried decision in order to meet with its requirements. If these things are all in the option, we know at least that is *bona fide* but having sworn statements made without the basic documents there at least to the Commission, is of little value.

The CHAIRMAN: The Commission will have the opportunity of comparing the statements with the document.

Mr. GORDON: Well, that is perfectly satisfactory to me.

It does not appear from the record that any person opposing the application other than Mr. Gordon asked for the production of the option and Mr. Gordon stated that he was satisfied with the procedure proposed by the Commission. These circumstances clearly distinguish this case

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from that of *Toronto Newspaper Guild v. Globe Printing Company*[1]. In these circumstances and in view of the provisions of ss. 58, 72 and 75 of the *Public Utilities Act* in my opinion this third point does not avail the respondents.

For the reasons which I have given, as well as for those of Sheppard J.A. as to the main issue, with which I am in substantial agreement, I would allow the appeal with costs here and below and restore the certificate.

LOCKE J.:—With the exception hereinafter mentioned, I agree with the reasons for judgment delivered by Mr. Justice Sheppard.

While the record does not disclose the fact, I assume that Mr. Gordon, who cross-examined certain of the witnesses on behalf of the Colwood Cemetery Company, is a member of the bar of British Columbia and that he acted in that capacity at the hearing before the Public Utilities Commission. We were informed at the hearing of this appeal that the person referred to was not Mr. D. M. Gordon, Q.C., who appeared for the respondents before us.

The passage from the transcript quoted in the reasons of my brother Abbott, which I have had the advantage of reading, shows that Mr. Gordon asked that the option might be produced for examination by the Commission "merely to verify statements that have been made". The chairman ruled that this should be done and counsel for the appellant at once agreed that the information should be disclosed to the Commission. When the chairman said that the Commission would have the opportunity of comparing the statements that had been made with the document, Mr. Gordon said that that was perfectly satisfactory. None of the other parties represented before the Commission appear to have evidenced any interest in the nature of the option. Having thus led the members of the Commission to understand that the course proposed was satisfactory to his clients, they should not now be heard to allege that the proceedings were invalidated by the

[1] [1953] 2 S.C.R. 18, [1953] 3 D.L.R. 561, 106 C.C.C. 225.

very course of conduct that they assented to: *Scott v. The Fernie Lumber Company, Limited*[1].

I would allow this appeal with costs in this Court and in the Court of Appeal.

Appeal allowed with costs.

Solicitors for the appellant: Clay, MacFarlane, Ellis & Popham, Victoria.

Solicitors for the respondent Colwood Cemetery Company: Crease & Co., Victoria.

Solicitors for the respondent cemetery trustees: Gregory, Grant, Cox & Harvey, Victoria.

Solicitors for the respondent District of Saanich: Manzer, Wootton & Drake, Victoria.

Solicitor for the respondent District of Victoria: T. P. O'Grady, Victoria.

Solicitor for the individual respondents: A. J. Patton, Victoria.

TAB 10

Alberta Utilities Commission

Alberta Electric System Operator

Needs Identification Document Application

AltaLink Management Ltd.

Facility Applications

ATCO Electric Ltd.

Facility Applications

Central East Transfer-out Transmission Development Project

August 10, 2021

Alberta Utilities Commission
Decision 25469-D01-2021: Central East Transfer-out Transmission Development Project

Alberta Electric System Operator
Needs Identification Document Application
Proceeding 25469
Application 25469-A001

ATCO Electric Ltd.
Facility Applications
Proceeding 25469
Applications 25469-A002 to 25469-A007

AltaLink Management Ltd.
Facility Applications
Proceeding 25469
Applications 25469-A008 to 25469-A010

August 10, 2021

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1 Decision summary

1. In this decision, the Alberta Utilities Commission approves a needs identification document (NID) application from the Alberta Electric System Operator, and facility applications from ATCO Electric Ltd. and AltaLink Management Ltd., to construct and operate a double-circuit, 240-kilovolt transmission line between ATCO Electric Ltd.'s Tinchebray 972S Substation and AltaLink Management Ltd.'s Gaetz 87S Substation, and to alter the two substations and associated Transmission Line 9L16 to accommodate the two circuits. For the reasons that follow, the Commission finds that approval of the NID application and facility applications, and specifically AltaLink's South Alternate route and ATCO's Preferred Route A with Route Option ABC, is in the public interest having regard to the social, economic, and other effects of the proposed facilities, including their effect on the environment.

2 Applications and interventions

2.1 Applications

2. The Alberta Electric System Operator (AESO) applied to the Commission on August 12, 2020, for approval of the need to construct transmission development to enable additional generation integration capability in the central east and southeast sub-regions of Alberta. Specifically, the AESO requested that the Commission approve two 240-kilovolt (kV) circuits between Tinchebray 972S and Gaetz 87S substations, and construction milestones based on 0.5 per cent annual congestion on the central east sub-region's west transfer-out path. As described in more detail below, the timing of construction is proposed to be determined in a future reaffirmation study. Collectively, this project is referred to as the Central East Transfer-out Transmission Development Project (CETO project, or the project).

3. ATCO Electric Ltd. applied to the Commission on September 25, 2020, to construct the facilities to meet the AESO's identified need in its service territory. Specifically, ATCO requested approval to:

- Construct and operate a new double-circuit, approximately 80-kilometre long, 240-kV transmission line between the existing Tinchebray 972S Substation and AltaLink Management Ltd.'s proposed 962L/968L transmission line, to be designated Transmission Line 9L62/9L68. ATCO applied with a preferred and alternate route and proposed route variations.

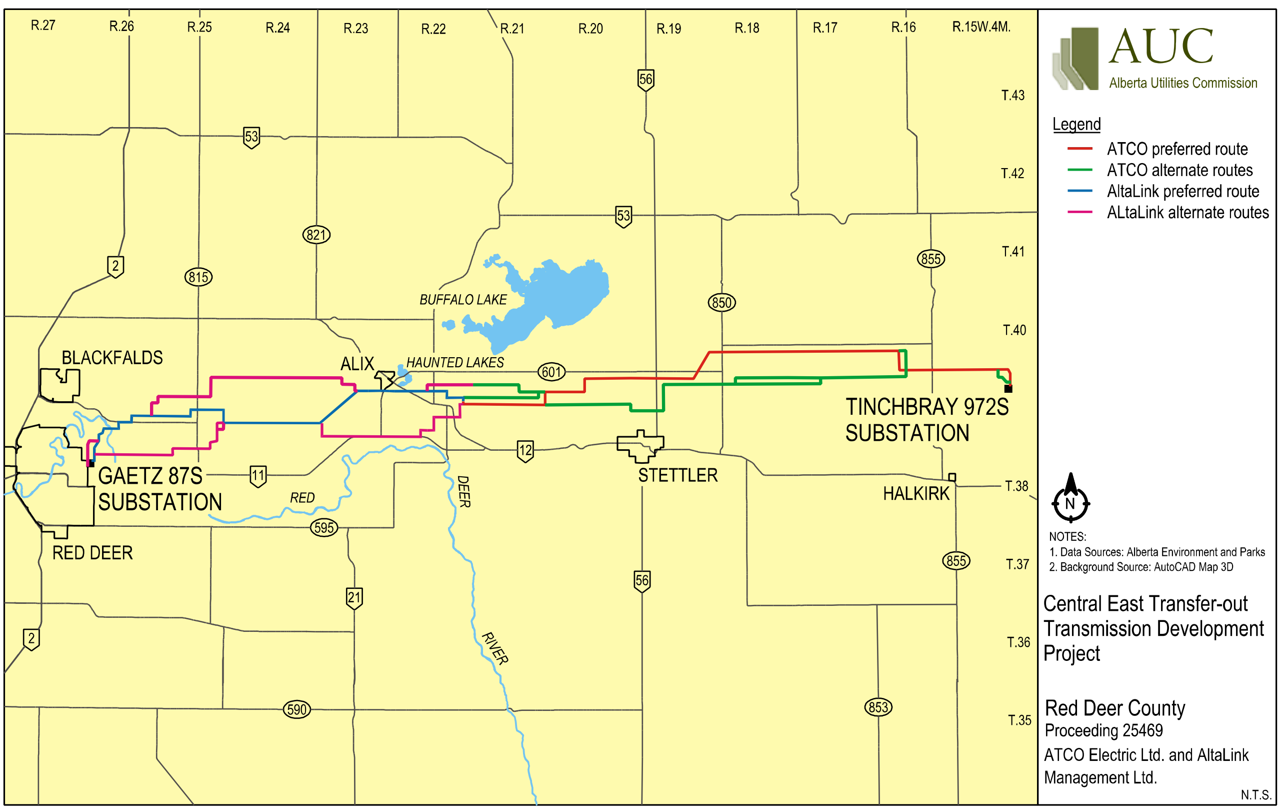
- Alter the Tinchebray 972S Substation to accommodate the two new 240-kV circuits.
- Alter Transmission Line 9L16 by reconnecting it at a new tie-in location in the Tinchebray 972S Substation.

4. AltaLink applied to the Commission on September 25, 2020, to construct the facilities to meet the AESO's identified need in its service territory. Specifically, AltaLink requested approval to:

- Construct and operate a new double-circuit, approximately 50- to 60-kilometre long, 240-kV transmission line between the existing Gaetz 87S Substation and ATCO's proposed 9L62/9L68 transmission line, to be designated Transmission Line 962L/968L. AltaLink applied with a preferred, alternate routes and proposed route variations.
- Alter the Gaetz 87S Substation to accommodate the two new 240-kV circuits.

5. The two transmission facility owners (TFOs) also applied for the interconnections of their transmission facilities. The applied-for routes are shown below.

Figure 1. Applied-for routes



6. ATCO and AltaLink's applications included the following:

- A participant involvement program that describes consultation with stakeholders within 100 metres of the project and notification to stakeholders within 800 metres of the project.

- An environmental evaluation that outlines project components and activities, describes baseline environmental conditions, identifies potential effects and mitigation measures, and assesses predicted residual effects of the project.
- An environmental protection plan that describes environmental compliance and protection measures to be applied during construction and operation of the CETO project to avoid or reduce adverse environmental effects.

7. The AESO estimated a total cost of $332 million for the CETO project. According to ATCO, its preferred Route A would cost approximately $163 million and its alternate Route C would cost approximately $162 million within plus 20 per cent to minus 10 per cent accuracy. AltaLink estimated the cost of its Preferred route to be approximately $159 million, and that of its four alternate routes to be between $149 million and $164 million, all within plus 20 per cent to minus 10 per cent accuracy.

2.2 Interventions

8. In response to its notice of hearing issued on October 13, 2020, the Commission received statements of intent to participate from stakeholders objecting to the need and the routing options, some of whom formed groups. The Commission issued nine standing rulings[1] in which it granted standing to numerous individuals, the Consumers' Coalition of Alberta (CCA), Capital Power Corporation, NOVA Chemicals and the Métis Nation of Alberta (MNA).[2] With respect to the facility applications, the Commission considered that persons who own or reside on property located within 800 metres of the finalized right-of-way of any of the proposed routes have standing to participate in the process.

9. The CCA, the primary intervener objecting to the AESO's NID, focused on the AESO's technical assessment of the need and the proposed transmission development. Throughout the proceeding, the CCA reiterated its concerns with one of the AESO's thermal generation scenarios which it asserted would affect the need and timing of construction of the proposed CETO development. The Commission granted only limited participation (not standing) to the CCA to participate in the facility applications, restricted to the anticipated costs of the proposed facilities that would ultimately be borne by ratepayers.

10. The Landowners Opposed to Route C (LORC), a group of landowners along ATCO's alternate Route C, opposed the AESO's NID application and ATCO's alternate Route C. LORC submitted that the CETO project is not needed and would be an overbuild. The group's concerns included residential, environmental, weeds and clubroot, agricultural, and fire impacts.

11. The Route A Opposition Group (RAOP) consists of landowners along the ATCO preferred Route A, who argued that Route A has high residential impacts because there are more potential country residential and yard site locations along that route. RAOP concerns included residential, environmental, weeds and clubroot, agricultural and health impacts.

12. Brian Perreault, a landowner with land adjacent to the Tinchebray 972S Substation, raised concerns with the substation, indicating that its original construction changed the drainage

[1] Exhibits 25469-X0402, 25469-X0409, 25469-X0440, 25469-X0442, 25469-X0468, 25469-X0476, 25469-X0478,25469-X0479, and 25469-X0691.

[2] Capital Power Corporation issued information requests to the AESO. Neither Capital Power nor NOVA Chemicals participated in the hearing.

patterns onto his lands, resulting in washout, erosion and flooding. He requested that the drainage issue be addressed prior to ATCO receiving permission to expand the substation.

13. The Craigievar Group, formed by landowners opposed to AltaLink's Preferred route and North Alternate route, raised issues with property value, agricultural operations, weeds and clubroot, and visual impacts.

14. The SBD Group, consisting of landowners along the AltaLink portion of the project who oppose AltaLink's Preferred route and South Alternate route, raised concerns with residential and social impacts, property value, environmental considerations, business impacts, agricultural impacts, weeds and clubroot.

15. The Solick Group, comprised of landowners opposed to AltaLink's South Alternate route and 138 kV Parallel Alternate route, raised concerns with agricultural impacts, property value and weeds.

16. The MNA, representing more than 3,872 of its members, expressed concerns with the adequacy of consultation, the potential to affect Métis traditional land use and unknown archeological sites in the Tail Creek area.

3 Hearing and other procedural matters

3.1 Virtual oral hearing

17. The Commission held a virtual oral hearing over 21 days, with oral argument and reply, from April 14, 2021 to May 14, 2021. Due to the virtual nature and size of the oral hearing the Commission divided each hearing day into scheduled blocks of time. Parties were directed to adhere to the schedule and were allotted time based on their best estimates, to ensure the hearing proceeded smoothly and that all parties had an opportunity to be heard. The Commission scheduled contingency time to accommodate adjustments to its hearing schedule and also imposed time limits on oral argument and reply argument. A hearing schedule and protocol letter[3] was issued to inform parties of the hearing process on April 7, 2021.

3.2 Brian Perreault's intervention in the proceeding

18. The Commission received submissions from Brian Perreault on impacts he attributed to the original construction of the Tinchebray 972S Substation. The Commission allowed B. Perreault to make submissions on the potential impacts to his land during the initial construction of the substation because its Market Oversight and Enforcement group indicated to B. Perreault that the remedies he sought would be affected by the outcome of this proceeding and that this proceeding may be the most efficient means for the Commission to consider his concerns with the Tinchebray 972S Substation, including any further design of the drainage area. This issue is addressed in Section 6 of this decision.

[3] Exhibit 25469-X0812, AUC letter - Virtual hearing schedule and protocol.

3.3 Brian Perreault's requests to file new evidence

19. During the oral hearing, the Commission considered a number of motions related to requests from Brian Perreault to file late evidence and the scope of his consultant, Craig Felzien's, testimony.

20. B. Perreault's first motion, to file four site plans as an addendum to the report prepared by C. Felzien as part of his evidence, was filed on April 23, 2021. B. Perreault also requested that C. Felzien be allowed to provide further commentary on the site plans during his direct evidence. In support of his motion, B. Perreault indicated that an expert report prepared by Stantec Consulting Ltd. and filed in ATCO's reply evidence added evidence to the record that C. Felzien was not able to address in his written report. The Commission granted B. Perreault's request[4] and in a subsequent ruling clarified the permissible scope of C. Felzien's further commentary and granted ATCO's request for further process in relation to the late filed evidence and further commentary.[5] C. Felzien was directed to file a summary of his direct evidence in relation to the site plans prior to his scheduled testimony on April 29, 2021.

21. On April 29, 2021, the Commission struck portions of C. Felzien's opening statement because they were found to be "contrary to the Commission's ruling of April 26, 2021 where Mr. Felzien's commentary was to be limited to an explanation of the site plans."[6] On the same day, the Commission also ruled on the permitted scope of C. Felzien's direct evidence and stated that it considered "providing commentary not already addressed in Mr. Felzien's pre-filed evidence and that goes beyond an explanation of the four site plans to be contrary to the Commission's ruling."[7] The Commission further clarified its interpretation of Section 42.2(b) of Rule 001: *Rules of practice* at the request of B. Perreault's counsel.

22. On May 6, 2021, B. Perreault filed a second motion requesting that the Commission allow him to file written reply evidence that responded to ATCO's written reply evidence, and clarification of the scope of ATCO's yet-to-be-filed written reply evidence. In denying B. Perreault's motion, the Commission disagreed that its April 29, 2021 ruling[8] could not have been predicted by him given that the Commission adopted an approach consistently applied in all its proceedings and B. Perreault was represented by experienced counsel who should be familiar with those well-established principles. The Commission further noted that B. Perreault had already been granted additional process to respond to the Stantec Report contained in ATCO's reply evidence and that if B. Perreault had concerns that portions of that report or any other evidence filed by ATCO constituted new evidence and not proper reply evidence, those concerns should have been raised much earlier in the proceeding.[9]

23. The Commission considers that some of the conduct of B. Perreault's counsel during the proceeding led to inefficiencies in the hearing process. As stated in its ruling of May 6, 2021, B. Perreault was represented by experienced counsel who should be familiar with the

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[4] Exhibit 25469-X0869, AUC ruling on motion to file new evidence.

[5] Exhibit 25469-X0875, AUC clarification on scope of C. Felzien's direct evidence and ruling on request for further process.

[6] Transcript, Volume 12, PDF page 16, lines 8-11.

[7] Transcript, Volume 12, PDF pages 64 and 65.

[8] The Commission's oral ruling of April 29, 2021 precluded B. Perreault from addressing the evidence placed on the record by ATCO after the submission deadline for intervener evidence.

[9] Exhibit 25469-X0914, AUC ruling on motion to file reply evidence and clarify scope of ATCO reply.

Commission's well-established principles that during direct examination a witness must confine their evidence to matters addressed in their pre-filed evidence. The lack of adherence to these principles resulted in the Commission issuing multiple rulings where it described and applied these principles in respect of C. Felzien's evidence that could have otherwise been avoided had C. Felzien been instructed properly. Further, counsel for B. Perreault brought a motion to file new evidence 13 days after an initial request to file evidence responding to ATCO's Stantec Report, and 41 days after the Stantec Report was filed. As stated in the Commission's ruling, "If Mr. Perreault had concerns that portions of the Stantec report or any other evidence filed by ATCO Electric constituted new evidence and not proper reply evidence, those concerns should have been raised for the Commission's consideration much earlier in the proceeding."[10]

3.4 Consumers' Coalition of Alberta process-related concerns

24. During its argument, the CCA expressed a concern with the limitation of oral argument in the NID application to one hour.[11] It stated that the imposed time limit resulted in difficulties in addressing the entirety of a complex record, that it only touched on the key points of some its concerns, and that it must consequently rely on the Commission and its staff in their combined effort to have thoroughly read and understood the entire record related to the NID application. In addition, the CCA stated that as interveners were not given an opportunity for reply argument, an apprehension of bias may have been created and its ability to comment on matters raised in argument by the AESO was limited.

25. In the circumstances and given the scope of the proceeding, the Commission was required to impose time limits on oral argument and reply argument to accommodate a large number of parties. This approach was clearly communicated to parties on April 7, 2021.[12] The Commission considers one hour to be an adequate length of time to deliver a comprehensive argument, particularly where the evidentiary portion of the hearing on the NID was largely concluded five days prior to the commencement of argument on the NID application. It disagrees that the lack of opportunity for intervener reply argument may create an apprehension of bias. In each of the NID and facility applications, intervener argument was preceded by applicant argument. Interveners were free to address issues arising from applicant argument in their respective arguments, should they have deemed it necessary.

4 Legislative framework

26. Except in the case of critical transmission infrastructure, two approvals from the Commission are required to build new transmission capacity in Alberta. First, an approval of the need for expansion or enhancement to the Alberta Interconnected Electric System, pursuant to Section 34 of the *Electric Utilities Act*, is required. Second, a permit to construct and a licence to operate a transmission facility, pursuant to sections 14 and 15 of the *Hydro and Electric Energy Act*, must be obtained.

27. The AESO, in its capacity as the independent system operator established under the *Electric Utilities Act*, is responsible for preparing and filing a NID application with the

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[10] Exhibit 25469-X0914, AUC ruling on motion to file reply evidence and clarify scope of ATCO reply, PDF pages 2 and 3.
[11] Transcript, Volume 18, PDF pages 78 and 79.
[12] Exhibit 25469-X0812, AUC letter – Virtual hearing schedule and protocol.

Commission for approval pursuant to Section 34 of the *Electric Utilities Act*. Section 34 describes the circumstances under which the AESO must file a NID application:

> **34(1)** When the Independent System Operator determines that an expansion or enhancement of the capability of the transmission system is or may be required to meet the needs of Alberta and is in the public interest, the Independent System Operator must prepare and submit to the Commission for approval a needs identification document that
>
> (a) describes the constraint or condition affecting the operation or performance of the transmission system and indicates the means by which or the manner in which the constraint or condition could be alleviated,
>
> (b) describes a need for improved efficiency of the transmission system, including means to reduce losses on the interconnected electric system, or
>
> (c) describes a need to respond to requests for system access service.

28. In brief, the AESO must file a NID application if it determines that an expansion or enhancement of the transmission system is required to meet Alberta's needs and is in the public interest, in three circumstances: there is a system constraint or condition affecting performance, a need to improve efficiency, or a request for system access service from a market participant.

29. In Decision 2004-087, the Commission's predecessor, the Alberta Energy and Utilities Board, described the NID process as follows:

> It is the Board's view that section 34 contemplates a two-stage consideration of an NID. In the first stage, the Board must determine whether an expansion or enhancement of the capability of the transmission system is necessary to alleviate constraint, improve efficiency, or respond to a request for system access…
>
> If it is determined that expansion or enhancement of the system is required to address constraint, inefficiency, system access requests, or any combination thereof, the Board must then assess, in the second stage, whether enhancement or expansion measures proposed by AESO are reasonable and in the public interest.[13]

30. Section 38 of the *Transmission Regulation* requires the Commission to have regard for a number of factors when considering whether to approve a NID, and Subsection 38(e) creates a presumption of correctness in favour of the AESO's assessment of the need, as follows:

> **38** When considering whether to approve a needs identification document under section 34(3) of the Act, the Commission must …
>
> (e) consider the ISO's assessment of the need to be correct unless an interested person satisfies the Commission that
>
> (i) the ISO's assessment of the need is technically deficient, or
>
> (ii) to approve the needs identification document would not be in the public interest.

[13] Alberta Energy and Utilities Board Decision 2004-087: Alberta Electric System Operator Needs Identification Document – Southwest Alberta 240-kV Transmission System Development Pincher Creek – Lethbridge Area, Addendum to Decision 2004-075, Application 1340849, October 14, 2004, PDF page 17.

31. When making a decision on a contested NID application, Subsection 34(3) of the *Electric Utilities Act* states that the Commission has three options: it may approve the application, refer the application back to the AESO with directions or suggestions for changes or additions, or refuse to approve the application.

32. The TFO assigned by the AESO prepares and files the facility application for the Commission's consideration. The Commission may approve or deny the application or approve the application subject to terms or conditions.

33. Applications to construct and operate a new transmission facility are made under sections 14 and 15 of the *Hydro and Electric Energy Act*. Section 2 of that act sets out its purposes, which include the provision of economic, orderly and efficient development and operation, in the public interest, of generation and transmission of electric energy in Alberta. Section 17 of the *Alberta Utilities Commission Act* requires the Commission to consider the social, economic and environmental effects of a proposed project when determining whether approval of the project is in the public interest. The Commission described its mandate under Section 17 in Decision 2009-028:

> In the Commission's view, assessment of the public interest requires it to balance the benefits associated with upgrades to the transmission system with the associated impacts, having regard to the legislative framework for transmission development in Alberta. This exercise necessarily requires the Commission to weigh impacts that will be experienced on a provincial basis, such as improved system performance, reliability, and access, with specific routing impacts upon those individuals or families that reside or own land along a proposed transmission route as well as other users of the land that may be affected. This approach is consistent with the EUB's historical position that the public interest standard will generally be met by an activity that benefits the segment of the public to which the legislation is aimed, while at the same time minimizing, or mitigating to an acceptable degree, the potential adverse impacts on more discrete parts of the community.[14]

34. The Commission is considering the facility applications under sections 14 and 15 of the *Hydro and Electric Energy Act* and Section 17 of the *Alberta Utilities Commission Act*. In accordance with Section 17, the Commission must assess whether approval of the applications is in the public interest, having regard to the social, economic and environmental effects of the project.

35. The Commission considers that the public interest will be largely met if an application complies with existing regulatory standards, and the project's public benefits outweigh its negative impacts.[15] It must take into account the purposes of the *Hydro and Electric Energy Act* and the *Electric Utilities Act*. The Commission must also determine whether the applicants have met the requirements of Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* and Rule 012: *Noise Control*. An applicant must obtain all approvals required by other applicable provincial or federal legislation.

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[14] Decision 2009-028: AltaLink Management Ltd. - Transmission Line from Pincher Creek to Lethbridge, Proceeding 19, Application 1521942, March 10, 2009, paragraph 33.

[15] EUB Decision 2001-111: EPCOR Generation Inc. and EPCOR Power Development Corporation 490-MW Coal-Fired Power Plant, Application 2001173, December 21, 2001, PDF page 12.

5 Discussion and findings

36. In this part of the decision, the Commission considers and makes findings on the NID application and the TFOs' facility applications. For the reasons outlined below and subject to all of the conditions outlined in Section 8, the Commission approves the applications from the Alberta Electric System Operator, ATCO Electric Ltd. and AltaLink Management Ltd.

5.1 Needs identification document application

37. In this section, the Commission discusses the issues to be addressed, the evidence before it, and its findings in its assessment of the AESO's NID application. It is generally organized as follows: (i) a brief summary of the planning methodology used by the AESO in its application; (ii) the identification of the need to reinforce the transmission system in the central east area and the proposed transmission development to address the need; (iii) the proposed construction milestones for each stage of the development; (iv) the three configuration options associated with the staging of the project; (v) the future reaffirmation study which would be used to trigger construction at each stage; and (vi), an examination of whether the AESO has met its participant involvement requirements and public interest mandates.

5.1.1 The AESO's planning methodology

38. The AESO performed deterministic system planning studies to assess the performance of the existing transmission system in the central east area in accommodating projected renewable generation development, identify the need for transmission reinforcements, evaluate short-listed transmission development options and select the preferred transmission development option.

39. The AESO also adopted a new approach in applying a congestion assessment, based on probabilistic studies, to estimate the levels of congestion in the study area, taking into account the projected increases in renewable generation. The AESO described the congestion assessment as a tool to evaluate and mitigate risk associated with uncertainties in the forecast increases in generation.

40. The congestion assessment informed the establishment of construction milestones for the AESO's transmission development and the associated timing of the need for the staged transmission development. The phased approach would include two stages of construction, with each stage triggered by a construction milestone. The AESO established the milestones based on the level of incremental generation that would cause 0.5 per cent congestion annually during Category A[16] conditions and a 200-megawatt (MW) margin to accommodate the concurrent construction of one average-sized wind farm with the CETO project development.

41. The AESO committed to conducting a reaffirmation study once the incremental generation reaches the upper limit of the milestone range at each stage. The reaffirmation study would take into account the most up-to-date information in the study area, including location, size and type of incremental generation that has met the certainty criteria, any changes to asset ratings enabled through optimization, any additional system optimization enabled within the study area, and the most recent forecast for thermal generation production profiles in the study area.

[16] Category A represents a normal system condition with all elements in service (N-0).

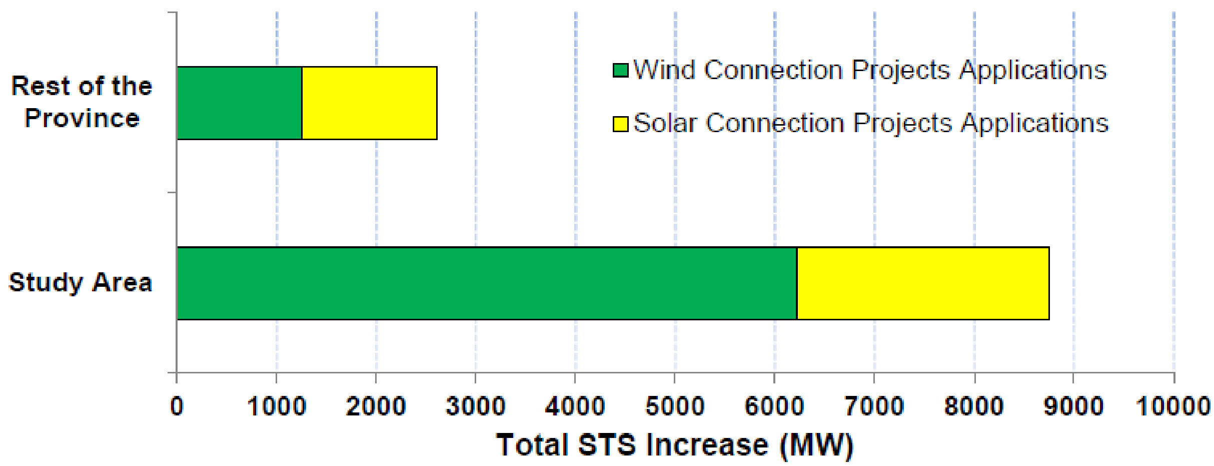
42. The AESO proposed to de-link the need decision (based on deterministic studies) from the construction timing decision (based on probabilistic congestion assessment) via a milestone monitoring process. As a result, it would mitigate the risk of unnecessary system enhancement and expenditure. The CCA generally agreed with the AESO that a congestion assessment is an improvement but cautioned that it added significant complexity.

5.1.2 Is there a need to reinforce the transmission system in the central east area?

43. According to the AESO, the driver of the need for the CETO project is the forecast renewable generation interest in the area, not the load growth. It asserted that in light of a forecast increase in renewable generation development in the central east and southeast sub-regions (study area), an expansion of the transfer-out capability of the transmission system is needed to enable surplus generation to be transferred from the study area to adjacent load centres.

44. The AESO submitted that the study area has a high interest for renewable generation, with a forecast of 900 MW by 2023 and up to 4,600 MW by 2031. The majority of renewable connection projects in Alberta are in the study area. Figure 2, which is based on the AESO's January 2020 project list,[17] illustrates renewable generation interest in the study area, relative to the rest of the province.

Figure 2. Wind and solar connection projects



45. The AESO's generation outlook evolved over the course of this proceeding. Its most up-to-date project list (February 2021) shows a total of 10,188 MW of renewable development interest in the study area and 3,281 MW in the rest of the province.[18] Compared to the January 2020 project list, there is an increase of 1,438 MW of renewable projects in the study area.

46. The study area is home to eight renewable electricity program (REP) projects, totalling 894 MW. While the REP was terminated in June 2019, interest in renewable development in the study area has continued, as demonstrated by generation developers paying their Generating Unit Owner's Contribution (GUOC). Historically, every generator that has paid its GUOC has

17 Exhibit 25469-X0195, Appendix B – AESO Load and Generation Forecast, PDF page 7.
18 Exhibit 25469-X0765, AESO Rebuttal Evidence, PDF page 12.

developed and connected its generation project. The GUOC payment, together with the awarded REP projects, constitute the AESO's certainty criteria for purposes of meeting construction milestones.

47. As of January 2020, the total existing generation in the study area was 2,321 MW, and excluding the Whitla Wind Project which began commercial operation in 2019, the total generation by the REP projects was 692 MW. During 2020, an additional 534 MW of incremental renewable generation met the certainty criteria, such that approximately 1,220 MW of incremental generation in the study area met the certainty criteria as at December 2020.[19] As of mid-March 2021, an additional 233 MW of incremental renewable generation had met the certainty criteria. The pace of projects meeting the certainty criteria is currently approximately 500 MW per year.

48. Due to uncertainties associated with the timing, volume, and offer behavior of the replacement or retirement of the existing thermal generation in the central east sub-region, as shown in Figure 3 below, generation dispatches using statistical and market simulation methods were developed for two thermal dispatch scenarios: Scenario 1 represents a Peaking Scenario where thermal generation has a lower capacity and energy dispatch than the historical thermal fleet, with primarily coal to gas conversion. Scenario 2 represents a Baseload Scenario where thermal generation has similar capacity and energy dispatch as the historical thermal fleet, with new gas replacement. The AESO viewed these two scenarios as bookends to cover a reasonable range of possibilities.

Figure 3. Thermal generation scenarios

Generating Unit Asset ID	Existing Capacity (MW)	Scenario 1		Scenario 2	
		2023	2031	2023	2031
BR3	149	Retired	Retired	New Simple Cycle	New Simple Cycle
BR4	155	Co-firing [b]	Retired		
BR5	385	Conversion	New Combined Cycle (479MW)	Conversion	New Combined Cycle (479MW)
SH1	400	Conversion	Conversion	Conversion	New Combined Cycle (790MW)
SH2	390	Conversion	Conversion	Conversion	
Total Capacity (MW)	1,479	1,330	1,269	1,479	1,573

Notes: [a] The future facility capacity is the same as the existing facility capacity if a capacity size is not specified in the table.
[b] Alterations to the Battle River Power Plant to allow additional natural gas as a supplemental fuel in the Battle River 4.

49. The CCA was concerned that the AESO did not develop a base case or most likely scenario along with its bookends and submitted that the Baseload Scenario was not realistically possible. The Peaking Scenario and Baseload Scenario were created by the AESO in late 2018 or early 2019. In its rebuttal evidence, the AESO indicated that in light of changes in the power

[19] Exhibit 25469-X0540, AESO response to CCA's information requests, PDF page 56.

industry, it now agreed with the CCA that the Peaking Scenario is the more likely future outcome compared to the Baseload Scenario. It explained that some material projects had met the certainty criteria since the application was submitted, including the 800-MW Cascade Power Plant and the 800-MW Suncor boiler replacement, and that these projects would push the Battle River thermal generation into being more of a peaking type of asset.[20] It added that there was also a significant number of renewable generation projects that had met the certainty criteria.

50. The CCA asserted that the Battle River and Sheerness thermal plants would no longer operate past 2023, and that the 304 MW of new gas-fired generation assumed to replace Battle River 3 and 4 would be unlikely. Although the Battle River and Sheerness plants could be converted to gas, the CCA does not believe this to be economical, and stated that it is more likely that the plants would be shut down. The CCA submitted that if this were to happen, 1,479 MW of generation in the Baseload Scenario would be freed up and, as a result, the need for the CETO project line could be deferred beyond 2029.

51. The AESO's evidence shows that the existing transmission capability in the study area is limited. The AESO currently uses remedial action schemes (RAS), automatic protection schemes (APS) and High Voltage Direct Current Transmission redispatch to manage the operation of the transmission system in the area and avoid thermal or voltage criteria violations. RAS or APS (or a combination of the two) could result in generation curtailment and reconfiguration of transmission lines.

52. The AESO developed study cases representing stressed operating conditions under both the Peaking and Baseload scenarios. These study cases included various load levels, intertie flows, dispatched percentages of wind generation and thermal generation dispatches. Under the Peaking Scenario in 2023, study cases M1 to M5 were created using the statistical dispatch method, while study cases M6 to M9 were created using the market simulation dispatch method. Cases M2, M6 and M7 have a total thermal generation dispatch from the Battle River and Sheerness plants of 296 MW, 285 MW and 292 MW, respectively.[21]

53. The AESO performed deterministic studies on the study cases for 2023 and 2031 and concluded that the primary transmission limiting component is the west transfer-out path, i.e., the 240-kV Transmission Line 912L between the Nevis 766S and Red Deer 63S substations.

54. The deterministic planning studies show that in 2023, under the Peaking Scenario, the Category B[22] generation integration capability in the study area is in the range of 450 MW to 565 MW and the Category A[23] generation integration capability enabled by generation RAS is in the range of 760 MW to 990 MW. Under the Baseload Scenario, the Category B generation integration capability in the study area is in the range of 120 MW to 280 MW and the Category A generation integration capability enabled by generation RAS is in the range of 250 MW to 680 MW.

[20] Transcript, Volume 2, PDF page 352.
[21] Exhibit 25469-X0068, Appendix A – AESO Planning Report, PDF page 27, Table 3-2.
[22] Category B events result in the loss of any single element (N-1) under specified fault conditions with normal clearing.
[23] Category A events represent a normal system condition with all elements in service (N-0).

55. In 2031, under the Peaking Scenario, the Category B generation integration capability in the study area is approximately 555 MW and the Category A generation integration capability enabled by generation RAS is approximately 880 MW. Under the Baseload Scenario, the Category B generation integration capability in the study area is approximately 50 MW and the Category A generation integration capability enabled by generation RAS is approximately 135 MW.

56. In summary, the AESO's deterministic planning studies showed that 250 MW to 990 MW of incremental generation in 2023 would cause reliability criteria violations, namely thermal overload, on the existing transmission facilities in the central east area, such as transmission lines 912L, 9L20, 174L and 701L. The AESO determined that in order to meet the forecast generation in the study area over the long-term, transmission development is needed to alleviate the constraints on the central east sub-region's west transfer-out path and satisfy the reliability criteria; that without additional transmission development, the transmission system does not have sufficient capability to integrate the forecast generation in its 20-year planning horizon.

57. The CCA submitted that in the next five years there is a clear need for not only an increased transfer capability out of the study area, but multiple other smaller transmission developments and modifications to provide the system capability required to meet the expected rapid growth in wind and other renewables.[24] However, it argued that the need to increase the transfer capability out of the central east area does not necessarily require the construction of the proposed double-circuit transmission line.[25]

58. The CCA submitted that the Battle River and Sheerness plants would no longer operate past 2023 and that the 304 MW of new gas-fired generation assumed to replace Battle River 3 and 4 is unlikely. This would free up 1,479 MW of generation in the Baseload Scenario and as a result, the need for the CETO project line could be deferred to beyond 2029 for both the Baseload and Peaking scenarios.

59. LORC submitted that there is no need for the CETO project and that excess capacity on the distribution system should be used before new transmission is built. The AESO responded that it has an obligation to connect qualifying customers and that the CETO project gives equal opportunity for distribution and transmission connected projects in the study area because it provides a path for generators to bring their electricity to market. The AESO explained that even if there is extra capacity on the distribution system, that electricity cannot leave the area without transmission system upgrades; and that the need for the CETO project would still exist if the incremental generation in the study area were distribution-connected instead of transmission-connected.

60. LORC pointed to increased transmission and distribution rates as a concern, stating that the AESO cannot say whether an increase in generation will lead to lower pool prices. It argued that renewable generation would be an addition to, rather than replacement of, gas and coal plants because of their status as intermittent generators. This characteristic would result in higher transmission and distribution charges to connect these additional power plants. The AESO replied that eliminating congestion results in the lowest priced electricity available to the market,

24 Exhibit 25469-X0679.02, CCA Evidence Part 3, PDF page 11.
25 Exhibit 25469-X0733, CCA IR Responses to AUC Round 1, PDF page 4.

regardless of where it is located, but that if congestion exists, it must meet customer demand using higher priced generation.

61. LORC submitted that the AESO is giving transmission-connected generation in the study area a competitive advantage by requiring ratepayers to subsidize transmission-connected projects to pay for the connection. It stated that these costs should be paid by the large wind developers. The AESO responded that because the CETO project would benefit the system, which includes many customers, its costs should be considered system (ratepayer) costs pursuant to the *Electric Utilities Act*.

5.1.2.1 Findings

62. The renewable generation interest in the study area is evident to the Commission: the evidence shows that the study area is renewable resource rich and home to 894 MW of REP projects; and in both the AESO January 2020 and February 2021 project lists, the volume of renewable generation connection projects in the study area is more than three times that of the rest of the province. The volume of generation projects in the study area satisfying the certainty criteria has also increased steadily.

63. The Commission also accepts the evidence that the existing transmission system in the central east area is thermally constrained due to the limited transfer out capability, especially the west path, as illustrated in the AESO's deterministic planning studies. With the forecast 900 MW of incremental renewable generation in the area by 2023, the 250 MW to 680 MW generation integration capability in the Baseload Scenario would fall short under all study cases, and the 760 MW to 990 MW generation integration capability in the Peaking Scenario would not sufficiently accommodate all forecast generation without violating reliability criteria. Clearly, in both scenarios, the existing transmission system would not be able to meet the forecast up to 4,600 MW of incremental renewable generation by 2031 because the available generation integration capability is 135 MW to 880 MW. The Commission therefore concludes that there is a need to expand the transmission system in the central east area in order to accommodate the forecast renewable generation projects.

64. The Commission finds that the current volume and pace of generation projects meeting the AESO's certainty criteria are solid indicators that incremental generation projects in the area will move ahead with greater certainty. In December 2020, approximately 1,220 MW of incremental generation in the study area met the certainty criteria, (of which 692 MW of generation are REP projects and 47 MW of generation are two solar generation projects energized and in commercial operation as of July 2020).[26] The current pace of projects meeting the certainty criteria is 500 MW per year. Depending on the thermal generation scenarios and study conditions, 250 MW to 990 MW of incremental generation in 2023 could be integrated to the area without causing reliability criteria violations on the transmission system. A comparison of the incremental generation projects meeting the certainty criteria with the range of the available generation integration capability confirms to the Commission that there is a need to expand the transmission system in the central east area in order to accommodate the renewable generation projects.

[26] The total existing generation capacity in the study area is counted as of January 2020. Incremental generation is counted after January 2020. Also see Exhibit 25469-X0195, Appendix B Load and Generation Forecast, PDF pages 4 and 5.

65. The AESO did not identify the need for the CETO project based on a single worst-stressed case in its deterministic planning studies. Rather, it developed a wide range of study cases with different load levels, intertie flows, wind and thermal generation dispatches and two thermal generation scenarios, both in the near-term (year 2023) and mid-term (year 2031). It also performed sensitivity studies to test the impacts of future generation distribution in three sub-regions (southeast sub-region, central east sub-region and southeast sub-region) on the total generation integration capability.

66. The Commission observes that some study cases in 2023 under the Peaking Scenario have an approximately 300-MW production profile from the Battle River and Sheerness plants, such that even if these two plants were to retire completely as asserted by the CCA, the freed-up generation integration capability would be approximately 300 MW in these study cases, contrary to the 1,479 MW asserted by the CCA. The Commission finds that with the strong interest and current pace of generation projects meeting the certainty criteria in the area, while the retirement of the Battle River and Sheerness plants may affect the timing, it will not eliminate the need for the CETO project.

67. The Commission does not accept LORC's assertion that large wind generation developers should pay for the cost of the CETO project. The project will contribute to a fair, efficient and openly competitive electric market in the province by enabling incremental generation integration capability in the area, regardless of whether the incremental generation is transmission or distribution-connected. It consequently properly qualifies as a system project, rather than an individual generator connection project, and must be paid for by all the ratepayers who benefit from it.

5.1.3 Is the AESO's proposed option the best solution to integrate renewable generation in the area?

68. The AESO developed six options to address the identified need. Option 1 is the AESO's preferred solution because, in its view, it provides the best overall technical performance, cost estimates, and environmental and land effects. It is also the only option the AESO has applied for. Option 1 involves adding two 240-kV circuits between the Tinchebray 972S and Gaetz 87S substations and modifying both substations to include the addition of 240-kV circuit breakers and associated equipment. The AESO estimated that Option 1 will enable 820 MW of incremental generation at a cost of $471 million.

69. The CCA stated that the concentration of the forecast generation growth to the northern part of the study area appeared to be misaligned with where generation projects are actually locating. The CCA submitted that accommodating generation in the southern half of the central east sub-region and the southeast and southwest sub-regions is more manageable than the proposed 240-kV lines to provide capacity out of the northern half of the central east sub-region. The AESO responded that because the southern portion of the transmission system has stronger outlets than the northern portion, building a line in the south end would not help with the unbalance.

70. The CCA asserted that the AESO also failed to factor the value of system loss reduction or system efficiency into its cost comparison of options. Selecting alternatives solely on the basis of the most transfer capability without consideration of the total cost of the alternative could result in an economically sub-optimal development proposal. The AESO responded that the

system losses do not vary significantly among options due to similar line length within the same area except for the Eastern Alberta Transmission Line (EATL) bi-pole option.

71. The CCA listed 17 transmission developments as alternatives but stated that it has "neither proposed or not proposed"[27] that all the developments listed are required. The AESO responded as follows:

1) EATL bi-pole: it was one of the six transmission options considered by the AESO. However, it was eliminated because it had lower integration capability, more cost, lower loss savings and would require additional system upgrades.
2) Inexpensive debottlenecking items (for example, phase shifter transformer, bus split at Milo Substation): these optimization opportunities may enable an additional 100 to 200 MW of generation integration capability and therefore do not replace the need for the preferred transmission development which is to provide material incremental generation integration capability for the longer term.
3) A high-capacity single circuit between Coyote Lake 963S and East Crossfield 64S substations: it would provide much lower generation integration capability.
4) Capital replacement/rebuild of the 912L and/or 9L20 line: it requires lengthy outages (seven to nine months) that will pose significant operational challenges in the absence of the proposed CETO project transmission lines. The AESO's planning studies include all approved capital maintenance projects that are planned to be implemented by 2023, including directing AltaLink to restore the capability of Transmission Line 174L to its full conductor rating.
5) Items outside of the study area (for example, re-termination of some Foothills Area Transmission Development lines): they do not increase the transfer capability in the CETO project study area.

72. The AESO submitted that it is unclear what the CCA's intentions are if they are not advancing any alternatives. The AESO added that six of the CCA's listed alternatives would advance transmission rebuilds by over 10 years and that the CCA underestimates the cost and viability of these plans.

73. The CCA stated that a single-circuit 2X795 conductor 240-kV line in combination with flow control devices would provide more transfer-out capability in the long term than the proposed two circuits. It also estimated that building a single-circuit line with a larger conductor would reduce the project cost by $88 million, reduce system losses, and reduce the land-use impacts by requiring shorter structures and half the wires.

74. Notwithstanding the foregoing, the CCA submitted that it is not currently practical or economical to withdraw the AESO's application and develop a new solution, and that a new line at the north end of the central east sub-region would be required in the next 10-20 years to accommodate new wind developments.

75. The CCA submitted that the AESO should have an obligation to fully vet the TFOs' cost of structures to ensure that cost estimates are uninfluenced by a TFO preference unrelated to an

[27] Exhibit 25469-X0736.01, CCA IR response to AESO Round 1 FINAL, PDF page 5.

optimal balance between risk, reliability and cost. The AESO replied that it had reviewed the TFOs' service proposal estimates against benchmark data and found the estimates to be reasonable.

76. Responding to LORC's assertion, the AESO indicated that it does not have any specific plan to use the Tinchebray 972S Substation as a hub in the next 10 years.

5.1.3.1 Findings

77. The Commission is convinced that the AESO has explored solutions thoroughly by screening potential alternatives, formulating development options, and evaluating and comparing options. It shortlisted six development options after eliminating 14 screening alternatives; conducted a comprehensive technical assessment on these development options including sensitivity assessments; and also conducted additional assessments on the preferred development option, including a voltage stability analysis, transient stability analysis and transmission system loss analysis.

78. The Commission is satisfied that Option 1 is technically superior to the other five options in terms of incremental generation integration capability and operational flexibility. For example, it provides flexibility to integrate approximately 400 MW more generation in the west Hanna area where there is strong market interest for renewable development. It also has lower estimated costs and lower potential environmental and land use effects.

79. The Commission accepts the AESO's evidence that the CCA's alternatives will likely be more costly, create significantly more landowner impacts or not materially increase generation integration capability in the study area. Notably, the CCA conceded that its alternatives were not fully developed and would require more work. As a result, the CCA's alternatives did not contribute to the Commission's understanding of the issues in this proceeding. The CCA has consequently failed to convince the Commission that these alternatives are superior to Option 1 or that the AESO's assessment of Option 1 is technically deficient.

80. For the reasons stated above, the Commission finds that the AESO's Option 1 is the best solution to integrate renewable generation in the area and approves the proposed CETO project development.

5.1.4 Has the AESO reasonably established the construction milestones?

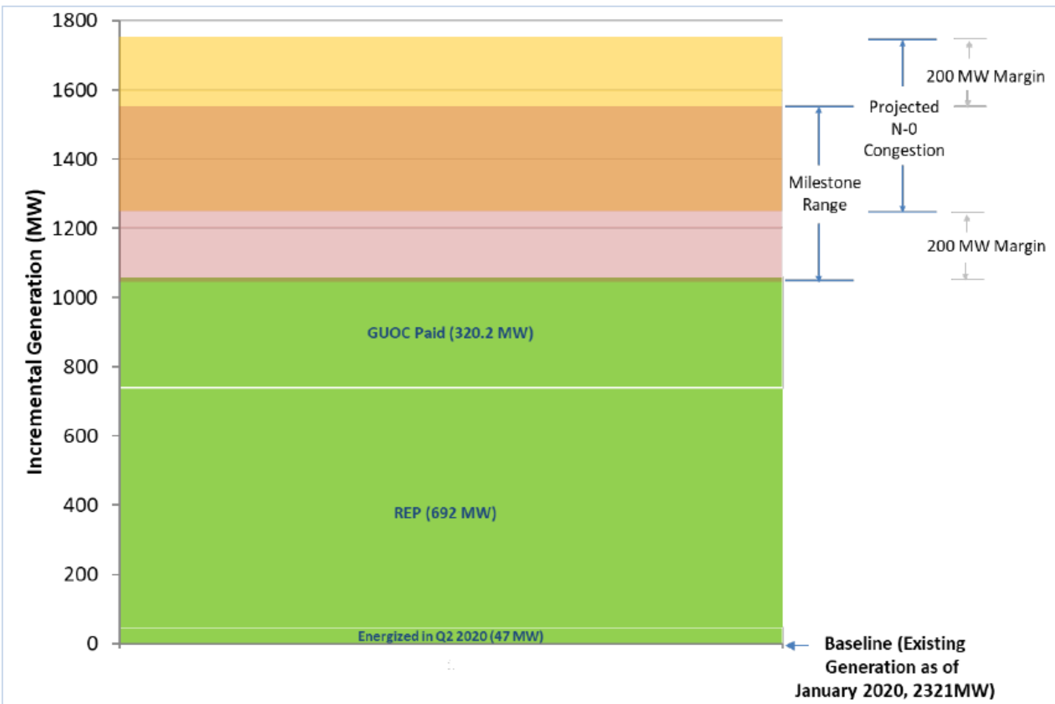
81. The AESO specified construction milestones associated with each stage of the proposed transmission development to minimize the risk that the transmission facility is built too early and therefore delays project costs to a point where the project in-service date aligns with the project need. The milestones were established by performing hourly probabilistic studies (congestion assessment) that demonstrate the relationship between the addition of generation in the study area and the likelihood of observing congestion using two generation scenarios in which the existence and operating patterns of thermal generation were varied.

82. The congestion assessment found that the expected percentage of congested hours increases steadily as new renewable generation development is added in the study area; and as the percentage of congested hours increases, the average magnitude of thermal criteria violations resulting in congestion is also expected to increase. This congestion would occur along the

240-kV transmission line 912L/9L20 of the central east sub-region west transfer-out path, as well as the 138-kV transmission lines 174L and 701L in the central east sub-region.

83. It is expected that the Stage 1 construction milestone will be met with the addition of approximately 1,050 MW to 1,550 MW of incremental generation (above the existing installed generation as of January 2020) that satisfies the AESO's certainty criteria in the study area, as shown in Figure 4.[28] Stage 1 development will increase the generation integration capability in the area by 400 MW to 600 MW.

Figure 4. Stage 1 construction milestones



84. It is expected that the Stage 2 construction milestone will be met with the addition of approximately 1,700 MW to 2,150 MW of incremental generation (above the existing installed generation as of January 2020) that meets the AESO's certainty criteria in the study area. Stage 2 development will increase the generation integration capability in the area by approximately 300 MW.

85. The CCA stated that the AESO's congestion assessment contained some fundamental flaws such as the bookend scenarios used to trigger construction being too low for the Baseload Scenario. It also argued that the Baseload Scenario appeared to have a forced scenario rather than being based on credible input assumptions. The CCA asserted that a more reasonable generation output forecast and assessment of congestion should be used to determine the need and the milestones.

[28] Exhibit 25469-X0068, Appendix A – AESO Planning Report, PDF page 6, Figure E-1.

86. The CCA submitted that the Peaking Scenario is a more reasonable approximation of the output of the converted coal plants and that the Baseload Scenario does not reasonably forecast in-merit generation. It stated that the Baseload Scenario underestimates the marginal costs for such plants and therefore causes them to dispatch many more hours than they would be dispatched economically. The CCA submitted that the Baseload Scenario should not be relied upon to forecast whether there will likely be congestion in the study area.

87. As mentioned earlier, the AESO now agrees with the CCA that the Peaking Scenario is the more likely scenario, and will accordingly use the upper MW limit of the milestones to trigger a reaffirmation study. Originally, the AESO implied that the lower MW limit of the milestones would be used. The lower limits of the milestones were drawn from the Baseload Scenario which would reach the construction milestones earlier than the Peaking Scenario.

88. The CCA stated that the failure to consider the strong inverse correlation between the hourly wind generation output and hourly thermal generation output would overstate the need to develop incremental transmission capacity. The AESO noted that generation from the Battle River and Sheerness plants plays a relatively small role in contributing to congestion in the Peaking Scenario. The average combined output at these two sites is only 250 MW at the time of congestion in the Peaking Scenario.

89. The AESO reiterated that the timing of the Battle River/Sheerness retirement is inconsequential to the congestion assessment results. The complete retirement of the sites would enable flexibility for the additional integration of less than one year of incremental renewable generation growth in the area because the current renewable growth pace is approximately 500 MW per year.

90. The AESO further pointed to the firm transport delivery service contract within the Battle River and Sheerness regions that requires the generator facility owner to have at least a five-year expectation of operating starting in 2022. As a result, the AESO proffered that there is a reasonable probability of continued production from those sites.

5.1.4.1 Findings

91. A substantial portion of the CCA’s evidence focused on the reasonableness of the AESO’s Baseload Scenario and how it affected the results of the congestion assessment and the establishment of milestones. The Commission finds that the AESO’s acceptance of the Peaking Scenario as the most likely scenario and its intention to use the upper limits of the milestones effectively eliminate the CCA’s primary concern with the AESO’s congestion assessment.

92. The AESO developed generation scenarios and performed congestion assessments in late 2018 and early 2019 based on the best information available at that time. The Commission is satisfied that in conducting the reaffirmation study, the AESO will take into account the most up-to-date information in the study area including location, size and type of incremental generation that has met the certainty criteria, any changes to asset ratings enabled through optimization, any additional system optimization enabled within the study area and the most recent forecast for thermal generation production profiles in the study area. The AESO will also solicit stakeholder feedback on study assumptions prior to conducting the reaffirmation study.

The Commission acknowledges the AESO's commitment to conduct a sensitivity study on the complete retirement of the Battle River and Sheerness plants and to examine whether the increased milestones would be accommodated in the reaffirmation study.

93. For the reasons stated above, the Commission finds the AESO's construction milestones to be reasonably established.

5.1.5 Is proposed Configuration 1 superior to other configurations?

94. The AESO considered the following three configurations to meet the need for the development of two circuits between the Tinchebray 972S and Gaetz 87S substations.

Table 1. Configuration considerations

Configuration	Description
1	Add two circuits on a double-circuit structure with the conductors tied together in Stage 1. The second circuit to be untied and energized when the Stage 2 milestone is met.
2	Add one circuit on a double-circuit structure in Stage 1 with a second circuit added when the Stage 2 milestone is met.
3	Add one circuit on a single-circuit structure in Stage 1. Add an additional circuit on a separate single-circuit structure when the Stage 2 milestone is met and file under a separate facility proposal.

95. The AESO supports Configuration 1 as recommended by the TFOs because it would reduce potential overall impacts to stakeholders and the environment and has lower life-cycle costs. The TFOs also indicated that Configuration 1 would reduce line losses and electric magnetic fields in comparison to Configuration 2.

96. The AESO expects the incremental generation required for Stage 2 to occur within a four-year period, even under the Peaking Scenario. The AESO's net present value analysis for the life-cycle cost favours Configuration 1 over Configuration 2 provided Stage 2 is in-service four or less years following Stage 1. Configuration 1 has a lower life-cycle cost than Configuration 3 provided Stage 2 is in-service 18 or less years following Stage 1. Currently, the first construction milestone will fall within the 2023 timeframe and the second construction milestone will fall within the 2027-2029 timeframe.

97. The AESO submitted that the system loss in 2023 for Configuration 1 would be more than 10 MW lower than Configuration 2. A high-level analysis of the economic benefit would yield a loss saving of approximately $4 million dollars per year for Configuration 1 when compared to Configuration 2, assuming an average system loss difference of 10 MW and an annual average pool price of $50/MWh.

98. Should the second stage be pushed beyond four years, or is not needed at all, there would be cost savings associated with the delay in that construction as illustrated in Figure 5:[29]

Figure 5. Net present values at different energization dates

Energization date	Second Stage energization date	NPV of Configuration 2 (millions)	NPV Configuration 3 (millions)
2023	2024	$340	$430
2023	2025	$337	$423
2023	2026	$334	$416
2023	2027	$332	$409
2023	2028	$329	$403
2023	2029	$326	$396
2023	2030	$324	$390
2023	2031	$321	$384
2023	2032	$319	$378
2023	2033	$317	$372
2023	2034	$314	$367
2023	2035	$312	$361
2023	2036	$310	$356
2023	2037	$308	$351
2023	2038	$306	$347
2023	2039	$304	$342
2023	2040	$303	$338
2023	2041	$301	$334
2023	2042	$299	$330
2023	2043	$298	$326

99. The CCA argued that the advantages of staging the project to better manage and defer cost is almost entirely lost as a result of the selection of Configuration 1.

5.1.5.1 Findings

100. Because the capital cost and life-cycle cost of Configuration 3 are much higher than configurations 1 and 2, the Commission finds Configuration 3 to be inferior and eliminates it from its consideration. It must consequently decide which of configurations 1 and 2 is superior.

101. Although Configuration 1 has a higher upfront capital cost than Configuration 2, its life-cycle cost is lower than Configuration 2 if Stage 2 of the CETO project development is required within four years of Stage 1. In light of the 500 MW per year pace of generation meeting the certainty criteria, the Commission finds that it is very likely that Stage 2 development will be required within four years of Stage 1 development. As such, the life-cycle cost of Configuration 1 is very likely to be lower than Configuration 2.

102. In addition, Configuration 1 would have the least impact on landowners and the environment because construction and reclamation would only occur once. It would also have

[29] Exhibit 25469-X0412, Attachment AESO-AUC-2020NOV06-001, PDF page 5, Table 3.

less potential to spread clubroot than Configuration 2. Under Configuration 1, construction crews only have to be mobilized once and land access agreements only have to be made once.

103. While the Commission agrees with the CCA that Configuration 1 nullifies the purpose of staging the CETO project, the Commission finds that the overall benefits of Configuration 1 outweigh Configuration 2 and therefore approves Configuration 1.

5.1.6 Reaffirmation study

104. The reaffirmation study will follow the same methodology as the congestion assessment filed with the CETO NID application. The AESO will study one scenario reflecting the most up-to-date information in the study area and conduct a sensitivity analysis assuming the retirement of the Battle River and Sheerness thermal plants The reaffirmation study will analyze the congestion trend to at least 2030 to confirm that congestion levels are not short-term and are large enough to trigger construction, and will also determine whether an increased milestone monitoring range can then be accommodated.

105. The AESO set out the process for reaffirmation[30] in which the AESO will determine, on an annual basis at a minimum, whether a reaffirmation study would be triggered, based on the incremental generation meeting certainty criteria. The CCA considered it critically important to vet the AESO’s supply assumptions prior to any modelling being done because there should be other metrics than only the inclusion criteria (i.e., certainty criteria) to assess the likelihood of new future generation builds. The AESO committed to seeking stakeholder feedback on key study assumptions prior to finalizing assumptions and conducting the reaffirmation study.

106. The CCA submitted that a significant amount of data must be disclosed so that stakeholders can assess whether the modelling input assumptions and the individual plant output forecast are reasonable. For example, unless plant revenue can be compared to plant cost, one cannot conclude whether it is reasonable for individual plants to continue to participate in the market. The AESO argued that the CCA was seeking large volumes of detailed and, in some cases, confidential data in order to audit the AESO’s work. The CCA indicated that stakeholders cannot possibly audit the AESO’s work because the CCA does not have access to its models and detailed results.

107. The AESO disagreed that all input assumptions requested by the CCA are fundamental and key to conducting the reaffirmation study due to confidentiality, magnitude of the data, and being outside the study area, publicly available or irrelevant. The AESO plans to provide similar information it included in its application or provided to the CCA during the information request process; for example, the assumptions for existing thermal generating units in the study area including technology type, average heat rate, fuel cost, carbon emission cost, variable operational and maintenance cost, and start-up cost. The AESO explained that if it makes changes to the existing generating facilities in the study area, it will share assumed block size and bidding assumptions for the Battle River and Sheerness thermal plants.

108. Should the reaffirmation study confirm that the construction milestone is not met, the AESO will summarize the study and notify the Commission. If the study confirms that the milestone is met, the study report will be filed with the Commission at least 15 days prior to directing the TFOs to commence construction. Although the AESO does not see a need for

[30] Exhibit 25469-X0765, AESO Rebuttal Evidence, PDF page 9.

another intensive regulatory review, it will follow the Commission's direction on the process required.

109. The CCA submitted that the reaffirmation process should be subject to review to ensure that the transmission line is not built too early and assess how the proposed CETO development may change.[31] It added that the Commission may want to direct the AESO to modify the solution, given the updated information.

110. The upper limit of the Stage 1 milestone, i.e., 1,550 MW of incremental generation that has to satisfy the certainty criteria, had not been met as of May 14, 2021, the close of record of this proceeding. While the AESO has not yet initiated the reaffirmation study, it expects to trigger it in the fourth quarter of 2021.

5.1.6.1 Findings

111. The Commission finds the proposed reaffirmation process to be reasonable because it would provide stakeholders with an opportunity to provide feedback on key study assumptions before the AESO finalizes those assumptions and conducts the congestion assessment. The reaffirmation study report would also include all similar information, including study assumptions, to what was in this NID application and in the responses to the CCA's information requests to the AESO.

112. The Commission accepts that the purpose of the reaffirmation study is not to re-evaluate the need for the CETO project, and that it instead serves to delink the need decision from the construction timing decision. The need to reinforce the transmission system in the central east area has been established by the AESO's deterministic planning studies, as discussed in Section 5.1.2. Likewise, the proposed CETO transmission development to meet the identified need has been found to be superior to any other options, including the CCA's proposals, as discussed in Section 5.1.3. As a result, subject to issues that the Commission may choose to explore in the reaffirmation study process, the Commission does not agree with the CCA that another regulatory review on the CETO development is justified.

113. As indicated in the AESO's NID application, if Stage 1 of the CETO project development is not in service by December 31, 2025, the AESO will notify the Commission whether the need to expand or enhance the transmission system described in the NID continues, and whether the preferred transmission development continues to be the AESO's preferred technical solution. In addition, if Stage 2 of the CETO development is not in service by December 31, 2030, the AESO will provide an update to the Commission on its status. The Commission finds that these commitments effectively examine the continuous validity of the need for and the proposed CETO development, which in turn address the CCA's concern with the project being built too early or requiring modifications.

114. The Commission is satisfied that the reaffirmation study would utilize the most up-to-date information, explore optimization opportunities like flow control devices and assess congestion over the long-term. In particular, the Commission finds that a sensitivity scenario

[31] Exhibit 25469-X0679.02, CCA Evidence Part 3 – Technical – Transmission Planning and Congestion, PDF pages 86 and 87.

with the complete retirement of the Sheerness and Battle River thermal plants would address the CCA's primary concern in this proceeding.

5.1.7 Has the AESO met the requirements of the participant involvement program?

115. The CCA asserted issues with the AESO's consultation process, specifically that ratepayers and their representatives, such as the CCA, were not seriously engaged until after the NID application was filed with the Commission. The CCA stated that at this stage, any input is seen as threatening the work undertaken by the AESO and the TFOs, or potentially delaying the in-service date of the project, preventing co-operation between the parties. The AESO replied that the participant involvement program for the CETO project was initiated well before the application was filed with the Commission, and that the CCA chose not to participate until after the application was filed.

116. The AESO conducted a participant involvement program for the CETO NID between January 2019 and March 2020. The AESO notified and provided information packages to stakeholders in the CETO project area, including occupants, landowners and residents, market participants, local authorities, agencies and government, and Indigenous communities. The AESO used various methods to notify stakeholders, such as postal code drop, newspaper, the AESO website, the AESO stakeholder E-newsletter, emails and information packages.

117. AESO personnel were available at the TFOs' open houses to discuss the need for the project and answered questions. The AESO hosted an information session on October 3, 2019 to provide an overview of three transmission projects, including the CETO project.

118. The AESO held a technical session to answer stakeholder questions regarding the NID application in December 2020. The CCA credited the AESO for holding this technical session and stated that informal discussions between the CCA and AESO were more helpful. However, the CCA asserted that the one-day technical session and timing of the session after filing the application did not allow for consideration of alternatives.

119. The CCA requested that the Commission encourage the AESO to work with external parties earlier to allow for a more productive and less adversarial process. It urged the Commission to direct the AESO to engage parties earlier in the process by filing a preliminary application before any major need decisions are made. The AESO responded that it would engage the CCA earlier in the process if the CCA were committed to provide input into the AESO's decision-making process and its participation were not contingent upon cost recovery.

5.1.7.1 Findings

120. The Commission is satisfied that the AESO has met the notification and consultation requirements in Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*. In addition to consulting with stakeholders prior to filing the NID application, the AESO continued to engage them. For example, the AESO held a one-day technical session to assist interested parties in better understanding the planning results, milestone design, alternative options considered and congestion assessment results. It also had informal discussions with the CCA to provide clarification and additional information, which resulted in the withdrawal of the CCA's motion for further and better responses to its information requests. That said, the Commission

acknowledges that an effective participant involvement program may not ultimately resolve all stakeholder concerns.

121. Given the findings above, the Commission considers that the CCA's submissions on the AESO's consultation process did not assist in its understanding of the relevant issues. Further, the Commission finds that the CCA's proposal to have the AESO file a preliminary application before any major need decision is made to be outside the scope of this proceeding.

5.1.8 Has the AESO met its public interest mandate?

122. LORC submitted that the AESO did not conduct any type of public interest analysis but assumed that the requirement to plan to accommodate 100 per cent of in-merit electric energy onto the Alberta Interconnected Electric System (AIES) is in the public interest. It stated that the AESO did not conduct its own environmental assessment and instead delegated that to the TFOs. LORC also submitted that the AESO did not examine the amount of agricultural land that will be displaced by the renewable projects, nor did it provide evidence on the positive or negative economic implications or effects on property taxes, construction jobs or capital investment.

123. The CCA argued that the strong advocacy approach that the AESO uses in advancing its projects seems to be inconsistent with its public interest mandate when Alberta economic conditions call for restraint.

124. The AESO submitted that there is a public interest benefit to pursuing an uncongested transmission system, which provides investment certainty and non-discriminatory access to the AIES and therefore supports generation development. It stated that to fulfill its public interest mandate, the AESO must balance several factors including reliability, cost and market access.

125. The AESO submitted that the NID application met the requirements established in the *Electric Utilities Act*, *Transmission Regulation* and AUC Rule 007. It studied a wide range of system conditions under which a wide variety of supply could compete to deliver low energy prices to customers. It considered six transmission development options and concluded that the preferred transmission development is technically superior to other options in terms of the incremental generation integration capability, operational flexibility, capital cost and environmental and land use effects. The AESO stated that it conducted a net present value analysis to better understand the differences in the life-cycle costs of three different configurations. The AESO added that it reviewed the TFOs' service proposal estimates against benchmark data and found the estimates to be reasonable.

5.1.8.1 Findings

126. When considering whether to approve a NID under Section 34(3) of the *Electric Utilities Act*, the Commission must have regard for the principle that it is in the public interest to foster an efficient and competitive electricity market and a transmission system that is flexible, reliable and efficient and preserves options for future growth. These criteria are set out in Subsection 38(a) of the *Transmission Regulation*. The AESO also has a legislated public interest mandate. This mandate is informed by Section 34(1) of the *Electric Utilities Act* and involves balancing several factors including cost, reliability and market access. The Commission acknowledges that in doing this balancing, the AESO considers the public interest criteria set out in Subsection 38(a) of the *Transmission Regulation*. The public interest as it relates to the Commission's assessment of a transmission facility application involves a different set of criteria

and includes social, economic and environmental components pursuant to Section 17(1) of the *Alberta Utilities Commission Act*.

127. The Commission finds that in evaluating the need and preparing its NID application, the AESO discharged its public interest mandate by balancing several factors, including cost, reliability and market access. For example, the AESO had conversations with the TFOs on their capital replacement or maintenance plans in order to co-ordinate the transmission system plans with the TFOs' capital maintenance plans, if effective and beneficial to do so; and as a result of that conversation, the AESO directed AltaLink to restore the capability of Transmission Line 174L to its full conductor rating. The Commission also accepts that the estimated project cost was reduced due to the AESO's prudent relaxation of certain transmission loading standards combined with new construction methods and that the reaffirmation study will contribute to mitigating the risk of overbuild.

128. Further, the Commission accepts that the AESO considered the public interest broadly: it evaluated six technical solutions to meet the need where social, environmental and economic factors were considered in its evaluation; and, as it pertained to project economics, its consideration of staging and milestones, as well as the life-cycle cost evaluations, assisted the AESO in selecting its lowest cost option, which meets the technical need, and provides more certainty in the timing of development.

129. The Commission is satisfied that the AESO's preferred transmission development is in the public interest and that it considered the factors set out in Subsection 38(a) of the *Transmission Regulation.* The AESO's preferred transmission development is the lowest cost option to meet the need, complies with Alberta reliability standards, is consistent with its long-term forecast and area transmission system plans which will foster an efficient and competitive market, and preserves options for future growth.

130. Lastly, the Commission is satisfied that it was appropriate to defer environmental and land use considerations to the TFOs, as required in NID7(9) of Rule 007. (This is particularly so in circumstances such as these, where the AESO NID application and TFO facility applications are requested to be considered jointly, pursuant to Section 15.4 of the *Hydro and Electric Energy Act* and Section 6 of Rule 007). LORC's submissions on and pursuit of environmental and land use considerations in the NID portion of the hearing did not contribute to the Commission's understanding of the relevant issues. This delegation is permitted under Section 13(1) of the *Transmission Regulation.* The TFOs have expertise in evaluating these elements and are required to do so as part of their applications.

5.1.9 Conclusion on the needs identification document application

131. For all the reasons described above, the Commission concludes that the AESO's NID application meets the requirements of Rule 007. None of the interested parties has satisfied the Commission that the assessment of the need to expand the transmission system in the central east area to improve system reliability and allow for the interconnection of future generation in the area is technically deficient or not in the public interest.

132. Having regard to the foregoing, the Commission approves the proposed CETO development and the construction milestones as filed by the AESO.

5.2 Facility applications

133. In this section, the Commission considers the issues and the evidence, and makes findings in its assessment of the ATCO and AltaLink facility applications. It is organized as follows: (i) the structure types proposed by the TFOs; (ii) agricultural impacts; (iii) environmental impacts; (iv) other potential impacts such as fire, noise and electromagnetic fields; (v) the assessment of the routing proposed by the TFOs; (vi) the Gaetz 87S and Tinchebray 972S substation alterations; (vii) the impacts to the MNA; and (viii), the consultation process and participant involvement programs.

5.2.1 Structure types

5.2.1.1 Structure choice

134. Earlier in this decision, the Commission approved the NID application for this project and a double-circuit configuration to meet the NID. This section discusses the ATCO and AltaLink proposals on the type of structure to use for the CETO project transmission line, that meets both the approved NID and double-circuit configuration. To be certain, this section does not discuss the single-circuit positions advanced by the CCA in its facility argument because the Commission has already made its determinations on this matter earlier in Section 5.1.3.

135. Both ATCO and AltaLink proposed the use of double-circuit steel monopole structures for this project because they meet the technical requirements and functional specification of the AESO’s NID, which requires the construction of two circuits. Both TFOs asserted that the double-circuit steel monopole structure is a cost-effective solution and the least-impact solution for the double-circuit transmission line. The Commission considers that insufficient evidence was filed to persuade it otherwise. Although the CCA proposed building a single-circuit option, it did not offer any evidence advancing a different double-circuit option. As a result, the CCA’s submissions on a single-circuit option did not assist the Commission in its understanding of these issues.

136. The CCA raised concerns regarding the double-circuit steel monopole structures, stating that historically monopole structures have cost 30 per cent more than lattice towers and likely even more when compared to H-Frame structures. The CCA suggested that inclusion of the higher cost risks associated with monopole structures in the TFOs’ line optimization studies would have identified the higher costs of the proposed monopoles when compared to the use of H-Frame structures. Both TFOs’ line optimization studies included all cost considerations directly associated with structure types and conductors, including foundation costs. The TFOs ruled out lattice towers early on in their assessments because the costs of these towers were shown to be much higher than the other options considered.

137. While the Commission found the TFOs’ line optimization studies to be helpful, it also recognizes that these studies only depict a specific point of time, are planning documents and have the potential to change. The Commission found the breakdown of costs provided in ATCO’s study to be particularly useful for the purpose of comparing the costs of different structure and conductor combinations. It would like to see this type of information in future line optimization studies and those studies included in facility applications.

138. In the Commission’s view, the line optimization studies demonstrate that double-circuit steel monopole structures are a cost-effective option for this project. AltaLink’s study showed

that double-circuit steel monopole structures had the lowest 20-year, net present value.[32, 33] Constructing two single-circuit transmission lines on either separate steel H-Frame structures or separate steel monopole structures was shown to have a higher cost than the double-circuit steel monopole option. ATCO's study showed that when considering capital costs, the double-circuit steel monopole structure with a 2x795 kcmil ACSR[34] conductor is the least cost option.[35] ATCO stated that when considering the 40-year cumulative present value (CPV), the double-circuit steel monopole only had a CPV 7.75 per cent greater than its base case of two separate single-circuit wood H-Frame structures.[36] It also noted that landowner feedback indicated a strong preference for double-circuit structures combined with a strong objection to two single-circuit structures due to the larger right-of-way required and resulting impact to land use. ATCO's witness Chris Storey testified that it proposed a double-circuit steel monopole structure because overall that choice had the least impact.

139. AltaLink's line optimization study did not consider wood H-Frame structures. The CCA suggested that if it had, the results might have been similar to those of ATCO, and possibly provide a $167,000 per kilometre reduction in direct construction costs when compared to steel monopoles.[37] AltaLink stated that it had reviewed the cost of wood H-Frame structures and steel H-Frame structures at the outset of its optimization study and found that the cost from its suppliers were very similar. AltaLink's witness Brian Townsend testified that after considering the additional costs of operations and maintenance for wood, the TFO decided to exclude wood from the line optimization study and go with steel because the cost was similar. ATCO's witness Dustin Baptist also testified that over time, wood H-Frame structures require a higher amount of ongoing maintenance when compared to steel monopole structures.

140. The CCA recommended that the TFOs prepare cost estimates of the foundation costs and risk range for double-circuit steel monopoles, single-circuit steel monopoles and single-circuit wood H-Frame structures. The CCA's perspective was that foundation costs for monopoles could be much higher than forecast, especially if soil conditions along the route are poor. ATCO explained that compared to foundations for a single-circuit H-Frame, monopole foundations do have a higher contingency line item in its estimates, and that as a result, the impact or risk of the foundation costs has already been included in its service proposal estimates.

141. The Commission approves the double-circuit steel monopole structures proposed by the TFOs in their facility applications. These structures meet the AESO's NID, the approved double-circuit configuration and have shown to be the least impact structures when considering the TFOs' line optimization studies and feedback from landowners during consultation.

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32 The study considered two circuits by 2028.
33 Exhibit 25469-X0512, AML-CCA-2020DEC17-001 Attachment 1 (CETO Line Optimization Study Rev 2), PDF pages 5 and 6, Tables 3 and 4.
34 Aluminium conductor steel-reinforced measured in thousands of circular mills.
35 Exhibit 25469- X0569, ATCO-CCA-2020DEC17-001(a), Attachment 1, PDF page 13, Table 6.
36 Exhibit 25469- X0569, ATCO-CCA-2020DEC17-001(a), Attachment 1, PDF page 20, Table 12.
37 25469 CCA Argument on AltaLink and ATCO Facility Appl FINAL for references, PDF page 13, paragraph 32.

5.2.1.2 Cost estimates

142. In an effort to protect customers from the TFOs taking undue risk, the CCA recommended that if the Commission approved a double-circuit transmission line, it should inform the TFOs that any actual costs that are more than the 30 per cent threshold of costs in the PPS estimate will be scrutinized very carefully in a deferral account application and will be at a significant risk of disallowance.

143. The Commission will evaluate all project costs, regardless of the quantum of variance to the PPS estimate in a well-established process. As such, it does not find it is necessary to make any statement to the TFOs on the scrutiny of their project costs.

5.2.1.3 Guyed structures for corner structures

144. The CCA recommended that the Commission direct ATCO and AltaLink to use guyed structures for the 90-degree, dead-end corners and only install self-supporting structures at corners where there is no practical and cost-effective means to use guyed structures. The CCA acknowledged that if guyed structures were used, additional payments would have to be made to landowners to obtain their support. Its estimated potential savings of $384,000 per structure, if guyed structures were used, did not include the cost of additional landowner payments.[38]

145. In its line optimization study AltaLink assumed using guyed dead-end and angle structures and agreed that guyed angle and dead-end structures may reduce structure costs. However, it disagreed with the CCA's evidence that the additional cost of using a self-supported structure is $384,000 higher than a guyed structure. When AltaLink compared structure costs in its initial line optimization study,[39] the incremental increase for a self-supporting dead-end structure was approximately $142,000;[40] and since updating its line optimization study for grillage foundations and Zone C loading, the incremental cost for self-supporting structures is even lower. AltaLink also indicated that additional land costs would partially offset any cost savings associated with guyed structures. It explained that during consultation on the use of guyed angle and dead-end structures, 28 of the 32 stakeholders who provided feedback objected to these structures because of the need to farm around them.[41]

146. In response to the CCA's suggestion, ATCO undertook a preliminary estimate of the potential cost difference, for its preferred route, of guying the outside corner of a two-pole monopole 90-degree corner. ATCO identified 11 corners in its project design and stated that only seven of these locations could support guy wires. ATCO submitted that after analysis, supported by vendor pricing, engineering modelling and a geotechnical desktop study, the estimated capital cost of a self-supporting two-pole monopole corner could be reduced by $82,200 by guying the outside corner pole. ATCO noted that this did not include any additional land costs that would offset the cost savings,[42] and would also have to be balanced against the additional disruption to landowner use of agricultural land from the guy wires.

[38] 25469 CCA Argument on AltaLink and ATCO Facility Appl FINAL for references, PDF page 11, paragraph 27.
[39] This study was subsequently superseded.
[40] Exhibit 25469-X0759, AML Reply Evidence, PDF page 68, paragraph 248.
[41] Exhibit 25469-X0759, AML Reply Evidence, PDF page 70, paragraph 257.
[42] Exhibit 25469-X0767.01, ATCO Reply Evidence, PDF pages 128 and 129, paragraph 569.

147. Although the parties could not agree on the quantum of savings, all agreed that the use of guyed structures would result in cost savings. It is important to the Commission that opportunities for cost savings, such as this one, be considered whenever possible. As such, in areas of the approved route (i.e., corner or dead-end locations) that can technically accommodate the use of guy wires, the TFOs are directed to consult with landowners on the potential use of a guyed structure on their land and inform them of any additional land payments resulting from their use. In those locations where the landowner agrees to have a guyed structure on their land, the Commission directs AltaLink and ATCO to use such a structure.

5.2.2 Agricultural impacts

148. Agricultural impacts were a contentious issue, primarily focused on concerns about farming around transmission structures and the management of clubroot and weeds. This section discusses those concerns generally; further findings that are specific to route segments are made later in the routing section.

149. In general, paralleling existing transmission lines is preferable because the incremental impacts are usually less than the new impacts to greenfield sites. However, paralleling existing transmission lines can increase the impact to cultivated land because the separation distance between the transmission lines often pushes the transmission line right-of-way further in-field. In contrast, a transmission line right-of-way can be sited on the boundary lines in a greenfield setting. In ATCO's portion of the route, preferred Route A would parallel existing transmission lines for 74 per cent of its length, whereas alternate Route C is sited on parcel lines for 72 per cent of its length. In the AltaLink portion of the project, paralleling existing transmission lines occurs primarily on the alternate route from Gaetz 87S Substation to point C31 (on both the 138 kV Parallel Alternate route and South Alternate route) and along the Preferred route and North Alternate route, from point C52 to point B95.

150. There were competing submissions from interveners on whether paralleling existing transmission lines or greenfield placement would result in greater adverse impacts, particularly on cultivated fields. This is discussed in more detail below. In response to concerns with farming around transmission towers, the RAOP and SBD groups filed reports from Elite Environmental Ltd., authored by Dale Fedoruk. ATCO filed a report from Robert Telford of Telford Land & Valuation Inc. in reply.

151. While weeds, clubroot and other soil-borne diseases did not factor into the selection of one route over another, interveners on all routes raised significant concerns in regard to all, along with associated mitigation measures to address them. The RAOP and SBD groups filed reports from Elite Environmental Ltd. and Dr. Ron Howard of RJH Ag Research Solutions Ltd., to address these issues.

5.2.2.1 Farming around transmission structures

152. The Commission heard concerns with farming around transmission structures in cultivated fields, from interveners along all routes. The level of impact varied based on some key distinctions, such as whether the CETO project structures parallel existing transmission lines, the distance between the CETO project structures and the fenceline or another transmission line, and whether the land on either side of the CETO project structures is farmed contiguously. The effect of the line on aerial spraying was also raised as a concern by interveners. AltaLink's 138 kV

Parallel Alternate route and ATCO's preferred Route A are characterized as paralleling existing transmission lines for 27.2 kilometres and 46.92 kilometres respectively.

153. The TFOs indicated that where possible, they endeavored to route transmission along field or quarter section lines, and away from mid-field placements, where impacts to farming operations are lower. Along greenfield routes, such as the western portion of AltaLink's Preferred route and ATCO's alternate Route C, the CETO structures would typically be placed on the property line, or one metre in-field from a road allowance.

154. RAOP submitted that farming around multiple transmission line circuits is more complex, involves more training, requires more time, uses more inputs (overlapped seed/spray or requiring more passes) and is less safe. Another impact of parallel routing is that the CETO project structures would be pushed further in-field to maintain a safe separation distance between the existing transmission line. ATCO requires separation distances of 28 metres from Transmission Line 9L20 and 22 metres from Transmission Line 7L143. Along ATCO's portion of the project, the CETO structures would be placed 12.6 metres and 22 metres in-field when paralleling transmission lines 9L20 and 7L143, respectively. For AltaLink, the separation distances from transmission lines range between 13 and 26 metres. Likewise, AltaLink's proposed structures would be pushed in-field if an existing transmission line were located on the quarter section line.

155. D. Fedoruk submitted that placement of towers along field margins or boundaries of properties would be less impactful to farming operational efficiencies. Mid-field tower placement creates more hazards and operational barriers, increases loss of farmable land, and increases operator risk and safety. D. Fedoruk also explained that the land between the fence and the towers can be difficult to farm, depending on the separation distance and size of equipment used. During cross-examination, landowners along greenfield routes conceded that in-field structure placement is more impactful than along property lines.

156. ATCO estimated the loss of land use for each structure to be 0.095 acres and 0.28 acres when structures are 12.6 metres and 22 metres from property boundaries, respectively.[43] ATCO submitted that landowners are compensated for these impacts with an annual structure payment for lost revenue and additional expenses for overlapping and missed areas along a property boundary. It confirmed it would work with landowners to identify opportunities to strategically locate structures to minimize potential impacts to agricultural activities, such as placing structures adjacent to existing in-field features that already obstruct cultivation.

157. Impacts on cultivated land are compounded in situations where there are multiple mid-field transmission lines and where both sides of the land are contiguously farmed: there are a greater number of structures to farm around, additional field passes are required, overlapping may occur, and areas may be unfarmable if the space between obstructions is too small for equipment to reach. In D. Fedoruk's view, having an additional parallel line increases safety risk, reduces equipment efficiencies and increases crop input costs.

158. R. Telford, retained by ATCO, submitted that the agricultural impact of multiple mid-field transmission structures described by D. Fedoruk appears to be overstated. R. Telford stated that D. Fedoruk's findings were based on knowledge of the equipment used by CK Farms

[43] Exhibit 25469-X0773.01, Appendix 06 – Rob Telford Report, PDF page 14.

and the true impacts of the project would vary depending on the size of the equipment, which could change from one landowner to another.

159. The TFOs argued that structure placement can mitigate some impacts where the line is placed on a contiguously farmed field paralleling an existing transmission line. They both noted that alignment preference and structure placement varies from one landowner to another and committed to working with landowners on structure placement.

160. From an aerial spraying perspective, although applicators generally fly parallel to transmission lines, they sometimes fly under conductors. RAOP submitted that spraying parallel lines is more difficult because the land between the lines can not be sprayed by plane. Applicators also do not fly under conductors when there is more than one set of transmission structures and do not spray on top of conductors. LORC submitted that, as it relates to its members the CETO project would create a new impact on aerial spraying, rather than an incremental one. It stated that its members spray crops routinely, generally in a north/south direction and the line would change the spray pattern to an east/west direction to parallel the line, requiring additional passes and expense. LORC is also concerned that the increased complexity of a transmission line would result in applicators placing its members' lands lower in the priority queue, or charging a premium.

161. The Commission considers that from an agricultural impact perspective, siting transmission structures in-field is more impactful than along property boundaries and on the edge of cultivated fields. While in-field structure placement occurs in both parallel and greenfield scenarios, it is more prevalent in the parallel scenario where an existing transmission line is present on or near property boundaries. It is more difficult to farm around and in between structures in this circumstance. This issue is further compounded where the land on both sides of the transmission line is being farmed contiguously.

162. The Commission agrees that the deeper in-field placement has a larger impact, as demonstrated by R. Telford's loss of use calculations. It also agrees with ATCO that equipment size plays a large role in determining the amount of lost cultivation; and, although beyond its jurisdiction, the Commission recognizes that compensation and annual structure payments are intended to address cultivation loss and make farmers whole.

163. The Commission is also of the view that the routing along parallel transmission lines has a slightly higher potential impact on aerial spraying. It does not agree with LORC's submission that a new impact is a significant detriment and notes that aerial spraying around transmission lines is a regular occurrence in Alberta, as demonstrated by the spraying currently occurring on ATCO's preferred Route A, where there is an existing transmission line.

5.2.2.2 Clubroot and weeds

164. Weed control and the prevention of clubroot and other soil-borne diseases, such as Aphanomyces, were major concerns among most interveners. As a result, the Commission has addressed this topic generally. Issues with clubroot and other diseases do not favour one route over another as they have been identified in the counties of Paintearth, Stettler and Lacombe, and on the lands of certain interveners. Interveners expressed a concern with the spread of the disease

and generally requested that the Commission require cleaning of equipment to protocol level 3[44] (level 3) between all titled parcels of land, regardless of ownership. Certain interveners, such as RAOP and LORC, also referred to the County of Stettler's recommendation that all parcels be treated as clubroot positive and a level 3 cleaning protocol be applied.

165. D. Fedoruk recommended that level 3 cleaning standards be applied to avert the spread of clubroot, Aphanomyces and other weeds. He emphasized that care and caution be taken to prevent the introduction of new or resistant weed species into any fields due to the difficulty managing introduced weeds.

166. The two TFOs proposed different approaches to address this issue. ATCO proposed to implement a level 3 cleaning requirement for the project where activities or conditions will result in the disturbance of soil, to perform this cleaning prior to entering each separately-owned parcel of land, and to provide landowners with advance notice of construction activities.

167. ATCO submitted that weeds and soil borne diseases are covered in its environmental evaluation and environment protection plan, and that it implements a variety of measures to limit the risk of spreading noxious weeds and plant diseases during construction, operations and maintenance. ATCO incorporated the applicable portions of the best management practices identified under the Government of Alberta, Alberta Clubroot Management Plan into its environmental management system procedures and practices for cleaning.

168. A number of interveners are concerned with ATCO's cleaning standard. They stated that ATCO does not test for clubroot before entering land and instead relies on information from counties and landowners. Interveners are also concerned that ATCO did not commit to doing a pre-construction weed survey and does not default to level 3 cleaning during emergency situations and frozen conditions. ATCO disagreed that a weed survey and field testing is required since level 3 cleaning is the default where soil is disturbed, even in frozen conditions. It added that although it may have to respond quickly without determining the appropriate cleaning level during emergency conditions, it is committed to ensuring that its equipment has been cleaned to the extent possible. ATCO further committed to using third party observers to ensure its clubroot protocol is followed.

169. Interveners requested that cleaning take place before ATCO enters each quarter section, regardless of ownership. D. Fedoruk confirmed his view that cleaning is only required prior to entering if a field spans more than one quarter section and is farmed as a single plot. ATCO indicated that if there is a grouping of land over multiple quarter sections with the same owner but are not farmed together, it would clean prior to entering the field the first time, as long as it was able to continue to the next field uninterrupted. ATCO added that it consults with landowners and would consider additional cleaning between commonly-owned parcels if it were made aware of existing clubroot that warranted further cleaning.

[44] Exhibit 25469-X0553, STD-06 Vehicle & Equipment Cleaning & Levels, PDF page 2. ATCO defines Level 1 as mechanical cleaning, reasonably removing rocks, mud and soil clumps using brooms, shovels or brushes or by hand. Level 2 is washing, using a compressed air, pressure washer or equivalent with water or steam to remove all soil and rocks. Level 3 is disinfection, incorporating a two per cent bleach, or comparable alternative solution, and letting the solution sit on the surface for 20 minutes.

170. AltaLink stated that if the project were approved, it would implement a clubroot sampling program to inform which fields required level 3 cleaning. In his report, Dr. R. Howard noted that AltaLink lacked information on soil testing methodology and recommended a two-stage clubroot sampling program which AltaLink agreed to. AltaLink's program involves taking an initial soil sample at the entrance of a field to test for clubroot, followed by a second collection of samples along the approved route, approximately every 150 metres; lands would be classified as infected, regardless of spore count, if clubroot is detected in the lab; and land parcels previously identified as containing the clubroot pathogen by municipal, provincial, or previous sampling programs would not be included in the sampling program, but would instead be treated as containing clubroot for the duration of the project and subject to the level 3 cleaning procedure.

171. For this project, AltaLink's level 3 cleaning procedure would involve the use of bleach or Spray Nine for the purpose of disinfecting equipment. AltaLink submitted that its clubroot mitigation measures are also applicable to Aphanomyces and that it will implement an Aphanomyces testing program based on the Saskatchewan Pulse Growers *Testing for Aphanomyces and Other Root Rot Pathogens* program. AltaLink specified that level 3 cleaning was not required during frozen conditions and committed to doing a pre-construction weed survey.

172. AltaLink explained that all vehicles and equipment would be cleaned to a level such that soil would not be distributed on the roadway after leaving a worksite, and that if rough cleaning does not sufficiently remove soil to prevent distribution on a roadway, it would employ onsite pressure washing or transport equipment offsite for cleaning. It also committed to having third party monitors on-site.

173. Certain interveners had specific concerns. The Craigievar Group members expressed concern that AltaLink would not commit to level 3 cleaning as a default. AltaLink submitted that it would consider level 3 cleaning but would first have informed conversations with landowners to determine appropriate mitigation measures based on the pathogens present. The SBD Group requested, and AltaLink agreed, that should AltaLink's Preferred route from points C49 to C31 to D31 and to D25 be selected, it be required to comply with the SBD Group's individual biosecurity plan prior to entry on their lands.

174. The Commission finds both TFOs' approaches to be appropriate to mitigate the risk of clubroot. The TFOs should take the landowners' preferences into consideration.

175. The Commission agrees with ATCO that field testing is not required when level 3 cleaning is deployed. The purpose of testing is to inform whether level 3 cleaning should be used and this is not required when level 3 cleaning has already been selected. The Commission also considers that AltaLink should comply with the request for level 3 cleaning from interveners along its route. In those situations, field testing is not required. For those landowners along AltaLink's routes who prefer field testing, AltaLink should comply with that request and conduct level 3 cleaning only where the test results detect the presence of clubroot.

176. From a cleaning frequency perspective, the Commission finds that the TFOs' proposed approach to clean prior to entering separately-owned parcels sufficiently mitigates clubroot risk and that cleaning between every quarter section is not required. The Commission encourages the

TFOs to consult with the counties and landowners to obtain additional information to inform whether additional cleaning is required.

177. Finally, as the evidence shows, ATCO's level 3 cleaning requirement is tied to the disturbance of soil, regardless of the season. The Commission accepts that soil disturbance has a high risk of the spread of clubroot, that ATCO's clubroot policy is sufficiently protective during these events, and that a condition requiring level 3 cleaning during winter conditions is consequently not required.

5.2.3 Environmental impacts

178. ATCO and AltaLink retained the consulting services of Stantec Consulting Ltd. and Jacobs Consultancy Canada Inc., respectively, to complete environmental studies and an environmental evaluation report for their respective portions of the CETO project. Both reports outline project components and activities, describe baseline environmental conditions, identify potential effects and mitigation measures, and assess predicted residual effects of the project. Both TFOs also prepared a project-specific environmental protection plan to be implemented for the CETO project.

179. From an environmental perspective, Stantec found that when considering the minor differences in potential effects on the various environmental components between ATCO's preferred Route A and alternate Route C, Route A would be preferred. However, Stantec stated that the proposed routes would each have similar biophysical characteristics and similar potential effects on environmental features, and therefore concluded that all routes would be suitable options with the implementation of proposed mitigation measures and standard best practices.

180. While Jacobs found that AltaLink's South Alternate route would be the most suitable route option when considering the potential environmental effects of the project, it concluded that the differences between the proposed route options would be minor from an environmental perspective. Jacobs stated that all route options are viable, provided that the mitigation measures outlined in AltaLink's standards and procedures, environmental protection plan and project-specific environmental requirements are implemented.

5.2.3.1 Adequacy of environmental surveys

181. The potential project impacts to wildlife and wildlife habitat were concerns raised by many of the intervener groups. The Brando Holsteins Inc. submissions included concerns around the adequacy of wildlife observation points selected by Jacobs for the wildlife field surveys. LORC raised concerns with the adequacy of Stantec's wildlife and baseline studies, the environmental evaluation methods, compliance with AUC Rule 007, project effects on groundwater and effects on wildlife and wildlife habitat.

182. LORC also questioned the route metrics and submitted that due to deficiencies in data collection, the route metrics and route comparison are inaccurate. It stated that the breeding bird surveys were inadequate because of the time of day at which they were completed and being conducted from the roadside. LORC members argued that additional fragmentation of existing wooded areas would be detrimental to wildlife and therefore Route A would have a lesser impact.

183. ATCO filed a report in which Stantec reviewed and responded to the evidence filed in relation to the environmental considerations associated with the project for LORC, RAOP and the MNA. ATCO submitted that AUC Rule 007 does not identify specific surveys that are required to establish a local baseline but that an environmental evaluation must describe the potential effects of construction and operation of the project on the environment.

184. Concerning the adequacy of baseline wildlife and vegetation surveys, Stantec stated that the desktop review and field surveys completed for the environmental evaluation complied with Rule 007 as well as the Commission's transmission line developments environmental guidelines checklist; and that all surveys were conducted in accordance with Alberta Environment and Parks (AEP) accepted standards and protocols, including the *Alberta Native Plant Council Guidelines* and Alberta's *Sensitive Species Inventory Guidelines*, by experienced vegetation ecologists and wildlife biologists familiar with the project region. Stantec indicated that surveys and protocols were discussed and agreed upon with AEP and were found to be reasonable for the proposed project.[45]

185. AltaLink stated that Jacobs' wildlife ground field surveys were conducted within representative habitat types that provide higher value for wildlife. Survey locations were determined based on aerial imagery, land cover classification data, safe access for field crews and land access permission. In addition, an aerial overflight of the entire project area was conducted to identify potential wildlife habitat features and open water wetlands with the potential to support large numbers of water birds.

186. AltaLink committed to completing pre-disturbance assessments on the approved route prior to the start of construction. It also indicated that mitigation measures specified in its standards and procedures, environmental protection plan and project-specific environmental requirements, which include industry-accepted best practices and provincial and federal guidelines, would be implemented to avoid or reduce potential adverse effects on wildlife species and wildlife habitat.[46]

5.2.3.2 Evidence of Cliff Wallis

187. In response to concerns with environmental impacts of the project, the LORC and SBD groups filed expert reports prepared by Cliff Wallis of Cottonwood Consultants Ltd.

188. Concerning AltaLink's portion of the project, C. Wallis agreed with the assessments by Jacobs in its environmental evaluation stating, "[w]ith appropriate mitigation as outlined in the application and supporting documents, all routes (Preferred, Alternate, Variants) are considered viable. Much of the routings parallel existing linear disturbances in what is already a highly fragmented landscape."[47]

189. As for the ATCO portion of the project, C. Wallis could not recommend one route over another based on biodiversity metrics, as he considered the differences between the proposed route options to be too minor. He noted that with appropriate mitigation all routes are considered

45 Exhibit 25469-X0771, Appendix 04- Stantec Reply Evidence, PDF page 9.
46 Exhibit 25469-X0759, AML Reply Evidence, PDF page 29.
47 Exhibit 25469-X0661, Appendix G – Evidence of Cliff Wallis, PDF page 16.

viable, and that other non-biodiversity metrics may be of greater assistance in determining a preferred route.

190. If the project is approved, C. Wallis recommended the following conditions of approval for both the ATCO and AltaLink portions of the project:

- The requirement for frozen ground conditions or use of access matting when working in and around wetlands.
- A protocol for dealing with snakes should be developed as part of the work under the environmental protection plan.

191. C. Wallis concluded in his reports that with the mitigation measures proposed by both TFOs, the non-treed nature of a significant portion of the various route options, the minimal pole footprint for most structures, and having the various proposed routes located on existing linear features would reduce the potential environmental risks associated with the project and keep the impacts on biodiversity to an acceptable level.

192. In response to C. Wallis's concerns around wetlands, ATCO explained that it would seek approval from AEP under the *Water Act* and other applicable legislation, as indicated in the project environmental evaluation, where avoidance of wetlands through structure placement would not be possible. It also specified that proposed activities and mitigation measures would be reviewed by AEP prior to issuance of *Water Act* approvals. ATCO stated that it develops constraint maps, that include wetlands, based on available provincial data sets which are supplemented by the assessments completed by Stantec as part of the environmental evaluation. It submitted that it would work to avoid placing structures within riparian areas and limit vegetation removal to the extent possible.

193. ATCO stated that it plans to complete work in frozen or dry conditions, particularly in sensitive areas such as wetlands. Where conditions are either not frozen or not dry, ATCO explained that it would employ a number of mitigation measures that may include matting. However, ATCO argued that a condition that matting must be used at all times if conditions are not frozen would not be reasonable and that construction may safely take place in dry conditions, without matting.

194. AltaLink stated that its approach for working in and around wetlands is provided in the Temporary Access Standard,[48] Temporary Access Procedure,[49] Work in and Around Water Standard and Work in and Around Water Procedure.[50] Specific requirements include using methods to prevent soil compaction, which may include clean access matting or low ground pressure equipment.

195. AltaLink submitted that the use of matting has the potential to result in vegetation or sod shearing as mats can experience frequent freeze and thaw cycles that may cause them to freeze in place.[51] It stated that its current construction schedule is planned for winter construction and

48 Exhibit 25469-X0530, AML-SBD-2020DEC17-003 Attachment (Standards and Procedures), PDF page 51.
49 Exhibit 25469-X0530, AML-SBD-2020DEC17-003 Attachment (Standards and Procedures), PDF page 60.
50 Exhibit 25469-X0530, AML-SBD-2020DEC17-003 Attachment (Standards and Procedures), PDF page 93.
51 Exhibit 25469-X0530, AML-SBD-2020DEC17-003 Attachment (Standards and Procedures), Section 6.6, PDF page 79.

specified that requiring it to work with frozen ground or to use access matting would remove some of the flexibility needed to construct with the least possible impact. As such, its view is that a further condition is unnecessary and could potentially result in greater impacts to the environment.[52]

196. AltaLink noted that no reptiles were observed during field surveys conducted for the project along any of the proposed routes. In its environmental evaluation, Jacobs noted the potential presence of snakes in the project area, stating that the plains garter snake, red-sided garter snake and wandering garter snake have the potential to occur in the local study area. AltaLink submitted that it would commit to conducting pre-disturbance assessments which would document the potential presence of wildlife, including snakes.

197. At the hearing, C. Wallis remarked that both TFOs agreed to develop a protocol for dealing with snakes as part of the work under their respective project-specific environmental protection plan and further, that he had reviewed the standards and procedures for work in and around wetlands and had no concerns with the proposed approaches and mitigation measures.

5.2.3.3 Proposed conditions

198. Both the RAOP and LORC groups submitted that the commitments made by ATCO should be required as conditions of approval. This included the recommended conditions outlined in the report prepared by C. Wallis. RAOP requested that the Commission include a condition of approval which requires ATCO to comply with its procedures in its working in wet/thawed conditions & restricted activity periods[53] and procedure for installing and maintaining access mats.[54]

199. The SBD Group also requested that the environmental commitments made by AltaLink be included as conditions of approval. Specifically, the SBD Group requested that:

- AltaLink adhere to its Temporary Access Standard, Temporary Access Procedure, Work in and Around Water Standard, and Work in and Around Water Procedure.
- AltaLink conduct and complete pre-disturbance assessments on the approved route prior to commencing construction.
- AltaLink implement mitigation measures specific to AltaLink's Standards and Procedures, environmental protection plan, and project-specific environmental requirements, which include industry-accepted best practices, provincial and federal guidelines to avoid or reduce potential adverse effects on wildlife species and wildlife habitat.
- Frozen ground conditions or use of access matting be required when working in and around wetlands.

200. ATCO committed to following its environmental protection plan and working in wet/thawed conditions and restricted activity periods work procedure regarding construction mitigation measures to employ if unfavourable conditions were encountered. ATCO stated that a

[52] Exhibit-X0759, AML Reply Evidence, PDF page 46.
[53] Exhibit 25469-X0557, RAOP-ATCO-2020DEC17-001(b), Attachment 1.
[54] Exhibit 25469-X0558, RAOP-ATCO-2020DEC17-001-(b), Attachment 2.

condition of approval such as that requested by RAOP would unreasonably restrict its construction practices and is therefore not warranted.

201. AltaLink submitted that it has developed a number of environmental mitigation measures to ensure that the construction of the project would mitigate potential environmental effects, including its environmental protection plan and project-specific environmental requirements document. AltaLink stated that its approach to working in and around wetlands is provided in its temporary access standard and procedure, and work in and around water standard and procedure. As such, it concluded that a further condition would be unnecessary and could result in greater impacts to the environment as it would remove the flexibility required to construct with the least possible impact.

5.2.3.4 Findings

202. In their respective environmental evaluation reports both Stantec and Jacobs concluded that with sufficient mitigation measures, all route options would be viable from an environmental perspective. Jacobs found that the South Alternate route would be the most suitable route option when considering the potential environmental effects on the AltaLink portion of the project, however, it noted that the differences between routes would be considered minor. Likewise, in concluding that ATCO’s preferred Route A would be the preferred option on its portion of the project, it considered the differences in potential environmental effects between route options to be minor. These conclusions were generally supported by C. Wallis, who noted that the proposed routings largely parallel existing linear disturbances and combined with the proposed mitigation measures should reduce the impacts to an acceptable level.

203. The Commission accepts that the wildlife surveys completed for the project were conducted in accordance with AEP accepted standards and protocols, including the AEP *Sensitive Species Inventory Guidelines*. In addition, the mitigation measures proposed by the TFOs included updating wildlife surveys as required prior to any construction to identify wildlife features including nests and dens. The Commission is therefore satisfied that any project activities will be informed by a current route-specific understanding of wildlife activity. It finds that the environmental evaluation reports filed by the TFOs comply with the information requirements prescribed in Rule 007 and is further satisfied that with the implementation of proposed mitigations measures, the project is unlikely to result in significant effects to the environment.

204. The Commission is of the view that a condition to require frozen ground conditions or use of access matting when working in and around wetlands is not required in the circumstances. Of note, both TFOs provided their respective standards and procedures for work in and around wetlands that outline mitigation measures to alleviate the potential impacts to wetlands; and more importantly, C. Wallis reviewed those standards and procedures and has no concerns with the mitigation measures proposed by the TFOs. The Commission consequently finds both TFOs’ approaches appropriately mitigate the risk to wetlands.

205. As recommended by C. Wallis, the TFOs committed to developing a snake protection protocol as part of the work under their respective project-specific environmental protection plan. Accordingly, the Commission imposes, to each of ATCO Electric Ltd. and AltaLink Management Ltd., the condition of approval set out in Section 8 of this decision.

206. The Commission is satisfied that the environmental effects of the project can be mitigated to a reasonable degree if the TFOs adhere to the above commitments, including abiding with all pertinent provincial and federal environmental legislation and guidelines and diligent implementation of the mitigation measures proposed in their respective environmental evaluation reports and environmental protection plans.

5.2.4 Other impacts to stakeholders

5.2.4.1 Does the CETO project pose a risk from electromagnetic fields?

207. Electric and magnetic fields (also known as electromagnetic fields or EMFs) are present wherever electricity flows. Sources of electric and magnetic fields include electric transmission and distribution lines, household appliances, power tools, office equipment, computers and any other electrical device. EMFs also occur naturally on the earth. EMFs associated with transmission lines are sometimes referred to as extremely low frequency (ELF) EMF because electric power is transmitted at 60 cycles per second (or 60 hertz or Hz), which is at the very low end of the frequency spectrum.

208. Electric fields are produced by voltages applied to electrical conductors, or wires, and equipment. The strength of an electric field is directly related to voltage and will increase as voltage increases. Electric fields may be shielded or blocked by intervening objects such as trees or buildings and are measured in volts per metre (V/m) or kilovolts per metre (kV/m).

209. Magnetic fields on the other hand, are created by the flow of electricity (the current). The strength of a magnetic field is directly related to the current; the higher the current, the higher the magnetic field. Unlike electric fields, magnetic fields are not easily shielded. They are generally measured in milligauss (mG).

210. The intensity of both electric and magnetic fields from transmission lines decreases with distance from the source.

211. AltaLink and ATCO submitted that although stakeholders are concerned with continuous exposure to transmission lines, including those proposed to be constructed as part of the CETO project, Health Canada and the World Health Organization (WHO) have reviewed EMF studies and have concluded that EMFs at extremely low frequencies, less than 300 hertz, do not cause any long-term adverse health effects.

212. The TFOs also referred to a 2010 update published[55] by the International Commission on Non-Ionizing Radiation Protection on exposure guidelines, which set the electric field and magnetic field exposure rates for the general population to a maximum of 4.2 kV/m and 2,000 mG, respectively. The TFOs submitted that their modelled exposure rates for electric and magnetic fields would be below these general population recommended exposure rates and both committed to conducting measures and discussions with stakeholders when requested.

213. On behalf of the RAOP and SBD groups, Dr. Paul Héroux and Dr. Anthony Miller submitted that there are health risks associated with long-term exposure to EMFs and that the transmission line should be buried underground in order to mitigate these concerns. Alternatively, Dr. P. Héroux recommended that the TFOs install EMF monitoring stations along

[55] Exhibit 25439-X0304, AML CETO - Appendix Q Electrical Considerations, PDF page 6.

the length of the transmission line. The SBD Group argued that monitoring stations installed near residences that are 50 to 150 metres from the transmission line is cost-effective and would align with its position that the precautionary principle[56] should be applied to the CETO project.

214. RAOP requested that conditions be placed on the transmission line approvals such that EMF levels must not exceed the calculated average magnetic fields 50 per cent of the time and that ATCO must not exceed the calculated peak magnetic field level more than one per cent of the time. ATCO submitted the requested conditions were not reasonable because the loading on the transmission lines are controlled by AESO and out of its control.

215. The Commission places significant weight on the WHO's conclusions that, based on available research data, exposure to electromagnetic fields is unlikely to constitute a serious health hazard, and that exposure to EMF from transmission lines is not a demonstrated cause of any long-term adverse effect to human or animal health.

216. The Commission finds that the evidence of Dr. P. Héroux and Dr. A. Miller on the health risks associated with ELF magnetic fields and the precautionary measures they advocate for are inconsistent with the conclusions of the WHO, Health Canada and other national and international organizations; and further that neither Dr. A. Miller nor Dr. P. Héroux provided sufficient evidence to displace the conclusions of those organizations.

217. Given the predicted EMF levels,[57] the Commission finds that the evidence before it does not support a conclusion that there will be health effects attributable to the EMF produced by the proposed transmission line at the nearest residences. As a result, there is no need to mitigate the effects of EMF; and in particular, there is no need to bury the transmission line on the basis of impacts from EMF nor to install remote monitoring stations to confirm the modelling conducted by the TFOs. The Commission expects AltaLink and ATCO to adhere to its commitment to conduct pre- and post-constructing monitoring at the request of stakeholders, and to explain to them the findings of those measurements. Likewise, the Commission finds that conditioning approval of the transmission line on magnetic field levels is not required given that the predicted levels are far below the exposure guidelines for the general population.

5.2.4.2 Noise

218. AltaLink provided noise modelling for the proposed project and stated that there are no significant noise sources associated with the normal operation of a transmission line. It confirmed that contribution to audible noise levels at the right-of-way edge from the proposed project would result in audible noise levels well below the nighttime permissible sound level of 40 dBA and are considered negligible.

219. Similarly, in its application, ATCO demonstrated audible noise levels well below the nighttime permissible sound level of 40 dBA and are considered negligible. ATCO submitted that noise will be greatest during construction of the transmission line and once construction is completed, minimal noise is anticipated from ATCO's operations over the life of the project.

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[56] Transcript, Volume 19, pages 2991-2996.
[57] Exhibit 25439-X0304, AML CETO - Appendix Q Electrical Considerations, PDF page 23.

220. Both TFOs stated they will comply with the requirements of Rule 012: *Noise Control* and would conduct construction activity according to applicable bylaws.

221. The Commission finds that the transmission line will not be a significant source of audible noise and is satisfied with both AltaLink's and ATCO's commitments to comply with the requirements of Rule 012 and applicable bylaws.

5.2.4.3 Does the CETO project pose a higher fire risk?

222. LORC and Brian Perreault raised concerns with electricity-associated fire risk. They stated that the proposed project would increase the risk of fire in the Tinchebray 972S Substation area, pointing to a fire around the Cordel 755S Substation and two recent grass fires on B. Perreault's property in support of their position. ATCO disagreed that project infrastructure would contribute to an elevated fire risk because the proposed transmission structures are steel rather than wood and the substation does not contain oil-filled equipment. ATCO also submitted that the substation's gravel pad provides a sufficient buffer to prevent fires from spreading off-site. It investigated the two recent grass fires on B. Perreault's property and concluded that fires in the area can be responded to properly.

223. The interveners also expressed a concern for the safety of their homes and properties in the Tinchebray 972S Substation area given the limited access and hilly terrain. They submitted that the coulees form an island, limiting access in and out of the Tinchebray area to Township Road 400 to the east and Range Road 151A to the south. They stated that local fire departments can not control fires in the coulees because they lack the skill and equipment and often rely on landowners to provide access and direction to fires.

224. ATCO stated that it offers free half-day power line safety training for emergency first responders (Fire, RCMP, Emergency Medical Services and Environment Sustainable Resource Development personnel) in its service area. These sessions are led by ATCO safety professionals and power line technicians, to provide information first responders may need to protect the public and respond safely to electrical emergencies. ATCO submitted that the coulee setting does not create a higher fire risk and that wooded areas pose the highest risk.

225. LORC requested that ATCO be required to adopt mitigation measures such as conducting a "point of ignition risk of fire assessment" and storing fire suppressing equipment for landowners to access. ATCO submitted that it is developing a risk assessment model to determine where ATCO's electrical assets are most exposed to risk of damage from fires and where fires have an elevated risk of escalating to large-scale events. While this tool has not been completed, ATCO indicated that initial data does not suggest this area to be high risk. Lastly, ATCO submitted that due to the safety-sensitive nature of its facilities, it cannot allow access to stored fire suppression equipment at the Tinchebray 972S Substation to landowners, or any third parties.

226. Based on the evidence before it, the Commission finds that the proposed CETO project, including the Tinchebray 972S Substation, does not pose a fire risk that is higher than for a typical transmission development. The Commission is persuaded by the fact that the Tinchebray 972S Substation does not contain oil field equipment, and agrees with ATCO that the gravel pad at the Tinchebray 972S Substation provides a sufficient buffer to prevent fires from spreading off-site. While the Commission does not associate the use of wood transmission

structures with a high risk of fire, the Commission does find that the use of steel structures results in a lower risk because they are not combustible.

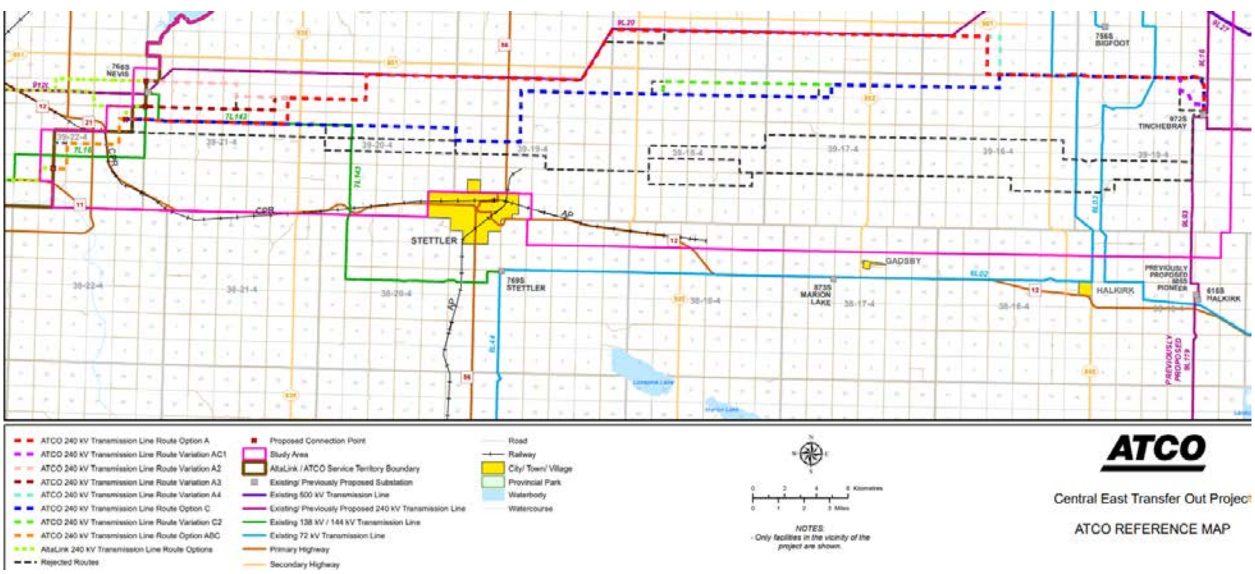
227. The Commission agrees that limited access into the area may decrease reaction time for emergency responders. To mitigate this concern, it encourages ATCO to consult with landowners and first responders in the area to develop a fire access plan. The Commission also acknowledges ATCO's other mitigation measures in this regard, such as its safety training course. As for LORC's request for a point of ignition risk of fire assessment, the Commission considers this to be unnecessary because ATCO is actively developing a system-wide risk assessment tool. Upon completion of this tool, the Commission expects ATCO to use the results to inform whether additional fire mitigation is required in its service territory. Finally, the Commission agrees with ATCO that providing and storing fire suppression equipment on-site within the Tinchebray 972S Substation is not advisable from a safety and security perspective.

5.2.5 Routing

5.2.5.1 ATCO Electric Ltd.

228. ATCO proposed the preferred Route A and alternate Route C to connect the Tinchebray 972S Substation to AltaLink's service territory. Parts of these routes are common, however, the routes deviate between points A15 and B69. ATCO also proposed three variants and four connection points with the AltaLink line. The Commission has assessed these routes in three parts: (i) Tinchebray 972S Substation to point A15, (ii) point A15 to point B69, and (iii) point B69 to AltaLink's service territory.[58] ATCO's proposed routes are depicted in the figure below.

Figure 6. ATCO's proposed routes for the CETO project[59]



[58] The map below does not show the location of reference points, ATCO provided route mosaic maps in exhibits 25469-X0225 and 25469-X0226, which do show these locations.

[59] Exhibit 25469-X0220, Atch4_CETO Project_Reference Map Drawing.

5.2.5.1.1 Tinchebray 972S Substation to point A15

229. This portion of the CETO project is common to the preferred and alternate routes (common route portion). Interveners along this route segment are Brian Perreault, Doreen Blumhagen, Jason Felzien and Dwayne Felzien.

230. B. Perreault's primary concern is the flooding of his land which he attributes to the initial construction of the Tinchebray 972S Substation and transmission line to connect the Halkirk Wind project.

231. This common route portion passes over the grain bin yard sites of LORC members J. and D. Felzien and requires the relocation of a distribution line. D. Blumhagen objected to the common route portion because it would require that a distribution line be relocated to her residence's side of the road.

232. Route Variant AC1[60] was suggested by landowners in the area, which ATCO in turn advanced as an applied-for variant. This variant increases the distance of the CETO line from residences and does not require that a distribution line be relocated next to D. Blumhagen's property.

5.2.5.1.1.1 Findings

233. The Commission approves the common route portion, from Tinchebray 972S Substation to point A15. It finds that this common route portion has a lower, overall impact than Route Variant AC1 when considering cost and available mitigation measures. Route Variant AC1 costs $1,289,000 more than the common route portion due to the increased number of turns. While the nearest residence is closer to the common route portion, the CETO line would be separated from this residence by Township Road 400. ATCO is also in discussions with D. Blumhagen and the Beaver Rural Electrification Association to bury a portion of the distribution line which would address D. Blumhagen's concern.[61]

234. From a mitigation perspective, the Commission is satisfied that ATCO's commitment to work with landowners on the relocation of hay bales and other structures within the right-of-way is sufficient to mitigate their concerns. It also acknowledges ATCO's commitment to work with distribution system owners and landowners to explore mitigation measures, including the relocation or burying of distribution lines.

5.2.5.1.2 Point A15 to B69

235. For this portion of the CETO route, ATCO proposed two route options, each with a route variant. ATCO's preferred Route A generally parallels existing Transmission Line 9L20, while its alternate Route C can generally be characterized as a new disturbance sited on parcel lines. Route A parallels an existing transmission line for 74 per cent of the route, whereas Route C parallels existing Transmission Line 7L143 for eight per cent of the route and is sited on parcel lines for 72 per cent of its length.

[60] Route Variant AC1 traverses northwest from Tinchebray 972S Substation and was suggested by area landowners.
[61] Transcript, Volume 11, PDF page 1803.

236. There were interventions along both route options, with RAOP members generally located along Route A and LORC members located along Route C. Several interveners would be affected by both routes. RAOP submitted that Route A has greater residential impacts due to the higher presence of potential country residential and yard site locations. The group stated that farming around another set of structures would be difficult, especially where structure locations do not align. RAOP members submitted that farming around multiple circuits is more complex, involves more training, requires more time, uses more inputs (overlapped seed/spray or requiring more passes) and is less safe. This was echoed by the RAOP group's expert, Dale Fedoruk, who stated that having an additional parallel line increases operator risk and operational barriers, reduces equipment efficiencies, and increases crop input costs. RAOP members are also concerned that in combination with the existing line, the proposed CETO line would nullify their ability to subdivide their land.

237. LORC submitted that Route C would affect a larger number of residences compared to Route A. In addition, it argued that the impacts of farming around multiple transmission structures on RAOP members along Route A is more of an incremental impact given that those individuals already have experience farming around structures. If the transmission line is sited along Route C, the agricultural impacts would be a new impact. LORC members explained that they currently use the right-of-way area for hay storage, seed cleaning, farming, corrals, airstrips and equipment storage. These items would have to be moved to accommodate Route C, which would not be an issue with Route A because the existing line does not allow for these uses. ATCO stated that it would work with landowners to relocate grain bins, hay piles, corrals and other structures within the right-of-way.

238. ATCO's applications included estimates of the length of cross-cultivated land parcels bisected by its proposed routes as a measure of potential impact to farming. However, where an existing transmission line is already bisecting a cross-cultivated parcel, it was not included in this estimate. In its reply evidence, ATCO updated these estimates, based on a review of aerial imagery, to reflect the total amount of potentially cross-cultivated land crossed by its proposed routes, which included parcels that were already bisected.

239. LORC submitted that ATCO's initial estimates were more representative of the impact of the CETO project because they were based on new impacts to landowners. In cross-examination, LORC questioned ATCO's newly-exposed cross-cultivation metric by going through photo mosaics of the route and confirming land use. It also disputed ATCO's estimate for cross-cultivation along alternate Route C and the C2 Variant as being too low since it measured 5.6 kilometres of cross-cultivation on LORC members' lands only. ATCO stated that the potential for cross-cultivation is an evolving metric that can change based on a number of factors, such as landowners buying or selling property, renting land, or altering agricultural practices.

240. The follow table summarizes ATCO and LORC estimates of cross-cultivation along the ATCO routes:

Table 2. Estimates of cross-cultivation

	Preferred Route A	Alternate Route C	Alternate Route C with C2 Variant
ATCO estimated length of newly exposed cross-cultivation from Application (km)	0.81	4.06	7.23
LORC estimated length of newly exposed cross-cultivation (km)	1.144	7.28	10.288
ATCO estimated length of total impacted cross- cultivation (km)	10.602	7.88	11.088

241. A number of LORC members have individual concerns. The Lysters explained that their pedigreed seed plots would be located directly under the proposed alternate Route C and that it would be difficult to operate or relocate these plots because they are subject to strict requirements through the Canadian Food Inspection Agency and Agriculture Canada for pedigreed status. The Lysters also applied to Transport Canada for an airstrip over which the alternate route would be routed. Niki and John Thorsteinsson are concerned about landing their helicopter at their residence. Janelle and Kent Robinson run an equestrian business that caters to special needs individuals and are concerned that the line would interfere with implantable medical devices.

242. ATCO provided the following (reproduced) table comparing the metrics applicable to its preferred Route A and alternate Route C:

Table 3. ATCO comparison of Route Option A and Route Option C between points A15 and B69[62]

Routing Factor	Route Option A Segment A15 to B69	Rout Option C Segment A15 to B69
Route length (km)	52.56	50.75
Area of right-of-way (ROW) (ha)	160.67	122.01
Number of major turns (≥45°)	8	8
Number of minor turns (5-45°)	0	4
Length following existing transmission line (km)	38.75	4.12
Length following parcel lines (km)	12.32	36.38
Length following road allowance (km)	1.49	7.65
Length following pipeline (km)	0	2.60
Length following railway (km)	0	0
Length of cross-country (km)	0	0
Length of route with adjacent access (km)[3]	25.04	29.77
Length with under-strung lines/ buried distribution lines (km)	1.00	0.58
Length of cross-cultivation (km)	0.81	4.06
RESIDENCES		
Nearest Residence (m)	140	60
Residences within 150 m of Centreline	1	4
Residences within 300 m of Centreline	6	9

62 Exhibit 25469-X0454.01, 25469_ATCO_AUC_2020NOV27_InformationResponseFINAL, PDF page 17.

Routing Factor	Route Option A Segment A15 to B69	Rout Option C Segment A15 to B69
Residences within 400m of Centreline	8	13
Residences within 800 m of Centreline	47	39
NEWLY EXPOSED RESIDENCES		
Nearest Residence (m)		
Residences within 150 m of Centreline	0	3
Residences within 300 m of Centreline	0	7
Residences within 400m of Centreline	0	10
Residences within 800 m of Centreline	6	32
OTHER FACTORS		
Cultivated lands within ROW (ha)	75.57	59.40
Pasture lands within ROW (ha)	66.40	46.62
Grasslands within ROW (ha)	8.07	8.89
Area Treed in ROW (ha)	11.37	8.68
Area of wetlands in ROW (ha)	14.23	10.36
Area of watercourse crossings (ha)	3.9	6.9
Area of ESA's in ROW (ha)	0.94	15.88
Area of sensitive species range in ROW (ha)	321.34	244.02
Area of HRV classes in ROW (ha)	0	1.18

243. ATCO proposed Route Variant A4 as an alternative to a portion of Route A. This variant was initially ATCO's preferred route because compared to ATCO's current preferred route, it increases the amount of alignment paralleling a road allowance and impacts less length of distribution lines. ATCO changed its preference due to the presence of a sharp-tailed grouse lek, but kept Variant A4 because it considered both routes to be viable. The lek is approximately 700 metres from ATCO's preferred route and 90 metres from Variant A4.

244. ATCO also proposed Route Variant C2 as an alternative to a portion of Route C. This variant was ATCO's initial route in the area. A landowner suggested an alternative which reduced the number of cross-cultivated parcels impacts, avoided grain bin locations and is equal in length to ATCO's initial route. ATCO later adopted the landowner suggested route as part of Route C and retained its initial route as Variant C2.

5.2.5.1.2.1 Findings

245. While the Commission finds that both the preferred and alternate routes are viable and buildable routes, it considers that preferred Route A will have a lower overall impact compared to alternate Route C. Route A follows linear disturbances for a greater portion of its length than Route C. The Commission is satisfied that following existing linear disturbances such as transmission lines and roads effectively minimizes transmission line impacts, especially when compared to a greenfield option where the line creates a new disturbance.

246. The Commission also finds that Route A has lower residential impacts. There are fewer residences within 150, 300 and 400 metres of ATCO's preferred route and the nearest resident is further away than on the alternate route. When considering newly exposed residences,[63] Route A has significantly fewer residences (i.e., six versus 32) within 800 metres. While RAOP submitted that Route A has more potential country residential and yard site locations, ROAP did not bring forward any approved or active subdivision plans. The Commission considers such potential

[63] A "newly exposed residence" is a situation where a transmission line is proposed to be close to a residence and there is no existing transmission line between that residence and the proposed transmission line.

future development activities to be uncertain and places greater weight on residences as they currently exist.

247. The Commission considers that preferred Route A is slightly more affected agriculturally than alternate Route C; Route A crosses more cultivated land in its right-of-way, has more in-field structures and slightly more cross-cultivated fields, while the agricultural impacts on Route C would be new.

248. As discussed in more detail in the agricultural impacts section, the Commission recognizes that there is a greater impact to farming around multiple structures and structures placed further in-field than when structures are placed on field boundaries. Route A has more in-field transmission structures than Route C. That said, the evidence indicates that most of the agricultural land along the paralleled length of preferred Route A has fences separating the proposed CETO structures and the existing transmission line structures. The evidence also showed that in these cases, the land on either side of the combined transmission line right-of-way is generally farmed separately, not contiguously. The Commission therefore finds that land with existing transmission structures along Route A would generally be unaffected by the CETO structures because of the presence of the fences between any farming activity and the CETO structures.

249. The Commission acknowledges that the land on the other side of the fence, where the CETO structures would be sited, would be subject to a higher impact because it would have new structures to farm around; and that the presence of existing structures and the required separation distance between the two lines pushes the CETO structures further in-field. (ATCO indicated that the CETO structures would be 12.6 metres in-field and that the existing Transmission Line 9L20 structures are 15.4 metres in-field.) The Commission therefore considers that there would be a minimal increase in farming complexity along Route A because of the presence of the fence. It also observes that the distance at which the CETO structures would be located in-field is similar to the distance of existing Transmission Line 9L20 structures, currently in-field and farmed around. Conversely, along Route C, the structures would generally be placed on boundary lines, resulting in minimal impacts to farming.

250. Turning to cross-cultivated lands, Route A crosses more total cross-cultivated land (10.602 kilometres vs. 7.88 kilometres), and Route C would create more new instances of cross-cultivated impacts (7.28 kilometres vs. 1.144 kilometres). The Commission considers that under both these metrics, Route A has the higher impact. While the impact is new on Route C, Route A's 9.459 kilometres of cultivated land would require landowners to farm around two sets of transmission structures, the existing and the CETO structures. The Commission acknowledges ATCO's statement that there should be enough space between structures to continue farming the area and its commitment to work with landowners on structure placement to further mitigate impacts to farming.

251. The Commission must weigh the impacts of potential route options considering general principles, but also site-specific impacts. Doing so here, it finds that Route A has less impact on residences and parallels existing linear disturbances for a greater portion of its length. It further considers that the agricultural impacts on Route A can be minimized due to the presence of fences between the proposed and existing transmission lines, and through structure placement. The increased agricultural impacts along Route A are ultimately not sufficient to persuade the Commission that Route C is a lower impact route overall.

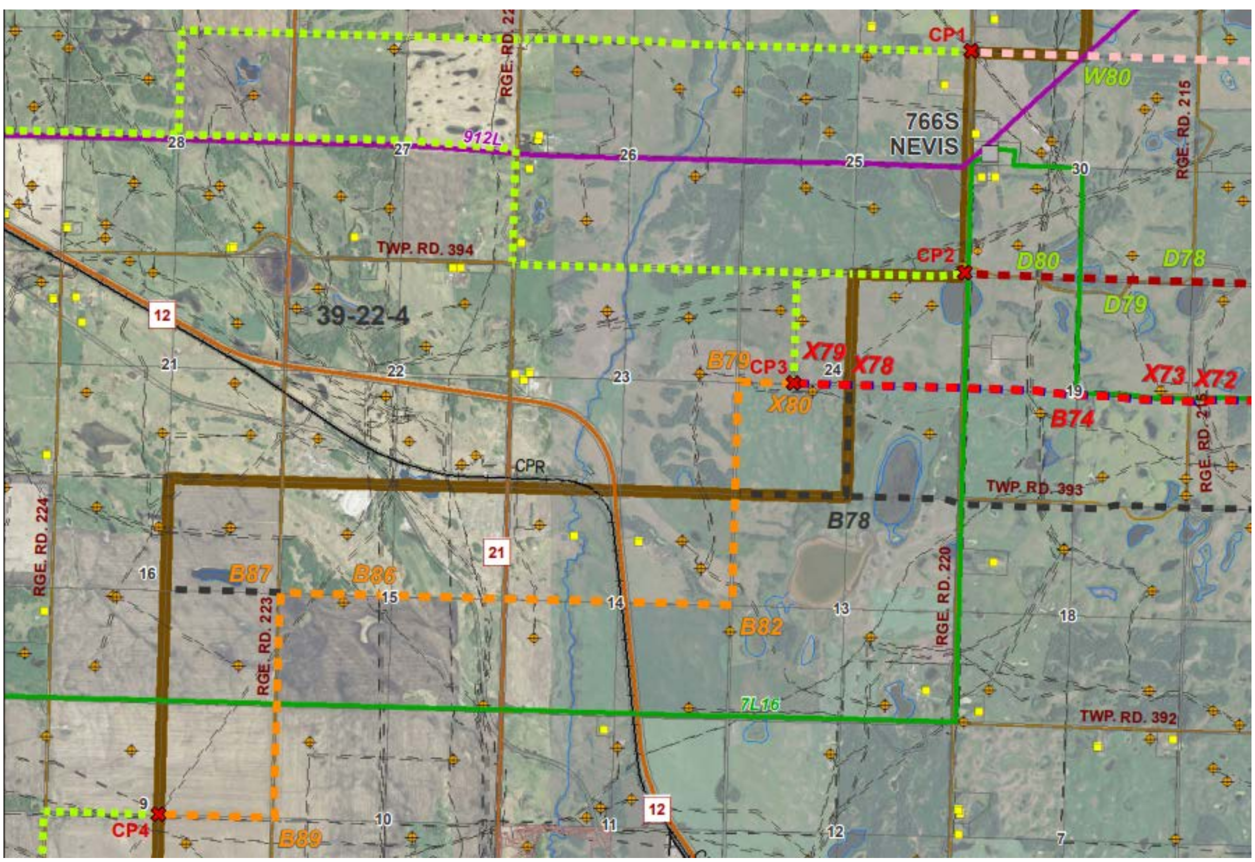
252. As discussed earlier, the Commission finds that the noise, environmental and EMF impacts do not favour one route over another, nor raise doubt that the CETO project should not be built.

253. Finally, the Commission rejects Route Variant A4 along Route A because it has a higher overall impact than Route A. More particularly, Route A is located further away from an existing sharp-tail grouse lek, is preferred by J. Felzien, and does not divide the Hendersons' land.

5.2.5.1.3 Point B69 to AltaLink's service territory

254. From point B69 westward, ATCO's preferred and alternate routes share a common alignment to connection point CP3. ATCO also proposed Route Variants A2 (to connection point CP1) and A3 (to connection point CP2), and a route extension designated as Route Option ABC (to connection point CP4), for a total of four possible connection points with the AltaLink portion of the project. The figure below shows the project area where the proposed connection points are located. On this map, the dashed red, pink, dark red and orange lines are ATCO's preferred common alignment, Route Variant A2, Route Variant A3 and Route Option ABC respectively. The dashed green routes are AltaLink's applied for routes; CP1, CP2, CP3 and CP4 are the proposed connection locations.

Figure 7. Excerpt from ATCO's project map[64]



[64] Exhibit 25469-X0225, Atch6_CETO Project_Proposed Route Mosaics, PDF page 8.

255. The common alignment primarily parallels existing Transmission Line 7L143, has the fewest major turns and avoids Crown land. While this option is the longest, it has the lowest residential impacts. The common alignment has the fewest residences within 800 metres, with the nearest residences 600 metres away, and none of the residences are newly exposed. Route Variant A2 is sited primarily on parcel lines. While it is the shortest option, it has more major turns and higher impact to residences than the common alignment and divides cross-cultivated lands. This variant has the most residences within 800 metres (total and newly exposed) with the closest resident 240 metres away. Route Variant A3 follows road allowance for the majority of its length, is approximately the same length as Route Variant A2, and has the same number of major turns. While it has the fewer total and newly exposed residences within 800 metres than Route Variant A2, Route Variant A3 has more residences within 150 and 300 metres, with the closest residences approximately 110 metres away.

256. If the Commission approved AltaLink's South Alternate route or Highway 11 Alternate route for the point C49 to ATCO service territory segment of AltaLink's route (referred to as Highway 11 segment), there would be a gap between the TFOs' routes. ATCO created Route Option ABC, located within both the AltaLink and ATCO service territories, to connect the transmission lines under that scenario. Route Option ABC, would be constructed and operated by ATCO, span 7.73 kilometres, and be sited on parcel lines or follow a road allowance. There are two residences within 800 metres of Route Option ABC, the closest being 430 metres from the CETO line.

257. Terry, Murray and Cody Rowledge are affected by all routes to all connection points. They also share or rent land with Lee Chapman and Glen Morbeck, who own lands along the variants. M. Rowledge prefers ATCO's preferred Route A over the route variants located further north as the variants would affect their farming operations and divide his land. He submitted that the use of Route Option ABC is acceptable as it would not adversely affect farming operations like the variants would. The other landowners did not express a preference on the connection.

5.2.5.1.3.1 Findings

258. The Commission considers that the common preferred and alternate portion has lower overall impacts than route variants A2 and A3. It finds this route to be superior because it parallels Transmission Line 7L143 for the majority of its route, does not traverse cross-cultivated lands and has the lowest impact to residences.

259. As discussed later in Section 5.2.5.2.3.1, the Commission finds AltaLink's Highway 11 segment to be the lowest impact route. As a result, ATCO's Route Option ABC is required to connect the two TFOs' routes. The Commission considers that along Route Option ABC there is a low residential impact, with two residences between 400 and 800 metres of the transmission line, and that the siting of this segment entirely on parcel boundaries and along road allowances will mitigate agricultural impacts. For these reasons, it approves the addition of Route Option ABC, which is required to connect the AltaLink and ATCO respective sections of the CETO project.

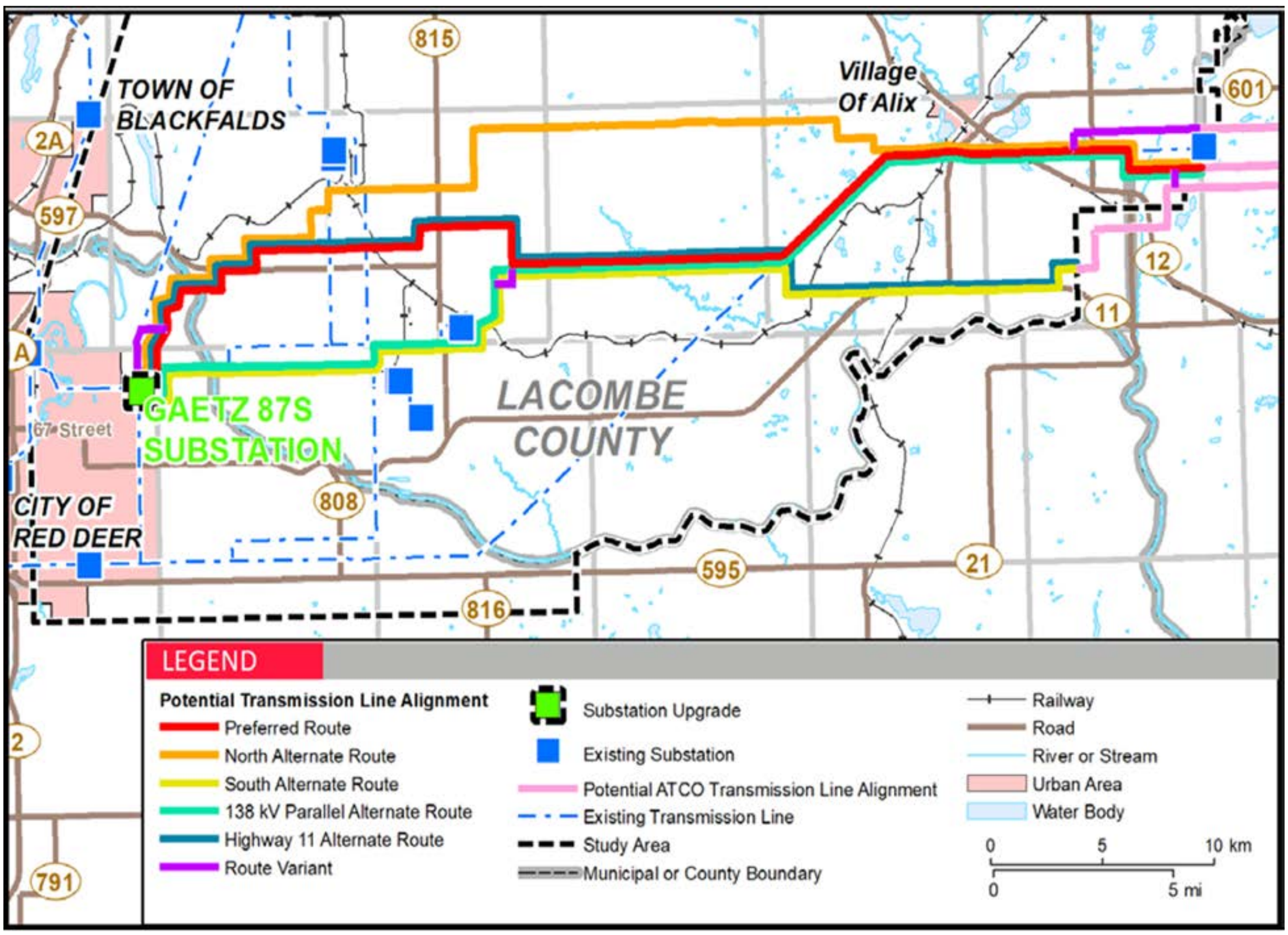
260. Further, should a dead-end structure be required where the CETO transmission line changes service territories, the Commission expects ATCO and AltaLink to co-ordinate such that only one dead-end structure is erected (in other words, that an AltaLink dead-end structure and

an ATCO dead-end structure not be used next to each other simply because of the boundary between service territories).

5.2.5.2 AltaLink Management Ltd.

261. As seen in the figure below, AltaLink proposed five routes to connect its Gaetz 87S Substation to ATCO's 9L62/9L68 transmission line at the service territory boundary. It also proposed two route variants, the Gaetz west and the B41 variants, and two connection variants, the C85 and the Crossover variants to connect to ATCO's transmission line at various points.

Figure 8. AltaLink's Preferred route and Alternate routes for the CETO project[65]



262. AltaLink provided the following (reproduced) table comparing the metrics between its proposed routes:

65 Exhibit 25649-X0263, AML Central East Transfer-Out Application, PDF page 101.

Table 4. Comparison of the Preferred and Alternate routes[66]

Major Aspects and Considerations		Preferred	South Alternate	138 kV Parallel Alternate	Highway 11 Alternate	North Alternate
Agricultural Considerations						
Agricultural Land Crossed by Centreline (km)	Crop (km)	24.4	17.6	21.3	20.7	28.4
	Tame Pasture (km)	4.5	0.7	4.0	1.1	4.2
	Crop - contiguously farmed or mid-field (km)	8.3	6.5	3.5	12.6	10.7
Residential Considerations						
Residences within 150 m of Centreline (#)		13	12	15	10	11
Residences within 150 m of Centreline not Separated by a Road or Transmission Line (#)		5	1	4	2	3
Residences within 800 m of Centreline (#)		86	52	78	60	86
Environmental Considerations						
Surface Water Crossed by Centreline (km)		0.5	0.3	0.5	0.3	0.3
Surface Water within 800 m from Centreline (ha)		248	114	247	114	199
Wetlands Crossed by Centreline (km)		2.4	1.3	2.0	1.6	2.2
Provincially Designated Environmentally Sensitive Areas Crossed by Centreline (km)		4.1	1.6	4.1	1.6	5.8
Electrical Considerations						
Parallel Existing Transmission Lines (km)		17.1	10.1	27.2	0.0	10.9
Distribution Lines Affected (km)		1.6	8.5	3.3	6.7	4.0
Special Constraints						
Active Oil or Gas wells within 50 m of Centreline (#)		8	0	5	3	10
Parallel Route to Pipelines within 250 m of Centreline (km)		23.3	16.2	18.5	21.1	26.5
Number of Pipeline Crossings on Centreline (#)		96	62	84	74	120
Length of Route within a Road Allowance (km)		20.6	27.3	22.3	25.6	18.2
HRVs within R-O-W Width (#)	HRV 4	0	0	0	0	0
	HRV 5	7	4	6	5	9
Cost						
Total Route Length (km)		57.9	49.3	55.0	52.3	60.4
Cost ($M)		159	149	154	153	164

66 Exhibit 25469-X0263, AML Central East Transfer-Out Application, PDF pages 103 and 104.

263. AltaLink submitted that the Preferred route has the least overall agricultural, residential and environmental impact to landowners, and that it would be located within a highway or government road allowance for approximately 35 per cent of its length, parallel existing transmission line infrastructure for approximately 30 per cent of its length, and be placed in a greenfield setting for approximately 35 per cent of its length.

264. In its applications, AltaLink presented its five routes in three parts: (i) Gaetz 87S Substation to point C31, (ii) point D25 to point F70 and (iii), point C49 to ATCO service territory. Part (i) contains a preferred and alternate segment to reach point C31. Part (ii) considers the North Alternate route which, if selected, would bypass a portion of part (i), and AltaLink's Preferred route from points C31 to F70. Lastly, part (iii) considers the preferred and alternate segments to a connection point with ATCO's transmission line. The Commission considered AltaLink's segments as they were proposed in its facility applications. AltaLink's preferred and alternate segment metric tables for each part were not disputed by any party and were helpful in comparing potential impacts.

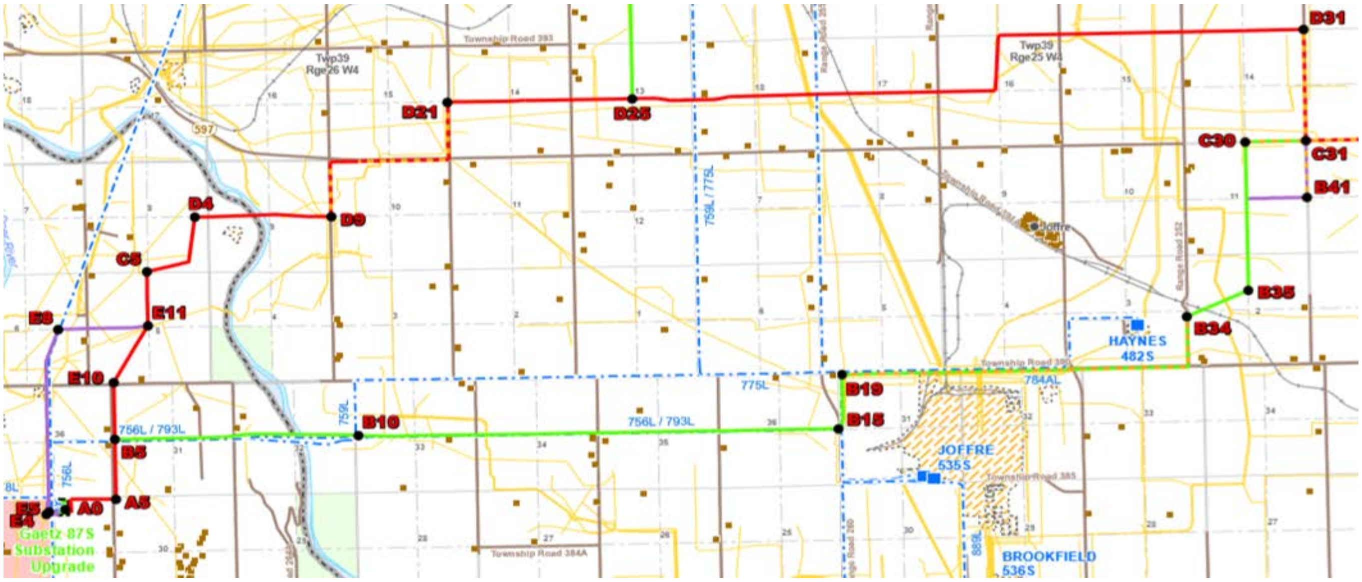
265. The table below summarizes the segments of parts (i), (ii) and (iii) that make up AltaLink's proposed routes.

Table 5. Comparison of the Preferred and Alternate routes

AltaLink route	(i) Gaetz 87S Substation to point C31	(ii) point D25 to point F70	(iii) Point C49 to ATCO service territory
Preferred	Preferred Gaetz to C31 segment	Preferred D25 to F70 segment	912L Parallel segment
South Alternate	Alternate Gaetz to C31 segment	Preferred D25 to F70 segment, from point C31 to F70	Highway 11 and ATCO segment
138 kV Parallel Alternate	Alternate Gaetz to C31 segment	Preferred D25 to F70 segment, from point C31 to F70	912L Parallel segment
Highway 11 Alternate	Preferred Gaetz to C31 segment	Preferred D25 to F70 segment	Highway 11 and ATCO segment
North Alternate	Preferred Gaetz to C31 segment, from Gaetz 87S Substation to point D25	Alternate D25 to F70 segment	912L Parallel segment, from point F70

5.2.5.2.1 Gaetz 87S Substation to C31

Figure 9. Excerpt from AltaLink's project map[67]



266. AltaLink’s five routes share the same alignment from the Gaetz 87S Substation to point B5 before deviating into the preferred Gaetz to C31 segment (the northern route depicted in red in the figure above) and alternate Gaetz to C31 segment (the southern route depicted in green in the figure above.)

267. The Preferred, North Alternate, and Highway 11 Alternate routes share the preferred Gaetz to C31 segment from B5 north to D25 before the North Alternate splits off to the north. The North Alternate is considered in Section 5.2.5.2.2 of this decision. The Preferred route and Highway 11 Alternate route continue to follow the preferred Gaetz to C31 segment east to D31 and south to C31.

268. The South Alternate and the 138 kV Parallel Alternate follow the alternate Gaetz to C31 segment and travel east of point B5 to point C31.

269. The alternate Gaetz to C31 segment parallels existing transmission lines for the majority of the route, whereas the preferred Gaetz to C31 route does not parallel existing transmission lines at all and primarily runs along quarter lines. AltaLink indicated that along the alternate Gaetz to C31 segment, it would match the existing transmission line spans to the extent possible.

270. AltaLink proposed two route variants between the substation and point C31, the Gaetz west and B41 variants. The Gaetz west Variant exits the substation to the west to point E5 and proceeds north to point E11 where it joins the preferred segment. It would parallel existing transmission lines 914L/1083L from points E5 to E8 and offer an additional option for the proposed transmission line to leave the substation.

271. The B41 Variant would travel east along the quarter line to point B41 and then north within an undeveloped road allowance to point C31. AltaLink stated that the variant would

67 Exhibit 26549-0254, AML CETO - Appendix A Project Maps, PDF page 1.

increase distance of the transmission line from two residences and would avoid crossing farmland but would add two additional dead-end structures to the south segment and increase its cost.

272. The alternate Gaetz to C31 segment would cross 3.2 kilometres of contiguously farmed crop land. The Solick Group members primarily reside and farm along the alternate Gaetz to C31 segment, between points B10 and B19. The Solick Group submitted that the alternate Gaetz to C31 segment would have an impact on its members' agricultural operations and that the crossing at the Red Deer River west of point B10 would be difficult and result in environmental impacts. The representative of the group, Harold Solick, stated that its members support the Preferred route and worked with AltaLink (prior to the filing of the application) on routing the Preferred route along the edge of quarter sections owned by H. Solick just east of the Red Deer River near point D9.

273. Bradley Shackel of Brando Holstein Inc., a member of the SBD Group, testified on behalf of his parents, Willem and Sylvian Schakel who reside on the alternate Gaetz to C31 segment between points B10 and B15. He stated that the proposed line would be located approximately 50 feet north of their fenceline making it difficult to operate farm equipment. Ron Duffy, another SBD member, would have his large contiguous block of land bisected with mid-field transmission lines if the preferred Gaetz to C31 segment were approved. As discussed in Section 5.2.5.2.2, the SBD Group favoured the North Alternate route.

274. The Craigievar Group would be affected by all of the proposed segments between the Gaetz 87S Substation and point C31, however, it supported the selection of the alternate Gaetz to C31 segment based on AltaLink's metrics. Ted and Ingrid Vander Meulen reside north of the preferred Gaetz to C31 segment two quarter sections east of point D25. Craigievar Farms Ltd., Eclipse Pork Ltd. and Sterling Ventures Ltd., for whom Glenn Sharp is the principal, each own lands between points D25 and D31 by Range Road 253. The Craigievar Group submitted that the only AltaLink metric favouring the preferred Gaetz to C31 segment is the number of residences within 150 metres of the centerline of the transmission line; and that although the alternate Gaetz to C31 segment has two more residences, each is already affected by a transmission line, as opposed to the preferred Gaetz to C31 segment which would be greenfield construction and therefore create a new impact.

275. The Craigievar Group also argued that the preferred segment would have structures placed in the middle of fields as opposed to near the edge. In particular, G. Sharp, who has 17 quarter sections of land along all the AltaLink proposed routes, would have new mid-field structures placed on his lands which would affect agricultural operations. The preferred Gaetz to C31 segment would cross 7.9 kilometres of contiguously farmed crop land.

276. AltaLink provided the following table comparing the metrics between the preferred Gaetz to C31 and alternate Gaetz to C31 segments:

Table 6. Aspects of Routing Between Gaetz Substation and C31[68]

Major Aspects and Considerations		Routes from Gaetz to C31 Comparison: Preferred Gaetz to C31	Routes from Gaetz to C31 Comparison: Alternate Gaetz to C31
Agricultural and Native Prairie Impacts			
Agricultural Land Crossed by Centreline (km)	Crop (km)	16.3	13.3
	Tame Pasture (km)	0.4	0.0
	Crop - contiguously farmed or mid-field (km)	7.9	3.2[69]
Residential Considerations			
Residences within 150 m of Centreline (#)		4	6
Residences within 150 m of centreline not Separated by a Road or Transmission Line (#)		2	1
Residences within 800 m of Centreline (#)		36	28
Environmental Impacts			
Surface Water Crossed by Centreline (km)		0.1	0.1
Surface Water within 800 m from Centreline (ha)		34.7	34.0
Wetlands Crossed by Centreline (km)		0.4	0.0
Provincially Designated Environmentally Sensitive Areas Crossed by Centreline (km)		0.0	0.0
Electrical Considerations			
Distribution Lines Affected		0.4	2.1
Parallel Existing Transmission Lines (km)		0	10.5
Special Constraints			
Active Oil or Gas wells within 50 m of Centreline (#)		3	0
Parallel Route to Pipelines within 250 m of Centreline (km)		15.6	10.7
Number of Pipeline Crossings on Centreline (#)		52	40
Length of Route within a road allowance (km)		4.4	6.2
Technical Considerations			
Total Route Length (km)		24.6	21.6

277. AltaLink favoured the preferred Gaetz to C31 segment because stakeholders raised concerns with the potential agricultural effects of the alternate Gaetz to C31 segment before and after the Red Deer River crossing; and that there would also be a visual impact to a residence in

68 Exhibit 25469-X0263, AML Central East Transfer-Out Application, PDF pages 115 and 116.
69 Does not include the 10.5 kilometres where the proposed route parallels existing transmission lines.

proximity to the Red Deer River crossing, shown as brown squares on the west side of the river in the figure below.

Figure 10. Red Deer River crossing on alternate Gaetz to C31 segment[70]

5.2.5.2.1.1 Findings

278. The Commission finds that the alternate Gaetz to C31 segment has the lowest overall impact because it has less line length, more transmission lines located within the road allowance, parallels existing transmission lines for the majority of the segment, and uses fewer heavy angle or dead-end structures.

279. The Commission finds that the alternate Gaetz to C31 segment would have less of an agricultural impact than the preferred Gaetz to C31 segment. In Section 5.2.2 of this decision, the Commission determined that mid-field structure placement has a higher impact than structures placed along boundary lines. Along AltaLink's preferred Gaetz to C31 segment, the routing would cross R. Duffy's large contiguous block of land and Craigievar lands with new mid-field structures. Solick Group members located along the alternate Gaetz to C31 segment would receive mid-field structures in parallel with existing mid-field structures. While the portion of the alternate Gaetz to C31 segment which parallels an existing line has the highest impact, the preferred Gaetz to C31 segment has a higher total impact because it would cross more agricultural land and more cross-cultivated crop land. The Commission expects AltaLink to work with affected landowners on structure placement to minimize the agricultural impact.

280. In addition, the Commission finds that the Red Deer River crossing along the alternate Gaetz to C31 segment has a lower impact. Along the preferred Gaetz to C31 segment, the river crossing would result in a new disturbance because it is the only transmission line crossing the river at that location. Conversely, along the alternate Gaetz to C31 segment, the crossing would

70 Exhibit 25469-X0264, AML CETO - Appendix A Project Maps, PDF page 6.

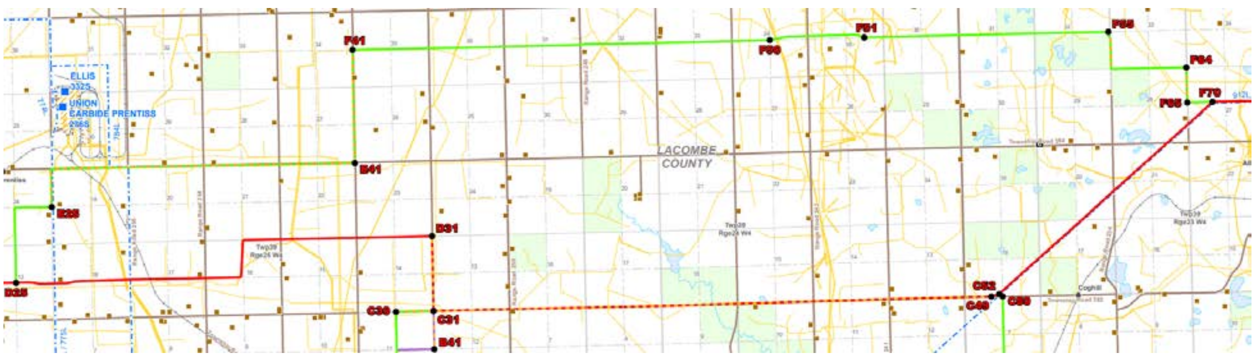
occur at a point where it would join existing transmission lines to cross the river, resulting in an incremental visual impact.

281. Although the alternate Gaetz to C31 segment has two more residences within 150 metres of the transmission line, this segment would be an incremental disturbance to those residences. In addition, when adjusted for newly-exposed residences (where there is not an existing transmission line or road between a residence and the proposed transmission line), the alternate Gaetz to C31 segment has a lower impact with one fewer residence within 150 metres. There are also fewer total residences within 800 metres along the alternate Gaetz to C31 segment.

282. Finally, the Commission rejects the Gaetz west and B41 variants: the Gaetz west Variant would require two crossings of an existing double-circuit transmission line, resulting in a higher cost; likewise, the B41 Variant would require two extra dead-end structures, resulting in a higher cost. No landowners supported these variants.

5.2.5.2.2 Point D25 to point F70

Figure 11. Excerpt from AltaLink's project map[71]



283. In this portion of the project, AltaLink proposed two segments: the preferred D25 to F70 segment (the southern route depicted in red in the figure above) and the alternate D25 to F70 segment (the northern route depicted in green in the figure above).

284. The preferred D25 to F70 segment continues east from point D25 primarily along the quarter line to point D31 where it deflects south along a road allowance to point C31. The preferred segment then proceeds east for 12 kilometres along Township Road 392 approximately one metre inside the north road allowance to point C49. It would then travel northeast from points C49 to F70, parallel the existing 912L transmission line and the proposed transmission line structures would be set approximately 24 metres northwest of the 912L structures. In Section 5.2.5.2.1.1 the Commission found the alternate Gaetz to C31 segment to be the lowest impact route. In this section, the Commission evaluates that routing to point C31, together with the preferred D25 to F70 segment from points C31 to F70, to determine whether it has a lower overall impact than the alternate.

285. The Preferred route and the Highway 11, South and 138 kV Parallel Alternate routes share the preferred D25 to F70 segment from point C31 to F70.

71 Exhibit 26549-0254, AML CETO - Appendix A Project Maps, PDF page 1.

286. The alternate D25 to F70 segment, shown in green in the figure above, deflects north from points D25 to E25 and travels north and east to point F55 before shifting in a south and east direction to point F70. From points D25 to F70, only the North Alternate route follows this route.

287. There were several interveners along the alternate D25 to F70 segment. James Heith Johannson, a member of the Craigievar Group, resides less than 150 metres from this segment. J. Johannson raised visual impact concerns. Pauline and Darrell Blacklock have multiple residences and dairy and farm facilities within 150 metres of the alternate D25 to F70 segment. The Blacklocks raised concerns that the transmission line would disrupt the dairy farm operations, potentially spread weeds and clubroot, and affect future expansion. The Blacklocks also indicated that a historic gravesite is located on the property. Craigievar Farms Ltd. and Eclipse Pork Ltd. also own land adjacent to the route, and the alternate D25 to F70 segment would bisect Craigievar Farms Ltd.'s cultivated land with mid-field structures.

288. The SBD Group opposed the preferred D25 to F70 segment. The group expressed concerns with residential, agricultural, and environmental impacts as well as potential effects on their property value and health. Bradon and Tammy Bushman, members of the SBD Group, are concerned with the number of trees that would be cleared on the north side of Township Road 392 and the impact the transmission line would have on them and their residence, including decreased property value and EMF. Their residence is located between points C31 and C49 and would be approximately 60 metres from the preferred D25 to F70 segment. They are also concerned that their bee colony would be affected. Although the SBD Group requested that the transmission line application be denied, in the event the application is approved, it requested that the Commission select the alternate D25 to F70 segment. The SBD Group submitted that although this segment would result in the Commission selecting the longest and most expensive of the proposed routes, it received the least amount of objection.

289. Expert reports were submitted by Serecon Inc. for AltaLink[72] and the HarrisonBowker Valuation Group for the SBD landowner group.[73] Both reports concluded that the Bushmans' acreage would have a potential property value impact of between 0 and 5 per cent, or 10 to 15 per cent, respectively.

290. AltaLink stated that the preferred D25 to F70 segment is shorter in length, lower in cost and has fewer heavy dead-end structures. Further, the preferred D25 to F70 segment has more length that parallels existing transmission structures or is located within the road allowance, as opposed to the alternate D25 to F70 segment. AltaLink submitted a table, reproduced below, which compared the preferred and alternate segments, from point D25 to point F70.

[72] Exhibit 25469-X0295, AML CETO - Appendix K Landowner Impacts, PDF pages 55-127.
[73] Exhibit 25469-X0664, Appendix I - Evidence of Pat Woodlock.

Table 7. Aspects of routing between D25 and F70[74]

		Routes from D25-F70 Comparison	
Major Aspects and Considerations		Preferred D25 to F70	Alternate D25 to F70
Agricultural and Native Prairie Impacts			
Agricultural Land Crossed by Centreline (km)	Crop (km)	10.8	14.8
	Tame Pasture (km)	1.3	1.0
	Crop - contiguously farmed or mid-field (km)	2.4	5.0
Residential Considerations			
Residences within 150 m of Centreline (#)		6	4
Residences within 150 m of centreline not Separated by a road or transmission line (#)		3	1
Residences within 800 m of Centreline (#)		34	36
Environmental Impacts			
Surface Water Crossed by Centreline (km)		0.3	0.1
Surface Water within 800 m from Centreline (ha)		96.4	47.1
Wetlands Crossed by Centreline (km)		1.4	1.2
Provincially Designated Environmentally Sensitive Areas Crossed by Centreline (km)		1.6	3.3
Electrical Considerations			
Distribution Lines Affected		0.2	2.7
Parallel Existing Transmission Lines (km)		6.2	0
Special Constraints			
Active Oil or Gas wells within 50 m of Centreline (#)		2	4
Parallel Route to Pipelines within 250 m of Centreline (km)		10.2	13.4
Number of Pipeline Crossings on Centreline (#)		46	70
Length of Route within a road allowance (km)		13.6	11.2
Technical Considerations			
Total Route Length (km)		29.7	32.2

5.2.5.2.2.1 Findings

291. The Commission finds that the preferred D25 to F70 segment has the lowest overall impact because it has less line length, lower agricultural impact, more transmission lines located within the road allowance, parallels existing transmission lines for a portion of the segment and landowner concerns can be adequately mitigated. The alternate D25 to F70 segment is longer,

74 Exhibit 25469-X0263, AML Central East Transfer-Out Application, PDF page 112.

within a road allowance for less of the segment, and does not parallel an existing transmission line.

292. Agriculturally, the Commission finds that the preferred D25 to F70 would result in a lower agricultural impact because it crosses less crop land and contiguously farmed fields. In Section 5.2.5.2.1.1 the Commission approved the alternate Gaetz to C31 segment, further reducing the amount of contiguously farmed land.

293. From point C31 to F70, Tammy and Bradon Bushman were the only interveners who submitted concerns to the Commission, and the evidence shows that the preferred D25 to F70 segment, and associated right-of-way and work space are not proposed to be located on the Bushmans' property. The transmission line would be located on the north side of Township Road 392 and the Bushmans are on the south side of Township Road 392. As a result, no trees are anticipated to be removed from the Bushmans' property. Moreover, the trees and road will create a separation from the residences and the transmission structures.

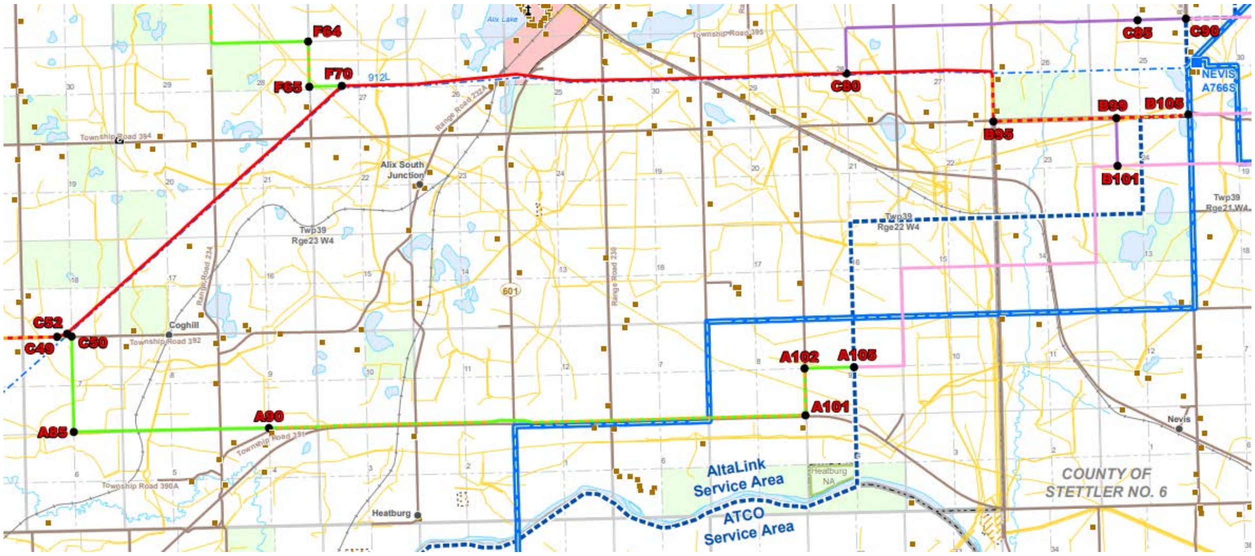
294. In response to the Bushmans' concerns about disturbance to their honey bees, AltaLink referred to research indicating that EMF does not impact bees, their ability to navigate, nor their ability to pollinate. While the transmission line may induce shocks to wood in bee hives, this can be mitigated by locating the hives further away or by grounding the hives. AltaLink committed to discuss any concerns with the Bushmans and to mitigate any issues that arise as a result of its facilities. AltaLink is not aware of any research that suggests bees would be affected by the low level of audible noise produced by the transmission line. The Commission is satisfied with the measures proposed by AltaLink to mitigate the potential visual impacts to the Bushmans, including its commitment to consult with them with respect to their bees.

295. In comparing the relative property value impacts between the preferred and alternate D25 to F70 segments, the Commission accepts the findings in the Serecon and HarrisonBowker reports that there is the potential for some negative market value impacts to certain country residential properties located directly adjacent to the proposed routes. The Commission finds that the potential impacts to property values on both routes would be similar and that the assessment of the relative impacts to property values does not favour either segment.

296. The Serecon and HarrisonBowker reports estimated that the Bushmans would have a potential property value impact of between 0 and 5 per cent, or 10 to 15 per cent, respectively. The Commission finds that proximity and visibility of the proposed transmission line are key factors and that visibility can be mitigated through the existence of visual barriers such as tree coverage. Further, existing trees and a road between the Bushmans residence and the transmission line will provide some mitigation. AltaLink has committed to work with the Bushmans on structure placement to minimize visual impacts.

5.2.5.2.3 Point C49 to ATCO service territory

Figure 12. Excerpt from AltaLink's project map[75]



297. To best consider the impacts of the routing options presented by AltaLink, a common start and end point, points C49 to B101, were selected.

298. In the figure above, AltaLink's preferred segment, referred to as the 912L Parallel segment, is depicted in red while the B101 Variant is in purple. From point C49, the 912L Parallel segment would deflect northeast toward point F70, then traverse east to C80 and B99. The B101 Variant would then be utilized, traveling south from points B99 to B101. This variant would connect the 912L Parallel segment to ATCO's preferred Route A.

299. The 912L Parallel segment would parallel the existing 912L transmission line or be located within the road allowance for a majority of its length. The Preferred route and 138 kV Parallel Alternate route also use the 912L Parallel segment. The North Alternate route uses only a portion of it, starting from point F70.

300. The alternate segment, referred to as the Highway 11 and ATCO segment, is depicted in green and pink to the south in the above figure. The Highway 11 segment deflects south from point C49 to point A85 and then east through point A90 along Highway 11, primarily within the highway right-of-way and on privately-owned lands, to point A101, and finally, point A105. To reach the common end point with the 912L Parallel segment, the ATCO segment is required. (The ATCO segment is also referred to as Route Option ABC in Section 5.2.5.1.3).

301. The Highway 11 segment parallels Highway 11 for a portion of its length and has lower residential impacts. The South Alternate route and Highway 11 Alternate route use the Highway 11 segment.

302. AltaLink also developed the C85 Variant along the 912L Parallel segment which travels north from point C80 to connect with ATCO's service territory at point C90 (shown as purple on figure above in the northeast corner). It stated that this route variant would cost $0.4 million

75 Exhibit 26549-0254, AML CETO - Appendix A Project Maps, PDF page 1.

more and increase agricultural impacts but avoid some residences within 150 metres. It would also offer flexibility to connect to a different connection point with ATCO further north.

303. AltaLink submitted that there are greater agricultural impacts along the alternate Highway 11 and ATCO segment but greater residential impacts along the preferred 912L Parallel segment. AltaLink submitted a table, reproduced below, comparing the segments.[76]

Table 8. Aspects of routing between C49 and ATCO service territory[77]

		Routes from C49 Comparison		
Major Aspects and Considerations		912L Parallel Segment	Highway 11 Segment	Highway 11 Segment + ATCO Segment
Agricultural and Native Prairie Impacts				
Agricultural Land Crossed by Centreline (km)	Crop (km)	8.0	4.4	9.7
	Tame Pasture (km)	4.0	0.7	0.8
	Crop - contiguously farmed or mid-field (km)	0.0	3.1	3.1
Residential Considerations				
Residences within 150 m of Centreline (#)		6	3	3
Residences within 150 m of Centreline not Separated by a Road or Transmission Line (#)		3	0	0
Residences within 800 m of Centreline (#)		39	13	15
Environmental Impacts				
Surface Water Crossed by Centreline (km)		0.2	0.1	0.1
Surface Water within 800 m from Centreline (ha)		162.0	28.5	60.7
Wetlands Crossed by Centreline (km)		1.0	0.3	0.8
Electrical Considerations				
Parallel Existing Transmission Lines (km)		17.3	0.0	0.0
Special Constraints				
Active Oil or Gas wells within 50 m of Centreline (#)		5	0	0
Parallel Route to Pipelines within 250 m of Centreline (km)		5.7	3.5	6.3
Number of Pipeline Crossings on Centreline (#)		33	11	24
Length of Route within a Road Allowance (km)		4.1	9.2	9.2
Technical Considerations				
Total Route Length (km)		21.4	15.7	23.4

76 The third column of Table 4-4 includes the ATCO segment which also known as Route Option ABC in ATCO's application. This route option connects the Highway 11 Alternate and South Alternate routes to ATCO's Preferred and Alternate Route.

77 Exhibit 25469-X0263, AML Central East Transfer-Out Application, PDF page 109.

304. April and Justin Aspden reside north of the 912L Parallel segment and would be within 150 metres of the proposed transmission line. The Aspdens stated that an additional transmission line on the preferred segment would have a cumulative impact on their views and their cattle business.

305. Maureen Rodgers, who owns farmland just north of the 912L Parallel segment, submitted that the 912L Parallel segment would affect her farming operation and that the transmission line should be routed along a roadway such as Highway 11.

306. The Commission did not receive any objections to the Highway 11 segment.

5.2.5.2.3.1 Findings

307. The Commission approves the Highway 11 and ATCO segment for the following reasons, but most importantly because it has the least overall impact to landowners: it has significantly fewer residential impacts with fewer residences within 150 and 800 metres of the transmission line. When considering newly-exposed residences (where there is no existing transmission line or road between the residence and the transmission line), the Highway 11 and ATCO segment has no residences whereas the 912L Parallel segment has three. Both segments parallel existing linear disturbances, either Highway 11 or Transmission Line 9L12. The Highway 11 and ATCO segment crosses slightly more crop land and crosses contiguously farmed land (where the 912L Parallel segment does not). The Commission finds this aspect to be mitigated because the Highway 11 and ATCO segment is generally placed within a road allowance, along Highway 11 or along quarter section lines for the majority of the route. In addition, there were no interveners along the Highway 11 and ATCO segment received by AltaLink.[78]

308. Should a dead-end structure be required where the CETO line changes service territories, the Commission expects ATCO and AltaLink to co-ordinate such that only one dead-end structure is erected (i.e., that two dead-end structures, an AltaLink and an ATCO structure, not be used next to the other simply because of the service territory boundary).

5.2.5.2.4 Overall findings of the AltaLink route

309. In addition to breaking down AltaLink's routing by segment, the Commission also considered the Preferred route and each of the alternate routes holistically. AltaLink's proposed routes have different deviation points and varying degrees of overlap, making an apples to apples comparison of the proposed routes difficult.

310. The Commission finds that while each of AltaLink's proposed routes are acceptable, the South Alternate route has the lowest overall impact. The Commission considers that following existing linear disturbances such as transmission lines, roads and highways is an effective approach to minimize the impacts of a proposed transmission line, especially when compared to a greenfield option where the transmission line would be a new disturbance. The South Alternate route parallels existing transmission lines 756L/793L along the south segment from point B5 until just after the NOVA Chemicals plant at Range Road 252. It then also travels east of point C31 along Township Road 392 and is located one metre inside the road allowance, to

[78] As discussed in Section 5.2.5.1.3, ATCO received an intervention from landowners concerned with the connection between the ATCO and AltaLink lines, however, they were receptive of the ATCO segment.

point C49. From there, the South Alternate route primarily parallels Highway 11 until ATCO's service territory.

311. The Commission is also persuaded by the fact that AltaLink's South Alternate route is the shortest and least expensive of its proposed routes. In addition, of the 12 residences within 150 metres of the South Alternate route, only one is not separated from the proposed transmission line by an existing transmission line or road.

312. AltaLink's South Alternate route crosses the least amount of crop land and the second least amount of contiguously farmed fields. The Commission recognizes that the paralleling of existing transmission structures within a field affects agricultural operations because the additional structure is pushed further in-field. It expects AltaLink to uphold its commitment to consult with landowners, such as the Solick Group, regarding structure spacing and placement to mitigate this impact.

5.2.6 Gaetz 87S and Tinchebray 972S substation alterations

313. To accommodate the addition of the two 240-kV transmission lines, AltaLink and ATCO applied to alter the Gaetz 87S Substation and Tinchebray 972S Substation, respectively. Both TFOs applied to alter the substation in two stages, with the start of construction triggered by the AESO's reaffirmation study.

314. AltaLink applied to alter its substation by adding two 240-kV circuit breakers during Stage 1 to accommodate Transmission Line 962L; and adding two 240-kV circuit breakers and salvaging an existing 240-kV bus tie breaker during Stage 2 to accommodate Transmission Line 986L. The alteration would occur within the existing fenced area.

315. Similarly, ATCO applied to alter the Tinchebray 972S Substation by adding a 240-kV circuit breaker during Stage 1 to tie in Transmission Line 9L62. During the Stage 2 alteration, ATCO applied to add four 240-kV circuit breakers, expand the fenced area, and alter existing Transmission Line 9L16 by changing the tie-in location to a new bay. The additional circuit breakers are required during Stage 2 to convert the substation from a ring bus configuration to a breaker-and-a-half scheme.

316. There were no objections to AltaLink's substation alteration. As discussed later, B. Perreault objected to ATCO's substation alteration, submitting that the substation alteration should not be permitted until his concerns with the existing substation are addressed.

317. The Commission finds that the alterations to Gaetz 87S Substation and Tinchebray 972S Substation proposed by the TFOs are appropriate and necessary to connect the transmission lines approved in this decision. Similarly, the alteration to Transmission Line 9L16 is minor in nature and required to connect the approved 240-kV transmission lines. The Commission is satisfied that the expansion of the fence boundary at the Tinchebray 972S Substation is necessary to accommodate the new substation equipment and that there is sufficient space for the expansion. It also recognizes that given the topography of the area, such an expansion requires updated drainage plans, which B. Perreault has objected to. His objections are addressed in Section 6.

5.2.7 The Métis Nation of Alberta

318. The MNA participated in this proceeding as the representative of more than 3,872 of its members, to whom it refers to as citizens. It stated that its members have harvesting and other rights affirmed in Section 35 of the *Constitution Act*, 1982 that may be affected by the project.

319. The MNA's participation included issuing and responding to information requests, submitting written evidence, and presenting two witnesses at the virtual oral hearing. It identified three key issues in its closing argument: the adequacy of consultation, the potential to affect Métis traditional land use and the potential to affect unknown archeological sites in the Tail Creek area. The MNA further requested that the Commission impose conditions on the proponents of the CETO project to address its potential impacts.

320. In the discussion below, the Commission addresses and makes findings on the duty to consult, including the scope and adequacy of consultation, in relation to the CETO project. The Commission also addresses the project's potential impact on Métis traditional land use and unknown Métis archeological sites in the Tail Creek area, as well as the conditions requested by the MNA.

5.2.7.1 Duty to consult

321. The duty to consult and accommodate is a legal duty with unique aspects that distinguish it from Aboriginal rights. The duty arises from the honour of the Crown and always rests with the Crown, although the Crown may delegate procedural aspects of consultation. Crown consultation is part of a process of fair dealing and reconciliation that flows from the historical relationship between the Crown and Aboriginal people.[79]

322. The duty is owed to Aboriginal communities as a whole and not to individual Aboriginal persons.[80] It arises when the Crown has knowledge, real or constructive, of the potential existence of an Aboriginal right, title or interest, and contemplates Crown conduct that might adversely affect it. When assessing potential impacts to Aboriginal claims or rights, the impacts must be causally linked to the proposed Crown conduct or decision. Addressing past wrongs is not one of the purposes of Crown consultation.[81]

323. The scope of the duty to consult is based on a preliminary assessment of the strength of the claim or right asserted and the extent of the alleged infringement. Where the perceived breach is less serious or relatively minor, the content of the duty will be at the lower end of the scale, for example, mere notice may be sufficient. If a strong *prima facie* case for the claim is established and the potential infringement is of higher significance, deep consultation that is aimed at finding a satisfactory solution may be required; however, the duty to consult does not confer a veto power on Aboriginal groups.[82]

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[79] Haida Nation v. British Columbia (Minister of Forests), 2004 SCC 73; Mikisew Cree First Nation v. Canada (Minister of Canadian Heritage), 2005 SCC 69.

[80] Newfoundland and Labrador v. Labrador Métis Nation, 2007 NCLA 75; leave to appeal to SCC refused Docket 32468 (May 29, 2008), 2008 CanLII 32711 (SCC).

[81] Rio Tinto Alcan Inc. v. Carrier Sekani Tribal Council, 2010 SCC 43.

[82] Haida Nation, ibid; Chippewas of the Thames First Nation *v.* Enbridge Pipelines Inc., 2017 SCC 41; Clyde River (Hamlet) v. Petroleum Geo-Services Inc., 2017 SCC 40.

324. The Commission is a provincial administrative tribunal and regulatory agency that serves as the final decision maker for applications to construct and operate transmission lines in Alberta. Although the Commission is an independent agency and is not the Crown or an agent of the Crown, it carries out functions, and exercises executive powers, that are authorized by the legislature.

325. In some situations, in addition to triggering the obligation to hold a hearing under Section 9(2) of the *Alberta Utilities Commission Act*, an application before the Commission may trigger the Crown's duty to consult with Indigenous peoples. Crown conduct sufficient to trigger the duty to consult can include the decisions of an independent administrative tribunal such as the Commission, notwithstanding that it is not itself the Crown.

326. Where the duty to consult is triggered, the Crown may rely on steps undertaken by a regulatory agency to fulfil the duty, provided that the regulatory agency has the necessary statutory powers and duties to provide an appropriate level of consultation and, where required, accommodation. Under its constating legislation, the Commission has broad powers that enable it to require applicants to notify or consult with potentially affected stakeholders, to hold hearings, to order the production of information, to impose conditions on applicants, and to provide participant funding. For these reasons, the government of Alberta has confirmed that where the duty to consult is triggered by an application before the Commission, the government of Alberta will rely on the Commission's process to address potential impacts to Aboriginal and treaty rights. The Commission is committed to ensuring that its processes and decisions uphold Section 35.

5.2.7.2 Triggering of the duty and adequacy of consultation

327. The MNA requested that the Commission confirm that AltaLink's and ATCO's applications triggered the duty to consult the MNA on behalf of the North Saskatchewan Regional Métis Community, and describe the extent of that duty.[83]

328. The Commission is satisfied that its decision on the applications before it in this proceeding amounts to conduct that may adversely affect the exercise of Métis harvesting or traditional cultural practices in the project area. The MNA has demonstrated that portions of the project are located within or in close proximity to lands, in particular Crown lands, that are frequented or travelled by MNA members for the purpose of harvesting or for traditional cultural practices, and that there may be some impact to those activities by the CETO project, for example, reduced access during construction. The Commission therefore finds that the duty to consult is triggered as it relates to Métis, as represented by the MNA.

329. As discussed in more detail below in Section 5.2.7.3 - Métis harvesting and traditional land use, the Commission considers that the CETO project will result in a relatively minor infringement on the exercise of Aboriginal rights by MNA members in the project area. Accordingly, it finds that the content of the Crown's duty of consultation in relation to the CETO project lies at the lower end of the spectrum, and that the consultation with the MNA was reasonable and fulfilled the duty.

330. While the MNA submitted that it was excluded from meaningful pre-application engagement, resulting in it "being pitted against AltaLink and ATCO in an adversarial process

[83] Transcript, Volume 20, PDF page 116, lines 12-2.

that did nothing to foster good faith discussions to resolve its concerns,"[84] the Commission finds that the MNA was adequately informed of the project and had an opportunity to voice its concerns and be heard.

331. The Commission considers that the MNA became aware of the CETO project as early as March 1, 2019, when it received correspondence from AltaLink on the CETO project and a request for feedback.[85] Between providing the MNA with pre-application materials and the filing of the CETO facility applications in September 2020, AltaLink undertook site visits and provided capacity funding to MNA Region 3 and MNA Region 4 to assist with identifying sites of historical and cultural significance to the MNA.[86] AltaLink responded to the concerns identified by the MNA and mitigation measures proposed in the traditional land use assessment reports, which included eliminating a route option from consideration.[87]

332. While ATCO did not engage with the MNA prior to filing its applications, the Commission is satisfied that since the filing of the MNA's statement of intent to participate, ATCO has sought to identify and understand the MNA's concerns outside of the AUC proceeding process. This is reflected by engagement records detailing 18 separate communications exchanged with the MNA outside the proceeding between December 18, 2020, and March 16, 2021 that included numerous emails, a virtual meeting, a virtual route tour, and written correspondence.[88]

333. In addition, the project materials initially provided to the MNA by AltaLink in March 2019 specified two distinct route segments: one to be constructed by AltaLink and another by ATCO.[89] The Commission considers that the MNA was made aware of the CETO project as early as March 2019, including ATCO's portion of the route.

334. In its submissions, the MNA described the AUC hearing process as "unnecessarily burdensome."[90] In this regard, the Commission considers that its process provided the MNA with adequate opportunity to participate as an intervener in the proceeding: the Commission gave the MNA direct notice of the proposed CETO project on October 13, 2020; granted it standing to participate in the proceeding on November 20, 2020; and, represented by legal counsel, the MNA formally participated in the Commission's process, including issuing and responding to information requests, filing evidence and participating in a virtual oral hearing in which it had an opportunity to give direct evidence, cross-examine and present final argument. Participant funding was also available to the MNA through Rule 009: *Rules on Local Intervener Costs*. Finally, as a result of the MNA's participation in the proceeding, both AltaLink and ATCO committed to additional mitigation measures (described in detail in sections 5.2.7.3 and 5.2.7.4) to accommodate the MNA's specific concerns.

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84 Transcript, Volume 20, PDF pages 114 and 115, lines 22-2.
85 Exhibit 25469-X0291, AML CETO – Appendix J Indigenous Relations (J-1 to J-4), PDF pages 16-23; Exhibit 25469-X0292, AML CETO – Appendix J Indigenous Relations (J-5).
86 Exhibit 25469-X0525, AML IR Responses to MNA, PDF page 6; Transcript, Volume 21, PDF pages 12 and 13, lines 23-4.
87 Exhibit 25469-X0263, AML Central East Transfer-Out Application, PDF pages 172-177.
88 Transcript Vol. 21, PDF page 51, lines 16-24; Exhibit 25469-X0767.01, ATCO Reply Evidence, PDF pages 101-103.
89 Exhibit 25469-X0291, AML CETO – Appendix J Indigenous Relations (J1-J4), PDF pages 16-23; Exhibit 25469-X0292, AML CETO – Appendix J Indigenous Relations (J-5).
90 MNA Oral Argument, PDF page 2, paragraph 7.

5.2.7.3 Métis harvesting and traditional land use

335. The proposed CETO project is within Harvesting Area D as defined in Alberta's *Métis Harvesting in Alberta Policy (2018)* and the *Métis Harvesting Agreement*. The MNA submitted that its citizens use the project area to exercise rights-related activities including hunting, trapping, fishing, gathering, camping, travelling and spirituality, and that these activities take place on both Crown and private lands.[91] The MNA expressed a concern that the CETO project would create a number of conditions that make the areas adjacent to it less desirable to MNA members for exercising harvesting rights and engaging in traditional land uses, and would result in decreased Métis harvesting and traditional land use in the area.[92] The conditions of concern include herbicide application, electromagnetic fields, mechanical clearing, construction runoff, construction vehicles and grubbing activities, which lead to avoidance behaviors for MNA citizens.[93]

336. The MNA identified 11 parcels of Crown and private land in proximity to the proposed project as being used for a variety of traditional land use purposes.[94] Of these 11 parcels, there is one Crown land parcel that would be traversed by the AltaLink South Alternative route, and five privately-owned land parcels that would be affected by the ATCO preferred Route A and Route Option ABC.

337. The MNA identified Crown land at Section 11, Township 39, Range 23, west of the Fourth Meridian as a parcel of interest. That parcel would be traversed by AltaLink's approved South Alternate route, which would be located along the entire south edge within the registered roadway for Highway 11, except for two structures to be set 30 metres farther north at the east edge of that section to accommodate future highway intersection improvement. The parcel is bordered on the east by Highway 601, and it is subject to a grazing lease, fenced with a locked gate, and contains a railway and eight well sites. While AltaLink acknowledged that access to some areas of the right-of-way and workspace will be restricted due to construction activities, it confirmed that it would not restrict use of the remainder of Section 11, Township 39, Range 23, west of the Fourth Meridian during construction.[95] AltaLink also confirmed that following completion of construction, MNA members would still be able to use AltaLink's right-of-way in this area.

338. Neither segment of the approved ATCO preferred Route A and Route Option ABC traverses Crown land. The MNA indicated that its members use, for traditional purposes, five privately-owned quarter sections of land that are traversed by this route.[96] ATCO noted that these privately-owned lands contain existing industrial, residential, or agricultural disturbances including a residence, transmission lines, a distribution line and pipelines. ATCO also reported

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[91] Exhibit 25469-X0646, MNA MNP CETO Evaluation Report Part 1 of 2 – Sections 1-4.2.5.
[92] MNA Closing Argument, PDF page 10, line 51.
[93] Transcript, Volume 20, PDF page 108, lines 4-24.
[94] Exhibit 25469-X0747, MNA Response to AUC Information Requests and Appendix A-B – Part 1 of 2 (12 March 2021); Exhibit 25469-X0748, MNA Response to AUC Information Requests Appendix C – Part 2 of 2 (12 March 2021).
[95] Exhibit 25469-X0759, AML Reply Evidence, PDF page 54, paragraph 199.
[96] NW 35-39-15-W4M, NW 20-39-21-W4M, NE 19-39-21-W4M, and NW and SW 13-39-22-W4M as indicated in Exhibit 25469-767.01, PDF pages 105-107.

that no traditional land use was identified by any landowners or occupants during the consultation process.[97]

339. Based on the characteristics of the parcels identified by the MNA as areas of interest and the project area in general, the Commission considers that any impact of the approved project on Métis harvesting and traditional land use will be minimal, temporary in nature and can be reasonably mitigated. Both the AltaLink and ATCO approved routes follow existing linear disturbances for significant portions of their length, which is consistent with the MNA's expressed preference for a route that prioritizes avoiding Crown and undisturbed land. Also consistent with the MNA's expressed preference, construction schedules for both TFOs contemplate winter construction to minimize environmental impact. The Commission encourages AltaLink and ATCO to engage with the MNA to further mitigate impacts should winter construction not be possible.[98] It is also satisfied that the environmental effects of the project can be mitigated to a reasonable degree if the TFOs adhere to the commitments discussed in Section 5.2.3. Lastly, both TFOs confirmed that once construction is complete, neither will restrict public access to the right-of-way.[99]

340. Throughout the proceeding, the Commission sought to better understand the MNA's site-specific concerns and the potential site-specific impacts of the CETO project on the exercise of Métis rights. While the MNA identified 11 parcels of interest in the project area that it stated were utilized by as many as six anonymous survey respondents who are members of the MNA, this information did not contain the level of specificity required for the Commission to develop a deeper understanding of specific sites, within the identified parcels, that MNA members utilize, how and when they are used, how they are accessed, whether there is suitable land available nearby for the same or similar purpose, and how the CETO project might affect their use of the lands and the continued exercise of their Section 35 rights.

341. Furthermore, the MNA witnesses who compiled information from MNA members were not traditional land users themselves and were unable to answer questions about site-specific uses and impacts posed by Commission counsel during the hearing.[100] The limited evidence submitted by the MNA in this regard contributed to the Commission's assessment that the CETO project will result in a relatively minor infringement on the exercise of Aboriginal rights by MNA members in the project area and its finding that the scope of consultation lies on the lower end of the spectrum.

342. The MNA submitted that proceeding timelines, coupled with constraints imposed by the COVID-19 pandemic, severely limited what information it could collect.[101] The Commission does not accept that these factors account entirely for the MNA's failure to provide more detailed information to support its intervention in this proceeding. As stated earlier, the MNA became aware of the CETO project as early as March 2019 and was granted standing to participate in the proceeding on November 20, 2020. The deadline for intervener written evidence was February 17, 2021. The Commission therefore considers that the MNA had sufficient time to

97 Exhibit 25469-X0767.01, ATCO Reply Evidence, PDF page 101, paragraph 448.
98 Transcript Volume 19, PDF page 33, lines 15-21; Exhibit 25469-X0216.01, Atch-1_CETO Project_Application Text, PDF page 17, paragraph 72.
99 Exhibit 25469-X0767.01, ATCO Reply Evidence, PDF page 108, paragraph 462; Exhibit 25469-X0759, AML Reply Evidence, PDF page 54, paragraph 199.
100 Transcript, Volume 14, PDF pages 60-64.
101 Transcript, Volume 20, PDF page 115, lines 3-9.

co-ordinate with at least one Métis traditional land user prior to filing its evidence or to seat a Métis traditional land user as a witness during the virtual oral hearing that commenced on April 14, 2021.

343. The MNA requested that the Commission impose the following conditions on the CETO project pertaining to traditional land use:[102]

- That ATCO and AltaLink be required to provide notice of construction activities to the MNA in any areas identified as being important to the MNA, and that, where reasonably possible, ATCO and AltaLink work with the MNA to accommodate traditional uses during construction.
- That ATCO and AltaLink be required to provide resources to the MNA so that it may deliver independent information sessions to address its members' concerns with the potential impacts of the CETO project.

344. Both AltaLink and ATCO made commitments to provide notice of construction activities and accommodate traditional land uses during scheduled construction. AltaLink committed to providing the MNA with construction updates to mitigate access concerns and to allow harvesting of traditional plants on the right-of-way outside of construction windows.[103] It also committed to ongoing consultation with the MNA and working with the MNA should new issues arise.[104] ATCO committed to providing the MNA with advance notice of its construction schedule and to work with the MNA to accommodate traditional land uses during construction.[105]

345. The Commission considers that the commitments made by AltaLink and ATCO are reasonable and responsive to the MNA's concerns around construction notification and accommodating traditional land uses during construction. The Commission expects the applicants to follow through with these commitments, as required under Rule 007, and does not find it necessary to include these commitments as conditions of approval.

346. Concerning the provision of funding for independent information sessions, ATCO agreed to support an information session by providing its in-house professionals.[106] AltaLink did not make a similar commitment. Although the Commission considers the facilitation of general transmission line education for Métis membership to be a worthwhile endeavor, it does not consider this to be the sole responsibility of the facility applicants in this proceeding, nor an activity whose benefit would be confined to the CETO project. While the Commission expects ATCO to follow through on its commitment to make in-house professionals available to attend a session if requested by the MNA, it does not consider that providing funding to procure an independent third party to host information sessions to be a necessary condition of approval.

347. The Commission is satisfied that MNA members use the project area for harvesting and other traditional land uses. That said, it does not expect the CETO project to significantly alter the current conditions in the project area or result in incremental avoidance behaviors among MNA harvesters in any significant way. The approved route follows existing linear disturbances

[102] Transcript, Volume 20, PDF pages 117 and 118.
[103] Exhibit 25469-X0525, AML IR Responses to MNA, PDF page 7.
[104] Transcript, Volume 19, PDF page 34, lines 17-22.
[105] Exhibit 25469-X0767.01, ATCO Reply Evidence, PDF page 112, paragraph 484.
[106] Exhibit 25469-X0767.01, ATCO Reply Evidence, PDF page 119, paragraph 527.

for a significant length and minimizes impact to Crown and previously undisturbed lands. The project will also have minimal environmental impact as discussed in sections 5.2.3 and 5.2.4, is expected to comply with the applicable requirements for noise and is not expected to result in significant changes to electromagnetic field levels.

348. The Commission recognizes that there may be some temporary access restrictions to certain portions of the right-of-way during project construction, however, these restrictions will be temporary and the impacts on MNA members will be reasonably mitigated by the commitments made by AltaLink and ATCO related to notification of construction and accommodating traditional land use. Similarly, the Commission finds that any impact to long term traditional land uses will be minimal and reasonably mitigated by winter construction, engaging with the MNA to mitigate impacts should winter construction not be possible, and allowing right-of-way access once construction is complete.

5.2.7.4 Métis historical resources

349. The MNA raised concerns about potential impacts to unknown archaeological sites in the Tail Creek area. It filed evidence about the potential to encounter archaeological sites in that area that are connected to the historical Métis community around Buffalo Lake.[107] Although the MNA recognized the role of Alberta Culture and Status of Women[108] (ACMSW) under the *Historical Resources Act* as it relates to historical resources, it submitted that archaeologists are not trained to recognize Métis historical sites.[109] The MNA further submitted that potential adverse impacts of the CETO project on Métis historical resources would not be fully mitigated by winter construction, given that construction in any season will cause some ground-breaking and that ground-breaking has the potential to disturb or destroy historical resources.[110] The MNA requested that the Commission impose the following four conditions to address Métis historical resources in the project area:[111]

- That a Métis cultural heritage monitor trained by the MNA be present during all activities undertaken in the Tail Creek area, including in and around the historical cart trails identified in the affidavit of Kisha Supernant.
- That AltaLink and ATCO be required to develop protocols with the MNA for notifying the MNA if potential Métis historical resources are discovered in the project area.
- That AltaLink and ATCO be required to consult with the MNA with a view to agreeing on reasonable mitigation measures if potential Métis historical resources are discovered in the project area.
- Alternatively, the MNA requested that Route Option ABC be chosen so that Métis cultural heritage resources at Tail Creek will be protected by ATCO's commitments.

350. The Commission acknowledges the authority of ACMSW in relation to historical resources pursuant to the *Historical Resources Act* and considers that the Commission's discretion and authority in such matters is limited. Based on the approved route, Tail Creek will

[107] Exhibit 25469-X0627, Affidavit of Kisha Supernant.
[108] Formally know as Alberta Culture, Multiculturalism and Status of Women.
[109] Transcript, Volume 14, PDF pages 65 and 66, lines 7-10; Transcript, Volume 20, PDF page 120, lines 2-8.
[110] Transcript, Volume 20, PDF pages 112 and 113, lines 21-2.
[111] Transcript, Volume 20, PDF pages 119-122.

be crossed by a segment of ATCO's Route Option ABC. ATCO has committed to contacting ACMSW to include the Tail Creek crossing in the project's historical resource impact assessment. The Commission will not impose alternative or additional requirements for the protection of historic resources; doing so would be beyond the Commission's jurisdiction and would constitute an unwarranted intrusion on ACMSW's expertise and authority.

351. Notwithstanding the above, the Commission acknowledges that ATCO has committed to having a Métis cultural heritage monitor on-site at the Tail Creek crossing and to notifying the MNA if Métis historical resources are discovered in the project area, in accordance with the applicable law and as permitted by the historical resources regulator. ATCO has also committed, to the extent allowed by provincial law, to engage with the MNA regarding reasonable mitigation measures in the event that a Métis historical resource is discovered.[112] As stated above, AltaLink has likewise committed to ongoing consultation with the MNA and working with the MNA should new issues arise. The Commission considers these commitments to be reasonably responsive to the MNA's concerns regarding unknown historical resources, both around Tail Creek and in the project area generally, and expects AltaLink and ATCO to uphold their respective commitments to the MNA in this regard, or otherwise follow the directions given by ACMSW.

5.2.8 Participant involvement program

352. Many interveners expressed concerns that the consultation undertaken by either AltaLink or ATCO was inadequate; some reported that a concern was incorrectly transcribed into the consultation record or that a response to a concern was insufficient.

353. AltaLink stated that stakeholders are mailed consultation records for review and for an opportunity to correct any errors and that its participant involvement program, conducted to inform stakeholders of the project, gives them an opportunity to raise concerns, ask questions, provide site-specific feedback and options for how AltaLink can mitigate their concerns. In response to an information request from the Commission, AltaLink provided a list of commitments it made to stakeholders.

354. ATCO indicated that it undertook a comprehensive participant involvement program, made proactive efforts to promote both an understanding of the project and the route selection process, and further, that consultation feedback affected its routing decisions. ATCO reviewed the evidence filed by interveners and responded to each intervener concern with consultation in its reply evidence. It submitted that it is not possible to address each and every concern raised by a stakeholder and that its participant involvement program was satisfactory in meeting the requirements of Rule 007.

355. The Commission finds that the participant involvement programs undertaken by ATCO and AltaLink meet the requirements of Rule 007. The Commission recognizes that many stakeholders had concerns about the participant involvement program for the proposed transmission line. The Commission is of the view, however, that the participant involvement programs were sufficient to communicate to potentially affected parties the nature, details and potential impacts of the project. It is also satisfied that the participant involvement programs gave potentially affected parties an opportunity to ask questions and to express their concerns.

[112] Exhibit 25469-X0767.01, ATCO Reply Evidence, PDF pages 117 and 118, paragraphs 516-521.

6 Erosion around the Tinchebray 972S Substation area

356. Brian Perreault's land is located immediately east and south of the Tinchebray 972S Substation. B. Perreault asserted that since its construction, the Tinchebray 972S Substation has significantly changed the drainage patterns on his lands, resulting in washout, erosion and flooding. He also stated that access to significant portions of his land has been lost.

357. B. Perreault submitted that since the construction of the Tinchebray 972S Substation and Halkirk transmission lines, he has attempted to work with ATCO to develop solutions to address his concerns, however, ATCO has not taken responsibility for, nor repaired the damage caused to his lands. He added that ATCO is not in compliance with its existing *Water Act* licence, as demonstrated by the recurrent flooding on his land. B. Perreault wishes to understand how ATCO intends to address the problems associated with the Tinchebray 972S Substation before it is allowed further access to his lands to expand the Tinchebray 972S Substation. B. Perreault retained Craig Felzien to prepare a field assessment report and provide commentary on ATCO's reports and drainage plans.

358. Notwithstanding ATCO's view that much of B. Perreault's drainage concerns are outside the scope of this proceeding, it submitted evidence in response to his concerns. ATCO retained Golder and Stantec to evaluate the drainage of the land and identify potential solutions to address B. Perreault's concerns. In its report, Stantec concluded that the coulees around the substation are in an area susceptible to significant groundwater elevation variability and that groundwater plays a contributing role to the observed erosion.

359. ATCO submitted that the expansion of the substation's footprint in Stage 2 of the CETO project presented an opportunity to redesign the drainage plan to address existing erosion issues and develop a new stormwater management plan. ATCO submitted revised drainage plans to address the flooding around the substation, committed to repairing erosion on parts of B. Perreault's land and installed temporary erosion control measures.

360. B. Perreault and C. Felzien disagreed that ATCO's redesigned drainage plan will prevent further erosion. They stated that water on the ATCO and adjacent Jackson lands has to be slowed down and stored for a period of time to attenuate the volume and velocity of the flow that is causing the erosion. B. Perreault submitted that the substation expansion should not be permitted until past erosion issues have been addressed and there is sufficient confidence that the new drainage plan will prevent further erosion when the substation is expanded.

361. ATCO submitted that the Commission does not have to adjudicate ATCO's compliance with its existing *Water Act* licences or new drainage designs in the CETO proceeding as both are out of scope. ATCO stated that it has provided B. Perreault with conceptual plans, revised site drainage plans and has agreed to provide a copy of its *Water Act* application for his review prior to submitting it to AEP.

6.1.1 Jurisdiction

362. B. Perreault submitted that the Commission should consider the public interest of approving the expansion of the substation before past impacts have been addressed. He stated that the Commission is the regulatory body responsible for ensuring that impacts of utility projects on their neighbours are mitigated.

363. ATCO submitted that in considering the public interest, the Commission can consider the impacts of a utility project on neighbouring landowners and that it has demonstrated that the Tinchebray 972S Substation expansion has been designed to limit impacts to neighbouring properties, including B. Perreault's. ATCO submitted that reclamation is addressed in its right-of-way agreement with B. Perreault and provides that any disagreement related to compensation for damages may be submitted to the Surface Rights Board (SRB) and, if outside the SRB's jurisdiction, then arbitration. ATCO submitted that approval of the final drainage design and any amendments thereto are properly within the jurisdiction of AEP and outside the scope of AUC approval in this proceeding. ATCO stated that AEP has both the legislative authority and the technical expertise to adjudicate ATCO's existing *Water Act* licence and *Water Act* application, and to address B. Perreault's concerns therewith, within its regulatory processes.

364. B. Perreault submitted that because the erosion from the water coming from the substation site is not subject to ATCO's right-of-way agreement, there is no arbitration clause or other means of claiming for erosion damages other than from the Commission. He argued that in *Fort McKay First Nation v Prosper Petroleum Ltd.* (Prosper),[113] the Court of Appeal of Alberta cautioned tribunals like the AUC not to narrow the scope of their considerations during decision making or rely on other decision makers to address the matters before them.

365. ATCO submitted that in *Prosper*, the court was clear that a statutory decision-maker must operate within the bounds of its legislative jurisdiction. In discharging its public interest mandate, the Commission is entitled to rely on AEP's jurisdiction and process under the *Water Act* in considering whether B. Perreault's concerns regarding drainage will be appropriately addressed.

366. ATCO submitted that the new drainage design is subject to approval by AEP under the *Water Act* and that the appropriate drainage design will ultimately be determined by AEP through a process that B. Perreault can participate in.

6.1.1.1 Findings

367. Most of the evidence associated with B. Perreault's concerns dealt with erosion observed after the completion of the previously approved Halkirk transmission project which included the construction of the Tinchebray 972S Substation.[114] B. Perreault submitted erosion reports of the substation lands and his lands, updated drainage plans, and critiques of those plans. Although as discussed below the Commission acknowledges that B. Perreault was invited to participate in this process to address his outstanding complaint, it finds that this evidence does not assist it in deciding whether approval of the CETO project is in the public interest, or which routes have the lowest overall impacts. While Stage 2 of the CETO project, if approved, requires the expansion of the Tinchebray 972S Substation, the approval of future drainage design is beyond the scope of the applied-for expansion.

368. The Commission considers that AEP is the appropriate regulator to address the alleged erosion caused by surface water runoff from the substation lands and the claim that ATCO is not

113 2020, ABCA, 163.
114 Halkirk Wind Energy Connection, Proceeding 1092, Applications 1607024-1 and 1607065-1 to 1607065-5, February 28, 2012.

operating in compliance with its *Water Act* licence, because these issues relate directly to a license issued under AEP authority. In addition, it would be inappropriate to condition an approval on matters not directly related to the application before it.

369. Likewise, the Commission is not in a position to review or approve future drainage plans for the Tinchebray 972S Substation site. It agrees with ATCO that AEP has both the legislative authority and the technical expertise to adjudicate this issue under the *Water Act*.

370. While the Commission recognizes that B. Perreault's concerns have gone unresolved for some time, it also recognizes that ATCO has considered his concerns and has attempted to work with B. Perreault throughout the CETO proceeding. ATCO has acknowledged that some erosion was caused by changes to the land when the Tinchebray 972S Substation was constructed and has committed to repairing this erosion. While B. Perreault did not indicate his support of ATCO's proposed mitigation measures, it appears to the Commission that his participation in the CETO process has assisted him in reaching some resolution with ATCO, including ATCO expediting some of its repairs. As described in more detail below, other avenues exist for B. Perreault to have his concerns addressed, including AEP's *Water Act* amendment process in which he will have an opportunity to participate.

6.1.2 Brian Perreault's request for adjournment and additional reclamation

371. Brian Perreault requested that the Commission adjourn ATCO's application to expand the Tinchebray 972S Substation until he has had meaningful engagement with ATCO regarding the current erosion damage from the existing site and that the proposed changes in drainage design have been considered within a defined AUC process.

372. ATCO submitted that it is not aware of any precedent that would support holding ATCO's application in abeyance pending the outcome of a separate regulatory process and that such a request is not properly before the Commission.

373. B. Perreault also requested that the damage to his land resulting from the Tinchebray 972S Substation be repaired prior to any substation expansion occurring. B. Perreault stated that the Commission should not issue an approval for the expansion of the Tinchebray 972S Substation until the matter has either been resolved between the parties or AEP has made a decision on the water licence amendment. ATCO submitted that this request was not appropriate because it gives B. Perreault control over the development of the substation as access to his land must be granted for repairs to occur. In addition, ATCO indicated it was not aware of any defined process that the Commission could order to consider the proposed changes to the drainage design.

374. B. Perreault requested that at a minimum, ATCO build two cattle/wildlife crossings and remediate the erosion after the first cattle/wildlife crossing to allow him to regain access to his land. Although ATCO did not commit to constructing the cattle/wildlife crossings, to address B. Perreault's erosion concerns, ATCO installed temporary erosion control measures in March 2021, prior to the yearly spring runoff, and plans to complete drainage civil engineering work in 2021. ATCO submitted that it has made an ongoing effort to work with B. Perreault to complete reclamation activities. It anticipates that outstanding reclamation work will be completed this year, if B. Perreault is willing to provide access to his lands and ATCO is permitted to erect temporary fencing to keep livestock out of the areas in question.

6.1.2.1 Findings

375. The Commission denies B. Perreault's request to adjourn its consideration of the Tinchebray 972S Substation expansion until meaningful engagement with ATCO has occurred. Such a condition is not sufficiently measurable or enforceable to properly form a condition of approval. In addition, it is AEP and not the Commission that has the expertise and jurisdiction to assess the current erosion damage from the existing site and the proposed changes to the drainage design. The Commission agrees with ATCO that it is inappropriate and unnecessary for the Commission to place this proceeding in abeyance pending the outcome of AEP's process.

376. The Commission also finds that it is unnecessary to withhold approval of the substation expansion until damage to B. Perreault's land has been repaired. It is satisfied with ATCO's commitment to repair erosion damage on B. Perreault's land, and observes that this work is anticipated to be completed in 2021, well before the substation site is expanded. The Commission agrees that conditioning the substation expansion on such repair work being completed would give B. Perreault control over the substation development and is unnecessary. It expects ATCO to honour its commitment to repair the damage on B. Perreault's land. The Commission does not consider it appropriate to impose a condition requiring that ATCO build two cattle/wildlife crossings nor one to repair damage on the Perreault lands, because the erosion is not associated with the components of the CETO project. It encourages ATCO and B. Perreault to continue to work together in reaching a solution that is agreeable to all parties, either directly or through the AEP process.

377. The Commission acknowledges that erosion has taken place on B. Perreault's land and that it may be associated with the initial construction of ATCO's Tinchebray 972S Substation. It also recognizes that B. Perreault has an outstanding complaint with the Commission's Market Oversight and Enforcement group that was placed in abeyance with a recommendation that he participate in this proceeding. However, the Commission's process to consider the applications in this proceeding is limited to consideration of the developments applied for and their associated impacts; it is unable to consider the technical development of the drainage design because this matter is beyond its jurisdiction. The appropriate drainage design will ultimately be determined by AEP, the *Water Act* regulator, in a process that B. Perreault can participate in. The Commission considers that B. Perreault may challenge ATCO's compliance with its *Water Act* licence or test its drainage plan through that process. Should B. Perreault be dissatisfied with the outcome of the AEP process and unable to reach a resolution with ATCO, he may file a complaint with AEP or reopen the Commission's Market Oversight and Enforcement proceeding, currently held in abeyance.

7 Conclusion

378. In summary, the Commission finds AltaLink's South Alternate route to have the lowest overall impact and its approval to be in the public interest. The South Alternate route, consisting of the alternate Gaetz to C31 segment, preferred D25 to F70 segment from point C31 to point F70, and the Highway 11 and ATCO segment,[115] parallels existing linear disturbances, and has low residential and agricultural impacts compared to the other routes.

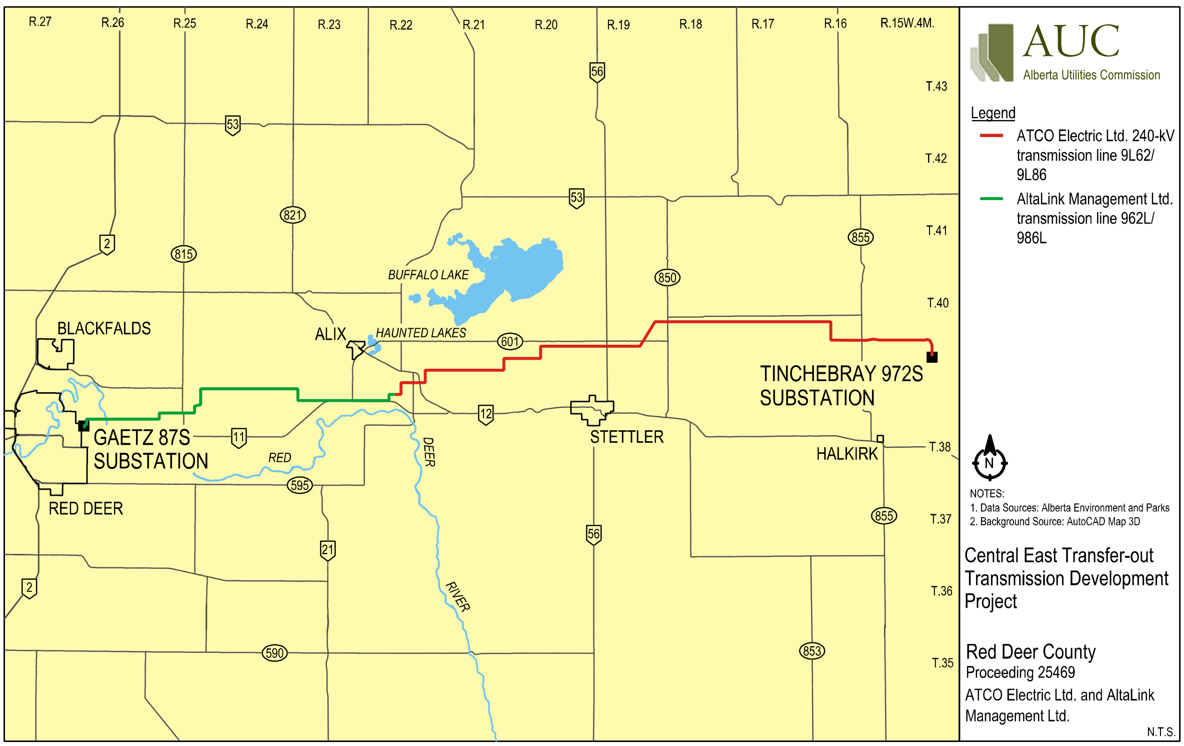
[115] AltaLink's "ATCO segment" and ATCO's "Route Option ABC" refer to the same route segment, ATCO will construct and operate this segment.

379. The Commission finds ATCO's Route A to have a lower overall impact than Route C and its approval to be in the public interest. Route A follows existing linear disturbances for much of its route and has lower residential impacts, especially when considering the newly-exposed metric.

380. The Commission finds construction of ATCO's Route Option ABC[116] to be required to connect the ATCO and AltaLink transmission lines. This route has low residential impacts and was unopposed.

381. The approved route of the Central East Transfer-out Transmission Development Project is depicted in the following figure.

Figure 13. Approved route of the Central East Transfer-out Transmission Development Project



382. In conclusion, for the reasons stated and subject to all of the conditions outlined in Section 8, the Commission approves the applications submitted by the Alberta Electric System Operator, ATCO Electric Ltd. and AltaLink Management Ltd. The AESO's NID application contains all of the information required by the *Electric Utilities Act*, the *Transmission Regulation* and Rule 007. The Commission finds that pursuant to Section 38 of the *Transmission Regulation*, no interested person has demonstrated that the AESO's assessment of the need is technically deficient or that approval of the NID would not be in the public interest.

383. The Commission is likewise satisfied that the ATCO and AltaLink facility applications meet the requirements of Rules 007 and 012 and that approval of the project is in the public

116 Ibid.

interest having regard to the social, economic, and other effects of the project, including its effect on the environment, in accordance with Section 17 of the *Alberta Utilities Commission Act*.

384. As set out earlier in this decision, the Commission approved the AESO's Option 1 of its proposed transmission development, the construction milestones and the proposed staging (Configuration 1). The TFOs shall, upon direction from the AESO and the Commission that the construction milestones have been reached, begin construction of the project. In Stage 1, the TFOs shall construct double-circuit structures with conductors strung on both sides. The conductors will be tied together as transmission lines 9L62 and 962L. The Gaetz 87S and Tinchebray 972S substations shall be altered as proposed by the TFOs in Stage 1.

385. In Stage 2, the transmission lines will be untied and energized as separate transmission lines 9L62/962L and 9L86/986L. ATCO shall alter existing Transmission Line 9L16 to terminate at a new tie-in location to accommodate the untied conductor. The TFOs shall alter their respective substations as applied for in the Stage 2 development.

8 Conditions of approval

386. The Commission imposes the following conditions of approval for the CETO project. Conditions that require subsequent filings with the Commission will be tracked as directions in the AUC's eFiling System.

(a) Conditions of Needs Identification Document Approval 25469-D02-2021 that require subsequent filings with the Commission by the Alberta Electric System Operator:

- The AESO shall, on a yearly basis at a minimum, determine and inform the Commission whether a reaffirmation study is warranted based on the incremental generation volumes that have met the AESO's certainty criteria.

- A reaffirmation study report determined to be warranted by the AESO shall be filed with the Commission and indicate whether the congestion assessments confirm that congestion is forecast to occur greater than 0.5 per cent of the time annually or whether an increased milestone monitoring range of incremental generation can be accommodated.

- If Stage 1 of the Central East Transfer-out Transmission Development Project listed above is not in service by December 31, 2025, the AESO must inform the Commission whether the need to expand or enhance the transmission system as approved remains and whether the technical solution approved continues to be the AESO's preferred technical solution.

- If Stage 2 of the Central East Transfer-out Transmission Development Project listed above is not in service by December 31, 2030, the AESO must inform the Commission whether the need to expand or enhance the transmission system as approved remains and whether the technical solution approved continues to be the AESO's preferred technical solution.

(b) Conditions of Needs Identification Document Approval 25469-D02-2021 that do not require subsequent filings with the Commission by the Alberta Electric System Operator:

- Construction of the development at each stage cannot commence until confirmation from the AESO and the Commission that the construction milestone for each stage, as defined in the AESO's needs identification document application for Central East Transfer-out Transmission Development approved by the Commission in Proceeding 25469, has been met.

(c) Conditions that will be included in Permit and Licence 25469-D03-2021 and Permit and Licence 25469-D04-2021, and require subsequent filings with the Commission by ATCO Electric Ltd.:

- ATCO shall submit an updated version of its project-specific environmental protection plan, which includes a snake protection protocol, at least 60 days prior to the start of construction in Stage 1.

- ATCO shall submit an updated version of its project-specific environmental protection plan, which includes a snake protection protocol, at least 60 days prior to the start of construction to decouple the transmission lines in Stage 2.

(d) Conditions that do not require subsequent filings with the Commission by ATCO Electric Ltd.:

- The commencement of construction of Transmission Line 9L62 is conditional upon receipt by ATCO of confirmation from the Alberta Electric System Operator (AESO) and the Commission that the construction milestone for Stage 1, as defined in the AESO's needs identification document application for the Central East Transfer-out Transmission Development Project approved by the Commission in Proceeding 25469, has been met.

- The commencement of construction of Transmission Line 9L86 is conditional upon receipt by ATCO of confirmation from the Alberta Electric System Operator (AESO) and the Commission that the construction milestone for Stage 1 as defined in the AESO's needs identification document application for the Central East Transfer-out Transmission Development Project approved by the Commission in Proceeding 25469, has been met.

- The alteration of Transmission Line 9L16 is conditional upon ATCO receiving confirmation from the Alberta Electric System Operator (AESO) and the Commission that the construction milestone for Stage 2, as defined in the AESO's needs identification document application for the Central East Transfer-out Transmission Development Project approved by the Commission in Proceeding 25469, has been met.

- ATCO shall have received formal notice from the AESO and the Commission that the construction milestone for Stage 1 as set out in the AESO's NID has been met, prior to commencing Stage 1 alteration of the Tinchebray 972S Substation.

- ATCO shall have received formal notice from the AESO and the Commission that the construction milestone for Stage 2 as set out in the AESO's NID has been met, prior to commencing Stage 2 alteration of the Tinchebray 972S Substation.

(e) Conditions that will be included in Permit and Licence 25469-D07-2021 and Permit and Licence 25469-D08-2021 and require subsequent filings with the Commission by AltaLink Management Ltd.:

- AltaLink shall submit an updated version of its project-specific environmental protection plan, which includes a snake protection protocol, at least 60 days prior to the start of construction in Stage 1.

- AltaLink shall submit an updated version of its project-specific environmental protection plan, which includes a snake protection protocol, at least 60 days prior to the start of construction to decouple the transmission lines in Stage 2.

(f) Conditions that do not require subsequent filings with the Commission by AltaLink Management Ltd:

- The commencement of construction of Transmission Line 962L is conditional upon receipt by AltaLink of confirmation from the Alberta Electric System Operator (AESO) and the Commission that the construction milestone for Stage 1, as defined in the AESO's needs identification document application for Central East Transfer-out Transmission Development approved by the Commission in Proceeding 25469, has been met.

- The commencement of construction of Transmission Line 986L is conditional upon receipt by AltaLink of confirmation from the Alberta Electric System Operator (AESO) and the Commission that the construction milestone for Stage 1, as defined in the AESO's needs identification document application for the Central East Transfer-out Transmission Development Project approved by the Commission in Proceeding 25469, has been met.

- AltaLink shall have received formal notice from the AESO and the Commission that the construction milestone for Stage 1 as set out in the AESO's NID has been met, prior to commencing Stage 1 alteration of the Gaetz 87S Substation.

- AltaLink shall have received formal notice from the AESO and the Commission that the construction milestone for Stage 2 as set out in the AESO's NID has been met, prior to commencing Stage 2 alteration of the Gaetz 87S Substation.

9 Decision

387. Pursuant to Section 34 of the *Electric Utilities Act*, the Commission approves the need outlined in Needs Identification Document Application 25469-A001 and grants the Alberta Electric System Operator the approval set out in Appendix 1 – Needs Identification Document Approval 25469-D02-2021 – August 10, 2021.

388. Pursuant to sections 14, 15 and 19 of the *Hydro and Electric Energy Act*, the Commission approves Application 25469-A002 and grants ATCO Electric Ltd. the approval set out in Appendix 2 – Transmission Line Permit and Licence 25469-D03-2021 – August 10, 2021, to construct and operate Transmission Line 9L62.

389. Pursuant to sections 14, 15 and 19 of the *Hydro and Electric Energy Act*, the Commission approves Application 25469-A003 and grants ATCO Electric Ltd. the approval set out in Appendix 3 – Transmission Line Permit and Licence 25469-D04-2021 – August 10, 2021, to construct and operate Transmission Line 9L86.

390. Pursuant to sections 14, 15 and 19 of the *Hydro and Electric Energy Act*, the Commission approves Application 25469-A004 and grants ATCO Electric Ltd. the approval set out in Appendix 4 – Transmission Line Permit and Licence 25469-D05-2021 – August 10, 2021, to alter and operate Transmission Line 9L16.

391. Pursuant to sections 14, 15 and 19 of the *Hydro and Electric Energy Act*, the Commission approves Application 25469-A007 and grants ATCO Electric Ltd. the approval set out in Appendix 5 – Substation Permit and Licence 25469-D06-2021 – August 10, 2021, to alter and operate Tinchebray 972S Substation.

392. Pursuant to sections 14, 15 and 19 of the *Hydro and Electric Energy Act*, the Commission approves Application 25469-A009 and grants AltaLink Management Ltd. the approval set out in Appendix 6 – Transmission Line Permit and Licence 25469-D07-2021 – August 10, 2021, to construct and operate Transmission Line 962L.

393. Pursuant to sections 14, 15 and 19 of the *Hydro and Electric Energy Act*, the Commission approves Application 25469-A010 and grants AltaLink Management Ltd. the approval set out in Appendix 7 – Transmission Line Permit and Licence 25469-D08-2021 – August 10, 2021, to construct and operate Transmission Line 986L.

394. Pursuant to sections 14, 15 and 19 of the *Hydro and Electric Energy Act*, the Commission approves Application 25469-A008 and grants AltaLink Management Ltd. the approval set out in Appendix 8 – Substation Permit and Licence 25469-D09-2021 – August 10, 2021, to alter and operate Gaetz 87S Substation.

395. Pursuant to Section 18 of the *Hydro and Electric Energy Act*, the Commission approves Application 25469-A005 and grants ATCO Electric Ltd. the approval set out in Appendix 9 – Connection Order 25469-D10-2021 – August 10, 2021, to connect Transmission Line 9L62 to AltaLink Management Ltd.'s 962L transmission line.

396. Pursuant to Section 18 of the *Hydro and Electric Energy Act*, the Commission approves Application 25469-A006 and grants ATCO Electric Ltd. the approval set out in Appendix 10 – Connection Order 25469-D11-2021 – August 10, 2021, to connect Transmission Line 9L86 to AltaLink Management Ltd.'s 986L transmission line.

Dated on August 10, 2021.

Alberta Utilities Commission

(original signed by)

Anne Michaud
Vice-Chair

(original signed by)

Cairns Price
Commission Member

(original signed by)

Vera Slawinski
Commission Member

Appendix A – Proceeding participants

Name of organization (abbreviation) Name of counsel or representative
Alberta Electric System Operator Brenda Hill Laura Estep
ATCO Electric Ltd. Jeff Sansom Deirdre Sheehan
AltaLink Management Ltd. Zora Lazic Brenden Hunter
Dwayne Felzien
Gerard and Donna Fetaz
Pauline and Darrell Blacklock Nickolas Bailey
J. Heith Johannson Michael Niven
Jason Felzien
Wade Yakelashek Ifeoma Okoye
Doreen Blumhagen
Dean Payne
Neil and Deneen Brown
Murray Rowledge
Harold Solick

Name of organization (abbreviation) Name of counsel or representative
Glen Morbeck
Terry Rowledge
Ted Vander Meulen Michael Niven
Ron and Marilyn Potter
Jean Payne
Albert Rairdan
Danny Brown
Brian Perreault Debbie Bishop
Nicole Thorsteinsson
County of Stettler No. 6
Cody Rowledge
Mark and Ann Siford
Lee Chapman
Ron Duffy Michael Niven
Tammy Bushman Michael Niven

Name of organization (abbreviation) Name of counsel or representative
April Aspden Patrice Brideau
Justin Aspden Patrice Brideau
Brian Fletcher Ifeoma Okoye
Landowners Opposed to Route C Daryl Bennett
Craigievar Farms Ltd. Michael Niven
Eclipse Pork Ltd. Michael Niven
Bradley Schakel
Sterling Ventures Ltd. Michael Niven
Norman Lyster
Cheryle Lyster
Sara and John Schultz
Consumers Coalition of Alberta Bema Enterprises Ltd.
Capital Power Corporation Brittney Morgan
Jack Bruning

Name of organization (abbreviation) Name of counsel or representative
Métis Nation of Alberta Riley Weyman
Ermineskin Cree Nation Carol Wildcat
NOVA Chemicals Andrea Brack
Tsuut'ina Nation Violet Meguinis
Blood Tribe Kainaiwa Mike Oka
Laurie and Dale Nagel
Route A Opposition Group Ifeoma Okoye
Lorne and Linda Haner Ifeoma Okoye
Colby Miles Ifeoma Okoye
Edward and Janet Fletcher Ifeoma Okoye
Roger and Malora Lee Ifeoma Okoye
Dale McNabb Ifeoma Okoye
Debbie and Betty Henderson

Name of organization (abbreviation) Name of counsel or representative
Erick and Sheryl Osterud Ifeoma Okoye
Calvin Nixon Ifeoma Okoye
Jack Brodsky Ifeoma Okoye
Mike and Christine Nicols Ifeoma Okoye
Dale and Lorna Gordon LaRose Ifeoma Okoye
Garret Hoppins Sean FitzGerald
SBD Group Bill McElhanney
Maureen Rogers

Appendix B – Oral hearing – registered appearances

Name of organization (abbreviation) Name of counsel or representative and witnesses
Alberta Electric System Operator (AESO) Laura Estep Fatima Shariff Dennis Frehlich Ata Rehman Lei Xiong Jin Hao David Johnson
ATCO Electric Ltd. (ATCO) Deirdre Sheehan Stephanie Ridge Chris Storey Dustin Baptist Rajat Goutam Derek Ebner Meghan Chisholm Robert Telford Gabor Mezei Benjamin Cotts
AltaLink Management Ltd. (AltaLink) Brenden Hunter Keith Turriff Brian Townsend Sean Heffernan Joe Gilbert Glen Doll Shawn Martin Gabor Mezei
April and Justin Aspden Patrice Brideau April Aspden
Brian Perreault Debbie Bishop Brian Perreault Craig Felzien
Consumers’ Coalition of Alberta (CCA) James Wachowich, Q.C. Dan Levson Trevor Cline David Butler

Name of organization (abbreviation) Name of counsel or representative and witnesses
Craigievar Group Michael Niven, Q.C. Ryan J. Barata Jasdeep Nijjer J. Heith Johannson Glenn Sharp Ingrid Vander Meulen Ted Vander Meulen
Landowners Opposed to Route C (LORC) Daryl Bennett Dwayne Felzien Donna Fetaz Gerard Fetaz Norman Lyster Brett Penosky Keith Rairdan Silas Chapman Diana Walgenbach Taylor Hunt
Métis Nation of Alberta (MNA) Zachary Davis Riley Weyman Germaine Conacher Kisha Supernant
Route A Opposition Group (RAOP) Ifeoma Okoye Brian Fletcher Lorne Haner Roger Lee Malora Lee Kelly Miles Cliff Wallis Dale Fedoruk Corey Lange Pat Woodlock Paul Héroux

Name of organization (abbreviation) Name of counsel or representative and witnesses
SBD Group Bill McElhanney, Q.C. Alexander Yiu Bradley Schakel Ron Duffy Jack Bruning Bradon Bushman Dale Fedoruk Ron Howard Cliff Wallis Pat Woodlock Paul Héroux Dr. Anthony Miller
Harold Solick
Darrell Blacklock Nickolas Bailey

TAB 11

IN THE MATTER OF

BRITISH COLUMBIA TRANSMISSION CORPORATION

AN APPLICATION FOR A
CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
FOR THE VANCOUVER ISLAND TRANSMISSION
REINFORCEMENT PROJECT

DECISION

July 7, 2006

Before:

Robert H. Hobbs, Chair
Nadine F. Nicholls, Commissioner
Liisa A. O'Hara, Commissioner

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transmission line EMF could not be assured and that VITR should therefore not be located on the existing ROW.

Several Intervenors challenge BCTC's use of the ICNIRP guidelines, arguing that the guidelines do not address the levels and duration of EMF exposure encountered by people living close to transmission lines (TRAHVOL Argument para. 64-65 ; Delta Argument, para. 70; SDSS PAC Argument, para. 34) and that reliance on only the ICNIRP guidelines is insufficient (Sea Breeze Argument, para. 219-220). TRAHVOL argues that the international organizations that establish guidelines are not keeping up with the science (TRAHVOL Argument, para. 67). TRAHVOL's expert witness, Dr. Havas, stated that "…it is clear that these outdated [ICNIRP/Health Canada] guidelines need to be reviewed based on recent scientific studies" (Exhibit C3-19, App. A, Evidence of Magda Havas, p. 9).

At TRAHVOL's request Dr. Havas prepared a report for this proceeding in which she reviewed and summarized the literature regarding adverse health effects associated with EMF exposure and other negative health effects from transmission lines (Exhibit C3-19, App. A, Evidence of Magda Havas). Dr. Havas' EMF review was based on her first work in the area, which was published in 2000 and referred to during this proceeding as "Havas 2000" (T27:4984). Dr. Havas did not review the research conducted on EMF exposure since Havas 2000 (T27:5035-37), although she had read some recent studies and reports which she selectively referenced in her testimony.

Dr. Havas disagreed with the conclusions of the IARC, ICNIRP, the National Health Radiological Board, Health Canada and the World Health Organization (T27:5118-20). She suggested that scientific studies and expert panel conclusions that do not conform to the established view "are often delayed or suppressed" (Exhibit C3-34, p. 5; T27:4994-95). However, she was unable to provide evidence to support that allegation or to conclude that the IARC, ICNIRP and National Radiological Protection Board reviews are biased (T27:5045).

Dr. Havas testified that, in her opinion, magnetic fields associated with high voltage transmission lines are a cancer promoter (T27:4982). She acknowledged that the scientific study findings are inconsistent but that, given the possible association between EMF levels and cancer and a number of other health problems, "…power lines should not be built in residential areas, near schools or near play areas unless peak exposures for the entire lifetime of the line can be guaranteed to be under 2 mG (and preferably under 1 mG) at the edge of the [ROW]…" and where prolonged human exposure is likely (Exhibit C3-19, App. A, Evidence of Magda Havas, p. 5).

Several parties advocated use of the precautionary principle, whereby low cost measures would be taken to reduce EMF exposure. On the issue of what constitutes "low cost", TRAHVOL suggested that an amount equal to 4 percent of project costs be used for mitigation measures, as has been done in some California cases (Exhibit C3-51), and that Option 3 could be considered as a mitigation measure (TRAHVOL Argument, para. 73-76).

5.2.6 Dr. Erdreich's Testimony

BCTC's expert witness, Dr. Erdreich, prepared a rebuttal of Dr. Havas's testimony. Dr. Erdreich stated that Dr. Havas did not follow appropriate scientific methods for reaching conclusions from scientific evidence, failed to acknowledge the efforts of independent scientific panels to evaluate the status of scientific research, and presented her conclusions without considering all of the evidence that has become available since her 2000 report (Exhibit B1-37, Evidence of Linda Erdreich, p. 4).

Dr. Erdreich's testimony included a summary of the conclusions of expert panels that have reviewed the scientific research. Dr. Erdreich also reviewed the research published between 2001 and 2005 in order to determine whether the recent findings are consistent with the ICNIRP and IARC conclusions. She concluded that "…the totality of the evidence (including recent studies and research conducted prior to 2001) does not support the idea that exposure to EMF is a cause of leukemia, nervous system tumors, breast cancer or miscarriage." Dr. Erdreich testified that studies have found a weak statistical association between long-term exposure to average magnetic field levels greater than 3-4 mG and childhood leukemia, but the scientific consensus is that there is not a cause-and-effect relationship between magnetic field exposure and childhood leukemia (Exhibit B1-37, Evidence of Linda Erdreich, pp. 45-46).

Dr. Erdreich acknowledged that there is scientific uncertainty concerning the health effects of EMF. She concluded that "[s]cience cannot prove the absence of an effect-but it can determine through extensive testing that, with the continued failure to substantiate the occurrence of adverse effects, the possibility of a real risk becomes very small" (Exhibit B1-37, Evidence of Linda Erdreich, p. 46). In reference to the ICNIRP guidelines, Dr. Erdreich noted that the exposure limits are conservative and incorporate safety factors to account for potential sources of uncertainty (Exhibit B1-37, Evidence of Linda Erdreich, p. 27).

Commission Determination

The Commission Panel concludes that the EMF exposure guidelines established by organizations such as the World Health Organization, ICNIRP, and Health Canada provide a relevant and useful reference point for considering the safety of EMF levels from the existing transmission lines and the proposed VITR. The Commission Panel notes that the current guidelines are based on broad reviews of the scientific studies and that the absence of a guideline for long-term exposure is based on reviews that have concluded that the scientific research does not support the need for such a guideline.

The Commission Panel also accepts that a standardized methodology for calculating and comparing EMF levels is necessary and that the IEEE Standard 644-1994 used by BCTC is the appropriate standard for these calculations. The Commission Panel accepts BCTC's calculations of the EMF profiles and finds that the EMF levels associated with the existing and proposed lines are well below the established exposure guidelines.

The Commission Panel recognizes that EMF levels in the homes and yards along the ROW may be higher than average but does not accept TRAHVOL's characterization of them as uniquely high, given the number of transmission lines located in residential areas of the Lower Mainland.

The Commission Panel notes that the residents living along the ROW purchased their homes after the existing lines were installed and that the benefits of large lots and/or low prices were weighed against the presence of the transmission lines (Exhibit C3-19, App. A, Affidavits). The Commission Panel recognizes that individual residents living along the ROW will have different exposure levels depending on the distance from the lines to their homes and on the relative amount of time spent in the houses and backyards. However, because VITR will reduce EMF levels at the edge of the ROW in many locations, some residents will experience reduced overall exposure with VITR relative to the existing lines.

The Commission Panel acknowledges that the EMF-related health concerns described by Intervenors living near the existing transmission line may be causing stress and anxiety in some residents, but concludes that the science does not support their fears. The Commission Panel finds Dr. Havas's evidence to be selective and her opinions unconvincing. Dr. Havas conducted one comprehensive study of the pre-2000 research but did not review the more recent scientific research and therefore could not support her position that recent scientific research indicated a need for lower exposure guidelines. **In the absence of convincing new evidence that indicates that change is warranted and/or imminent, the Commission Panel concludes that it should not impose lower EMF exposure standards on VITR.**

The Commission Panel finds that terms such as "the precautionary principle" and "prudent avoidance" are open to a range of interpretations, and is therefore not adopting either term in its determinations. Consistent with previous Commission decisions, the Commission Panel supports efforts to reduce EMF levels where mitigation costs are not significant or where the benefits clearly exceed the cost of mitigation measures. In this proceeding, the evidence does not show that the additional reductions attainable through shielding, deeper burial or taller poles would have positive health impacts and therefore the Commission Panel concludes that the costs of additional mitigation measures to further reduce EMF exposure along the existing ROW are not justified. Mitigation measures may reduce the level of concern and worry experienced by nearby residents. However, while this benefit is not insignificant, **the Commission Panel concludes that it does not warrant actions beyond the very low cost measures that BCTC**

TAB 12

ERICA HAMILTON
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
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TELEPHONE: (604) 660-4700
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Log No. 40806

VIA EMAIL

November 23, 2012

FORTISBC INC. – CPCN FOR THE ADVANCED METERING INFRASTRUCTURE PROJECT EXHIBIT A-14

TO: FortisBC Inc.
Registered Interveners

Re: FortisBC Inc.
Application for a Certificate of Public Convenience and Necessity
for the Advanced Metering Infrastructure (AMI) Project
Procedural Conference Proposed Agenda and Regulatory Timetable

Further to submissions made at the November 8, 2012 Procedural Conference held in Kelowna for the above noted Application, enclosed please find Order G-177-12 issuing the Amended Regulatory Timetable with Reasons for Decision.

Yours truly,

Erica Hamilton

cms
Enclosure

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-177-12

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

and

An Application by FortisBC Inc.
for a Certificate of Public Convenience and Necessity
for the Advanced Metering Infrastructure Project

BEFORE: L.F. Kelsey, Commissioner
D.M. Morton, Commissioner
N.E. MacMurchy, Commissioner

November 23, 2012

O R D E R

WHEREAS:

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

B. On August 2, 2012, the Commission established a Preliminary Regulatory Timetable, attached as Appendix A to Order G-105-12, requesting comments on the regulatory process by which to review the Application, such as written, oral or both;

C. The Preliminary Regulatory Timetable was amended on September 26, 2012 by Order G-135-12 to include a Procedural Conference to be held in Kelowna, BC on November 8, 2012;

D. By letter dated October 11, 2012, the Commission identified the matters to be addressed at the Procedural Conference. Appendix "A" to the letter provided a Proposed Regulatory Timetable;

E. The Procedural Conference took place in Kelowna on November 8, 2012;

F. By Order G-169-12 dated November 9, 2012, the Commission provided for a process to address the written requests of Mr. Andy Shadrack on behalf of Area D in the Regional District Central Kootenay (RDCK) and Michael Jessen on behalf of the Nelson-Creston Green Party Constituency Association (Nelson-Creston) for a suspension of the proceedings. That process is currently underway;

.../2

G. The Commission Panel has considered the submissions made at the Procedural Conference.

NOW THEREFORE as set out in the Reasons for Decision attached as Appendix B to this Order, and subject to the Commission's determination on the applications to suspend the proceedings, the Commission orders as follows:

1. The Amended Regulatory Timetable is attached as Appendix A to this Order.

2. The review of the Application will proceed by a combination of a written and an oral hearing, divided as follows:

    i. Financial, operations, fire safety and privacy issues will be reviewed by way of the written process.
    ii. Health, security and environmental issues will be reviewed by way of the oral hearing.

3. The oral hearing will take place in Kelowna, BC commencing March 4, 2013 and be concluded by no later than March 15, 2013.

4. The request to extend the date for filing of Intervener Information Request No. 2 by one week is denied.

5. The request for a third round of Information Requests is denied at this time. An Intervener may renew its request for a third round of Information Requests following the filing of FortisBC's responses to Commission and Intervener Requests No. 2. Any such request is to be made no later than Friday, December 21, 2012.

6. The date of February 26, 2013 for a second Procedural Conference is a placeholder date only. The Commission will determine at a later date whether a second Procedural Conference is required.

DATED at the City of Vancouver, in the Province of British Columbia, this 23rd day of November 2012.

BY ORDER

Original signed by:

L.F. Kelsey
Commissioner

Attachments

An Application by FortisBC Inc.
for a Certificate of Public Convenience and Necessity
for the Advanced Metering Infrastructure Project

AMENDED REGULATORY TIMETABLE

ACTION	**DATE (2012)**
Commission and Intervener Information Requests No. 2	Friday, November 23
FortisBC Responses to Commission and Intervener Information Requests No. 2	Friday, December 14
	DATE (2013)
Intervener Filed Evidence	Thursday, January 24
Information Requests on Intervener Filed Evidence	Thursday, February 7
Intervener Responses to Information Requests on Intervener Filed Evidence	Thursday, February 21
Placeholder date for Procedural Conference #2 – in Kelowna (final location to be advised)	Tuesday, February 26
Oral Hearing – Kelowna (final location to be advised)	Monday, March 4 to Friday, March 15
FortisBC Final Written Submission	Thursday, March 28
Intervener Final Written Submissions	Thursday, April 18
FortisBC Written Reply Submission	Thursday, April 25

An Application by FortisBC Inc.
for a Certificate of Public Convenience and Necessity
for the Advanced Metering Infrastructure Project

REASONS FOR DECISION

1.0 BACKGROUND

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

By Order G-105-12 dated August 2, 2012, the Commission established a Preliminary Regulatory Timetable, for the proceeding. The Timetable provided for, among other things, the opportunity to make comments on whether the regulatory process for the review of the Application should be written, oral or both.

The Preliminary Regulatory Timetable was amended on September 26, 2012 by Order G-135-12 to include a Procedural Conference to be held in Kelowna, BC on November 8, 2012.

By letter dated October 11, 2012 (Exhibit A-10), the Commission identified the following matters to be addressed at the Procedural Conference:

1. The proposed agenda for the Procedural Conference;
2. The identification of issues or topics of significance related to health, security and privacy that should be included in the oral hearing;
3. The identification of issues or topics of significance of a financial and operations nature that should be included in the written process;
4. The identification of other significant issues;
5. Other matters that would assist the Commission to efficiently review the Application;
6. The Proposed Regulatory Timetable for the review of the Application which was set out in Appendix A to the letter; and
7. The timing, location and duration of the oral hearing process.

The letter encouraged participants to file written submissions on those matters with the Commission Secretary by Tuesday, October 30, 2012.

On October 30, 2012, Mr. Andy Shadrack, as an elected representative of Area D in the Regional District Central Kootenay (RDCK), and Mr. Michael Jessen on behalf of the Nelson-Creston Green Party Constituency Association (Nelson-Creston) submitted letters requesting that the proceedings be suspended. They further requested that an oral hearing be held on all issues.

On the same date, FortisBC, B.C. Sustainable Energy Association, Sierra Club of Canada, British Columbia Chapter (BCSEA), Mr. Jerry Flynn, Citizens for Safe Technology Society (CSTS), and the Commercial Energy Consumers Association of British Columbia (CEC), submitted written comments on the regulatory process to be used in the review of the Application. In addition, Christina Postnikoff, an Interested Party, filed a written submission.

On October 31, 2012, the West Kootenay Concerned Citizens (WKCC) submitted its comments.

The Procedural Conference took place in Kelowna on November 8, 2012.

In addition to the Applicant, the following Interveners entered appearances and made submissions at the Procedural Conference:

- CSTS (by conference call),
- British Columbia Hydro and Power Authority (BC Hydro),
- CEC,
- British Columbia Municipal Electrical Utilities (BCMEU),
- British Columbia Pensioners' and Seniors' Organization *et al*. (BCPSO),
- BCSEA,
- WKCC.

Those Interveners not attending the Procedural Conference but who filed written submissions were:

- Mr. Shadrack, and
- Nelson-Creston

PROCEDURAL CONFERENCE

2.0 INTRODUCTION

In addition to those issues raised by the Panel, the Interveners raised the following issues or requests:

- A suspension of the proceedings,
- An extension of the deadline for the filing of the Intervener second round Information Requests,
- A third round of information requests,
- Holding the entire hearing by way of an oral hearing,
- The number of witnesses,
- The deadline for filing evidence,
- The scheduling of expert witnesses, and
- The use of video conferencing for cross-examination.

2.1 Suspension of the Proceedings

During the Procedural Conference, Commission counsel brought the Panel's attention to Exhibits C13-4 and C18-3 filed on October 30, 2012. These are respectively the submissions by Mr. Shadrack and Nelson-Creston which request a suspension of the proceedings. At the Procedural Conference and subsequently by Order G-169-12 dated November 9, 2012, the Commission Panel established a process for submissions on these requests. That process is underway. Order G-169-12 also provides that the review of the Application is to continue in accordance with the timetable established by Order G-169-12 until further Commission order.

2.2 Extension of the deadline to file Information Request No. 2 (IR2)

CSTS submits that the November 23rd deadline for the second round of Intervener Information Requests ought to be extended by a week as it is concerned about having enough time to process FortisBC's IR1 responses with its consultants. [T1:80] At page 3 of its written submission, it asserts that "various intervener parties have been thrust into the information request component of the written hearing without having the benefit of consultants." It submits this is due to the fact that the process for approving interim Participant Assistance/Cost Award (PACA) funding did not sufficiently precede the deadline for IR1. It seeks a week extension to the date for submitting IR2. [Exhibit C9-3]

FortisBC submits that it has been able to answer a large volume of IRs very quickly and is again working towards its IR response deadline quickly. It submits that Interveners should also work towards their deadlines and notes the upcoming second round IR deadline of November 23rd was set quite some time ago, on September 26, 2012, as part of Order G-135-12. [T1:112]

Commission Determination

The Commission Panel does not accept the submission of CSTS that because of its failure to receive interim PACA funding prior to the first round of Information Requests, CSTS should be allowed an extension in time to file Intervener IR2. There is no requirement to approve interim PACA funding awards prior to the deadline for submitting the first round of Information Requests. Further, an Intervener should not consider a request for interim PACA funding as a guarantee that interim PACA funding will be approved. Even if approved, the interim funding may not be received until the proceedings are well under way.

As FortisBC points out, November 23rd was established as the date for Intervener IR2 on September 26th.

The Commission Panel is of the view that the November 23, 2012 date is sufficient time for CSTS to prepare its IR2. The Commission Panel denies an extension to the date for filing IR2.

2.3 Third Round of Information Requests

CSTS requests the Commission establish a third round of Information Requests for the same reasons that it requests an extension in the date for filing Intervener IR2, namely that the Commission's process for approving interim PACA funding awards did not sufficiently precede the deadline for submitting the first round of IRs. [Exhibit C9-3, p. 3; T1:12-13, 68-69]

WKCC supports the request for a third round of IRs. [T1:91-92]

While observing that it is premature to talk about a third round of IRs when it has not yet seen FortisBC's responses to IRs 1 and 2, CEC/BCMEU presently believes two rounds of Information Requests will be sufficient, assuming the responses provided by FortisBC are "fulsome". [T1:47]

BCPSO suggests that a third round of IRs could be useful if it could reduce the days of oral hearing. In BCPSO's view, the usefulness of a third round depends on the responses to both IRs 1 and 2. [T1:53-54]

BCSEA points out that a third round of IRs is not normal and that there does not appear to be a need for a third round at this time. However, it also comments that a third round of IRs may have some benefit depending on the responses to IRs 1 and 2, particularly if an IR3 was an alternative to having matters raised at an oral hearing. [T1:57]

FortisBC opposes a third round of information requests, submitting that there is already a considerable burden on the utility and correspondingly its ratepayers in dealing with the two rounds of Information Requests from both the Commission and Interveners that are presently set out in the schedule. FortisBC's counsel advised the Commission that approximately 1,500 Information Requests had been made to FortisBC and a further round [IR2] was contemplated. [T1:24]

Commission Determination

The reasons the Commission Panel has given for refusing an extension to the date for filing of Intervener IR2 apply to the CSTS's request for a third round of IRs as well.

There has been a large volume of Information Requests at this time, with further Information Requests to be filed in round two on November 23rd. As BCSEA has pointed out, it is not usual for the Commission to allow a third round of IRs in its proceedings. However, the Panel finds merit in the submissions that it may be premature to decide the need for a third round of IRs without Interveners having the opportunity to review the FortisBC responses to IRs 1 and 2.

Accordingly, the Commission Panel is not prepared to order a third round of IRs at this time. If, following its review of the responses to IRs 1 and 2, an Intervener believes a further round of IRs is necessary, it can make the request at that time. The request is to be made no later than Friday, December 21, 2012.

2.4 Health, Security and Privacy Matters

BCSEA's Exhibit C4-5 provides the following definitions of health, security and privacy:

- Health includes the health effects of the wireless radio frequency network component of the AMI Project, and the RF-LAN and ZigBee transmissions to and from the meter, as well as wireless transmissions between the collection system and the head-end.
- Security includes the potential unauthorized interception of information (utility information, not just personal information) and includes interception by FortisBC of information belonging to a customer or by a customer of utility information not just interception by third parties.
- Privacy includes the collection and use of information only for its intended and authorized purpose and what those intended and authorized purposes should be.

FortisBC accepts the definitions of health and security as put forward by BCSEA in Exhibit C4-5 for the purposes of the oral hearing. However, it views the privacy concerns as quite limited in nature in the sense of being discrete and narrow and submits they can be addressed through written evidence and parties' submissions on that evidence. Further, FortisBC states a large part of the privacy issue really relates to what are the applicable laws that may pertain and govern what FortisBC is doing to ensure the privacy of the information and this matter is more suited for written legal argument. [T1:25]

BCPSO submits concerns about health and privacy should be examined in an oral hearing. [T1:54] BCSEA also submits that privacy, along with health and security issues proceed by way of an oral hearing. [T1:59]

CSTS states that the issues of security and privacy can cause some confusion. It divides the issues into those of fire, hacking for the purpose of interfering with electricity supply and hacking for the purpose of obtaining private information. Further, it recognizes that there are also the legal issues dealing with FortisBC's proposed collection of information. [T1:73-74] In its written submission, CSTS includes expert evidence on security risks, including fire risks, as a subject for the oral hearing. [Exhibit C9-3, p. 2]

CEC supports the review of health and security by way of an oral hearing. As for the privacy issue, it is indifferent as to the nature of the hearing. It submits that the privacy issue will certainly be a matter for legal argument and that the privacy issue will not likely be a subject of cross-examination by it at the oral hearing. [T1:48]

Commission Determination

The Commission Panel has considered the definitions of health and security provided by BCSEA in Exhibit C4-5 and adopts these definitions for the purposes of scoping the oral hearing issues on health and security.

While evidence concerning health will be considered as part of this hearing, the Commission Panel reminds all parties that it has no jurisdiction over regulations made by Health Canada and other agencies. Accordingly, it is not within the Commission's mandate to consider any changes to these regulations.

The Commission Panel accepts that security and privacy have different characteristics and determines that security will be addressed in the oral hearing. However, it also agrees with FortisBC that the issue of privacy can best be addressed in the context of a written hearing. While there may be evidentiary issues relating to the use FortisBC makes of the information it obtains, these issues can be dealt with through written evidence and the IR process. The laws that govern FortisBC's use of the information are a matter for legal argument. Therefore, issues of privacy, which the Commission Panel considers relate to the FortisBC use of the information it may receive, will proceed by way of a written review process.

2.5 Financial and Operations Matters

While acknowledging that the Commission Panel's preliminary determination to review financial and operations issues by a written process can be changed, FortisBC supports the written review of those matters. It submits that addressing those matters through a written process is a very reasonable approach that lends itself to an efficient process, since many of these items are highly technical in nature, involve numbers and particulars and can conveniently be addressed in written form. [T1:28]

FortisBC proposes that the financial benefits of the AMI project, the non financial benefits, the future benefits, project costs and project alternatives, with one exception, be addressed in the written process and by written submissions. The exception is where health or security issues relate to project alternatives. FortisBC contemplates that exception being part of the oral hearing. [T1:32; Exhibit B-10, p. 2]

The CEC/BCMEU support the review of financial and operations matters by way of a written process, if the responses to its IRs are "fulsome". [T1:39]

BCSEA generally agrees with FortisBC's proposal relating to the treatment of financial and operations matters with one qualification. It states that it supports a hybrid oral and written proceeding on the basis of "*efficiency*". [Emphasis in original] It does not have the resources to participate in lengthy oral hearing sessions involving financial and operations issues that could be dealt with in writing. However, it does support Interveners having an opportunity to cross-examine the witnesses of FortisBC or others on topics relevant and material to the Commission's determination on the Application. [T1:63-64; Exhibit C4-5]

Depending on the responsiveness of FortisBC's responses to IRs, BCPSO submits some financial or operational consequences may be suited to oral cross-examination. [T1:54-55]

Commission Determination

The Commission Panel agrees with FortisBC that the review of financial and operations matters are highly technical in nature, involve financial spreadsheets and particulars that participants can conveniently address in written form. Thus, the Commission Panel determines the review of financial and operations matters in this proceeding will be by way of a written process, except where health or security issues relate to project alternatives. Those matters will be the subject of the oral hearing.

2.6 Identification of Other Significant Issues

FortisBC states it doesn't have any significant issues to add into the mix in terms of what would be dealt with at either an oral or a written hearing. However, FortisBC expects to submit an application shortly to the Commission to acquire the City of Kelowna's electrical utility. FortisBC anticipates filing additional written evidence that will show the impact of the AMI project if both the AMI project and the City of Kelowna acquisition are approved. [T1:33]

The CEC/BCMEU support confining the hearing to the review of the Application without expanding it to a review of the BC Hydro Smart Meter program and notes the current budgeted regulatory cost of $4.9 million. [T1:49-51]

BCPSO would like to add the issue of AMI allowing a remote disconnect, but it did not suggest whether either an oral or written process for the review of the remote disconnect function would be appropriate. [T1:55]

BCSEA identifies the following additional issues: applicable safety standards or guidelines, how the AMI meters comply with the applicable standards, the health risk mitigation measures that could or should be taken when deploying a wireless AMI system, the merits of changing the entire system away from wireless to a wired system, the technical options, costs and benefits of a non-wireless system, the impact of a customer opt-out program on financial benefits, and the defining characteristics of an opt-out system including costs borne by those opting out. BCSEA proposes that the Commission include the topic of the electronic relationship between the customer and FortisBC in the oral hearing. According to BCSEA, the topic involves elements such as Zigbee and the proposed software protocols and the alternatives to these elements, the in-home devices, home area networks, and the software/hardware upgrade path that is implicit in the proposal. [T1:60-63]

Commission Determination

The Commission Panel notes the additional items: remote disconnect, AMI meter compliance with applicable safety standards or guidelines, analysis of using a wired system versus a wireless, remote disconnect, and analysis of the impact of an opt-out program. The Commission Panel determines that these additional items are more suited to a written hearing process as they are of a technical or financial nature.

2.7 Other Matters for Efficient Review the Application

FortisBC has no suggestions to improve the efficiency of the review of the Application beyond the proposed regulatory timetable contained in Exhibit A-10. [T1:31-34] With the exception of Mr. Shadrack and Nelson-Creston, FortisBC and the remaining Interveners who provided submissions in advance and at the Procedural Conference were generally satisfied with the proposed hybrid hearing process for review of the Application. There were, however, some differences on the topics to be covered in the written and oral reviews.

Ms. Postnikoff, who is registered as an Interested Party, requested an oral process for all matters.

Commission Determination

The Commission Panel notes FortisBC and most of the Interveners did not oppose the hybrid review process proposed by the Commission. The Commission Panel is of the view that the proposed split of issues between the oral and written reviews is appropriate and determines that the review of the Application will proceed using the hybrid process.

2.8 The Number of Witnesses

CSTS has identified four issues: health, environment, fire safety, and hacking (information technology security issues) and proposes to put forward three witnesses on each issue. [T1:78]

FortisBC has concerns regarding the number of witnesses proposed by CSTS. FortisBC's concerns are the possibility of redundancy and excessive cost to the ratepayer. [T1:34]

The CEC/BCMEU suggest that if the Commission determines that multiple experts are appropriate, those witnesses sit as one panel in order to more effectively manage hearing time. Further, they submit that due to what they describe as an "unprecedented request for the number of witnesses that are being proposed" the Commission consider a second Procedural Conference after the evidence has been filed. The second Procedural Conference would allow participants to make submissions as to whether the witness qualifies as an expert or needs to be called for cross-examination. [T1:51-52]

BCSEA supports the CEC/BCMEU position that a second Procedural Conference may allow for the identification of topics for cross-examination at the oral hearing. [T1:55, 64]

BCSPO also agrees that a second Procedural Conference would be useful. [T1:55]

FortisBC submits that an efficient process can be achieved by an order issued out of the Procedural Conference without the need for a second Procedural Conference. [T1:111-112]

Commission Determination

In order to reduce the number of expert witnesses who may be required for cross-examination, the Commission Panel determines that fire safety will be dealt with by way of the written process as it is a technical and code compliance issue. Environmental issues, in addition to health and security issues, will be the subject of the oral hearing. The Commission Panel agrees with CEC that where expert witnesses are addressing a common topic, they sit in panels in order to more effectively manage hearing time and control costs. Accordingly, the Commission Panel determines the witness panels to be cross-examined in the oral hearing will relate to health, security, and environmental issues.

2.9 The Proposed Regulatory Timetable

As a result of the submissions it has received, the Commission Panel will revisit the Proposed Regulatory Timetable attached as Appendix A to Exhibit A-10.

2.9.1 Hearing Days and a Second Procedural Conference

CSTS estimates that the oral hearing will take 28 days. That estimate is based on its "best guess … to adduce expert opinion from twelve witnesses." [Exhibit C9-3, p. 3; T1:80-81]

FortisBC accepts the Proposed Regulatory Timetable. [T1:34]

The CEC/BCMEU state they have no difficulties with the Proposed Regulatory Timetable with the exception of a proposed additional second Procedural Conference. They are concerned about the length of hearing proposed by CSTS. [T1:52]

BCPSO submits that the proposal for a 28 day hearing "seems quite high for this proceeding." It further states the Proposed Regulatory Timetable is acceptable from a scheduling standpoint, but submits that three days for the oral hearing may or may not be sufficient to balance a thorough process with an efficient hearing. [T1: 54-55]

BCSEA does not want an overly lengthy hearing and submits it "really ought to be possible for the parties to get the best information before the Commission in a relatively short time, if things are organized properly." [T1:65]

Commission counsel pointed out that there is very limited direct examination of witnesses in Commission proceedings which results in a reduction in the amount of time taken by witness panels giving evidence before the Commission. He also noted that parties usually advise as to the witness panel or one expert in particular to be made available for cross-examination. He believes those matters are taken into account in scheduling. [T1:92-93]

BCSEA commented that "witness" in Commission proceedings means a person who will provide their evidence in advance. If a party wishes to cross-examine them, they will then attend, either in person or provide their evidence by video, if permitted, and answer questions. [T1:101-102]

Commission Determination

The number of witnesses proposed by CSTS, when added to the witnesses that may be called by FortisBC and other Interveners requires the Commission Panel to adjust the three day estimate projected for the oral hearing in the Proposed Regulatory Timetable. Without knowing the amount of expert evidence that will be led by the Interveners, the Commission Panel acknowledges three days may be insufficient for cross-examination on the filed evidence. The Commission Panel will therefore set aside a two week period for the hearing of the Application. That period will commence on Monday, March 4, 2013 and conclude on Friday, March 15, 2013. A hearing of this length should also minimize any concerns about the scheduling of witnesses.

The Commission Panel acknowledges that a second Procedural Conference may be useful for further refining the scope of the oral hearing. Therefore, the Commission Panel will set Tuesday, February 26, 2013 in Kelowna as the placeholder date and location for a second Procedural Conference, should it determine that such a conference is necessary. It will make that determination following the filing of all the expert evidence.

2.9.2 Deadline for Filing of Expert Evidence

CSTS requests an extension from January 10, 2013 to February 15, 2013 to file its expert evidence. [T1:80; Exhibit C9-3, p. 3]

FortisBC does not agree that the deadline for the filing of evidence should be extended by four weeks. It says that such an extension may result in CSTS accomplishing through procedural means, the substantive result that it seeks, which is endangering the AMI project and the project's ability to proceed under a fixed price contract. [T1: 35-37, 112]

Commission Determination

The Commission Panel concludes that a four week extension is excessive, but determines that an additional two weeks is an appropriate compromise considering that FortisBC's response to Commission and Intervener Information Requests No. 2 is due Friday, December 14, 2012.

2.9.3 Deadline for Filing Final Arguments

CSTS requests the opportunity to prepare written submissions for at least three weeks and preferably four weeks after having received FortisBC's written submissions. CSTS submits that a one-week interval between FortisBC's submissions and their response is insufficient. [T1:82; Exhibit C9-3, p. 4]

FortisBC does not object to extending the date for filing Interveners' Final Submissions to a date two weeks from the date of the filing of the FortisBC Final Submission. [T1:113]

Commission Determination

The Commission notes the tight timeline for the filing of Final Submissions and determines the filing of Final Submissions will be adjusted to allow for FortisBC to file its Final Submissions on March 28, 2013, Interveners to file their Final Submissions on April 18, 2013 and FortisBC to file its Reply on April 25, 2013.

2.10 The Use of Video Conferencing for Cross-Examination

CSTS seeks a determination on whether the Commission would accept testimony by video conference. [T1:13, 81-82; Exhibit C9-3, pp. 3-4]

FortisBC states that it will arrange for its experts to be available in person and hopes that the other Interveners who are bringing forward witnesses will do the same. FortisBC has no technical objection to the use of video conferencing for cross-examination of witnesses. [T1:37-38]

The CEC supports the use of video conferencing for cross-examination as a cost effective measure in this Application. [T1:37-38]

BCPSO suggests that it is easier and better to assess credibility with live evidence and cross-examination, but BCPSO is not opposed to videoconferencing, if that is the only way that certain witnesses are able to join. [T1:56]

Commission Determination

The Commission Panel considers that it is better able to assess witness credibility when a witness gives evidence in person. However, it is prepared to consider cross-examination of witnesses by way of video conferencing in this matter, provided it can be persuaded that that it should do so. A participant who wishes to have a witness or witnesses provide its evidence by video-conferencing must persuade the Commission Panel that it should allow the evidence to be given in that way. To the extent that the Commission Panel approves the use of video-conferencing for cross-examination of certain experts, the Intervener will be responsible for ensuring (in advance of the hearing) that the hearing video equipment and the equipment in the location where the witness or witnesses are situated are technically compatible.

2.11 The Location of the Oral Hearing

FortisBC and most of the Interveners prefer Kelowna as the location of the Oral Hearing; CSTS prefers Rossland, BC.

Commission Determination

The Commission Panel agrees that Kelowna is the most effective and accessible location for the majority of Interveners and determines that the Oral Hearing will be held in Kelowna.

TAB 13

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-220-13

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

and

FortisBC Inc.
Application for a Radio-Off
Advanced Metering Infrastructure Meter Option

BEFORE: L.F. Kelsey, Commissioner
D.M. Morton, Commissioner
N.E. MacMurchy, Commissioner

December 19, 2013

O R D E R

WHEREAS:

A. On July 26, 2012, FortisBC Inc. (FortisBC) applied to the British Columbia Utilities Commission (Commission), pursuant to sections 45, 46 and 56 of the *Utilities Commission Act*, for approval of the Advanced Metering Infrastructure (AMI) Project;

B. Order C-7-13 dated July 23, 2013, granted FortisBC a Certificate of Public Convenience and Necessity (CPCN) for the AMI Project (AMI Decision). The approval was subject to the condition that FortisBC confirm in writing that it would file an application for an opt-out provision by November 1, 2013, based on principles set out in the AMI Decision;

C. On July 31, 2013, FortisBC confirmed in writing that it would file an application for an opt-out provision;

D. On August 30, 2013, FortisBC filed an application for a Radio-Off AMI Meter Option (Application) based on principles set out in the AMI Decision. The Application sets out the rates and processes for customers who choose the Radio-Off AMI Meter Option. Specifically, the proposed rates per customer are as follows:

- Per-premises setup fee: $110.00; and
- Bi-monthly per-read fee: $22.00.

E. Order G-142-13 dated September 9, 2013 directed FortisBC to promptly publish notice of the Application in specific newspapers and to distribute copies of Order G-142-13 and its Appendices in a timely fashion, via email, to the Registered Interveners and Interested Parties in the AMI Project CPCN proceeding. The Order also directed those parties wishing to participate in the review of the Application to register as soon as possible;

F. Order G-154-13 dated September 18, 2013 established a written hearing process and a Regulatory Timetable for the review of the Application;

G. Order G-160-13 dated October 1, 2013 established an Amended Regulatory Timetable in order to allow for a filing deadline for Participant Assistance/Cost Award budgets;

H. On October 18, 2013, FortisBC filed responses to Information Requests (IRs) from the Commission and Interveners;

I. Order G-176-13 dated October 24, 2013 directed FortisBC to file complete responses to specific IRs and respond to additional questions. The Order also established a Further Amended Regulatory Timetable; and

J. The Commission Panel has reviewed the Application, the evidence and the written submissions and sets the rates for the Radio-off AMI Meter Option service.

NOW THEREFORE for the reasons stated in the Decision attached as Appendix A to this Order and pursuant to sections 59 and 60 of the *Utilities Commission Act*, the Commission orders as follows:

1. The rates proposed in the FortisBC Inc. Application are not approved as filed.

2. The following rates for the Radio-off AMI Meter Option service are considered just and reasonable and are approved as permanent rates:

   - Per-premises setup fee - Customers who choose the Radio-off AMI Meter Option prior to the commencement of AMI project deployment in their region: $60.00;
   - Per-premises setup fee - Customers who choose the Radio-off AMI Meter Option after the commencement of AMI project deployment in their region: $88.00; and
   - Bi-monthly per-read fee: $18.00.

3. FortisBC must track the actual number of Radio-off AMI Meter Option participants and the actual annual manual meter reading costs separately from other costs and submit a report on these items with the British Columbia Utilities Commission on or before September 30, 2016.

4. FortisBC Inc. must resubmit Rate Schedule 81 incorporating all of the applicable directives outlined in the Decision attached as Appendix A to this Order, on or before January 27, 2014.

5. FortisBC Inc. is directed to comply with all other directives in the Decision attached as Appendix A to this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 19th day of December 2013.

BY ORDER

Original signed by:

L.F. Kelsey
Commissioner

Attachment

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

FORTISBC INC.
APPLICATION FOR THE ADVANCED METERING INFRASTRUCTURE
RADIO-OFF AMI METER OPTION

REASONS FOR DECISION

December 19, 2013

BEFORE:

L.F. Kelsey, Panel Chair / Commissioner
D.M. Morton, Commissioner
N.E. MacMurchy, Commissioner

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EXECUTIVE SUMMARY

On August 30, 2013, FortisBC Inc. filed its Radio-Off AMI Meter Option Application with the British Columbia Utilities Commission. The Application was filed to meet a requirement of Commission Order C-7-13, which was issued on July 23, 2013, and granted FortisBC a Certificate of Public Convenience and Necessity for an Advanced Metering Infrastructure project. The AMI Decision required FortisBC to file an application for an opt-out provision by November 1, 2013, based on principles set out in the AMI Decision. The scope of the Application was limited to the opt-out principles outlined by the Commission in Order C-7-13.

The Commission previously determined that FortisBC account holders (customers) who are scheduled to have an AMI meter installed can choose to have an AMI meter installed that has the wireless transmit functions disabled. This is referred to as the Radio-off AMI Meter.

In its Application FortisBC proposed that:

- Customers may choose to have a Radio-off AMI Meter put in place at any time;
- Customers wanting to have a Radio-off AMI Meter must complete and sign an application form as prescribed by FortisBC;
- FortisBC will charge a per-premises setup fee of $110.00. This fee applies to customers who elect to have a Radio-off AMI Meter installed during the initial AMI project roll-out, to customers who elect to have a Radio-off AMI Meter put in place subsequent to the AMI meter being installed and to existing participants in the Radio-off AMI Meter Option that move premises;
- FortisBC will read the Radio-off AMI Meter every two months, charging a $22.00 fee for each reading; and
- A customer electing to switch from a Radio-off AMI Meter to a standard radio-on AMI meter will pay a final manual meter reading fee of $22.00.

The Commission Panel agrees with the FortisBC proposal that customers may choose to have a Radio-off AMI Meter put in place at any time.

The Panel reviewed the fees proposed and had concerns about the accuracy of the stated costs and does not accept the proposed fees as being just and reasonable.

The Panel determines that:

- **FortisBC must confirm with the Commission on or before January 27, 2014 that the enrolment process for the Radio-off AMI Meter Option is comparable to the process a customer must follow to obtain general electric service. Processes that impose an unnecessary barrier for those wishing to avail themselves of the service are not acceptable to the Commission;**
- **Customers who elect, prior to the deployment of AMI meters in their region, to have a Radio-off AMI Meter put in place will be charged a per-premises setup fee of $60.00;**
- **Customers who elect, subsequent to the deployment of the AMI meters in their region, or customers who have previously had a Radio-off AMI Meter installed and move premises, will be charged a per-premises setup fee of $88.00;**
- **The Radio-off AMI Meter will be read every two months and customers will be charged an $18.00 fee for each reading;**
- **A customer electing to switch from a Radio-off AMI Meter to a standard radio-on AMI meter will pay a final manual meter reading fee of $18.00; and**

- **The per-premises setup fees and the bi-monthly manual meter reading fee are set on a permanent basis. FortisBC is directed to track manual meter reading costs associated with the Radio-off AMI Meter program and to provide a report on these costs and the number of participants to the Commission by September 30, 2016, irrespective of whether or not a fee revision is proposed.**

1.0 THE APPLICATION

On August 30, 2013, FortisBC Inc. (FortisBC) filed its Radio-Off AMI Meter Option Application (the Application) with the British Columbia Utilities Commission (Commission). FortisBC is an investor-owned, regulated utility engaged in the business of generation, transmission and distribution and bulk sale of electricity in the southern interior of British Columbia, serving over 162,000 customers directly and indirectly through municipally owned utilities in its service area.

The Application was filed to meet a requirement of Commission Order C-7-13, which was issued on July 23, 2013 and granted FortisBC a Certificate of Public Convenience and Necessity (CPCN) for an Advanced Metering Infrastructure (AMI) project, subject to certain conditions (AMI Decision).[1] The specific condition leading to the Application was a requirement that FortisBC file an application for an opt-out provision by November 1, 2013, based on principles set out in the AMI Decision.

The Commission previously determined that FortisBC account holders (customers) who are scheduled to have an AMI meter installed can choose to have an AMI meter installed that has the wireless transmit functions disabled (Radio-off AMI Meter).

Key components of the FortisBC Application are:

- Customers may choose to have a Radio-off AMI Meter put in place at any time.
- Customers wanting to have a Radio-off AMI Meter must complete and sign an application form as prescribed by FortisBC.
- FortisBC will charge a per-premises setup fee of $110.00 (Per-premises Setup Fee). This fee applies to customers who elect to have a Radio-off AMI Meter installed during the initial AMI project roll-out, to customers who elect to have a Radio-off AMI Meter put in place subsequent to the AMI meter being installed and existing participants in the Radio-off AMI Meter Option that move premises.
- FortisBC will read the Radio-off AMI Meter every two months, charging a $22.00 fee for each reading (Per-read Fee).
- A customer electing to switch from a Radio-off AMI Meter to a standard radio-on AMI meter will pay a final manual meter reading fee of $22.00.

2.0 BACKGROUND AND REGULATORY PROCESS

2.1 Order C-7-13 Granting a CPCN to FortisBC to Install Advanced Metering Infrastructure

Order C-7-13 grants a CPCN to FortisBC (subject to conditions) for the AMI project. It was issued following an extensive regulatory process that included Community Input Sessions and a two week Oral Hearing. As set out in the AMI Decision, the Commission considered a wide variety of issues including:

- Economic and rate impacts;
- Assessment of policy and environmental issues including implications for greenhouse gas emissions and theft reduction benefits;
- Health implications associated with radio frequency emissions;
- Safety and privacy issues; and
- Applicability of the *Clean Energy Act*.

[1] *In the Matter of FortisBC Inc. and an Application for a Certificate of Public Convenience and Necessity for the Advanced Metering Infrastructure Project,* Decision and Order C-7-13, July 23, 2013 (AMI Decision)

The AMI Decision is available on the Commission's website.[2]

2.1.1 Findings in Order C-7-13 Regarding an Opt-out Provision

In the application for a CPCN to acquire and install advanced metering infrastructure, FortisBC did not provide any provision for customers to opt-out of the requirement to have a radio-on AMI meter installed at their premises. The position adopted in the application was that FortisBC would work with customers who had concerns about the installation of a radio-on AMI meter, but if these concerns could not be satisfied and the customer continued to refuse to have a meter installed, then FortisBC would discontinue service to that customer.

On page 148 of the AMI Decision the Commission states:

> "In Section 6.5.2, the Panel identified a potential risk to the implementation schedule arising from a protracted difference of views concerning the Project. This risk could increase costs to and reduce potential benefits from the Project, which would be detrimental to all FortisBC ratepayers. The Panel is of the view that an opt-out program could mitigate these potential schedule impacts. On the issue of financial or medical hardship, the Panel is of the view that a properly designed opt-out program allows individuals to decide not to accept a transmitting AMI meter while protecting the remaining FortisBC customers from the increased costs associated with the opt-out Program."

Therefore, to mitigate this potential risk to the implementation schedule, the Commission directed FortisBC to bring forward an application for an opt-out program based on the following principles:

- **Customers may choose to opt-out of accepting a wireless transmitting meter.**
- **Customers who choose to opt-out will be provided with an AMI meter that has the wireless transmit functions disabled. Transmit functions on these meters will remain disabled until the individual chooses to opt back in to the AMI program; in the event that the customer moves to a new property, the opt-out choice will move with the customer.**
- **The incremental cost of opting-out of the AMI program will be borne by the individual choosing to opt-out.**

The Commission also noted in the AMI Decision that as radio-frequency (RF)-related issues, including health, security and privacy had been extensively dealt with, the opt-out provision application should be limited to dealing with the issues associated with the an opt-out option that is set out in accordance with the principles outlined above.[3]

2.2 Regulatory Process for the Current Proceeding

Following the August 30, 2013 filing of the Application, the Commission issued Order G-142-13, dated September 9, 2013, directing FortisBC to publish notice of the Application in specific newspapers and to distribute copies of Order G-142-13 and its Appendices to registered Interveners and Interested Parties in the FortisBC AMI proceeding (AMI Proceeding).

By Order G-154-13 dated September 18, 2013, the Commission established a written hearing process and a Regulatory Timetable for the review of the Application. Subsequent Orders, G-160-13 and G-176-13 dated October 1, 2013 and October 24, 2013 respectively, amended the original timetable set out in Order G-154-13.

[2] http://www.bcuc.com/Documents/Proceedings/2013/DOC_35184_C-7-13_FBC-AMI-ProjectDecision-WEB.pdf
[3] AMI Decision, pp. 148-149.

The final regulatory process included the following components:

• Intervener and Interested Party Registration Deadline	Wednesday, September 25, 2013
• Commission and Intervener Information Request Number 1	Friday, October 4, 2013
• Filing of Participant Assistance/Cost Award Budgets	Friday, October 11, 2013
• FortisBC Response to Commission and Intervener Request No.1	Friday, October 18, 2013
• FortisBC Response to Directives No. 2 and 3 of G-176-13	Wednesday, October 30, 2013
• FortisBC Final Written Submission	Wednesday, November 6, 2013
• Intervener Final Written Submission	Wednesday, November 13, 2013
• FortisBC Written Reply Submission	Wednesday, November 20, 2013

2.3 Scope of the Proceeding

The Panel, in determining the scope of the Proceeding, was mindful of the directives contained in Order C-7-13 and the principles described in section 2.1.1 above. Consequently, in Directive 2 of Order G-154-13, the Panel provided the following direction to participants on the limited scope of the proceeding:

> "2. In reviewing the Radio-Off Advanced Metering Infrastructure Meter Option Application, the written hearing is limited in scope to the opt-out principles outlined by the Commission Panel in Order C-7-13. …" (Order G-154-13)

2.4 Evidence and Submissions

Nine parties were registered as Interveners in the proceeding. Five of these parties filed Information Requests (IRs), to which FortisBC replied. Eight of the Interveners filed Final Submissions. One Interested Party also filed IRs with FortisBC. FortisBC declined to answer the IRs of the Interested Party on the basis that (a) there is no provision for interested parties to put forward IRs; (b) the Interested Party was not a direct customer of FortisBC; and (c) many of the questions put forward by the Interested Party had already been answered in responses to Interveners and certain questions were out of scope. (Exhibit B-3)

Despite the Panel's specific directive on the limited scope of the proceeding, a number of parties in both their IRs to FortisBC and in their Final Submissions dealt with issues that were out of scope. Given the clear direction on the limited scope of the proceeding and the extensive regulatory process that led to the AMI Decision, which dealt with many of the out of scope issues, the Panel has disregarded evidence and submissions that could be seen as outside the limited scope of this proceeding. The Panel also found some instances where information that was not part of the evidentiary record was brought forward in Final Submissions. For example, Director of Electoral Area "D" of the Regional District of Central Kootenay (RDCK) introduced an Ernst & Young study commissioned by the Economics Ministry of the Federal German Republic in its Final Submission (RDCK Final Submission, para. 12). Final Submissions are to be based on the material contained in the evidentiary record. For this reason the Panel places no weight on information that has been introduced in Final Submissions that is not found within the evidentiary record.

The Panel considers that the specific items discussed in the sections below, while they may be seen as out of scope, should be clarified.

2.4.1 FortisBC Radio–off AMI Meter Option Application Form

In its Application FortisBC states that a customer electing the Radio-off AMI Meter Option must communicate that choice to FortisBC by completing and signing an application form set out by the Company and delivering it by one of the following methods:

(a) mailing it to FortisBC;
(b) submitting the form by fax; or
(c) emailing a completed and signed form to FortisBC. (Exhibit B-1, p. 3)

In its Final Submission British Columbia Pensioners' and Seniors' Organization *et al.* (BCPSO) states:

> "BCPSO questions the limitations of these methods. All three of these "alternative means" require a certain level of literacy and cognitive ability. Limiting communications options in this way makes it difficult for a segment of the population to exercise the Radio-Off option. Further, it is unclear why a one-to-one telephone conversation with a customer service person could not "constitute a valid means of communicating a customer's choice to participate in FBC's Radio-Off Option." Meter technicians conducting site visits could also carry copies of the form, and concerned customers could fill them out with the technician's assistance at that time." (BCPSO Final Submission, p. 2)

FortisBC in reply asserts that it is standard and reasonable practice to require signed forms and a clear record of customer participation. FortisBC further suggests that customers with challenges with regard to literacy or cognitive ability can seek assistance in filling out the form from the FortisBC Contact Center staff or from friends, family or others as appropriate. (FortisBC Reply Submission, pp. 6-7)

FortisBC proposes that customers can elect to participate in the Radio-off AMI Meter Option at any time. (Exhibit B-7, CEC IR 6.1) The Commission Panel agrees with this proposal as being reasonable.

The Panel views the election of the Radio-off AMI Meter Option as comparable to the process customers must go through to elect other forms of service, including the obtaining of electric service in the first place. FortisBC must deal with customers at different levels of literacy or cognitive ability in initiating these services. The Panel believes that the election process for participating in the Radio-off AMI Meter Option should be no more onerous than the process for initially obtaining electrical service. **FortisBC is directed to confirm with the Commission on or before January 27, 2014 that the enrolment process for the Radio-off AMI Meter Option is comparable to the process a customer must follow to obtain general electric service. Processes that impose an unnecessary barrier for those wishing to avail themselves of the service are not acceptable to the Commission.**

2.4.2 Change of Circumstances Argument

RDCK challenged the Application on the basis that "a change of circumstances" has occurred, specifically due to the following events:

> "On September 25, 2013, the Lieutenant Governor in Council issued Enacting Direction No. 4 (B.C. Reg. 203/2013, 319/2013) to the B.C. Utilities Commission and, on October 9, 2013, with respect to an application by B.C. Hydro for Approval of Charges Related to the Meter Choices Program, the Commission issued Order G-166-13 which stated in part:
>
> *"B. The Lieutenant Governor in Council issued Direction No. 4 on September 25, 2013, and provides direction to the BCUC with respect to implementing the Government of British Columbia policy that BC Hydro will offer new meter options and related services to eligible customers who choose not to have a smart meter at their premises, and that eligible customers choosing an alternative meter option will have to pay additional charges designed to recover the costs attributable to their chosen option;*
>
> *C. Section 3(2) of Direction No. 4 provides direction to the BCUC to allow BC Hydro to establish a regulatory account for the recovery of program costs, investigation costs and infrastructure costs not recovered from customers at premises where a legacy meter or radio-off meter is installed, and costs related to smart meters, which are incurred during the period of January 1, 2013 to March 31, 2014. In accordance with section 3(2), BC Hydro proposes to add these costs to the existing SMI Regulatory Account established pursuant to Commission Order G-64-09 to avoid the creation of a new regulatory*

> *account, to enable BC Hydro to recover those costs in the same manner as SMI Program costs, and is consistent with Direction No. 4;*
>
> *. . .*
>
> *E. Pursuant to the Government policy, BC Hydro is offering the following meter options to eligible customers that do not have a smart meter installed at their premises:*
>
> *1. the installation of a standard smart meter,*
> *2. the installation of a radio-off meter, or*
> *3. the existing legacy meter can remain installed at the premises;""*
>
> (RDCK Final Submission, para. 5)

FortisBC in reply disagrees that there is a significant change in circumstances, stating:

> "There has been no change in circumstances applicable to FortisBC or this Application since the Commission Radio-Off Principles were set out by the Commission in its Decision on FortisBC's AMI CPCN Application. The BC Hydro Direction does not change the facts which were before the Commission on the AMI CPCN Application but, rather, expresses the Government's instructions (made without engagement in a process similar to that which the Commission undertook) with regard to BC Hydro, the publicly-owned utility. If the Government had intended to bind the Commission in respect of dealings with FortisBC and its customers, it could have enacted a regulation or other legislation which applied generally or applied expressly to FortisBC. Further, the Commission has previously held that the rates applicable to FortisBC and BC Hydro need not be the same. The Commission Panel involved in FortisBC's 2012-2013 Revenue Requirements Application, where such issues were canvassed, noted that it had "no mandate, nor does it find it appropriate, to require FortisBC to manage its utility business to produce rates or programs identical to those of BC Hydro."
> (FortisBC Reply Submission, pp. 2-3)

The Panel finds that directions from the Government of British Columbia to the Commission relating to BC Hydro have no bearing on FortisBC's application for a Radio-off AMI Meter Option. The Panel concurs with the statement made by the Commission in the FortisBC 2012-2013 Revenue Requirements and Integrated System Plan Decision[4] that the Commission has "no mandate, nor does it find it appropriate, to require FortisBC to manage its utility business to produce rates or programs identical to those of BC Hydro."[5]

2.4.3 Argument that the Application is Discriminatory and Violates both the Canadian Charter of Rights and Freedoms and the Human Rights Act

A further challenge to the Application was raised by Citizens for Safe Technology Society (CSTS). CSTS argues that because there are no special provisions with respect to the fees to be charged to persons with disabilities, such as those who are sensitive to electromagnetic radiation, the opt-out program put forward by FortisBC will have a discriminatory effect and hence is in violation with the *Canadian Charter of Rights and Freedoms* (Charter), and specifically with Section 15 of the Charter. (CSTS Final Submission, pp. 17-18)

Section 15 of the Charter states:

> (1) Every individual is equal before and under the law and has the right to the equal protection and equal benefit of the law without discrimination and, in particular, without discrimination based on race, national or ethnic origin, colour, religion, sex, age or mental or physical disability.

4 *In the Matter of an Application by FortisBC Inc. for Approval of 2012-2013 Revenue Requirements and Review of the 2012 Integrated System Plan,* Decision and Order G-110-12, August 15, 2012 (2012-2013 RRA/ISP Decision)
5 2012-2013 RRA/ISP Decision**,** pp. 20-21**.**

(2) Subsection (1) does not preclude any law, program or activity that has as its object the amelioration of conditions of disadvantaged individuals or groups including those that are disadvantaged because of race, national or ethnic origin, colour, religion, sex, age or mental or physical disability.

FortisBC in reply notes that (a) the Charter is "limited to government actors" and does not apply to FortisBC as a privately owned company; (b) there is no evidence to support that the opt-out fees would be in breach of Section 15 of the Charter; and (c) there is no discrimination on any other grounds found in the Charter. FortisBC states that the Commission in the AMI Decision was not persuaded that there is a causal link between RF emissions and electromagnetic hypersensitivity (EHS). FortisBC further submits that "the Radio-Off Option does not constitute discrimination under the Human Rights Code, R.S.B.C. 1996, c. 210, which is the subject of one case that CSTS includes in its submission (though CSTS does not specifically claim in its submissions that it will be violated)" as it is equally available to all eligible customers. (FortisBC Reply Submission, pp. 19-22)

RDCK submits that charging different rates based upon meter preference is discriminatory under section 59 of the *Utilities Commission Act* (Act). (RDCK Final Submission, para. 10) In reply, FortisBC states that "the proposed Radio-Off Option fees do not constitute rate discrimination under section 59 of the *Utilities Commission Act* or at all. All eligible FortisBC customers have access to the same AMI meters at the same prices. They may choose the default radio-on AMI meters or, if they wish, radio-off AMI meters at a price representing the additional incremental costs associated with providing and reading radio-off AMI meters." (FortisBC Reply Submission, para. 54)

The issue of potential discriminatory effects of the AMI project on persons who claim to be sensitive to electromagnetic radiation was first raised in the AMI Proceeding. In that proceeding, after a full consideration of the applicability of the Charter, including Section 15, the Commission Panel agreed with FortisBC that the Charter does not apply to non government actors. Although this issue of violation of the Charter rights of individuals with disabilities has again been raised, there has been no additional analysis provided concerning the applicability of the Charter to FortisBC. **Accordingly, the Panel finds the Charter is not applicable to FortisBC.**

The Panel also finds that the Radio-off AMI Meter Option put forward by FortisBC, including the fees that must be paid, is not discriminatory under the *Human Rights Code.* Parties are free to choose if they will participate in the program and all parties making this choice are treated in an equal manner.

The Panel notes that the Radio-off AMI Meter option is available under exactly the same terms to all FortisBC ratepayers, as is the radio-on option. Each of the options has its own costs and attributes, which are reflected in the rates. The Panel finds that charging different rates based upon meter preferences is not unduly discriminatory under section 59 of the Act.

2.5 Context of the Decision

The Commission Panel, in reviewing the Application, has considered sections 59 and 60 of the Act. Specifically:

Section 59(1) of the Act states:

"A public utility must not make, demand or receive

(a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia, or
(b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law."

Section 59(5) of the Act states:

"In this section, a rate is "unjust" or "unreasonable" if the rate is

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,
(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or
(c) unjust and unreasonable for any other reason."

Section 60(1)(a) of the Act states:

"In setting a rate under this Act
(a) the commission must consider all matters that it considers proper and relevant affecting the rate
(b) the commission must have due regard to the setting of a rate that
(i) is not unjust or unreasonable within the meaning of section 59...
(iii) encourages public utilities to increase efficiency, reduce costs and enhance performance,"

The definition of "rate" in section 1 of the Act includes "a general, individual or joint rate, fare, toll, charge, rental or other compensation of a public utility." In this proceeding and Decision, the term 'fee' and 'rate' have the same meaning.

The Panel has assessed this Application in the same manner that it assesses any application for a new rate or service. Specifically, the Panel is concerned that FortisBC provide the service using rates that are not unjust, unreasonable or unduly discriminatory while meeting the opt-out principles set out by the Commission in the AMI Decision. The costs for both the Per-premises Setup Fee and for the Per-read Fee must be just and reasonable. Charges should recover only the incremental costs that should be properly attributed to the customers electing to use this optional service in order to ensure there is not a cross-subsidy by the customers not opting out.

Any deviation from the principle of setting the rates in a just and reasonable manner, or the putting in place of unnecessarily onerous processes for applying for the service, which could provide a barrier to those wishing to avail themselves of the service, is not acceptable.

3.0 RATE IMPLICATIONS

3.1 Estimates

The AMI Decision requires the individual choosing to opt-out to bear the incremental cost of opting-out of the AMI program.[6] In the Application, costs are identified for two activities, specifically $110 for the Per-premises Setup Fee (Exhibit B-1, p. 5) and $22 for the Per-Read Fee (Exhibit B-1, p. 7). To arrive at these fees the Application identifies the work associated with each activity and the resulting labour and vehicle costs, in addition to other cost estimates and assumptions, such as the Radio-off AMI Meter Option participation rate. FortisBC presents these components as inputs to the total cost for each activity and the proposed fee.

The Panel has serious concerns about the accuracy of the stated costs and will not accept the proposed Per-premises Setup Fee and Per-read Fee for the following reasons.

During the IR process it became apparent that several of the inputs to the Radio-off AMI Meter Option fees are not precise. Rather they are estimates developed looking at the work as discreet building blocks and in isolation of other work which offers opportunities for an increase in efficiency, reduced cost and enhanced performance.

In response to BCUC IR 3.1 (Exhibit B-4) concerning the costs for Metering Analyst time included in the Per-premises Setup Fee FortisBC states:

> "The detailed process (and resulting timings) required for this function are to be developed during the Define/Design stage of the project. At that time, more precise definitions and work breakdowns (between Meter Analyst and Contact Centre work) will be known and assigned."

[6] Order C-7-13, Directive 1(c); AMI Decision, p. 148.

This qualification was repeated for the costs for Contact Center time included in the Per-premises Setup Fee. (Exhibit B-4, BCUC IR 5.3)

With respect to the vehicle cost inputs to the Per-read Fee Fortis BC states:

> "It is anticipated that there will be no vehicles assigned solely to meter reading. It is anticipated that the work associated with gathering a relatively small number of manual meter reads from disparate locations throughout the service territory will form part of other roles within the Company – roles for which vehicles are already assigned.
>
> Final decisions of this nature will be concluded during the Define/Design phase of the project."
>
> (Exhibit B-4, BCUC IR 6.3)

In its Final Submission FortisBC states:

> "54, Due to inherent uncertainty in the Contact Centre and Metering Analyst time estimates, FortisBC proposes the following reconciliation process.
>
> (a) FortisBC will track actual meter analyst costs directly related to the activities described in paragraphs 52 and 53, above, starting November 1, 2013 and until the AMI project is complete;
>
> (b) Within three months of AMI project completion, FortisBC will file a report with the Commission detailing the meter analyst costs incurred and the number of Radio-Off Option meter installations;
>
> (c) If the sum of the average meter analyst and TCC [undefined, but taken to refer to the Contact Centre] costs per Radio-Off Option meter differs by more than $5 from the estimate in this Application (excluding range extender costs), FortisBC will adjust the fees as follows:
>
> (i) If the actual average cost is less than the estimated cost by more than $5, FortisBC will retroactively refund the difference, with interest, to Radio-Off Option Customers and adjust the tariff rate to the actual average cost on a go-forward basis;
> (ii) If the actual average cost is more than the estimated cost by more than $5, FortisBC will adjust the tariff rate to the actual average cost on a go-forward basis. For clarity, FortisBC does not intend to retroactively charge Radio-Off Option Customers for these additional costs."
>
> (FortisBC Final Submission, pp. 16-17)

Section 2.5 of this Decision explains the expectations of the Commission with respect to providing the Radio-off AMI Meter Option using rates that are just, reasonable and not unduly discriminatory. The Commission accepts that FortisBC has not yet had an opportunity to turn its mind to any detailed process planning for the opt-out related activities. The Commission expects that FortisBC will approach this planning work with the objective of finding all efficiencies possible in providing the Radio-off AMI Meter Option service. This work will take some time. In the meantime, customers who are considering opting-out must be given rates that are just and reasonable. The following sections of this Decision set out the Panel's determination in this regard.

3.2 Per-premises Setup Fee

FortisBC proposes a Per-premises Setup Fee of $110 to recover the costs associated with configuring a Radio-off AMI Meter within the AMI system. FortisBC asserts that this covers all incremental labour costs for FortisBC Contact Centre and Metering Analyst staff time, in addition to incremental capital costs. The components of the proposed Per-premises Setup Fee are presented in the following table:

Proposed Per-premises Setup Fee	Minutes	Rate	Total per Customer
Contact Centre	60	$ 51.41	$ 51.41
Metering Analyst	60	$ 57.14	$ 57.14
Allowance for RF Range Extenders			$ 2.12
Total			$ 110.67
Proposed Per-premises Setup Fee			**$ 110.00**

(Exhibit B-1, p. 5)

For the reasons outlined below, the Panel does not find the Per-premises Setup Fee of $110 proposed by FortisBC in the Application to be just and reasonable. In addition, the Panel finds it appropriate that there should be a separate Per-premises Setup Fee for those customers who elect to participate prior to the commencement of AMI project deployment in their particular region and those who elect to participate after this time.

FortisBC proposes to provide 30 days notice to customers of AMI project deployment in their particular region. Accordingly, the pre-AMI project deployment Per-premises Setup Fee outlined below in this Decision is for those customers who elect to participate prior to the commencement of AMI project deployment *in their particular region* rather than prior to overall AMI project deployment. The process and deadlines for this are discussed further in Section 3.2.4 of this Decision.

The Panel has assessed the cost components behind the Per-premises Setup Fee and determined fees that are just and reasonable. The Panel used the best data made available in the evidence. It then rounded the resulting fees, recognizing that some uncertainties still remain. **The following Per-premises Setup Fees are approved:**

Pre-Commencement of AMI Project Deployment

Approved Per-premises Setup Fee	Minutes	Rate	Total per Customer
Contact Centre	35	$ 50.50	$ 29.46
Metering Analyst	30	$ 56.13	$ 28.06
Allowance for RF Range Extenders			$ 2.12
Total			$ 59.64
Final Approved Per-premises Setup Fee			**$ 60.00**

Post-Commencement of AMI Project Deployment

Approved Per-premises Setup Fee	Minutes	Rate	Total per Customer
Contact Centre	35	$ 50.50	$ 29.46
Metering Analyst	60	$ 56.13	$ 56.13
Allowance for RF Range Extenders			$ 2.12
Total			$ 87.71
Final Approved Per-premises Setup Fee			**$ 88.00**

3.2.1 Per-premises Setup Fee – Pre-Commencement of AMI Project Deployment

3.2.1.1 Cost Components

Contact Centre

The Contact Centre costs included in the Per-premises Setup Fee are a function of both time estimate and an hourly rate. The Panel considers each of these components individually.

The Per-premises Setup Fee includes $51.41 for one hour of FortisBC Contact Centre staff time. The hourly labour rate of $51.41 is calculated by inflating the 2010 Contact Centre Agent hourly rate to 2016 at 1.8 percent per annum and adding a fringe benefit load factor. (Exhibit B-4, BCUC IR 5.1.1 - 5.1.1.1)

BCPSO contends that the labour costs included in the Per-premises Setup Fee, for both Contact Centre and Metering Analyst time, are "artificially inflated" to 2016 as the full deployment of the AMI is expected by the end of 2015. (BCPSO Final Submission, p. 3) In its Reply Submission, FortisBC maintains that the escalation to 2016 is reasonable given that the deployment will be complete at the end of 2015 and submits that "To the extent that there might be a slight overpayment by Radio-Off Option Customers who begin to exercise the Radio-off Option earlier than others, it will be offset by the likelihood of an adjustment lag (due to the use of 2016 dollars rather than 2017 dollars) until completion of the adjustment process in 2017 or later." (FortisBC Reply Submission, p. 15)

The Panel does not consider it reasonable to inflate the hourly labour rates used in the calculation of the Per-premises Setup Fee to arrive at a 2016 rate. The Panel expects that a significant portion of Radio-off AMI Meter Option customers will elect to participate in the program before the completion of deployment of the AMI project at the end of 2015. **Accordingly, the Panel considers it reasonable to inflate the hourly labour rates used in the calculation of the Per-premises Setup Fee, including both Contact Centre and Metering Analyst rates, to arrive at a 2015 rate. For the Contact Centre, this results in an hourly rate of $50.50.**[7]

One hour is an estimate for the time required for the following Contact Centre actions: discuss AMI-related concerns, prepare and print email information packages, discuss options, assist customers with application form, process the application form and forward the account to the Metering Analyst. FortisBC submits that the estimated amount of time required for each action is not provided in response to BCUC IR No. 1 (Exhibit B-4), given that "[t]he detailed process (and resulting timings) required for [the Contact Centre] function are to be developed during the Define/Design stage of the project." (Exhibit B-4, BCUC IR 5.3) In response to Directive 2 of Order G-176-13, FortisBC provided estimates of the amount of time required for each action required by the Contact Centre. The total average time for Contact Centre activities is 58.75 minutes. (Exhibit B-4-1, BCUC IR 5.2)

In response to BCUC IR 5.4 (Exhibit B-4), FortisBC submits that under the pre-AMI system the average time spent by the Contact Centre to set-up a new customer is 13 minutes if an account does not already exist and 9 minutes if an account does exist, in addition to 3 minutes on average to complete a billing order once a meter reading returns. Additionally, if the actual premises does not yet exist 19 additional minutes on average is required for various actions.

BCPSO asserts that only those costs incurred by the Contact Centre "from the point of processing the [application] Form forward" should be included in the Per-premises Setup Fee for two reasons. First, BCPSO argues that it is unfair that only those customers that participate in the Radio-off AMI Meter Option are charged a fee for their dealings with the Contact Centre when customers that ultimately choose not to participate in the Radio-off AMI Meter Option may call the Contact Centre regarding the Radio-off AMI Meter Option and request an information package. Second, BCPSO submits that the budget included in the FortisBC AMI Project CPCN application included incremental costs for an increased call volume to the Contact Centre in 2013, 2014 and 2015. (BCPSO Final Submission, p. 3)

[7] 2016 Contact Centre hourly rate of 2016 of $51.41 divided by 1.018 = $50.50.

Commission Determination

The Panel is not persuaded that that the Contact Centre time estimate used to calculate the Per-premises Setup Fee should be greater than 35 minutes, which is the highest end of the range of time required to setup a new customer in the pre-AMI system, under the most complex set of circumstances. The Panel finds that a Contact Centre time estimate of 35 minutes is reasonable.

The average amount of time to setup a new customer and complete a billing order under the pre-AMI system can be as little as 12 minutes if an account already exists. On the highest end of the range, in those situations where both an account and the premises do not yet exist, the average amount of time to setup a new customer is 35 minutes. However, the Panel expects that the majority of customers choosing to participate in the Radio-off AMI Meter Option, particularly in the early stages of the program, will likely already have accounts and premises. The Panel recognizes that in the context of the Radio-off AMI Meter Option additional time may be required to discuss issues specific to the Radio-off AMI Meter Option program.

The Panel also takes note of BCPSO's submission regarding the Contact Centre costs included in the Per-premises Setup Fee. The Panel agrees with BCPSO that customers that ultimately choose not to participate in the Radio-off AMI Meter Option may call the Contact Centre to discuss their concerns and options surrounding the program and request an information package, in addition to those customers that do elect to participate in the Radio-off AMI Meter Option.

The Panel accepts that it is reasonable to include Contact Centre time for performing administrative tasks associated with preparing the account for those customers who have elected to participate in the Radio-off AMI Meter Option in the calculation of the Per-premises Setup Fee. These administrative tasks include assisting customers with the application form, processing the application form and forwarding the account to the Metering Analyst. However, Contact Centre time for discussing AMI-related concerns, preparing and printing email information packages and discussing options are likely to be incurred in connection with both Radio-off AMI Meter Option participants and those customers that ultimately elect to not participate in the program. FortisBC estimates that these tasks will comprise 41.25 minutes of the one hour time estimate. (Exhibit B-4-1, BCUC IR 5.2) Accordingly, excluding these tasks would reduce the Contact Centre time proposed in the Application to 18.75 minutes.

Based on the estimate provided, the other Contact Centre enrollment activities identified in IRs and recognizing that this is a new activity, the Panel considers it reasonable to base its decision on the 35 minute average time to setup a new customer in the pre-AMI system under the most complex set of circumstances. **Using the time estimate of 35 minutes and an hourly rate of $50.50, the Panel finds that the reasonable Contact Centre cost per customer to include in the Per-premise Setup Fee is $29.46.**[8]

<u>Metering Analyst</u>

The Metering Analyst costs included in the Per-premises Setup Fee are a function of both a time estimate and an hourly rate. The Panel considers each of these components individually.

The Per-premises Setup Fee includes $57.14 for one hour of Metering Analyst staff time. The hourly labour rate of $57.14 is calculated by increasing the 2011 hourly rate for a Metering Analyst to 2016 at 1.8 percent per annum and adding a fringe benefit load factor. (Exhibit B-4, BCUC IR 2.1.1)

Under the Radio-off AMI Meter Option program, FortisBC proposes that the installation, in instances where a standard AMI meter is not yet installed, and configuration within the AMI system of the Radio-off AMI Meters be performed by FortisBC employees. (Exhibit B-4, BCUC IR 3.3) This is different from the deployment of standard radio-on AMI meters, which will be subcontracted under the Itron contract at an estimated average per meter deployment cost of $39. (Exhibit B-4-1, Additional BCUC IR 1.0) FortisBC has not factored in any AMI-deployment cost savings into the Per-premises Setup Fee for the following reasons:

8 2015 Contact Centre hourly rate of $50.50 x 35/60 = $29.46.

> "Without a reasonable way to forecast the proportion of radio-off customers that may decide that they wish to have a radio-off meter after deployment is complete or that decide to refuse a meter installation (and then apply for a radio-off meter) when the AMI installer attends their premises, FortisBC has assumed that there will be no AMI deployment-related cost savings. Also, there would be no avoided project costs after AMI deployment was completed at the premises, or in cases where the AMI installer otherwise properly attended the radio-off premises to install a regular AMI meter." (Exhibit B-4-1, Additional BCUC IR 2.0)

One hour of Metering Analyst staff time is an estimate for the time required for the following actions: processing the application form, searching the CIS system [undefined, but taken to refer to the Customer Information System] for relevant information, physically retrieving the meter from inventory, downloading security keys, driving to the premises, exchanging the meter, disabling the LAN and downloading meter information, driving back to the office and configuring the customer meter within CIS. FortisBC submits that "[t]he travel time to attend the customer premises is expected to be a significant portion of the hour." (Exhibit B-4, BCUC IR 3.1; Exhibit B-4-1, BCUC IR 3.1) Like the Contact Centre time, FortisBC did not provide the estimated amount of time required for each action in response to BCUC IR 1 (Exhibit B-4) but did provide the estimate in response to Directive 2 of Order G-176-13. (Exhibit B-4-1, BCUC IR 3.1)

In response to BCUC IR 3.1.2 (Exhibit B-4), FortisBC submits that under the pre-AMI system the average time spent by an employee in a role similar to the Metering Analyst to setup a new customer and connect them to a new meter is 45 minutes. This includes the time required to perform the following actions: retrieve order request, confirm required meter type, retrieve meter from warehouse, install meter, seal meter and update order request with installation details. FortisBC notes that this time can vary, depending on the installation location.

BCPSO submits that the costs associated with Metering Analyst time included in the Per-premises Setup Fee should be lower for those customers that choose to participate in the Radio-off AMI Meter Option after an AMI meter has been installed at their premises. (BCPSO Final Submission, p. 4)

Commission Determination

For the reasons outlined above, the Panel does not consider it reasonable to inflate the hourly labour rates used in the calculation of the Per-premises Setup Fee to arrive at a 2016 rate. The Panel finds that the hourly labour rates used in the calculation of the Per-premises Setup Fee should be inflated to arrive at a 2015 rate. For the Metering Analyst, this results in an hourly rate of $56.13.[9]

The Panel is not persuaded that one hour is a reasonable Metering Analyst time estimate for those customers that elect to participate in the Radio-off AMI Meter Option prior to AMI project deployment in their region. The Panel finds that a Metering Analyst time estimate of 30 minutes is reasonable.

For context, the average amount of time to connect a new customer to a new meter under the pre-AMI system is 45 minutes. In addition, the Panel considers that the following actions will be required during AMI project deployment, regardless of whether or not the customer receiving the meter chooses to participate in the Radio-off AMI Meter Option program or not:

- Physically retrieving the meter from inventory;
- Driving to the customer premises;
- Exchanging the meter; and
- Driving back to the office.

[9] 2016 Metering Analyst hourly rate of 2016 of $57.14 divided by 1.018 = $56.13.

The estimated amount of time for the above-noted actions as part of the one hour estimate of Metering Analyst time is 30 minutes. (Exhibit B-4-1, BCUC IR 3.1)

An alternative approach that could be considered is the deduction of the $39 estimated average per meter deployment cost under the AMI project from the FortisBC Metering Analyst costs. However, the Panel does not consider this to be reasonable, given that the installation and deployment of meters under the Radio-off AMI Meter Option and the AMI project require different actions as they are treated as two separate programs.

Given that several actions included in the FortisBC Metering Analyst time estimate will be required during AMI project deployment, regardless of whether or not the customer receiving the meter chooses to participate in the Radio-off AMI Meter Option program, the Panel finds that a 30 minute time estimate is reasonable.

Using the time estimate of 30 minutes and an hourly rate of $56.13, the Panel finds that the reasonable Metering Analyst cost per customer to include in the Per-premises Setup Fee is $28.06. [10]

Allowance for RF Range Extenders

The Per-premises Setup Fee includes $2.12 per customer for additional RF range extenders required to preserve the reliability of the RF mesh in the presence of the "network gaps" created by the AMI Radio-off Meters. (Exhibit B-1, p. 5) FortisBC assumes 2.1 additional RF range extenders will be required, with capital and installation costs of $187 and $520 per unit, respectively. FortisBC proposes to recover the total incremental capital and installation costs related to additional RF range extenders from Radio-off AMI Meter Option participants through the one-time Per-premises Setup Fee. (Exhibit B-2, Electronic Attachment, "Radio-off Fee Derivation")

The Irrigation Ratepayers Group (IRG) supports the cost estimate for the RF range extenders as reasonable. (IRG Final Submission, para. 31)

The Commercial Energy Consumers Association of British Columbia (CEC) argues that there is other equipment required to manually read the Radio-off AMI Meters and that these should be accounted for as incremental costs in the Per-premises Setup Fee; however, CEC notes that these costs are "not likely [to] add more than a few percent to the total installation fee." (CEC Final Submission, p. 8)

CSTS submits that the cost of RF range extenders should not be included in the Per-premises Setup Fee as the cost is "inappropriate, unprincipled and unfair" and is "arbitrary and based on conjecture." (CSTS Final Submission, pp. 7-8)

Commission Determination

The Panel accepts the capital and installation costs associated with the additional RF range extenders of $2.12 per customer included in the Per-premises Setup Fee as reasonable. With respect to the method of recovery of these costs from the Radio-off AMI Meter participants, the Panel recognizes that alternatively, the depreciation costs associated with the RF range extenders could be recovered from participants through the Per-read Fee. **However, in order to ensure that the full amount of incremental costs are recovered from Radio-off AMI Meter Option participants and considering that the capital and installation costs are relatively small compared to the other Per-premises Setup Fee costs, the Panel finds the proposed method of recovery to be reasonable.**

3.2.2 Per-premises Setup Fee – Post-Commencement of AMI Project Deployment

The approved Per-premises Setup Fee for those customers that elect to participate in the Radio-off AMI Meter Option subsequent to the commencement of the AMI project deployment in their region is summarized on page 14 of this Decision.

[10] 2015 Hourly labour rate of $56.13 x 30/60 = $28.06

3.2.2.1 Cost Components

Contact Centre

The Panel does not find any reason to vary the Contact Centre costs included in the Per-premises Setup Fee for those customers that elect to participate in the Radio-off AMI Meter Option subsequent to commencement of AMI program deployment in their region. Contact Centre costs are discussed in Section 3.2.1.1 of this Decision.

Metering Analyst

As discussed in Section 3.2.1.1 of this Decision, the Panel finds that an hourly rate of $56.13 for the Metering Analyst is reasonable for use in the calculation of the Per-premises Setup Fee.

For those customers that elect to participate in the Radio-off AMI Meter Option subsequent to the commencement of AMI project deployment in their region, the Panel accepts the Metering Analyst time estimate of one hour as reasonable. These customers include existing Radio-off AMI Meter Option participants that move from one property to another and new Radio-off AMI Meter Option participants.

The majority of Metering Analyst actions included in the one hour time estimate will be required following the mass deployment of AMI meters, regardless of whether or not the premises already has a standard radio-on AMI meter installed. As noted by FortisBC, the majority of the one hour time estimate is for driving to and from the customer premises. Driving to and from the customer premises is estimated to take 20 minutes of the one hour time estimate; however, FortisBC submits that it could vary depending on where the customer is located within the service territory. (Exhibit B-4-1, BCUC IR 3.1) This action will be required in all instances and will result in incremental costs.

The Panel is aware that a few actions will not be required if the premises already has a standard radio-on AMI meter installed, specifically retrieving the meter from inventory and exchanging the meter. FortisBC estimates that these actions will require 10 minutes of the one hour time estimate (Exhibit B-4-1, BCUC IR 3.1). However, given that the time estimate related to driving to and from the customer premises could vary from the 20 minute time estimate, the Panel does not consider it appropriate to make any adjustments to FortisBC's one hour Metering Analyst time estimate proposal.

The Panel notes that FortisBC has not included any vehicle costs in the calculation of the Per-premises Setup Fee, while an hourly vehicle rate of $23.95 was used in the calculation of the Per-read Fee discussed below in Section 3.3.3 of this Decision. There is no evidence on the record in this proceeding regarding vehicle costs as they relate to the Per-premises Setup Fee and accordingly, the Panel has not considered these costs further here.

Allowance for RF Range Extenders

The Panel does not find any reason to vary the allowance for RF range extenders included in the Per-premises Setup Fee for those customers that elect to participate in the Radio-off AMI Meter Option subsequent to commencement of AMI program deployment in their region. RF range extenders are discussed in Section 3.2.1.1 of this Decision.

3.2.3 Adjustment Mechanism

FortisBC acknowledges that there is uncertainty regarding the estimate of Contact Centre and Metering Analyst costs. Accordingly, in response to Directive 2 of Order G-176-13 FortisBC proposes a reconciliation process for these costs. Under the proposed process, FortisBC will submit a report to the Commission within three months of the completion of the AMI project detailing the actual Metering Analyst and Contact Centre costs incurred and the number of Radio-off AMI Meter installations starting on November 1, 2013 until the project is complete. If the average cost per customer is less than the estimated cost by more than $5, FortisBC will retroactively refund the difference. If the average cost per customer is greater than the estimated cost by more than $5, FortisBC will adjust the rate on a go-forward basis. Capital costs related to the RF range extenders are excluded from the reconciliation process proposed by FortisBC. (Exhibit B-4-1, BCUC IR 3.1, 5.2)

IRG supports the adjustment mechanism proposed by FortisBC in response to Directive 2 of Order G-176-13. (IRG Final Submission, para. 30)

BCPSO argues that there is uncertainty regarding the number of RF range extenders that will be required because of the Radio-off AMI Meter Option and accordingly submits that these costs should be included in the adjustment mechanism process proposed by FortisBC. (BCPSO Final Submission, p. 5)

CEC submits that overhead charges could be applicable to Contact Centre and Metering Analyst costs and should be included any future Commission review of costs. (CEC Final Submission, p. 8)

Commission Determination

The Panel does not consider it reasonable to retroactively adjust or refund the Per-premises Setup Fee charged. To do so would create rate uncertainty for those customers making a decision as to whether or not to participate in the Radio-off AMI Meter Option. Removing rate uncertainty is consistent with the Commission's approach to setting rates based on evidence provided in a rate proceeding. Accordingly, the Panel sets the Per-premises Setup Fee as permanent. For clarity, the Premises Setup Fee is $60 for those customers that elect to participate prior to the commencement of AMI project deployment in their region and $88 for those customers that elect to participate after this time.

After full implementation of the AMI project FortisBC may bring forward an application for review of future Radio-off AMI Meter Option rates, following its normal practice.

3.2.4 Process

FortisBC proposes in the Application that all customers will receive notice 30 days prior to scheduled AMI project deployment in their region. The notice will "...clearly indicate that customers can select the Radio-Off Option, set out the means by which that choice must be communicated to FortisBC, and provide the fee schedule associated with that option." (Exhibit B-1, p. 4)

As highlighted in Section 3.2 of this Decision, the Panel finds it appropriate that there should be a separate Per-premises Setup Fee for customers who elect to participate prior to the commencement of AMI project deployment in their particular region. **FortisBC is directed to report to the Commission on or before January 27, 2014 on the process and deadlines for those customers that elect to participate in the Radio-off AMI Meter Option prior to commencement of the AMI project deployment in their region. The report must include the following:**

- **Final process and timeline for notifying customers of the scheduled AMI project deployment in their region, including the number of days notice that will be provided;**
- **Final process and timeline for notifying customers of both the Radio-off AMI Meter Option, and the requirements and deadlines for opting out prior to the commencement of AMI project deployment in their region; and**
- **The number of days ahead of AMI project deployment in their region that will be required for customers to elect to participate in the Radio-off AMI Meter Option in order to qualify for the $60 Per-premises Setup Fee.**

In the event that this activity must be developed during the Define/Design stage of the AMI project and will not be available by the stated deadline, FortisBC may apply for relief.

3.3 Per-read Fee

FortisBC proposes a Per-read Fee of $22 to recover the cost of manually downloading consumption and operational data from Radio-off AMI Meters on a bi-monthly basis. FortisBC asserts that this covers all incremental labour costs for FortisBC staff involved in the manual meter reading process, in addition to incremental vehicle costs.

For the reasons outlined below, the Panel finds that a Per-read Fee of $18 is reasonable. This is calculated by applying the determinations described below with respect to the total time per read and hourly vehicle rate to FortisBC's financial model, included in Exhibit B-2, Electronic Attachment, "Radio-off Fee Derivation."

The Panel assessed the cost components of the Per-read Fee and determined fees that are just and reasonable. The Panel used the best data made available in the evidence. It then rounded the resulting fee, recognizing that some uncertainties still remain.

3.3.1 Alternatives to Bi-monthly Manual Meter Reading

Several of the Interveners contend that alternatives to the bi-monthly manual meter reading process proposed by FortisBC could reduce costs to Radio-off AMI Meter Option participants. Specifically, BCPSO questioned "...whether a few less manual meter reads per year by FBC (supplemented by customer self-reads) would impact the theft reduction and other benefits of the AMI system enough that it would outweigh the costs saved by avoiding manual reads." (BCPSO Final Submission, p. 8)

CSTS submits that manual meter reading by FortisBC staff should be required as little as annually and proposes monthly billing based on either of the following methods:

1. Estimates based on prior year's billings;
2. Customer reporting by phone, photograph or web portal. (CSTS Final Submission, p. 5)

FortisBC maintains that the process of manually downloading consumption and operational data from Radio-off AMI Meters by FortisBC staff on a bi-monthly schedule is required in order to preserve certain benefits of the AMI project, in particular the theft reduction benefits. Theft reduction benefits are dependent on the collection of hourly interval data from AMI meters, which is used for the energy balancing. (Exhibit B-5, BCPSO IR 2.1) In addition, FortisBC submits that bi-monthly manual meter reading also maintains safety and outage response benefits and the expected conservation effect of the AMI project. (Exhibit B-4, BCUC IR 9.4)

British Columbia Sustainable Energy Association and Sierra Club British Columbia (BCSEA), CEC and IRG support the bi-monthly manual meter reading process proposed by FortisBC, in order to preserve the benefits of the AMI project. (IRG Final Submission, paras. 17-18; CEC Final Submission, p. 3) BCSEA submits that "The theft-reduction benefit of the AMI program depends on the utility receiving hourly interval data from all the AMI-meters at least bimonthly. Retrieving the interval data from the meter requires a specialized device and computer security measures." (BCSEA Final Submission, pp. 7-8)

Commission Determination

The Panel finds that downloading consumption and operational data from Radio-off AMI Meters on a bi-monthly basis appropriately preserves certain benefits of the AMI project. Namely, the collection of hourly interval data is required in order to preserve the theft reduction benefits of the AMI project. In the view of the Panel, the bi-monthly process proposed by FortisBC is a reasonable balance between the immediate collection of hourly interval data from standard radio-on AMI meters contemplated as part of the AMI project and the submissions by several Interveners that the meter reading frequency should be reduced to less than bi-monthly or supplemented with customer self-reads. In addition, the Panel notes that the practice of bi-monthly meter reading is consistent with existing rate schedules. (FortisBC Reply Submission, p. 13)

3.3.2 Participation Rate

The proposed Per-read Fee of $22 assumes a Radio-off AMI Meter Option participation rate of 0.5 percent, based on the experience of similar programs in the United States. FortisBC collected data from the November 2012 issue of *Power Grid International*, where the average opt-out rate of seven similar programs in the United States is 0.4 percent. (Exhibit B-2, November 2012 issue of *Power Grid International*, "Smart Meter Opt-out Policies Explained", p. 3) FortisBC submits that "Because the Company recognises that there is controversy about what the actual participation rate will be, it submits that that its conservative estimate is an appropriate compromise between the experience of utilities in other jurisdictions and the possibility that a larger than expected number of customers will wish to select the Radio-off Option." (FortisBC Reply Submission, p. 9)

In response to BCUC IR 1.3 and 1.3.1 (Exhibit B-4), FortisBC submits that the only other jurisdiction in Canada that it is aware of with a fee-based opt-out program is Quebec, where Hydro Quebec reports an approximate opt-out rate of 0.2 percent as of June 30, 2012.

Some Interveners argue for participation rates other than 0.5 percent. RDCK submits that the participation rate proposed by FortisBC underestimates the number of customers who want to participate in the Radio-off AMI Meter Option program. (RDCK Final Submission, para. 23) Conversely, CEC argues that 0.5 percent is overestimated and the 0.35 percent median participation rate experienced by similar programs in the United States should be chosen. (CEC Final Submission, p. 5)

CSTS contends that "... the preferable approach would be for FBC to determine what percent of its customer base wishes to opt out and to develop an opt-out fee structure on the basis of a predetermined participation rate. In the interim, any opt-out out fee should be suspended or set at a nominal level so as to ensure that no willing participant is deterred by a fee that ultimately fails to receive final approval." (CSTS Final Submission, p. 16) In reply, FortisBC submits that a predetermined participation rate is not a feasible approach given that customers will not know the approved fees in advance. (FortisBC Reply Submission, p. 9)

IRG finds the 0.5 percent participation rate proposed by FortisBC to be reasonable. (IRG Final Submission, para. 22)

Commission Determination

The Panel is in agreement with FortisBC that 0.5 percent is an appropriate compromise between the 0.4 percent average opt-out rate experienced by similar programs in the United States and the possibility that the actual participation rate may be higher than expected. The 0.5 percent participation rate is based on the experience of similar programs in the United States, where the average opt-out rate is 0.4 percent. The Panel notes that the opt-out rate reported by Hydro Quebec as of June 30, 2012 is lower at 0.2 percent; however, this is based on experience during the implementation phase and accordingly, is not representative of the completed project.

The Panel considers that the CSTS proposal to suspend the opt-out fee or set the opt-out fee at a nominal rate is not feasible given that customers would not have the fee information required to make a decision as to whether or not to participate in the Radio-off AMI Meter Option.

3.3.3 Cost Components

The proposed Per-read Fee of $22 includes all incremental labour and vehicle costs required to manually download consumption and operational data from Radio-off AMI Meters, based on FortisBC's estimated total time per read of 16 minutes. (Exhibit B-2, Electronic Attachment, "Radio-off Fee Derivation")

Total Time per Read

The estimated total time per read of 16 minutes is comprised of 13 minutes of travel time and 3 minutes of read time, which captures the time to manually download data from the Radio-off AMI Meter. The travel time estimate assumes that the Radio-off AMI Meter Option participants are equally distributed over the FortisBC service territory and that the average travel speed between reads is 30 km/hr. (Exhibit B-1, p. 6; Exhibit B-2, Electronic Attachment, "Radio-off Fee Derivation")

With respect to the average travel speed of 30 km/hr., FortisBC submits that the estimate was developed as follows:

"In the absence of existing data a sensitivity analysis using reasonably possible average travel speeds was performed. In determining "reasonably possible average travel speeds" it was assumed that balancing highway speeds utilized between rural locations of radio-off meters with "near walking speeds" utilized in urban areas would result in an average speed somewhere below legal urban speed limits.

The sensitivity analysis resulted in the following (where "Travel time" includes both "Between read time" and "Mobilization time"):

Sensitivity to Travel Time	
at 20kmh :	20 min
at 30kmh :	13 min
at 40kmh=	10 min

FortisBC selected 30 km per hour as a reasonable average travel speed resulting in the average travel time of 13 minutes used as a component of the per read fee proposed." (Exhibit B-7, CEC IR 10.2.1)

The read time estimate is developed based on supplier estimates that the work involved in manually downloading interval data can take between 3 to 5 minutes. FortisBC submits that the selected read time estimate of 3 minutes is "[i]n keeping with the Company's conservative approach to estimating fees applicable to the proposed Radio-off option..." (Exhibit B-7, CEC IR 11.1)

IRG submits that there is uncertainty surrounding the travel time estimate, specifically the average travel speed and the distance between reads, given that the distribution of Radio-off AMI Meter Option participants is unknown. IRG proposes that the FortisBC estimate be implemented and adjusted for actual travel time at a later date. IRG supports the read time estimate proposed by FortisBC as reasonable. (IRG Final Submission, paras. 25-26, 35-36)

CEC argues that the travel time estimate is underestimated for several reasons. First, CEC contends that the travel time is linked to the participation rate, which it argues should be lower. Second, CEC submits that the average travel speed should be closer to 25 km/hr to reflect that "it is more likely that highway travel will occur once for a number of reads in a residential area increasing the proportion of slower residential area travel." CEC also argues that the read time estimate is underestimated and 4 minutes is more reasonable. (CEC Final Submission, pp. 6-7)

Commission Determination

The Panel finds a total time per read of 14 minutes in the calculation of the Per-read Fee to be reasonable. This allows for 10 minutes travel time and 4 minutes read time.

The Panel is in agreement with IRG that the travel time estimate is likely to vary from the actual travel time, given that the distribution of the Radio-off AMI Meter Option participants in the FortisBC service territory is presently unknown. **However, in the absence of evidence of the actual location of Radio-off AMI Meter Option participants at this time, the Panel considers the FortisBC assumption that the Radio-off AMI Meter Option participants are equally distributed over the FortisBC service territory to be reasonable.**

FortisBC notes that the sensitivity analysis provided in response to CEC IR 10.2.1 represents the "reasonably possible average travel speeds" derived by "balancing highway speeds utilized between rural locations of radio-off meters with "near walking speeds" utilized in urban areas." The sensitivity analysis provided includes "reasonably possible" speeds of 20 km/hr, 30 km/hr and 40 km/hr. FortisBC has not provided further details on why 30 km/hr specifically was chosen for the calculation of the Per-read Fee. The Panel questions the use of "near walking speeds" in FortisBC's calculation of reasonably possible speeds in urban areas. The Panel is not persuaded that 30 km/hr is a reasonable average travel speed. **The Panel finds that an average travel speed of 40 km/hr in the calculation of the Per-read Fee, which FortisBC includes in its sensitivity analysis of reasonably possible speeds, is reasonable.** Using FortisBC's financial model (included in

Exhibit B-2, Electronic Attachment, "Radio-off Fee Derivation") to make this adjustment results in an estimated travel time of 10 minutes.

The Panel finds a read time estimate of 4 minutes in the calculation of the Per-read Fee to be reasonable. The Panel agrees with CEC that a read time estimate of 4 minutes is more reasonable than the 3 minutes used by FortisBC in the calculation of the Per-read Fee, as this represents the average of the supplier's estimate that the work involved in manually downloading interval data takes between 3 to 5 minutes.

Labour and Vehicle Costs

The estimated total time per read is applied to the hourly labour and vehicle costs of $59.57 and $23.95, respectively, to arrive at the Per-read Fee.

The hourly labour rate of $59.57 is calculated by inflating the Customer Service Person 2012 hourly rate to 2016 at 1.8 percent per annum and adding a fringe benefit load factor. FortisBC submits that this estimated rate is consistent with those in the most recent FortisBC Revenue Requirements Application. (Exhibit B-4, BCUC IR 7.2.1-7.2.1.1)

The hourly vehicle rate of $23.95 is developed by dividing the 2012 vehicle expenses for the applicable vehicle class by the total actual hours charged out for that class and escalating annually at 1.8 percent to 2016. Additional cost recovery components including financing costs are also added. (Exhibit B-4, BCUC IR 6.1) The average actual cost of a 2012 meter reading vehicle is $5,990. With respect to the 2012 meter reading vehicle costs, FortisBC submits the following:

> "Providing information for one meter reading vehicle is not an accurate representation of the group because the utilization and cost of a meter reading vehicle fluctuates depending on the service territory and the unit itself. Furthermore, servicing customers who have chosen the radio-off option will be a component of a different job than performed in 2012 and the vehicles used for those purposes will fall within the Radio-Off fee. The existing vehicle cost has no impact on the radio-off metering costs." (Exhibit B-4, BCUC IR 6.2)

FortisBC further submits that no vehicles will be allocated exclusively to meter reading Radio-off AMI Meters and instead meter reading will be performed by other vehicles as "part of other roles within the Company." (Exhibit B-4, BCUC IR 6.3)

IRG submits that there is uncertainty regarding the estimated vehicle costs per read. (IRG Final Submission, para. 37)

Commission Determination

FortisBC inflates, at 1.8 percent per annum, the hourly rates for both labour and vehicle costs to arrive at an estimate of 2016 rates. **The Panel finds this approach reasonable for the Per-read Fee given that the completion of the AMI project is anticipated at the end of 2015 and the meter reading activity extends beyond project completion.** However, the Panel is not persuaded that the hourly vehicle rate of $23.95 is reasonable. **The Panel finds that a reasonable hourly vehicle rate in the calculation of the Per-read Fee is $16.11.**

FortisBC has provided the average actual annual cost of a 2012 meter reading vehicle to be $5,990. Inflated to 2016 dollars using FortisBC's inflation rate of 1.8 percent per annum, the Panel notes that this results in a 2016 average annual cost of a meter reading vehicle of $6,433. Furthermore, the estimated annual hours required to travel to and manually download data from Radio-off AMI Meters is 973 hours.[11] Accordingly, using the 2016 average annual meter reading vehicle cost of $6,433 will result in an hourly vehicle rate of $6.61. **This calculation is theoretical in nature and does not consider unspecified factors, including how the manual meter reading function will be configured within FortisBC operations. In order to account for these uncertainties the Panel considers that grossing this rate up is fair. In the absence of any evidence to the contrary, the Panel finds 25 percent is reasonable. This results in an estimated hourly rate for one meter reading vehicle of $8.26.**[12]

[11] 695 participants x 6 reads per year x 14 minutes per read (as per Section 3.3.3 above) = 58,380 minutes / 60 minutes = 973 hours.
[12] $6.61 + 25% = $8.26

The Panel is aware that FortisBC intends to utilize vehicles that are assigned to other roles within the Company for manually reading the Radio-off AMI Meters, rather than using dedicated meter reading vehicle(s). The hourly vehicle rate of $23.95 is based on a dividing a pool of annual costs for an entire vehicle class by the total number of hours charged out for that vehicle class. However, the Panel is not persuaded that assigning an hourly vehicle rate for an entire vehicle class to the Per-read Fee is the appropriate approach, in particular given the discrepancy between the hourly vehicle rate of $23.95 included in the Per-read Fee and the hourly vehicle rate for one meter reading vehicle of $8.26, as estimated by the Panel. FortisBC has not provided details of the types of vehicles, the number of vehicles or the different uses for the vehicles included in the applicable vehicle class. The Panel notes that the utilization of vehicles included in the applicable class could vary significantly from meter reading.

The Panel considers that $16.11 is the reasonable vehicle hourly rate to use in the calculation of the Per-read Fee, as this represents the middle point between the rate of $23.96 proposed by FortisBC for a vehicle class and the rate estimated by the Panel of $8.26 for operating one meter reading vehicle.

3.3.4 Adjustment Mechanism

FortisBC proposes to track the actual number of Radio-off AMI Meter Option participants and actual manual meter reading costs and to suggest fee revisions, if appropriate, in the next Cost of Service/Rate Design Application. (Exhibit B-1, p. 7) FortisBC currently has a five year Performance Based Ratemaking application before the Commission and FortisBC submits that the Company "...could perform a full cost of service study as early as 2017." (Exhibit B-4, BCUC IR 10.1)

CEC recommends that the costs be updated annually but a period of three years after implementation is allowed before any major changes in the assumptions used to derive the fees are made. (CEC Final Submission, p. 10)

BCPSO argues that required fee adjustments should be evident by the end of 2015 and accordingly, fee adjustments should be made as soon as possible. (BCPSO Final Submission, p. 8)

BCSEA and IRG supports FortisBC's proposal to put forward any required fee revisions with the next Cost of Service / Rate Design Application. (BCSEA Final Submission, p. 6; IRG Final Submission, para. 40)]

Commission Determination

Given that the completion of the AMI project is expected by the end of 2015, the Panel agrees with BCPSO that the actual number of participants and manual meter reading costs should be reported as early as possible. **Accordingly, the Panel directs FortisBC to track the actual number of Radio-off AMI Meter Option participants and the actual annual manual meter reading costs separately from other costs. FortisBC must provide a report on these items to the Commission by September 30, 2016, irrespective of whether or not a fee revision is proposed.**

3.4 Reverting to a Standard Radio-on Meter

FortisBC proposes that Radio-off AMI Meter Option participants can elect to revert back to a standard radio-on AMI meter at any time and will only be charged one final Per-read Fee. (Exhibit B-1, p. 8)

CEC and IRG supports the process for dealing with customers reverting back to a standard radio-on AMI meter, as proposed by FortisBC. (CEC Final Submission, p. 11; IRG Final Submission, para. 41)

Commission Determination

The Panel supports the process as proposed by FortisBC, including the final Per-read Fee charge. However, for the reasons outlined in Section 3.3.3 above, the Panel does not approve the Per-read Fee of $22 proposed in the Application and FortisBC is instead directed to use the final Per-read Fee approved in this Decision of $18.

3.5 Rate Schedule 81

The Application includes proposed Rate Schedule 81. Rate Schedule 81 includes the charges and terms and conditions applicable to customers that have a Radio-off AMI Meter installed at their premises.

The proposed Rate Schedule 81 indicates that a False Site Visit Charge may apply. Specifically, Rate Schedule 81 includes the following:

> "If the Company attends a Customer's Premises at the request of a Customer but, on attending, is unable to install a Radio-Off Meter because the **Customer refuses access** or because the facilities required to be provided by the Customer are found to be deficient, the False Site Visit Charge set out in Rate Schedule 80 may be charged." [emphasis added] (Exhibit B-1-1, Errata 1)

The False Site Visit Charge is included in FortisBC's existing Rate Schedule 80, as follows:

> "A charge of $182.00 per occurrence may be levied if a FortisBC representative attends a Customer's Premises at the request of a Customer but, on attending, is unable to perform the requested work because the facilities required to be provided by the Customer, for this purpose, are found to be deficient." (Exhibit B-6, BCSEA IR, Attachment 18.2)

Rate Schedule 80 is included in FortisBC's Electric Tariff and contains charges for connection or reconnection of service, transfer of account, testing of meters, and various customer work. (Exhibit B-6, BCSEA IR, Attachment 18.2)

IRG supports Rate Schedule 81, including the False Site Visit Charge. (IRG Final Submission, paras. 39, 43) CEC also supports the False Site Visit Charge as reasonable. (CEC Final Submission, p. 10)

BCPSO submits that the False Site Visit Charge is "vague" and "has the potential for overly broad application." BCPSO recommends that FortisBC be required to "explicitly notify" customers that the charge exists when the installation appointment is made. (BCPSO Final Submission, pp. 5-6)

BCSEA supports the objective of informing the Radio-off AMI Meter Option participants of the False Site Visit Charge; however, takes no position as to whether or not this should be included in the proposed Rate Schedule 81. (BCSEA Final Submission, p. 7)

Commission Determination

The Panel notes that the False Site Visit Charge is already included in existing Rate Schedule 80. The proposed Rate Schedule 81 includes the False Site Visit Charge and notes that the charge may apply if the "Customer refuses access." This specific cause for applying the charge is not included in the existing Rate Schedule 80. The Panel recognizes that additional wording included in Rate Schedule 81 adds clarity to the False Site Visit Charge to account for circumstances that were not previously contemplated. However, the Panel does not consider it appropriate to include the False Site Visit charge in Rate Schedule 81 when it is already applicable under Rate Schedule 80. **Accordingly, the Panel directs FortisBC to submit an updated Rate Schedule 80 for approval with the Commission in order to capture any proposed changes to the False Site Visit charge. For clarity and transparency, at the time of providing notice of the AMI project deployment and the Radio-off AMI Meter Option FortisBC is directed to advise customers that the False Site Visit Charge may apply.**

FortisBC must file Rate Schedule 81, updated to include the Per-premises Setup Fee and Per-read Fee approved in this Decision and exclude the False Site Visit Charge, with the Commission for approval on or before January 27, 2014.

TAB 14

IN THE MATTER OF

FORTISBC INC.

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
FOR THE ADVANCED METERING INFRASTRUCTURE PROJECT

DECISION

July 23, 2013

Before:

L.F. Kelsey, Commissioner/Panel Chair
N.E. MacMurchy, Commissioner
D.M. Morton, Commissioner

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EXECUTIVE SUMMARY

FortisBC applied for a Certificate of Convenience and Necessity for an advanced metering infrastructure (AMI) project. The Project consists of replacing the existing fleet of meters with advanced (or smart) meters and related infrastructure and software (see Section 1.0 for details of the application). The application generated a high degree of interest from a number of parties, including members of the general public. This interest stemmed from concerns related to a wide variety of topics including costs and benefits of the project, potential health effects, and security, privacy and safety concerns. To hear the community concerns raised by the public in the FortisBC service territory, the Commission held Community Input Sessions in Trail, Osoyoos, and Kelowna (see Section 2.2 for details). This was followed by a public hearing process, with the participation of registered Interveners, that included both written and oral components (see Sections 2.4 and 2.5).

Based on the extensive evidence that was put forward to the Panel, including the testimony of a number of expert witnesses the key decisions of the Panel are:

1. FortisBC is granted a Certificate of Public Convenience and Necessity for the Project subject to a condition that it must confirm by August 1, 2013 that it will file an application for an opt-out provision by November 1, 2013 that follows the direction in Section 11.4 of this decision. The approved capital budget, including approved development costs is $50.898 million. The reasons for this decision include;

    - Over its 20 year life the Project is expected to generate a net benefit of $13.9 million as a result of reductions in operating costs and electricity theft;

    - The Project is expected to reduce rates over the 20 year life of the Project. However, it is estimated there will be a modest increase in rates due to the Project over the next five years. Non quantified, “soft” benefits enabled by the Project may mitigate the rate increase;

    - The Project advances the BC 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” as stated in section 17(6) of the *Clean Energy Act*. The Project also supports British Columbia's energy objectives, specifically *Clean Energy Act* sections 2(b) (to take demand side measures to conserve energy); 2(d) (to use and foster the development in BC of innovative technologies that support energy conservation and efficiency) and 2(g) to reduce greenhouse gas emissions. (Sections 5.0 and 8.2.1);

    - There is a potential risk to the implementation schedule arising from a protracted difference of views concerning the Project. This risk could increase costs to and reduce potential benefits from the Project, which would be detrimental to all

FortisBC ratepayers. An opt-out program could mitigate these potential schedule impacts. (Section 6.5.2)

- The Project complies with Canadian safety standards as set out by Health Canada with respect to RF emissions;
- The Project complies with provincial privacy standards as set out by the *Personal Information Protection Act*; and
- Security and safety issues have been adequately addressed.

2. A depreciation rate of 5 percent is approved for the advanced meters based on an expected economic life of 20 years. (Section 8.5.2.1)

Section 10 makes additional key findings including:

- Health Canada's Safety Code 6 takes into account the scientific evidence related to the impact of thermal and non-thermal effects of radio frequency emissions on human health and provides an appropriate degree of precaution in setting the limits for these emissions;
- The radio frequency emissions generated by the Project are significantly below the levels set out in Safety Code 6 established by Health Canada to ensure such emissions are not harmful to human health;
- While there are individuals who feel strongly the low level electromagnetic emissions will have a negative impact on their health, the scientific evidence in this Proceeding does not persuade the Panel that there is a causal link between radio frequency emissions and the symptoms of electromagnetic hypersensitivity.

In reaching its decision, the Panel considered all of the evidence put before it. The Panel endeavoured to ensure the Proceeding record included evidence related to the topics put forward by concerned FortisBC customers in the Community Input Sessions, by interested parties, as well as in the many letters of comment received by the Commission.

FortisBC is required to provide reporting on the Project as it proceeds.

1.0 THE APPLICATION

On July 26, 2012, FortisBC Inc. (FortisBC) filed an application with the British Columbia Utilities Commission (Commission) seeking approval pursuant to sections 45 and 46 of the *Utilities Commission Act* (UCA), for a Certificate of Public Convenience and Necessity (CPCN) for the Advanced Metering Infrastructure (AMI) Project (Project; Application). 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, serving over 162,000 customers directly and indirectly through municipally owned utilities in its service area.

Figure 1-1

Extracted from Exhibit B-11, BCSEA 1.8.1 Appendix, p. 4

The Project consists of replacing the existing fleet of electrical meters with advanced meters and related infrastructure and software. The Application was the subject of a public process (Proceeding) discussed in detail under Section 2 of this Decision.

On November 16, 2012, FortisBC submitted an addendum to the Application following the filing of a separate application to the Commission to purchase the electric utility assets of the City of Kelowna. The addendum included spreadsheets and calculations of costs and benefits for the Project considering the inclusion of an additional approximately 15,000 meters in the City of Kelowna. By Order C-4-13 dated March 1, 2013, the Commission approved the Kelowna utility assets purchase with conditions that were subsequently met. Unless otherwise noted all discussions of financial considerations in this Decision include the City of Kelowna electrical service territory and assets.

1.1 Specific Orders Sought

In this Application FortisBC specifically seeks:

1) Pursuant to sections 45 and 46 of the UCA, an order issuing a CPCN for the Project at an estimated cost of $51.2 million, including salvage value (Exhibit B-1, p. 6; Exhibit B-1-4, p. 2); and
2) Pursuant to section 56 of the UCA, an order approving a revised depreciation rate for the proposed meters of 5 percent until the next depreciation study is completed (Exhibit B-1, p. 7).

2.0 THE PROCESS

Following the submission of the Application, a Commission Panel was established on August 1, 2012, and the following day a Preliminary Regulatory Timetable (Order G-105-12) was issued. The Order required FortisBC to promptly publish a Notice of Application and also re-publish it prior to September 5, 2012. The Regulatory Timetable was amended several times during the course of the Proceeding with the final amendment on May 13, 2013, providing for the filing of the International Agency for Research on Cancer monograph (IARC Report) and for Supplemental Submissions limited to that report. The Regulatory Timetable is shown in Appendix B.

2.1 Interveners

Persons wishing to actively participate in the proceeding were instructed on how to register with the Commission as Interveners and referred to resource material on how to file for Participant Assistance Cost Awards (PACA) to enable participation where financial assistance would be required. Interveners were required to identify issues they intended to pursue and demonstrate that they are either a FortisBC Inc. (electric) customer or a resident in the FortisBC Inc. service territory. Nineteen Interveners registered in the Proceeding and are listed below as they appear in the Proceeding record.

Table 1-1

C1	BC Southern Interior (BCSI) – (represented by Alex Atamanenko, MP)	C11	Keith Miles
C2	BC Municipal Electrical Utilities (BCMEU)	C12	Irrigation Ratepayers Group (IRG)
C3	BC Pensioners and Seniors Organization (BCPSO)	C13	Area D, Regional District of Central Kootenay (RDCK) – (represented by Andy Shadrack)
C4	BC Sustainable Energy Association-Sierra Club British Columbia (BCSEA)	C14	Shonna Hayes
C5	British Columbia Hydro and Power Authority (BC Hydro)	C15	Joe Tatangelo
C6	Jerry Flynn	C16	Beryl Slack
C7	Norman Gabana	C17	Commercial Energy Consumers Association of BC (CEC)
C8	BC Residential Utility Customers Association (BCRUCA)	C18	Nelson Creston Green Party (NCGP) – (represented by Michael Jessen)
C9	Citizens for Safe Technology Society (CSTS)	C19	West Kootenay Concerned Citizens (WKCC) – (represented by Curtis Bennett)
C10	Industrial Customers Group, Zellstoff Celgar Limited Partnership (ICG)		

There were also 13 Interested Parties registered in the Proceeding.

2.2 Community Input Sessions

Community Input Sessions were held in Trail, Osoyoos and Kelowna on November 6, 7 and 8, 2012 respectively. The sessions provided a forum for ratepayers of FortisBC and for ratepayers of its wholesale customers: the Cities of Kelowna, Penticton and Grand Forks, the District of Summerland and Nelson Hydro to present on issues concerning the Application to the Commission Panel. The Panel heard from a total of 51 persons through the three separate Community Input Sessions. Transcripts of the presentations form part of the record. Additional detail is provided in Section 0.

2.3 Procedural Conference

The Commission, by Order G-135-12, established a Procedural Conference to be held in Kelowna on November 8, 2012. The Procedural Conference provided an opportunity for Interveners to identify issues of significance in the proceeding and provide input into the proposed review process and Regulatory Timetable.

Following the Procedural Conference, the Panel issued Order G-177-12 on November 23, 2012, which included an Amended Regulatory Timetable. The Commission determined that the review of the Application would proceed by a combination of a written and an oral hearing, divided as follows:

i. Financial, operations, fire safety and privacy issues by way of a written process only.
ii. Health, security and environmental issues by way of an oral hearing.

Other requests made at or prior to the Procedural Conference were also dealt with in Order G-177-12.

2.4 Written Process

Prior to Order G-177-12, the Regulatory Timetable provided for two rounds of Information Requests (IRs) on the Application from each of the BCUC and Interveners. As of the date of Order G-177-12, FortisBC had responded to the first round of IRs. The written process established by Order G-177-12 included the second round of IRs to the Applicant and one round of IRs on any Intervener evidence that was to be filed by January 24, 2013. It also provided for final submissions in writing. Subsequent amendments to the written process included a third round of Intervener IRs, a confidential round of Intervener IRs, an information request by Commission staff and BCPSO related to the Kelowna municipal utility acquisition and supplemental written submissions on the IARC Report. (Exhibit A-32, Order G-17-13; Exhibit A-36, Order G-24-13; Exhibit A-43, Order G-80-13)

2.5 Oral Hearing

The Oral Hearing, which was also provided for by Order G-177-12, took place in Kelowna over two weeks from March 4, 2012 to March 15, 2012. A Commission letter issued on January 10, 2013 (Exhibit A-25) provided participants with information on what to expect and how to prepare for the Oral Hearing, and identified Commission counsel as the contact for any questions relating to the hearing process and Commission staff as the contact for technical questions.

FortisBC provided two witness panels for cross-examination: one on security issues and a second on health and environment issues. FortisBC's security panel consisted of Tom Loski, Paul Chernikhowsky and Tim Swanson of FortisBC, and Michael Stuber of Itron. The health and environment panel consisted of Tom Loski and Mark Warren of FortisBC and Dr. William Bailey and Dr. Yakov Shkolnikov, two of the authors of the Exponent Report[1] upon which FortisBC relied in its Application.

CSTS called five expert witness panels, each consisting of a single witness. The CSTS expert witnesses in order were as follows: Dr. Ronald Maisch, Dr. Martin Blank, Dr. Margaret Sears, Dr. Isaac Jamieson and Dr. David Carpenter. All CSTS witnesses gave their evidence by internet video conference. The transcripts of the Oral Hearing number nearly 2100 pages for the ten hearing days.

2.6 Procedural Motions

During the Proceeding numerous procedural requests were made by participants. A Summary of the Rulings Made Before and After the Oral Hearing is found in Appendix B. The Panel also made a number of Rulings during the Oral Hearing.

3.0 REGULATORY AND POLICY CONTEXT

The Commission's jurisdiction to regulate the operations of public utilities in British Columbia is found in the *Utilities Commission Act*, RSBC 1996, c. 473. The matters over which the Commission has jurisdiction include rates and other terms and conditions of service. The Commission also regulates the construction or operation of new facilities by public utilities through its power to grant a Certificate of Public Convenience and Necessity pursuant to sections 45 and 46 of the UCA. In exercising its CPCN granting powers, the Commission, among other matters, must consider certain provisions of the *Clean Energy Act*, SBC 2010, c. 22 (CEA).

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1 Exhibit B-1, Appendix C-5.

3.1 Jurisdiction

Section 45(1) of the UCA states:

> "Except as otherwise provided, after September 11, 1980, a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the commission a certificate that public convenience and necessity require or will require the construction or operation."

Section 45(8) states:

> "The commission must not give its approval unless it determines that the privilege, concession or franchise proposed is necessary for the public convenience and properly conserves the public interest."

Section 45(9) states:

> "In giving its approval, the commission
>
> (a) must grant a certificate of public convenience and necessity, and
> (b) may impose conditions about
>   (i) the duration and termination of the privilege, concession or franchise, or
>   (ii) construction, equipment, maintenance, rates or service, as the public convenience and interest reasonably require."

Section 46(3) sets out the Commission's powers with respect to granting a CPCN:

> "Subject to subsections (3.1) to (3.3), the commission may, by order, issue or refuse to issue the certificate, or may issue a certificate of public convenience and necessity for the construction or operation of a part only of the proposed facility, line, plant, system or extension, or for the partial exercise only of a right or privilege, and may attach to the exercise of the right or privilege granted by the certificate, terms, including conditions about the duration of the right or privilege under this Act as, in its judgment, the public convenience or necessity may require."

Section 46(3.1) requires the Commission, in deciding whether to issue a CPCN to a public utility (other than British Columbia Hydro and Power Authority), to consider the applicable energy objectives set out in section 2 of the CEA, the most recent long-term resource plan filed by the utility under section 44.1 of the UCA, and the extent to which the application for the CPCN is consistent with the applicable requirements of sections 6 and 19 of the CEA. The British Columbia energy objectives relevant to the Application are discussed in Section 3.3 of the Decision. No party made submissions that either sections 6 or 19 applied to the Application.

By Order G-50-10, the Commission issued guidelines (CPCN Guidelines) to assist public utilities and other parties wishing to construct or operate utility facilities in preparing CPCN applications and to facilitate the Commission's review of such applications.

In addition to the Commission's CPCN jurisdiction, the Application also engages the Commission's jurisdiction to set rates of depreciation under section 56 of the UCA. Section 56(2) of the UCA states that "[t]he commission must determine and, by order after a hearing, set proper and adequate rates of depreciation."

Rates of Depreciation are discussed in Section 8.5.3.

3.2 What Constitutes Public Convenience and Necessity

Section 45(8) of the UCA contains two elements: (1) that the proposed application "is necessary for the public convenience" and (2) "properly conserves the public interest." The UCA does not define either phrase. FortisBC submits that the phrases have been held to be synonymous, relying upon *Emera Brunswick Pipeline Co. (Re)*, 2007 LNCNEB 3 at para. 43 (FortisBC Final Submission, p. 38). No Intervener challenged this submission.

Memorial Gardens Assn. (Can.) Ltd. v. *Colwood Cemetery Co.*, [1958] S.C.R. 353, 1958 CanLII 82 (*Memorial Gardens*) is the leading case on public convenience and necessity. Abbott J. for the majority, after commenting that it would "be both impracticable and undesirable to attempt a precise definition of general application of what constitutes public convenience and necessity" and that "the meaning in a given case should be ascertained by reference to the context and to the objects and purposes of the statute in which it is found," describes the determination of public convenience and necessity as follows:

> "As the Court held in the *Union Gas* case the question whether public convenience and necessity requires a certain action is not one of fact. It is predominantly the formulation of an opinion. Facts must, of course, be established to justify a decision by the Commission but that decision is one which cannot be made without a substantial exercise of administration discretion. In delegating this administration discretion to the Commission the Legislature has delegated to that body the responsibility of deciding in the public interest, the need and desirability of additional cemetery facilities, and in

> reaching that decision the degree of need and of desirability is left to the discretion of the Commission." (p. 357)

The Commission has adopted the *Memorial Gardens* test in past Decisions; *In the Matter of Vancouver Island Energy Corporation (a wholly-owned subsidiary of British Columbia Hydro and Power Authority), Vancouver Island Generation Project, Application for a Certificate of Public Convenience and Necessity,* Decision and Order G-55-03 dated September 8, 2003 (VIGP Decision) the Commission found that "...the test of what constitutes public convenience and necessity is a flexible test." (VIGP Decision, pp. 75-76)

As noted by FortisBC at paragraphs 99 and 100 of its Final Submission, the Commission also adopted the *Memorial Gardens* test in its Decision *In the Matter of British Columbia Transmission Corporation An Application for a Certificate of Public Convenience and Necessity for the Vancouver Island Transmission Reinforcement Project,* Decision and Order C-4-06*,* July 7, 2006 (VITR Decision)[2] where it stated:

> "The Commission Panel accepts the submissions of BCTC that there is a broad range of interests that should be considered in determining whether an applied-for project is in the public convenience and necessity. The Commission Panel concludes, as is stated in Memorial Gardens, that it is both impractical and undesirable to attempt a precise definition of general application as to what constitutes public convenience and necessity. As the Commission concluded in the VIGP Decision, the test of what constitutes public convenience and necessity is a flexible test …" (p. 15)

No Intervener proposed an alternative framework for considering public convenience and necessity.

However, in the case of BCPSO, while it accepts that *Memorial Gardens* provides the test for what constitutes public convenience and necessity, it also suggests that the need must be immediate (BCPSO Final Submission, pp. 5, 15). FortisBC addresses whether there must be an immediate need in its May 2, 2013 Reply Submission at paras. 29-33. It refers to the fact that *Memorial Gardens* states that "necessity" includes future needs. At page 356 of *Memorial Gardens*, Abbott J. states as follows:

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[2] Leave to appeal granted in part: ***Tsawwassen Residents Against Higher Voltage Overhead Lines Society v. BC Utilities Commission*** 2006 BCCA 496, 2006 BCCA 537 (Reasons); Leave order varied ***Tsawwassen Residents Against Higher Voltage Overhead Lines Society v. BC Utilities Commission*** 2007 BCCA 95; Appeal dismissed: ***Tsawwassen Residents Against Higher Voltage Overhead Lines Society v. British Columbia (Utilities Commission)****,* 2007 BCCA 211.

> "…The term "necessity" has also been held to be not restricted to present needs but to include provision for the future [citation omitted] and this indeed would seem to follow from s. 12 of the *Public Utilities Act*, which provides that the certificate may issue where public convenience and necessity "require or *will require"* such construction or operation."

The phrase "require or will require" is also found in section 45(1) of the UCA.

The Panel adopts the view that a flexible test of what constitutes the public convenience and necessity is appropriate. It is also of the view that future needs can be considered given the wording of section 45(1). FortisBC states that the pertinent public interest concerns that the Commission should consider with respect to the Project include a) cost effectiveness; b) reliability of service; c) rate impact; and d) socio-economic considerations (including public health, security, and environmental impact) (FortisBC Final Submission, p. 38). The Panel considered these and additional public interest factors and each factor is discussed throughout this Decision.

3.3 How do British Columbia's Energy Objectives, Legislation and Regulations Inform this Decision

The 2007 BC Energy Plan establishes the framework and goals for the Province in terms of energy self-sufficiency, conservation, efficiency and greenhouse gas (GHG) reductions. Relevant legislation includes:

- *Greenhouse Gas Reduction Targets Act*, SBC 2007, c. 42 (GGRTA)
- *Carbon Tax Act,* SBC 2008, c. 40
- *Clean Energy Act*

In addition, as of June 21, 2010, the Province of BC, together with the Islands Trust and 179 municipalities across British Columbia, signed the British Columbia Climate Action Charter (Climate Action Charter). The Climate Action Charter describes how the signatories both endorse and actively support the goal of GHG emissions reductions. It is, however, not intended to be legally binding on the signatories or to impose any legal obligations upon them and has no legal effect (Exhibit B-1, pp. 21-22 and Appendix B-3).

As noted in Section 3.1 of this Decision, section 46(3.1) of the UCA requires the Commission to consider, among other things, the applicable of British Columbia's energy objectives. Section 2 of the CEA lists British Columbia's energy objectives. FortisBC submits that the proposed Project is consistent with the following energy objectives:

> 2(b) to take demand-side measures and to conserve energy;
>
> 2(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources; and
>
> 2(g) to reduce BC greenhouse gas emissions. (FortisBC Final Submission, p. 39)

The CEA also specifically identifies advanced or "smart" metering as a goal in achieving the objectives of the CEA for utilities other than the BC Hydro. Section 17(6) of the CEA states:

> (6) If a public utility, other than the authority [BC Hydro], 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.

3.4 2008 Advanced Metering Infrastructure Project Decision

In December of 2007, FortisBC filed its first CPCN application for an AMI project. On March 28, 2008 FortisBC amended the application to include additional functional capabilities including allowing in-home display (IHD) units in the future and hourly meter reading capabilities. The cost estimate for the amended application was $37.3 million, not including costs for implementing future rate structures, capabilities and in-home displays. Following a public hearing process, the CPCN application was denied in the 2008 AMI Decision.[3] The 2008 AMI Decision included the following conclusions:

- "No regulations have yet been issued concerning Smart Meters and their installation. While the regulations, when issued, will apply specifically to BC Hydro, the Commission Panel is of the view that it would be prudent to consider the regulations before FortisBC proceeds with its AMI Project" (2008 AMI Decision, p. 6).

[3] *In the Matter of FortisBC Inc. An Application for a Certificate of Public Convenience and Necessity for theits Advanced Metering InfrastructureProject Reinforcement Project,* Order G-168-08 dated November 12, 2008; Decision, dated December 3, 2008.

- "…the application of the AMI technologies/protocol, and the opportunities for co-ordination [with other utilities including BC Hydro] 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" (2008 AMI Decision, p. 12).
- "The Commission Panel considers that FortisBC has not been sufficiently proactive in conducting consultations and research to determine the extent to which its AMI Project can or will be coordinated and/or compatible with other utilities, including BC Hydro, the distribution utilities with FortisBC's service area and with its own sister utilities in the natural gas distribution sector" (2008 AMI Decision, p. 15).
- "The Commission Panel is of the view that there is insufficient information in the Application and/or Amended Application to allow it to conclude that the expenditures being proposed will, in fact, facilitate development of cost-effective demand side measures" (2008 AMI Decision, p. 30).
- "The Commission Panel concludes that the scoping, planning and overall cost estimates of the AMI Project are not sufficiently complete and advanced to determine whether the end product of the AMI program, including the instant Applications, can be assessed as to the cost effectiveness, appropriateness and ability to qualify for approval of a CPCN" (2008 AMI Decision, pp. 30-31).

These issues can be categorized as:

1) Timing – (Smart meter regulations not yet issued and BC Hydro smart meter implementation plan not yet developed)
2) Collaboration – (opportunities for efficiencies across utilities)
3) Completeness – (sufficiently detailed scope, planning, vision, costs, and evidence of cost-effective demand side measures)

The current Application will be evaluated to ensure the issues raised in the 2008 AMI Decision have been adequately addressed and developed by FortisBC as applicable.

<u>Timing</u>

The *Smart Meters and Smart Grid Regulation* came into force on December 15, 2010. Sections 2 and 3 of the Regulation, prescribe the requirements for smart meters that BC Hydro must install under subsection 17(2) of the CEA. Although there is no regulation defining the term "advanced meter" as that term is used in the *CEA*, FortisBC compared the Project with the Regulation and concluded that the Project aligns with its requirements (Exhibit B-1, p. 23).

The CEA requires BC Hydro to complete the implementation of its Smart Meter program by the end of the 2012 calendar year (section 17(3)). This requirement was subsequently extended by one year. FortisBC also identifies changes to Measurement Canada compliance requirements that will come into force January 1, 2014 as justification for the current timing of the Project (Exhibit B-1, p. 93).

Collaboration

In Section 8.2 of the Application, FortisBC describes collaborative efforts it undertook with BC Hydro which result in certain province wide consistency benefits of common capability for such things as in-home displays, and ability to incorporate gas and water meter readings (Exhibit B-1, pp. 127, 128). FortisBC further states that shared infrastructure savings with BC Hydro are not possible due to geographic location or are not cost efficient in the case of software systems; however, should FortisBC Energy Inc. (the utility the provides natural gas to customers in the FortisBC territory) decide to pursue a similar system, the FortisBC AMI system infrastructure will be shared "wherever possible and appropriate" (Exhibit B-1, p. 129).

Completeness

In response to the directives in the 2008 AMI Decision, FortisBC undertook several activities:

- Developing the details of specific functional, operational and technical requirements of the proposed AMI system;
- Commissioning a future use study of programs relying on AMI technologies;
- Actively participatiing in technology and industry groups 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 FortisAlberta, Fortis Ontario, BC Hydro, and Southern California Edison; and
- Engaging AMI industry experts to help track advances in metering technologies and software products.

(Exhibit B-1, pp. 12-13)

4.0 EVIDENCE AND EXPERT WITNESSES

4.1 How does the Panel Weigh the Evidence?

Subject to issues of relevance and admissibility, all parties to a proceeding are free to put forward "factual" evidence. This evidence provides specific information that may then be used by parties to argue for a specific ruling or outcome that they believe should be reached by the Panel. This factual evidence may be challenged through the information request process or through the cross-examination of witnesses.

The Panel assessed the factual evidence and reached its conclusions with respect to the validity of that evidence and the weight that should be placed upon it. The Panel, in reaching its conclusions, examined the information filed, and in some cases tested by cross-examination. Based on all of the evidence put forward on a specific factual issue the Panel applied its judgment as to the weight to be placed on that evidence.

Another form of evidence is opinion evidence. In assessing opinion evidence, the Panel took into account the education and work experience of the expert, whether the expert adopted an objective approach in putting forward their evidence, and the ability of the expert to defend their evidence when challenged through the information request process or through cross-examination. The Panel also considers a number of matters, including the facts and assumptions upon which the evidence is based, whether there is other evidence that contradicts those facts and assumptions, the effect of cross-examination on the evidence and whether a witness adopts an advocacy role. To facilitate this review the individuals providing evidence have been grouped as follows:

1) Qualified as an expert in a particular field, filed opinion evidence and cross-examined at the Oral Hearing; and
2) Filed opinion evidence, but not cross-examined.

4.2 Expectations for Expert Witnesses

The Commission does not have published guidelines for its expectations of expert witnesses. However, it looks to them for assistance on the technical issues for which they have been qualified to give their evidence. It expects them to provide their evidence in an objective manner and not to act as advocates.

4.3 Individuals Qualified as Experts

4.3.1 Dr. William Bailey

Dr. Bailey gave evidence on behalf of FortisBC. He was qualified by the Commission Panel as an expert, to give opinion evidence in the field of bio-electromagnetics and in particular, in the health risk assessment of exposure to electromagnetic fields, including radio frequency signals. For the purpose of this qualification, bio-electromagnetics was defined as the study of the interaction of electromagnetic fields with organisms or the environment over a wide range of frequencies. (T3:450-451)

Dr. Bailey's education includes a Ph.D., Neuropsychology, City University of New York, 1975, an M.B.A., University of Chicago, 1969 and a B.A., Dartmouth College, 1966. His curriculum vitae is found in Exhibits B-11[4] and B-32. His experience includes laboratory and epidemiologic research, health risk assessment, and comprehensive exposure analysis. Dr. Bailey has investigated exposures to alternating current, direct current, and radiofrequency electromagnetic fields.

Dr. Bailey was the lead author of the Exponent Report,a summary report on the status of research related to radiofrequency exposure and health commissioned by FortisBC. He also provided assistance to FortisBC in responding to certain information requests.

RDCK submits that the fact that Dr. Bailey is neither a physician or a clinician affects the weight to be given to his evidence:

> "106. Dr. Bailey's evidence and testimony on the issue of patient safety needs to be weighed against the fact that he is neither a physician nor a clinician who has dealt with patients with electro-hypersensitivity. Nowhere did this become more clear than during the cross examination of Dr. Bailey by Mr Andrews, in which Dr. Bailey suggests that one way to resolve the scientific argument around EHS is to increase the intensity of exposure in those claiming to be sensitive."
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> …
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> "108. Scientific certainty and risk analysis perception for which Dr. Bailey is qualified to offer an opinion is not the issue here. Dr. Bailey is simply not qualified to make judgments about the medical and clinical portions of the two

[4] CSTS 1.23.4

> AAEM papers, especially in view of the fact that he failed to explain the limitations to his expertise around medical and clinical matters. Dr. Bailey was far too quick to dismiss the opinion of AAEM without explaining the respective roles that he plays as a scientist as compared to the role played by physicians who have to treat patients presenting themselves with symptoms now commonly called Electro Hypersensitivity Syndrome (EHS)." (RDCK Final Submission, pp. 30-31)

In RDCK's view, Mr. Bailey did not delineate the limits of his personal experience and knowledge. (RDCK Final Submission, p. 26)

RDCK further had this to say about Dr. Bailey's evidence:

> "83. Dr. Bailey is a very knowledgeable and experienced scientist, who vigorously defends his scientific opinion. A scientist with a well-honed opinion, however, is not necessarily useful as an expert in a proceeding. An expert witness should provide a proceeding with the range of opinion on the subjects under discussion and then explain, in his or her considered opinion, what appropriate conclusions may be drawn. Suggesting unanimity and/or consensus when such clearly does not exist shows bias, and the weight of that evidence should be lessened by the Commission accordingly."
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> …
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> "90. Expert opinion must offer the full range of possibilities and probabilities and carefully explain why a certain outcome is likely, or unlikely, given all the variables in play. In contrast, Dr. Bailey consistently expressed the opinion that uniformity and consensus existed in the scientific community, when it was so very obvious from listening to the cross-examination of Citizens for Safe Technologies Society expert witnesses that that was not the case."
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> …
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> "94 In regard to Dr. Bailey's and Exponent's failure to acknowledge the range of opinion concerning the Hardell and similar studies, Area D respectfully submits that that omission brings into question the overall accuracy of the Exponent Report. Dr. Bailey and the Exponent Report have a bias to the exclusion of other equally valid scientific opinions, that Area D respectfully asks the Commission to consider when weighing Exponent's opinions." (RDCK Final Submission, pp. 24-25, 27)

CSTS argues that the evidence of both Dr. Bailey and Dr. Shkolnikov should be given limited weight in the absence of Dr. Erdreich appearing as a witness. CSTS submits:

> "Given that the Exponent Report was not independently authored by either Dr. Bailey or Dr. Shkolnikov, their testimony in defence of its contents, in the absence of Dr. Erdreich, must be given limited weight. As well, the report itself should be given limited weight."
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> …
>
> "Dr. Bailey's doctorate is in psychology. He did not go to medical school and has not conducted scientific research into matters in issue. As will be discussed below - under the heading Blind Faith, Dr. Bailey's evidence was largely deferential to the findings of bodies, such as ICNIRP [International Commission on Non-Ionizing Radiation Protection] and Health Canada, and was v<u>oid of his own independent analysis</u> on contested matters of scientific opinion. The bodies to which Dr. Bailey defers have, themselves, omitted to publicly disclose any reasoning or analysis behind their positions. As such, the basis upon which Dr. Bailey defers to these bodies is unsubstantiated by his evidence." [emphasis in original]
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> …
>
> "…the expert opinion evidence adduced by FortisBC is inferior in weight to the direct medical & scientific expert opinion evidence provided by Dr. Blank, Dr. Carpenter & Dr. Sears, the former of whom has personally conducted his own independent laboratory research on the very matter in issue."
>
> …
>
> "In cross-examination, Dr. Bailey demonstrated that the Exponent Report itself is void of any substantive analysis on the issue of whether there might be adverse bio-effects at the non-thermal level…" (CSTS Final Submission, pp. 16-17) (footnotes omitted)

In reply, FortisBC notes that several Interveners sought to "carve out" exceptions to Dr. Bailey's expertise, on the basis of a lack of medical expertise. FortisBC submits that the Commission Panel has already rejected this carve-out, citing Transcript Volume 3, p. 450, lines 1-21.

FortisBC also submits that among the aspects of medical-related background about which Dr. Bailey testified were the following:

> "(a) he has 30 years of training and experience that include laboratory and epidemiologic research, health risk assessments and comprehensive exposure analysis;
>
> (b) while he does not have a degree in epidemiology, his training has been in the tools that are used by epidemiologists and he has designed and carried out epidemiological studies;

(c) he received a Ph.D. in neuropsychology, which is also referred to as neurobiology, and involves research with application to health problems. (Dr. Bailey's doctorate is not, as CSTS asserts on page 16, in "psychology");

(d) he had also earlier taken courses in the medical school and worked in laboratories including biological research laboratories at Michael Reese Hospital and the Illinois State Psychiatric Institute;

(e) he was awarded a two-year post-doctoral fellowship by the National Institute of Health to take advanced training in neurochemistry, which he did;

(f) he is part of the Medicine and Biology Society (whose interest or focus is, as its name indicates, medicine and biology) within the IEEE [Institute of Electrical and Electronic Engineers] Subcommittee for Safety Levels with Respect to Human Exposure to Radiofrequency Fields, 3 kHz to 3 GHz;

(g) he has authored numerous health-related publications and made numerous health-related presentations;

(h) since 1986 he has been a Visiting Fellow, Department of Pharmacology, Cornell University Medical College;

(i) he was the Head of the Laboratory of Neuropharmacology and Environmental Toxicology at the Institute for Basic Research in Developmental Disabilities;

(j) he has lectured at the University of Texas Health Sciences Centre and the Harvard School of Public Health, among others." (FortisBC May 2 Reply, pp. 56-57) [footnotes omitted]

In the Panel's view Dr Bailey demonstrated a comprehensive knowledge and understanding of a wide range of studies that have been conducted within the area of his qualified expertise. As FortisBC notes the issue of the scope of Dr. Bailey's expertise was dealt with by the Panel during the Oral Hearing. His assessment of comparative studies and their interrelation was objective and presented in an understandable way. He exhibited no apparent signs of bias and he was careful to restrict his responses to those areas where he had been qualified to give opinion evidence. He also did not advocate for any particular position. On a number of occasions, when asked rather complex questions in a way that required a yes or no answer, he was careful to qualify his answer. In some cases the qualifications were rather extensive and preceded the yes/no answer, although the Panel finds that in no way undermined the weight to be given to his evidence. The evidence provided by Dr. Bailey was very useful to the Panel. The issue raised by CSTS regarding the absence of Dr. Erdreich is dealt with below.

For these reasons, the Panel gives considerable weight to the evidence of Dr. Bailey.

4.3.2 Dr. Martin Blank

Dr. Blank gave evidence on behalf of CSTS. He was tendered and qualified as an expert to give opinion evidence "as a specialist in physiology and cellular biophysics and specifically the health-related effects of electromagnetic fields" (T9:1664).

Dr. Blank's education includes a Ph.D. (Colloid Science) Cambridge University, England, Ph.D. (Colloid Science) 1957-1959, a Ph.D. (Physical Chemistry) Columbia University, 1954-1957 and a B.S. Magna Cum Laude (Chemistry), City College of New York, 1950-1954. His curriculum vitae is found in Tab 1F in Exhibit C9-8. Dr. Blank's experience includes research, and teaching in Electromagnetic field effects on cells (cellular stress response, enzyme reactions, DNA reactions), Membrane biophysics and transport mechanisms (active, passive, excitation mechanisms) and Biopolymers (surface and electrical properties of proteins, DNA).

Dr. Blank's written evidence is found at Tabs 1C and D of Exhibit C9-8. His written evidence included, as an enclosure, an article he co-authored with Reba Goldman entitled "DNA is a fractal antenna in electromagnetic fields." That article forms Tab 1E to Exhibit C9-8. Dr. Blank responded to information requests which are found in Exhibit C9-12-6.

Notwithstanding the areas for which Dr. Blank was qualified, he spent considerable time in his evidence and while under cross-examination advancing views based on epidemiology, an area for which he was not qualified (T9:1726). His evidence in this area was also undermined by cross-examination with a negative resulting effect to the weight the Panel attaches to his evidence. An example is his reference to the recent long term study of cell phone base stations in Belo Horizonte, Brazil (Dode *et al.*, 2011), which showed a 13-fold increase in radio frequency (RF) power density from 2003 to 2008 along with a 35 percent increase in cancer deaths near the center of the city where the RF exposure is greatest. When asked under cross-examination why cancer deaths would increase in a five year period in parallel with the increasing RF energy when it can take many years and sometimes decades for cancers to develop, Dr. Blank agreed that the results do not mesh or make sense. He concluded that "there is no good answer" (T9:1684).

Dr. Blank states that he is an academic scientist who conducts *in vitro* work in a laboratory and is firm in his belief and position that *in vitro* studies are an invaluable component in understanding and assessing health risk related to RF radiation. Notably, other witnesses for CSTS, Dr. Carpenter and Dr. Maisch, disagreed with Dr. Blank's view on *in vitro* studies and thought it was questionable whether studies of isolated cells could be used to identify adverse health effects in humans and animals (T8:1531,1631-1632,1637; T11:2125).

During cross-examination Dr. Blank was confronted with critiques of his view from WHO, Advisory Group on Non-Ionising Radiation (AGNIR), and IGNIRP (T9:1749-1750). Instead of addressing the critiques, Dr. Blank was dismissive of the qualifications of the scientists that were involved in reaching these conclusions, expressing the view that the "scientific value" of these studies and commentaries was limited. For example, Dr. Blank was presented with an extract on the comparison of using animal and human studies as compared with *in vitro* studies where the WHO is referenced as concluding that *in vitro* studies cannot serve as the basis for health risk assessments in humans (T9:1748). Dr. Blank questioned the accuracy of this conclusion, stating "unfortunately World Health Organization copy is written by humans, and sometimes humans don't express themselves exactly" (T9:1748).

Dr. Blank made the following comment at the conclusion of his re-examination by counsel for CSTS: "...I appreciate the chance to tell people about this. My role as a professor and teacher, I think has been amply demonstrated. I've tried to be-- to not get too emotional in my presentation of my point of view, but I hope I can get across the urgency of my message" (T9:1786).

The weight to be given to the evidence of Dr. Blank was was the subject of submissions by both FortisBC and the Intervener CEC. The CEC states: "Dr. Blank's focus on his studies at the ELF [extremely low frequency] level and his absence of work with RF in the range of the AMI meters severely limits the usefulness of his testimony." (CEC Final Submission, p. 108) With respect to the Brazil Study, CEC submits that this is evidence that Dr. Blank readily advances advocacy material, which on light questioning he cannot support. CEC further submits that: "Dr. Blank's evidence should be significantly downgraded in weighting because of his lack of ability to adequately defend it." (CEC Final Submission, p.108)

FortisBC submits that Dr. Blank has failed to properly consider any opinions or studies contrary to his own in preparing his report, and that his opinion should be given little weight in this proceeding.

The Panel considers Dr. Blank's evidence to have been more in the nature of advocacy of his position and as such fails to meet the criteria of objectivity. Further, a portion of the evidence he advanced was outside his acknowledged area of expertise as discussed under epidemiology above. Within his area of expertise, when confronted with conflicting opinions by other qualified persons and organizations, Dr. Blank was quick to discredit the source rather than assist the Panel to understand the differences.

For these reasons, the Panel places little weight on the written evidence and oral testimony of Dr. Blank.

4.3.3 Dr. David Carpenter

Dr. Carpenter gave evidence on behalf of CSTS. He was tendered and accepted as an expert witness qualified to provide opinion evidence as a public health specialist with expertise in electrophysiology, low frequency electromagnetic field bio-effects, and radio frequency and microwave radiation bio-effects (T10: 2069-2070).

Dr. Carpenter's education includes an M.D., Harvard Medical School, Boston, MA 1964 and a B.A., Harvard College, Cambridge, MA 1959. His curriculum vitae is found in Tab 2E of Exhibit C9-8. His experience includes research and education in Ionizing and non-ionizing radiation biology.

His written evidence is found at Tab2B of Exhibit C9-8. His written evidence also includes an article he co-authored with Cindy Sage: "Setting Prudent Health Policy for Electromagnetic Field Exposures" (Exhibit C9-8, Tab 2C). He also responded to information requests (Exhibit C9-12-3.)

FortisBC expressed concern that Dr. Carpenter had been disqualified as an expert witness by the Quebec Board [Régie de l'énergie], and had failed to disclose this (T11:2107).

Further, FortisBC submits that Dr. Carpenter's conclusions regarding the harms posed by AMI meters are made without any reference to, or regard for, the specific level of exposure from the AMI meters. Dr. Carpenter noted that he did not have expertise in exposure levels and was not qualified to comment on the exposure levels from the AMI meters. He provided no scientific reason to disagree that the AMI meters meet the Safety Code 6 limit for both average and peak pulse levels. He does not have the scientific expertise to measure the RF from AMI meters as compared to the standards of the BioInitiative Report 2007. (FBC Final Submission, pp. 174-175)

FortisBC submits that Dr. Carpenter summarizes the references he cites in a manner consistent with his own beliefs, rather than accurately reporting their findings and provides the following illustration at paragraphs 520-521 of its Final Submission:

"…Dr. Carpenter referred to a study by Volkow et al. in support of his theory that cell phone RF alters the metabolism of the brain and various clinical measures in humans at exposure levels below the intensities that cause tissue heating:

> Volkow ND, Tomasi D, Wange GJ, Vaska P, Fowler JS, Teland F, et al. 2011. Effects of cell phone radiofrequency signal exposure on brain glucose metabolism. Journal of the American Medical Association 305:808-814.: <u>In healthy participants and compared with no exposure, 50-minute cell phone exposure was associated with increased brain glucose metabolism in the region closest to the antenna. This shows direct effects of RF radiation on the brain with cell phone use.</u>" [underlining added by FortisBC; footnote omitted]

FortisBC submits that the full quote shows that the authors considered the findings in the study much less conclusive:

> "**Conclusions** - In healthy participants and compared with no exposure, 50-minute cell phone exposure was associated with increased brain glucose metabolism in the region closest to the antenna. This finding is of unknown clinical significance." [underlining added by FortisBC; footnote omitted] (FortisBC Final Submission, p. 177)

The CEC submits that the evidence submitted by Dr. Carpenter is "of limited assistance in informing the issue." "Dr. Carpenter's evidence is unduly weighted in favor of a particular viewpoint and not representative of the body of scientific literature. Such actions typify those of an advocate and are not in keeping with that of an objective contributor to the proceeding. The BCUC should find Dr. Carpenter's evidence to be of limited value. Certain portions of Dr. Carpenter's evidence are potentially misleading. Dr. Carpenter is somewhat injudicious in his commentary and is at times disrespectful to organizations which have considerable stature. Several of Dr. Carpenter's statements are inflammatory and unreasonably dismissive of opinions that are not the same as his, regardless of the credentials of the statute of the decision-maker or the analysis conducted."[5]

The CEC is of the view that the references cited by Dr. Carpenter were "decidedly weighted" in favour of one viewpoint. In support of this view, the CEC provided the following analysis: "Dr. Carpenter cited a total of 59 studies of which 43 were supportive of their being a negative effect

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[5] CEC Final Submission, pp. 92-93

(73%), 14 were not supportive (24%) and 2 were inconclusive. Of the 14 that were not supportive, Dr. Carpenter cited 5 with caveats. Dr. Carpenter did not provide any caveats with respect to the 43 supportive documents."

The CEC further submits that some of the information provided as reference material without caveat by Dr. Carpenter is not necessarily well-respected and has been found to be implausible. For example. Dr. Carpenter cites reference item (g) "Mortality by neoplasia and cellular telephone base stations in the Belo Horizonte municipality, Minas Gerais state, Brazil by Dode AC et al without caveat and characterizes it as showing higher rates of death from cancer among individuals living close to cell towers than among those living further away. Rates were highest in residences less than 1 00 m, falling to near background a 1,000 m. This report has been subject to considerable critique and one of the other witnesses, Dr. Blank recognized that the results did not make sense." (T9: 1681-1685) (CEC Final Submission, pp. 92-94)

CTCS submits "the expert opinion evidence adduced by FortisBC is inferior in weight to the direct medical & scientific expert opinion evidence provided by Dr. Blank, Dr. Carpenter & Dr. Sears the former of whom has personally conducted his own independent laboratory research on the very matter in issue" (CSTS Final Submission, p. 17)

The Panel has significant concerns about Dr. Carpenter's testimony. Of particular concern is that Dr. Carpenter, in the words of FortisBC, "summarizes the references he cites in a manner consistent with his own beliefs, rather than accurately reporting their findings." (FortisBC Final Submission, p. 177; T11:2091-2099) The Panel is also concerned with Dr. Carpenter's reference to studies that suit his views and his inability to properly defend them as exhibited by the Belo Horizonte municipality study example.

In his attempt to summarize the references, Dr. Carpenter adopted a less than objective and fully informed approach. For this reason, the Panel gives little weight to his evidence.

4.3.4 Dr. Isaac Jamieson

Dr. Jamieson gave evidence on behalf of CSTS. Dr. Jamieson was tendered and accepted as an expert witness to provide opinion evidence as "as an environmental scientist with expertise in environmental health, in particular expertise in exposure to radio frequency emissions and the environmental health implications of same." A caveat was placed on his expertise noting that he was not an expert on the law. (T10:1918)

Dr. Jamieson's education includes a Ph.D. Environmental Science Imperial College London 2008. His Ph.D thesis "investigated the effects of different types of electromagnetic phenomena on the built environment and suggested ways in which environments could be made more biologically sustainable." He also holds a Diploma in Advanced Architectural Studies, Robert Gordon University, Aberdeen 1988, and a B.Sc. Architecture, Robert Gordon University, Aberdeen 1986. Dr. Jamieson is a Chartered Architect. His detailed curriculum vitae is found in Exhibit C9-10-2. His work experience includes research, writing and organizing conferences on electromagnetic phenomena and health and he has been a stakeholder or committee member on a number of UK and European groups dealing with EMF issues.

Dr. Jamieson provided an extensive report entitled "Comments on Health, Human Rights, Environmental and Security Concerns" which is marked as Exhibit C-10-1.

With regard to Dr. Jamieson's evidence on Human Rights, the Panel notes the caveat placed on his expertise noting that he was not an expert on the law, and therefore no weight is given to this portion of his evidence.

With regard to Dr. Jamieson's evidence on security, the Panel notes that Dr. Jamieson has authored papers on the impact of cold weather on smart meters and the potential impact of electromagnetic pulses (EMPs) on smart meters. Dr. Jamieson was not tendered or accepted as an expert on security and for this reason no weight is given to this portion of his evidence.

In the area of health and environmental matters, Dr. Jamieson provided a great deal of information, including references to, and discussion of, a number of studies. In response to information requests and to questions during cross-examination, Dr. Jamieson admitted that many of the studies he refers to or discusses in his evidence either lack in scientific rigour, such as self report studies, or have potential deficiencies such as the likelihood of confounding factors. Dr. Jamieson repeatedly responded that the studies did indicate that future research was warranted under more carefully designed conditions. Dr. Jamieson, when challenged with the proposal that not all studies indicate that there is a link between EMF exposures and negative health effects, responded: "Indeed. Basically the approach I've taken with regards to writing the document is to raise awareness of studies where it's been indicated there may be a cause for concern so that debate can be opened with BCUC ..." (T10:2008).

In choosing a particular subset of studies in order to open debate with the Commission, Dr. Jamieson strayed from providing objective expert evidence to assist the Panel, into the role of an advocate in support of a particular position.

Given the deficiencies as noted above in many of the studies that Dr. Jamieson relied on to reach conclusions in his report, and his admitted practice of deliberately choosing studies that advocate a particular position, the Panel places little weight on this portion of Dr. Jamieson's evidence.

4.3.5 Dr. Donald Maisch

Dr. Maisch gave evidence on behalf of CSTS. He was tendered and qualified as an expert to give opinion evidence in health standards relating to exposure to electromagnetic radiation (T8:1504).

Dr. Maisch's education includes a Ph.D., University of Wollongong, NSW, Faculty of Arts, Science, Technology and Society Program, 2009. His Ph.D thesis was entitled "A Procrustean Approach: Setting Exposure Standards for Telecommunications." His curriculum vitae is found in Tab 4E of Exhibit C9-8. His experience includes consulting on Exposure to Electromagnetic Fields, EMF standards and related health issues.

His written evidence is found at Tab 4C of Exhibit C9-8. His written evidence also includes his doctoral thesis (Exhibit C9-8, Tab 4D). He also responded to Information Requests

Dr. Maisch acknowledges that AMI meter emissions are far below the human exposure limits in Safety Code 6 but suggests a novel theory, relating to "extremely brief transient emissions", for potential human health issues from advanced meter RF. Fortis BC submits that this theory is beyond Dr. Maisch's qualification to give opinion evidence in this proceeding. Dr. Maisch admitted that it was outside his area of expertise. His theory is highly speculative and, as Dr. Maisch's citing of anecdotal sources suggests, unsupported by scientific research on adverse health effects. Dr. Maisch admits that his only evidence of such effects is "basically discussions with people who are involved in the issue." (FortisBC Final Submission, pp. 192-193)

With regard to Dr. Maisch's submission regarding conflict of interest in standard setting, FortisBC noted that he is also the principal of EMFacts Consultancy. Its consulting work consists mainly of surveys for people who have health complaints and want to check out magnetic fields, and advising of ways to reduce exposure. Essentially Dr. Maisch's consulting livelihood depends upon public fears or concerns about RF exposure. (FBC Final Submission, p. 193)

The CEC submits that Dr. Maisch's qualifications as an expert in 'health standards relating to exposure to electromagnetic radiation' are limited to identifying the jurisdiction of health organizations setting standards electromagnetic radiation and their role in public policy. CEC recommends that the Commission accept Dr. Maisch's evidence with respect to the jurisdiction and credentials of Health Canada and reject his evidence on most other subjects as being inadequately researched or outside his area of expertise. (CEC Final Submission, p. 99)

The Commission Panel agrees with the CEC that the Commission accept Dr. Maisch's evidence with respect to the jurisdiction and credentials of Health Canada and that other evidence presented by Dr. Maisch should be "limited to identifying the jurisdiction of health organizations setting standards electromagnetic radiation and their role in public policy." (CEC Final Submission, p. 99)

The Panel finds merit to FortisBC's argument that "Dr. Maisch's consulting livelihood depends upon public fears or concerns about RF exposure" (T8:1562-1564). In the Panel's view this was reflected in Dr. Maisch's testimony. The Panel notes that while Dr. Maisch was critical of both Health Canada's Safety Code 6 and FortisBC's proposed AMI meters, his Report was based on the 1999 version of Safety Code 6 (T8:1535) and he was not familiar with the proposed meters (T8:1573).

For these reasons, the Panel assigns only limited weight to the testimony of Dr. Maisch. The Panel is not able to assign any weight to the thesis advanced by Dr. Maisch concerning extremely brief transient emissions because the evidence presented in support of the theory is anecdotal.

4.3.6 Dr. Margaret Sears

Dr. Sears gave evidence on behalf of CSTS. She was tendered and qualified as an expert to give opinion evidence "as a researcher and author of scientific literature with expertise in the scientific body of material relating to the health effects of electromagnetic fields, including radio frequency emissions" (T9:1804-1805).

Dr. Sears' education includes a Ph.D., McGill University 1985. Her Ph.D. thesis was titled "Effects of growth conditions on biosorption by *Rhizopus* biosorbents." A Masters of Chemical Engineering, McGill University 1981. Her Masters thesis was titled "Measurement and mathematical modelling of biosorption of uranyl ion by biomass of the mould *Rhizopus arrhizus",* and a Bachelors of Applied Chemistry and Chemical Engineering, with Honours, University of Toronto 1979. Her curriculum vitae is found in Tab 7C in Exhibit C9-8.

Dr. Sears' experience includes research, education, consulting and writing on health and medicine, epidemiology and toxicology, chemistry, ecology, biology and chemical engineering and topics related to environmental health. Her written evidence is found in Tab 7B in Exhibit C9-8.

Dr. Sears seemed to rely on conversations with others with whom she deals who are treating people. This is evident in one of Dr. Sears' statements on this point: "It's really hard in this world today to be avoiding all wireless signals, but there are some people who are very affected by them. Apparently. According to the physicians that I work with" (T9:1807). In the Panel's view, this is not a sound basis upon which to draw conclusions.

Dr. Sears concedes that EHS is not a disease or condition that is, at this point, specifically included in the (Diagnostic and Statistical Manual of Mental Disorder, Fourth Edition) DSM 4 (T9:1835).

In considering Safety Code 6, Dr. Sears is critical of the Code because it is not designed to avoid all biological effects as in the standard in Russia. (Exhibit C9-8, Attachment 7B, pp. 8-9, 20). When asked on cross-examination whether she had any basis for disagreeing with Dr. Shkolnikov's conclusion that the AMI meter which FortisBC proposes to use would meet even the Russian standard, Dr. Sears deferred to Dr. Shkolnikov's opinion. She testified: "[t]he standard as it's laid out is very clear, and I can't disagree with Dr. Shkolnikov, because he's really the expert" (T9:1832).

Dr. Sears cites research by others and at times makes statements that support her view with no substantiating facts. As an example, she testified:

> "I have not measured them, but I actually have an Itron meter on my house, because this has happened in Ontario, and I know it's perhaps -- well, it's relevant in terms of exposure, but the internet providers here are having a great deal of difficulty because of the interference from these meters. And in fact I was told today that some are going out of business because they can't provide service as a result of the interference since these meters have been installed. And I have not measured them, but I've heard recently that there is a lot of problems that way.

> So if there is enough exposure to interfere with internet service, then perhaps it's significant." (T9:1850)

CSTS makes numerous references to Dr. Sears' evidence in its Final Submissions. They relate primarily to the Precautionary Principle, transparency of Health Canada's analysis, the effect of RF and the flaws in Safety Code 6 with respect to non-thermal effects. (CSTS Final Submission, pp. 11, 29, 35, 47)

CEC recommends that the Commission find Dr. Sears' information to be biased in its selection of information and presentation and as such, is evidence of one viewpoint and of limited weight. CEC also recommends that Dr. Sears' analysis of the strength of the radio frequency signal is beyond the scope of her credentials. In reviewing the information provided by Dr. Sears, CEC finds significant bias in the examples cited, substantial gaps in the evidence discussed and inaccurate portrayals of medical opinion. In CEC's view, the evidence presented was clearly one-sided and intended to advocate rather than inform. CEC recommends that the Commission attribute little weight in Dr. Sears' analysis except with respect to the lack of time and resources available to conduct proper analyses. (CEC Final Submission, p. 106)

FortisBC submits: "It is also evident from Dr. Sears' publications and work history that her predominant interests relate to pesticides and toxic metals, not EMF" (FortisBC Final Submission, p. 197). The Panel agrees with FortisBC.

The two areas where Dr. Sears offers an expert opinion that could be helpful to the Commission are Electromagnetic Hypersensitivity (EHS) and a perspective on Safety Code 6 in both cases as a researcher rather than a medical specialist. However, Dr. Sears' evidence on the connection between electromagnetic hypersensitivity syndrome and RF emissions was weakened by her reference during cross-examination to a conversation with her neighbour, who reported getting headaches from his cell phone and the conclusion she appeared to draw from that conversation (T9:1811). This is not the only anecdotal evidence tendered by Dr. Sears. However, the Panel is unable to give weight to evidence that does not have a scientific basis.

While it does not consider Dr. Sears to have adopted the role of an advocate in her evidence to the extent of Dr. Jamieson, the Panel does consider Dr. Sears to have a bias towards the justification of "curtailing and modifying our increasing reliance upon wireless communication" (Exhibit C9-8, Tab 7B, p. 21). Overall, Dr. Sears contributed very little to the Panel's understanding of the matter before it. Considering her narrow field of expertise related to this matter and the concerns cited above with respect to her expert evidence, the Panel attributes little weight to Dr. Sears' evidence.

4.3.7 Dr. Yakov Shkolnikov

Dr. Shkolnikov gave evidence on behalf of FortisBC. He was tendered and qualified as an expert to give opinion evidence in the fields of electromagnetic exposure, electromagnetic interference and engineering physics, including the physics of electromagnetic fields, which includes radio frequency fields (T3:451). He also provided assistance to FortisBC in responding to certain information requests.

Dr. Shkolnikov's education includes a Ph.D. in Electrical Engineering (minor in Mechanical Engineering), Princeton University (2005), an M.A. in Electrical Engineering, Princeton University, 2004 and a B.S. Engineering Physics, Cornell University , 1999. His curriculum vitae is found in Exhibits B-11[6] and B-32.

Dr. Shkolnikov's experience includes the development and analysis of high performance electronic devices, software, and communication systems, evaluation and testing systems that produce or communicate via electromagnetic signals as well as analysis and exposure assessments of devices and systems including smart meters.

Dr. Shkolnikov is one of the three co-authors of the Exponent Report that provides a summary report on the status of research related to radiofrequency exposure and health.

CSTS states that Dr. Shkolnikov is an electrical engineer and claims no medical expertise (CSTS Final Submission, p 16).

The Panel is satisfied that Dr. Shkolnikov is sufficiently experienced in the subject matter he responded to. Dr. Shkolnikov provided information in his area of expertise that was very useful to the Panel. The Panel notes that Dr. Shkolnikov was careful to restrict his responses to those areas where he had been qualified to give opinion evidence. He was very thorough in his responses and exhibited no apparent signs of bias. He also did not advocate for any particular position. In responding to questions that were often of a very technical nature, Dr. Shkolnikov demonstrated

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[6] CSTS 1.23.4.

his depth of knowledge and his expertise and articulated his responses in a manner that both directly responded to the questions put to him and put the answers in a form that was readily understandable for parties not as scientifically conversant as Dr. Shkolnikov.

Given the nature of his responses under cross-examination and his education and experience, the Panel gives considerable weight to the evidence of Dr. Shkolnikov.

4.4 Individuals Filing Evidence but not Cross-Examined

4.4.1 Mr. Curtis Bennett

Mr. Bennett appeared and provided evidence on behalf of WKCC. He was not cross-examined at the Oral Hearing. Mr. Bennett's education includes Interprovincial Journeyman Electrician (Red Seal), Building Construction Engineering Technologist. He did not file a curriculum vitae. Mr. Bennett is associated with Thermografix Consulting Corporation.

Mr. Bennett does not claim to have any academic credentials or degrees in the fields of medicine, the health sciences, molecular biology, or geology and admits he is not a physician or registered professional engineer (Exhibit C19-13, WKCC 1 1.1 - 1.4).

Mr. Bennett actively participated in the Proceeding by filing evidence, delivering and responding to information requests, speaking at the Trail Community Input Session, cross-examining FortisBC's witness panels and making a Final Submission.

The Commission Panel acknowledges Mr. Bennett's participation in the Proceeding. Mr. Bennett has no prior experience with a proceeding of this nature, and the Panel appreciates Mr. Bennett's interest and efforts in this proceeding.

Mr. Bennet's evidence was not tested in cross-examination, although there was discussion of some of it in the cross-examination of the FortisBC Health Panel. In particular, Dr. Shkolnikov and Dr. Bailey refuted many of Mr. Bennett's theories including the following:

(a) RF electro-magnetic fields from the AMI meters will "break DNA" (T6: 1139);
(b) RF fields will cause electrical failure in the body (T6:1141);

(c) AMI meters will cause a charge to develop within the AMI Project coverage area which could cause an explosion or fire in volatile areas (T6:1218);

(e) AMI meter RF emissions will cause high-speed vibration of buildings or lead to B.C. Building Code violations or building collapse (T6: 1186); and

(f) RF interferes with animals such as birds and bees which make use of the Earth's magnetic field (T6: 1214).

FortisBC describes Mr. Bennett as "a lay advocate and not an expert witness. While Mr. Bennett has an electrician's knowledge of electrical systems, it is clear that he is unqualified to give expert opinion evidence on the health effects of RF, exposure standards for RF, engineering, physics, or geological phenomena such as earthquakes" (FortisBC Final Submission, p. 159).

The Panel agrees with FortisBC's evaluation of Mr. Bennett's qualifications related to the matters in this Proceeding and considers Mr. Bennett's evidence to be of limited value. No weight is assigned to it.

4.4.2 Mr. Jerry Flynn

Mr. Flynn appeared, provided evidence and participated actively throughout the Hearing. He did not represent a particular group. He was not cross-examined at the Oral Hearing.

Mr. Flynn's education is not documented in a curriculum vitae format. He states "I have no degrees in the fields of medicine or the health sciences; I am not a physician; I have never had any clinical experience with patients; I am not a registered professional engineer" (Exhibit C6-13). Mr Flynn further states "I am a retired Canadian Armed Forces Captain who spent most of my 26-plus year military career in a "special" branch of wireless radio operations in which I became expert in most matters related to wireless radio communications, electronic warfare (EW) and signals intelligence (SIGINT) operations. My most relevant appointments included: two years as the Executive Officer (2-i/c) and Operations Officer of one of Canada's largest "special" radio stations. Following that, I was posted to National Defense Headquarters, for another two years, in the Directorate of Electronic Warfare (DEW) as Staff Officer EW, charged with supporting Canada's Land EW squadron in Kingston, ON. During the latter posting, I successfully completed a NATO Army EW Officers course in Anzio, Italy, following which I participated in a NAT0-wide Army EW exercise in Germany" (Exhibit C6-1, p. 1).

Mr. Flynn filed evidence, spoke at the Kelowna Community Input Session, delivered and responded to information requests, cross-examined the FortisBC witness panels and filed a Final Submission.

Mr. Flynn demonstrated a passion for the concerns he holds. The Panel listened to and considered his submissions and his participation is appreciated.

In terms of formal qualifications, other than perhaps Mr. Flynn having an understanding of the terminology and science unique to RF communications, the Panel sees little evidence that the overlap between Mr. Flynn's military career and the issues under consideration was helpful in determining the issues specific to this hearing.

Frequently the Panel found the evidence provided by Mr. Flynn to be incorrect, exaggerated and/or unsubstantiated bringing into question the reliance to be attributed to it. Examples include:

1. "Austria's Salzburg Health Dept. recommends Limits of **0.001** uW/cm2 for outdoors and **0.0001** uW/cm2 for indoor exposure; (i.e., **1 million to 10,000,000 times** lower/safer than Canada's current Safety Code 6 Exposure Limit)!" (Exhibit C6-4) [Emphasis in original]

   "Austria's *Exposure Limit* for 1800 MHz is *10,000 times lower (SAFER) than is Canada's*!" (Exhibit C6-10, p. 1). [Emphasis in original]

   "It is also very important that BCUC clearly understands that there currently exists an enormous chasm between Health Canada's, the WHO's and ICNIRP's "*RF" Exposure Limits for 1800 MHz Range* and those of the "safest" country in the world – Austria. Austria permits an Exposure Limit of just 1,000 uW/m2" (Flynn Final Submission, p. 2). [Emphasis in original]

This matter is further clarified and corrected by FortisBC in its Reply Submission and by Dr. Jamieson in response to a FortisBC IR (Exhibit C9-10-1, p. 47). In its May 2 Reply FortisBC had this to say, in part, about Mr. Flynn's evidence:

> "102. Mr. Flynn refers to a limit in Austria. He may be referring to a limit in Salzburg, a particular region within Austria that does not have authority over matters related to limits for RF exposure.
>
> 103. In any event, even the Salzburg limits would be met by the proposed advanced meters. Dr. Shkolnikov noted that "Salzburg which matches Bioinitiative 2007 number, under those guidelines you would -- the Fortis AMI

smart meters would actually still fall below that level…" [footnotes omitted] (FortisBC May 2 Reply, p. 41).

The FortisBC IR asked:

"In Table 2.2 of Dr. Jamieson's Report he has included Salzburg, an Austrian state. Please confirm that the Austrian constitution has assigned sole authority to the federal parliament for matters related to limits for exposure of radio frequency and that the enforcement of these laws are also exclusive to their federal government.

Confirmed. Telecommunications issues like frequency management, licensing, standards etc., are a federal issue with federal regulations applying to the whole of Austria. The Telecommunications Ministry (BMVIT) applies ICNIRP guidelines." (Exhibit C9-13-2, FortisBC 1.8.16.3)

2. Understandably, neither Fortis nor any other electric utility wants us to know that every Smart Meter contains two, separate microwave transmitter/receiver circuits: a LAN (local area network) and a "Zigbee." Nor do they want us to know that they envisage every home eventually having 15-or-so "smart" appliances, each appliance having its own built-in wireless pulsing microwave transmitter that will be controlled by the Smart Meter's ZigBee transmitter and receiver radio circuit. (Exhibit C6-10, p. 2)

The Panel notes that the Application is clear about the presence of two, separate transmitters and makes specific reference to Zigbee technology and the interaction with what Mr. Flynn refers to as smart appliances (Exhibit B-1, pp. 43, 44). Appendix 5 of the Application states "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. 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" (Exhibit B-1, Appendix 5, p. 42).

Mr. Flynn states when filing his PowerPoint presentation on this electromagnetic radiation (EMR), smart meter, meshed-grid subject "... I have assumed the role of 'messenger' not the 'expert'." (Exhibit C6-10, pp. 1, 3)

FortisBC asserts that Mr. Flynn is a passionate advocate, unwavering in his belief that electro-magnetic radiation and wireless AMI meters are "The Worst Threat to our Health Personal Privacy Democracy and National Security in Canada's Entire History." He relies upon any negative information regarding EMF and wireless advanced meters without regard to the reliability of the source. Further, many of the sources he referred to in cross-examination related to the state of scientific research in the 1970s or earlier. These are unhelpful given that there has been extensive research into RF health effects in the years since. Mr. Flynn's evidence should be given little or no weight (FortisBC Final Submission, p. 184).

The Panel is of the view that throughout the Proceeding Mr. Flynn demonstrated that he was an advocate. A considerable amount of the evidence he submitted was questionable and from untested or unreliable sources. His qualifications are not considered by the Panel to be relevant and Mr. Flynn admitted he is not an 'expert'. For these reasons, the Panel assigns little to no weight to the evidence provided by Mr. Flynn.

4.4.3 Dr. Girish Kumar

Dr. Kumar was retained by CSTS. He did not give evidence at the Oral Hearing.

Dr. Kumar's education includes a Ph.D. (Electrical Engineering), I.I.T. Kanpur, India, 1983, and a B.Sc. (Electrical Engineering), A.M.U. Aligarh, India, 1978. His curriculum vitae is found at Tab 3D of Exhibit C9-8. His experience includes research, education and business in the broad area of microwaves and antennas.

He has no medical or epidemiology qualifications nor does he appear to have completed any formal study or research in health or environmental matters, although he may have an interest in the area. His written evidence is found at Tabs 3B, 3C and 3E to G of Exhibit C9-8. He responded to information requests.

FortisBC states "he makes a few health-related statements in his filing, this is obviously outside the area in which he is qualified, given that his degrees and academic work are specifically in electrical engineering and that there is no health-related reference in his noted 'areas of interest' on his resume" (FortisBC Final Submission, p. 190). He confirmed during information requests that he does not have any academic qualifications or degrees in the area of health sciences, and that he is not a biological scientist (Exhibit C9-13-4 , CSTS 1 3.3.1-3.3.2).

FortisBC submits that Dr. Kumar does not have the necessary qualifications to provide any evidence with respect to the impact of AMI meters on the environment, stating "Dr. Kumar's academic qualifications were obtained only in the area of electrical engineering" (FortisBC Final Submission, p. 208). In support of this assertion, it cites a particular question posed and the response which FortisBC argues draws into question Dr. Kumar's qualifications on environmental matters:

> "609. …he was asked to confirm whether he was submitting the sections of the Cell Tower Report dealing with adverse effects on birds, animals and the environment as an expert report in this proceeding. He responded by stating:
>
> > I am not expert as a biological or health scientist but I can read English and acquired knowledge by going through several hundreds of scientific/technical papers, and references of nearly 200 papers have been given. Please question the competence of all these researchers who wrote these papers and also question the competence of all journals/conferences, who published them."
>
> (Exhibit C9-13-4, CSTS 1 3.3.2; FortisBC Final Submission, p 208)

The Panel notes that CSTS did not refer to or rely on Dr. Kumar's evidence in its Final Submission.

The Panel does not consider Dr. Kumar's education and experience relevant to the matters under consideration in this hearing and also note the absence of any referral or reliance on the evidence of Dr. Kumar by CSTS. For these reasons the Panel attaches no weight Dr. Kumar's evidence.

4.4.4 Robert McLennan

Robert McLennan gave evidence on behalf of RDCK. He did not give evidence at the Oral Hearing. Robert McLennan's education includes a B.Sc. degree and MBA Simon Fraser University 1994, Certified Wireless Network Administrator 2005, Microsoft Certified Systems Engineer and C.N.E. Certified Novell Engineer designations in Computer Networking in 1996. His curriculum vitae is found in Exhibit C13-1.

Mr. McLennan's experience includes Avionics, advanced avionics development and testing, Global Positioning System development, Design and maintenance of HF, HF-SSB, VHF-FM (Very High Frequency), Mobile and Fixed communications systems and wireless networking. He is conversant with electronics communications and navigation systems from 150-1720 Khz ADF to 12 Ghz radar.

RDCK indicated that it intends to call Mr. Robert McLennan, former President of Kaslo information Network (KiN), as an expert witness who will give evidence that the wireless technology chosen by FortisBC is incompatible with certain Wi-Fi, ham radio, cordless phones, baby crib monitors, etc. wireless equipment (all using the same non-licensed 900 Mhz frequency band). Mr. McLennan will conclude by explaining that since this wireless technology is so dated, it is likely that it will have to be changed out within the next few years at great expense to FortisBC customers, who will in effect have to pay capital costs twice in as many years. (Exhibit C13-5)

Mr. McLennan filed evidence titled: "Smart Meters and the 21st Century" (Exhibit C13-19). Through February 2013, Mr. McLennan was unavailable to respond to information requests due to health problems. On February 27, 2013, the Commission was advised by RDCK that Mr. McLennan is unable to answer most questions due to ongoing illness (Exhibit C13-34).

Mr. McLennan did not participate further in the Proceeding. Mr. McLennan's evidence was not tested through information requests or cross-examination.

For these reasons the Panel ascribes no weight to it.

4.4.5 Dr. Karl Maret

Dr. Maret was retained on behalf of CSTS. He did not give evidence at the Oral Hearing and his qualifications relative to the matters under consideration in this hearing have not been established.

Dr. Maret's education includes a Post-Doctoral Fellowship in Pulmonary Physiology, School of Medicine, University of California San Diego, 1978-1982, a Doctor of Medicine, University of Toronto, 1973-1979, a B.Sc. in Electrical Engineering, Queen's University, Kingston and Ontario, 1967-1969, and an Engineering Diploma, School of Engineering, Memorial University, St. John's, 1964-1967. His curriculum vitae is found in Exhibit C9-8, Appendix F of Tab 5C.

Dr. Maret's experience includes research, education and consulting in energy medicine instrumentation and complementary and alternative medicine.

Dr. Maret's written evidence is entitled "Commentary on Questions by David M. Aaron Esq. associated with FortisBC Inc, Application for a Certificate of Public Convenience and Necessity for the Advanced Metering Infrastructure Project-Project No. 3698682." It forms Tab 5C in Exhibit C9-8. As the title of his evidence suggests, it is provided in the form of comments on a number of specific pieces of evidence filed by FortisBC. A number of these responses were of a detailed technical nature. Unfortunately, Dr. Maret was unable to respond to information requests or to be available for cross-examination due to health problems.

In its Final Submission, FortisBC argues that because Dr. Maret was unavailable for cross-examination and unable to respond to information requests, his evidence is untested and should be given little or no weight.

Dr. Maret's education and experience suggests that he has the background to have provided meaningful input to the Proceeding. His written evidence contains detailed information some of which, such as his comparison of emission standards in a variety of countries, was recognized as useful by other parties to the Proceeding. However, given Dr. Maret's inability to respond to information requests or to be available for cross-examination, the Panel accordingly gives little weight to Dr. Maret's evidence.

4.4.6 Dr. Timothy Schoechle

Dr. Schoechle was retained by CSTS. He did not give evidence at the Oral Hearing.

Dr. Schoechle's education includes a Ph.D. in Communications School of Journalism and Mass Communication, University of Colorado, Boulder, 2004, a MS in Telecommunications: Interdisciplinary Telecommunications Program, University of Colorado, Boulder, 1995, and a B.Sc. in Administrative Science, School of Management, Pepperdine University, Malibu, CA, 1973. His curriculum vitae is found at Tab 6C of Exhibit C9-8.

Dr. Schoechle's work experience lies primarily in research, education, and consulting in standardization, innovation, and intellectual property rights.

His written evidence is found at Tab 6B of Exhibit C9-8. It is in the form of a paper he had prepared for the National Institute for Science Law and Public Policy entitled "Getting Smarter About the Smart Grid."

Dr. Schoechle, while making comments in his paper on health, environment, safety and privacy issues associated with smart meters, does not appear to have personal expertise in any of these areas. In response to information requests, Dr. Schoechle demonstrated that he was not aware of the specifics of the FortisBC advanced metering infrastructure proposed in the Application or of the role and policies of regulators in British Columbia and Canada. (Exhibit C9-14, CEC 7.6-7.7; Exhibit C9-13, FortisBC 6.7, 6.8)

CSTS does not rely on the evidence of Dr. Schoechle in its Final Submission.

Given Dr. Schoechle's educational background and experience and his lack of knowledge of the specifics of the Application, the Panel finds that no weight can be given to Dr. Schoechle's evidence.

4.5 Adverse Inference

As noted in Section 3.5, the Panel heard from seven expert witnesses at the Oral Hearing. Dr. Erdreich, one of the joint authors of the Exponent Report, was not available to attend the Oral Hearing. CSTS submits that an adverse inference should be drawn against FortisBC for its failure to call Dr. Erdreich. The two areas in which CSTS invites the Commission to draw an adverse inference are:

(a) Whether Dr. Erdreich, under oath, would have continued to stand by the contents of the Exponent Report; and

(b) Whether Dr. Erdreich's testimony would have been supportive of FortisBC's position on health issues.

CSTS argues that although Dr. Erdreich was in Israel, FortisBC could have made her available for cross-examination by way of Skype and/or video conferencing in the same way that CSTS made its witnesses available (CSTS Final Submission, pp. 14-16).

FortisBC responds that no such inference is necessary in the circumstances as both Dr. Bailey and Dr. Shkolnikov were cross-examined extensively on the Exponent Report. Further, it submits that FortisBC answered extensive IRs from multiple interveners on the contents of the report and counsel advised the Panel that Dr. Erdreich was unavailable because she was attending to family matters in Israel. In addition, FortisBC submits that the testimony of Dr. Erdreich "would be of no further assistance to the Commission given the testimony of Dr. Bailey and Dr. Shkolnikov." FortisBC submits that Dr. Bailey's evidence:

> "... is superior to that of Dr. Erdreich in that he directed and supervised the Exponent Report…he was the project director and involved in pulling together the information for the Exponent Report. He requested two of his colleagues, Dr. Shkolnikov and Dr. Erdreich, to provide input to that report. The work was entirely undertaken under Dr. Bailey's direction and supervision."
>
> (FortisBC May 2 Reply, pp. 52-53)

The drawing of an adverse inference is a matter of discretion. As stated in Sopinka, Lederman & Bryant (Third Edition at p. 377):

> "In civil cases, an unfavourable inference can be drawn when, in the absence of an explanation, a party litigant does not testify, or fails to provide affidavit evidence on an application, or fails to call a witness who would have knowledge of the facts and would be assumed to be willing to assist that party. In the same vein, an adverse inference may be drawn against a party who does not call a material witness over whom he or she has exclusive control and does not explain it away. Such failure amounts to an implied admission that the evidence of the absent witness would be contrary to the party's case, or at least would not support it."[7]

The Panel notes that Dr. Erdreich was a co-author of the Exponent Report and Dr. Bailey was the Project Director and accepted responsibility for the Exponent Report. There was extensive cross-examination of both Dr. Bailey and Dr. Shkolnikov by CSTS and others, and their ability to respond did not appear to be compromised by the absence of Dr. Erdreich. Further, FortisBC answered a substantial number of IRs on the Exponent Report. The Panel also accepts FortisBC's explanation for why Dr. Erdreich was not available.

For the reasons described, the Panel is not prepared to draw an adverse inference against FortisBC for its failure to call Dr. Erdreich.

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[7] Alan W. Bryant, Sidney N. Lederman and Michelle K. Fuerst, eds., *Sopinka, Lederman & Bryant: The Law of Evidence in Canada*, 3rd ed. (Markham, Ontario: LexisNexis Canada, 2009).

5.0 PROJECT NEED

As previously discussed, the Commission must only give its approval if it finds the proposed project is "necessary for the public convenience and properly conserves the public interest" (UCA, s. 45(8)).

FortisBC states that the primary need for the Project is to more efficiently manage electricity usage and associated costs by:

1) Enabling customers to make informed decisions about electricity consumption leading to conservation and more efficient use of energy.
2) Enabling the Company to:
    a. Improve the quality and timeliness of information gathered from and provided to customers
    b. Manage the cost of electricity from "recovery and deterrence of a portion of the estimated $3.7 million in annual lost revenue due to electricity theft..."
    c. Make "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." (Exhibit B-1, p. 6)

FortisBC further submits the Project:

1) is consistent with British Columbia's energy objectives;

2) is consistent with the Company's long-term vision and provided for in the most recent long term resource plan (Exhibit B-1, p. 32);

3) provides other benefits (financial and non-financial) (Exhibit B-1, p. 17);

4) addresses the need to replace the existing meter population due to new Measurement Canada Compliance regulations and manufacturing and support being gradually eliminated for electro-mechanical meters (Exhibit B-1, pp. 17-18); and

5) will permit, through the transition to advanced meters as the standard form of metering, 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 (Exhibit B-1, p. 32).

FortisBC states that given customer concerns regarding rising electricity rates, the rate-mitigating effect of the Project underscores that the Project is in the public interest (Exhibit B-1, p. 18). FortisBC also submits that the need and benefits of the Project are highly interconnected (FortisBC May 2 Reply, p. 13).

The Commission heard comments that challenged the need for the advanced meters. These included:

- "Would you accept that I am 77 years of age, I've lived all over this country in many many homes, all I've ever wanted from my utility was they give me a bill at the end of the month. Why is it suddenly I need this stuff?" (T7:1344)
- "I believe households can use electricity responsibly without the devices of the smart meter program and use electricity at off peak periods without the smart meter." (CIS T1(Trail):25-26)
- "Fortis also states immediate detection of power outages, therefore allowing for more effective restoration of electricity to customers. My goodness we're doing just fine with this, it doesn't seem that we need a smart meter for that." (CIS T2(Osoyoos):36)
- "I would say that Fortis should perhaps improve their internal monitoring for electricity use on these various subsections before imposing this system on the rest of us, which may not be nearly as effective as they claim it will be in terms of energy conservation." (CIS T2(Osoyoos):77)

BCPSO submits that the need is how to respond to the anticipated acceleration of meter replacement as a result of Measurement Canada's new requirements (BCPSO Final Submission, p. 3). FortisBC states that BCPSO has too narrowly interpreted the meaning of the term "public convenience and necessity" and references *Memorial Gardens,* submitting that future needs may also be considered (FortisBC May 2 Reply, pp. 12-13).

CEC and BCSEA submit that FortisBC's submissions on project need are valid and well established. Both further state that the Project is being proposed in the context of BC Hydro having nearly completed its installation of smart meters, which could drive grow-operations into the FortisBC service territory. Both state this represents a need for FortisBC to engage similar technological capabilities for theft detection to avoid detriment to its customers. (CEC Final Submission, p. 12; BCSEA Final Submission, p. 10)

Commission Determination

The Panel finds that the Project need has been established.

The Panel accepts that the need for the Project is not singular. The Commission Panel has concluded in Section 3.2 that it can consider future needs. These future needs include ongoing and future system modernization to improve efficiency, reducing losses due to theft of electrical energy, enhance customer service, and reduce costs. Further, the current timing of changes to Measurement Canada's regulations is also a driver and a consideration in the timing and opportunity for cost and benefit optimization.

The Panel gives considerable weight to the BC 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" as stated in section 17(6) of the CEA. In this regard, the Panel considers the Project and its components to be aligned with the CEA.

While the Panel appreciates the opposing views raised by parties with respect to the need for the Project it does not find their arguments to be persuasive because they raise questions but fail to address issues faced by FortisBC, including the changes to Measurement Canada regulations and the requirements of the CEA.

6.0 PROJECT DESCRIPTION

The CPCN Guidelines require that the applicant provide sufficient detail of the project scope and the planned implementation and risks. The Panel will assess the adequacy of the project planning in defining the project scope, schedule, management, risks and contingencies.

6.1 Existing System

The current FortisBC metering fleet consists of approximately 80,000 electro-mechanical and 35,000 digital meters for residential and commercial customers, plus an additional approximately 15,000 customer meters in the recently acquired Kelowna area. FortisBC has been installing digital meters for new or replacement meters for the last six years (residential) and nine years (commercial) as the support for electro-mechanical meters has been gradually eliminated.

(Exhibit B-1, p. 17; Exhibit B-1-2, p. 4)

The current meter fleet, including digital meters, requires manual meter reading whereby a FortisBC representative must physically access the customer's meter and record the meter reading into a hand-held data-logger for subsequent upload into FortisBC's computer billing system. At the end of each day the meter reader must return to the field office to upload the reads into the Customer Information System (CIS) for billing. Currently every customer's meter is read approximately once every two months (Exhibit B-1, p. 79). The current meters record energy consumed in aggregate or totalizing form which FortisBC describes as being like a car odometer (Exhibit B-1, p. 18).

Interim monthly billing is based on consumption estimates and corrected once the actual readings are received. For customer service calls that require verification of meter reading or for service disconnection/reconnection, a service technician must travel to the individual meter to perform the service.

Changes and new regulations from Measurement Canada that will come into force at the beginning of 2014 will increase the accuracy requirements for calibrating and testing meters and increase sampling sizes for meter lots (batches) to be tested. FortisBC states that the increased sampling/testing and accelerated replacement of meters to comply with the new Measurement Canada regulations will have to take place and will have cost impacts. (Exhibit B-1, p. 18)

Based on its 2011 Depreciation Study, FortisBC estimates the average age of the meter fleet to be between 12.7 and 14.7 years at December 31, 2011. The current book value is $9.1 million as at December 31, 2013. (Exhibit B-6, BCUC 1.6.2, 1.6.2.1)

6.2 Proposed AMI Project

The proposed Project will replace the existing fleet with new advanced meters capable of two-way communication with FortisBC's back-office support system to automate meter reading and certain customer service activities. FortisBC states that these AMI capabilities will allow FortisBC to improve the safety, efficiency and reliability of its electric service, thereby helping to mitigating future rate increases. (Exhibit B-1, p. 18)

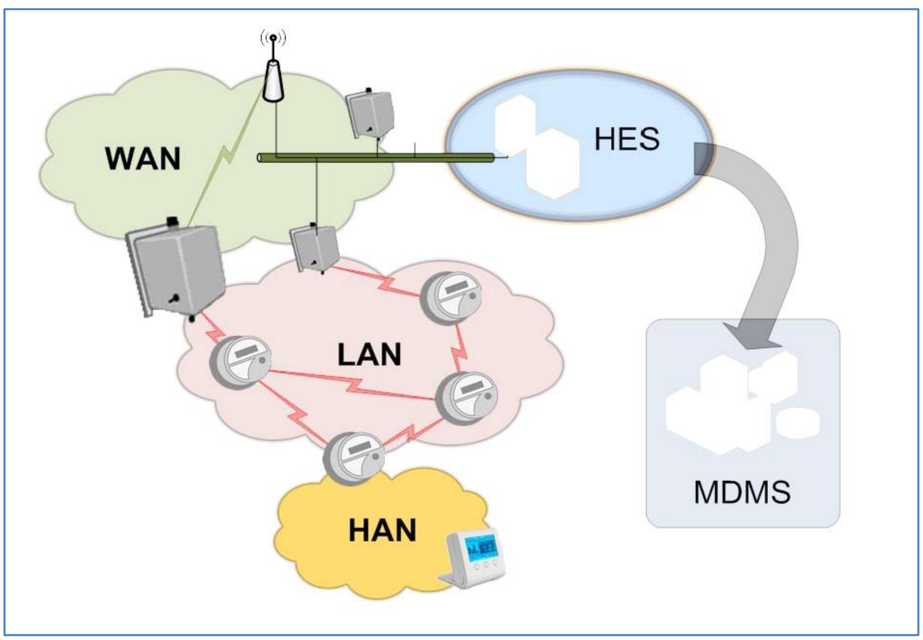
FortisBC proposes that the timing for implementing the Project is opportunistic given that:

1) The new Measurement Canada regulations (S-S-06) will come into effect January 1, 2014 and that a delay in the Project will result in unnecessary duplication of capital expenditures related to the replacement of meters to meet Measurement Canada regulations.
2) FortisBC believes that if the Project is not deployed at this time, FortisBC will experience a marked decrease in theft deterrence (and a consequent increase in electricity theft) as a result of a perception that energy theft will be a more viable option in FortisBC's service territory as compared to BC Hydro's service territory (Exhibit B-6, BCUC 1.2.1).
3) FortisBC calculates a $5.7 million loss of benefits if the project is delayed by two years (Exhibit B-6, BCUC 1.53.11) but confirms that there is no immediate requirement or critical safety issue driving the timing (Exhibit B-6, BCUC 1.2.2).

6.3 AMI Components

FortisBC's AMI system overview shows a series of two-way communication networks and devices which are reproduced in Figure 6-1.

Figure 6-1



(Extracted from Exhibit B-1, p. 42)

The Home Area Network (HAN) consists of the customer's individual meter and an optional in-home display that can show consumption information. The LAN or Local Area Network consists of advanced meters, range extenders and collectors that communicate with each other to transmit meter data four to six times per day. The Wide Area Network (WAN) aggregates the data from the individual LAN collectors and transmits this data back to FortisBC's Head End System (HES). In locations where collectors are located on infrastructure where FortisBC has fibre optic cables the system will connect directly to this fibre. The Wide Area Network will be built using a combination of direct connect to optical fibre or wireless communication technologies including "WiMAX", cellular or satellite. (Exhibit B-1, pp. 41-47)

FortisBC anticipates that less than one percent of the AMI meters will not have an economic Wide Area Network connection option at the time of deployment and will still require manually downloading data from the meters. These costs have been included in FortisBC's project cost estimates. (Exhibit B-1, p. 49)

The HES comprises computer hardware and software that manage the secure data transfer and processing to other utility systems, troubleshooting the overall system performance and monitoring diagnostic events and alarms (Exhibit B-1, pp. 49-50). The Meter Data Management System (MDMS) is the software within FortisBC for storing the consumption data and events and allows data verification algorithms or rate structure algorithms to be applied to the raw data received, before the information is transmitted by the MDMS to billing applications.

6.4 Project Scope

FortisBC developed twenty-four immediate and future, functional, process and business requirements for the AMI system. These business requirements were used to develop the specifications for planning, procurement, final design, testing and training (Exhibit B-1, p. 51).

Future uses include compatibility for:

- In-home devices such as a display
- Ability to contract meter reading for other utilities (i.e. gas and water)
- Pre-pay billing
- Innovative rate structures (Exhibit B-1, p. 52)

FortisBC describes Project activities associated with the following key Project phases:

- Define/Design
- Build
- Deploy/Operate
- Transfer

The Define/Design phase will take approximately four months after Commission approval of the proposed project and will refine the scope through the final design of the Project. (Exhibit B-6-4, BCUC 1.40.1, Erratum 2)

6.4.1 Procurement

The requirements identified by FortisBC were used in the Project's procurement process (Exhibit B-1, p. 51). FortisBC engaged an experienced consultant to facilitate the procurement process and shared experiences with BC Hydro to help ensure an efficient Request for Proposals (RFP) process (FortisBC Final Submission, p. 18). Separate RFP processes were used for the MDMS software solution and for the AMI hardware components. The AMI hardware RFP was sent to eleven vendors and two integrators with seven of the thirteen responding with proposals (Exhibit B-34, Table Shadrack 3.24). FortisBC notes that the RFP did not specify the type of communication technology for the AMI system and that all proposals received use wireless RF communications technology (Exhibit B-1, p. 55). Three vendors were selected based on operational and financial scores and were invited to provide product demonstrations. This process resulted in Itron being selected to provide both the AMI hardware and the MDMS software solution. An RFP process will be competitively tendered by Itron for the meter deployment sub-contract (Exhibit B-1, p. 53).

6.5 Project Management

FortisBC states that [t]he management of the AMI project is supported by a dedicated cross-functional team following standard project management practices and tools" (Exhibit B-1, p. 56). FortisBC has identified key Project phases and resources that can be mobilized to begin the Project within 60 days of Commission approval (Exhibit B-1, p. 59). Project roles and responsibilities, from the Steering Committee and Executive Sponsor to the AMI Manager and functional Project Managers are identified and defined (Exhibit B-1, pp. 59-66). FortisBC provided a more comprehensive Project Management plan in an Erratum that describes its ongoing Integrated

Management Plan with the following components:

- Scope Management Plan
- Schedule (Time) Management Plan
- Cost (Budget) Management Plan
- Quality Management Plan
- Human Resource Management Plan
- Communication Management Plan
- Risk Management Plan (Exhibit B-6-4, BCUC 1.40.1, Erratum 2).

6.5.1 Project Schedule and Phasing

In addition to the Project phases, FortisBC describes four key activities:

1. Scope Management (Define/Design)
2. Deploy software
3. Deploy communications network
4. Deploy meters

Subject to Commission approval, the Project will begin in third quarter of 2013 and end with meter deployment and system acceptance testing in the fourth quarter of 2015 (Exhibit B-1, p. 57). In response to IRs, FortisBC provided a detailed Gantt chart showing the planned Project schedule with milestones (Exhibit B-6, Attachment BCUC 1.40.1). This Gantt chart was subsequently corrected by an Erratum filing to be consistent with the fourth quarter of 2015 in service date (Exhibit B-6-4, Attachment BCUC 1.40.1, Erratum 2).

The Project deployment is further broken down by geographic regions to focus and balance resources and to allow reduced operating cost benefits to begin accruing sooner, region by region. FortisBC states that meter deployment in any region will not commence until the communications network is deployed and functional. Testing and validation milestones in the early stages of deployment include a “1000 Meter Test group” to ensure the software, communications network and meters function as required. From this 1000 Meter base, Region 1 deployment will continue with general deployment to the other Regions proceeding after Region 1 has been tested and accepted. (Exhibit B-6-4, Attachment BCUC 1.40.1, Erratum 2)

6.5.2 Project Risks

FortisBC provides a table of the major risks to schedule, cost, scope and quality along with its mitigation strategy and contingencies (Exhibit B-1, p. 67). Evidence was filed describing a number of installations of 'smart' or advanced meters in Canada and globally, demonstrating the broad application of wireless meter technology (Exhibit B-23). FortisBC references the selection process and contract with Itron as helping to mitigate project risks by dealing with a single vendor with major contract cost elements (meters, communication devices, software) provided on a fixed price or fixed unit price basis (Exhibit B-1, p. 67).

BCPSO submits "that some of the underlying assumptions contained in the cost benefit analysis may be optimistic. In particular, it appears that the number of refusals (0.5%) and perhaps regulatory costs will prove to be low estimates." (BCPSO Final Submission, p. 18) No other Interveners expressed concern about these project risks.

Some Interveners, interested parties and FortisBC customers challenge the need for the additional information on consumption that advanced meters are expected to provide, and raise health, privacy and security concerns that might cause customers to resist the installation of an advanced meter on their home. Specific examples include:

> "I totally and completely object to the forced installation of these meters by FortisBC. If someone wants one, that's his or her choice." (Exhibit E-7)
>
> "We [would] like to let you and FortisBC Inc. know that we are strictly against all smart meters and therefore do not want FortisBC to install any smart meter on our property." (Exhibit E-39)
>
> "And so as I was going out the door my son called. He's an engineer, and he says—I sent him what I was going to submit to you. And he said, 'Well, I won't be letting them on my property because they're not – they haven't been proven safe'." (CIS T3(Kelowna): 33)

FortisBC states that through communications and education these people will either agree to have advanced meters installed or ultimately face disconnection by FortisBC (T7:1406-1407).

More details on these concerns are found in the Public Input and Health, Privacy and Security sections of this Decision.

Commission Determination

The Panel finds that the stated Project risks have been adequately identified and mitigated with one exception. The number of customers opposed to the installation of AMI as proposed is not known. However, even if this is a small percentage of the total number of customers in the FortisBC service territory, the Panel is of the view that any protracted difference of views could result in implementation delays, additional costs to the Project and the potential reduction in benefits. The Panel further discusses these customer concerns in subsequent sections of this Decision.

The Panel finds it difficult to reconcile FortisBC's plan of communication, education and ultimate disconnection with the strongly held and passionately articulated views of a number of its customers opposed to wireless advanced meters. The Panel finds that FortisBC has not adequately considered this risk. This risk must be mitigated for the Project to proceed. This matter will be discussed further in Section 11.4.

6.6 Consultation

The CPCN Guidelines provide requirements for both public and First Nations consultations to be considered in a CPCN application. FortisBC states it has been engaged in public and First Nation consultation processes related to the Project for some time (Exhibit B-1, p. 144). FortisBC refers to a 2008 workshop for its 2009/2010 Capital Expenditure Plan where AMI was introduced, and more recently in 2011 where AMI was discussed as part of its Integrated System Plan public consultation open houses. In June of 2011 FortisBC held a series of open houses focussed on AMI in Kelowna, Osoyoos, Princeton, Creston and Trail with 93 people attending. FortisBC submits these open houses were well attended compared to other open houses it has held in the region (Exhibit B-1, p. 144; Exhibit B-6, BCUC 1.119.1). Feedback through June of 2012 included 305 emails or letters opposing the installation of AMI meters, most (273) without providing a specific reason and others referencing concerns with health issues, rate impacts and/or privacy and security of personal information (Exhibit B-1, p. 144). As of September 28, 2012, FortisBC had been contacted by 324 individuals indicating disapproval of the Project and/or refusal to accept an AMI meter (Exhibit B-6, BCUC 1.119.3).

FortisBC advertised its open houses through local community newspapers and hosted kiosks in shopping malls in Kelowna and Trail. It also sent invitations to Mayors, Council and First Nations in the FortisBC service area to offer presentations on AMI and encouraging participation in its open houses. FortisBC notes it has received some letters of support, namely from the Fire Chiefs' Association of BC and several sustainability/environmental organizations (Exhibit B-1, p. 146).

<u>First Nations Consultation</u>

FortisBC submits that the Project does not involve any green-field construction on any Band land or traditional territory and that no aboriginal or treaty rights are affected as a result of the Project. FortisBC is not a Crown utility and therefore is not required to provide information requirements as set out in the British Columbia Utilities Commission 2010 First Nations Information Filing Guidelines for Crown Utilities. (Exhibit B-1, p. 146)

FortisBC contacted local First Nations' governments via telephone in May/June 2011 requesting input and involvement from First Nations in the AMI process and open houses. FortisBC followed up with letters dated July 4, 2011 to the Chiefs of First Nations in the FortisBC service territory informing them of the Project, providing a link to the open house presentation and providing a contact at FortisBC for any questions or comments. (Exhibit B-1, pp. 146-147, Appendix E-4)

FortisBC submits that the consultation process carried out to date is reasonable and sufficient (Exhibit B-1, p. 147).

Commission Determination

Based on the evidence set out above, **the Panel finds that the consultation process to date has been reasonable and sufficient.**

7.0 PUBLIC INPUT

7.1 Public Participation

There has been a high degree of public interest in this Proceeding. The Commission has attempted to be as accommodating as possible to interested members of the general public in the FortisBC service territory that might not normally participate in a Commission proceeding. In making its determinations, the Panel carefully weighed the views expressed at the Community Input Sessions and in the Letters of Comment, as well as the evidence presented by the Applicant and the registered Interveners.

The Commission received 178 Letters of Comment, with nearly all of them expressing opposition to the Application. When signatures from petitions are included, the number of individuals who wrote to the Commission in opposition to the Application was over 2,200. The letters and petitions form part of the record of the Proceeding.

In addition to the large volume of letters and the high attendance at the Community Input Sessions, the number of registered Interveners who asked to participate in this Proceeding was higher than is normal for a CPCN application brought before the Commission. Some of these Interveners represented private citizens' groups, others represented themselves. The Commission made every effort to ensure that all had a full opportunity to participate in the hearing process.

7.2 Letters of Comment

Of the 178 letters received by the Commission, 92 percent were generally opposed to the Project. Seven percent asked for the Commission to instruct FortisBC to allow for an opt-out provision due to health and privacy concerns. Parties requesting an opt-out also included the Town of Osoyoos, the Regional District of Kootenay Boundary, the Village of Kaslo, and the Regional District of Okanagan Similkameen.

Many of the letters expressed concerns about AMI, though not all for the same reasons. One hundred and forty letters expressed concern over potential negative health impacts from radiofrequency transmissions, while 59 letters brought up issues of privacy relating to FortisBC potentially data-mining power usage data on individual customers. In addition, 56 letters expressed concerns over meter fires related to installation of the AMI system, and a further 44 letters dealt with the potential negative impact of EMF on the environment more generally. Finally, 24 letters submit that the cost of the project is onerous.

7.3 The Community Input Sessions

Community Input Sessions were aimed at both informing residents about the application process and how the Commission operates, as well as giving residents the opportunity to express their views directly to the Panel, so that their views could be taken into account in the decision-making process.

These sessions were advertised via public notice to ensure that everyone who wished to attend was informed. Rules were set out to ensure the participation process was fair and everyone who wished to speak had an opportunity to do so. To encourage individuals who might not normally be comfortable addressing the topic in public, the media, was permitted to take notes, but not permitted to record the event. The Commission Secretary described how a hearing proceeds and how people could participate in the process.

The Panel was pleased with the turnout to all three sessions, and expresses appreciation to all those who made the effort to attend and participate. The concerns heard in all three locations largely mirrored those in the letters the Commission received, and further served to clarify the issues of concern to FortisBC ratepayers and the ratepayers of its wholesale customers.

Some of the views expressed at the Community Input Sessions are provided below:

on health:

- "I know that there is such an overwhelming amount of evidence against wireless infrastructures that in other countries they are taking them out of schools and so on" (CIS T1(Trail): 7).
- "So, I guess my three most concern is the health and safety...the EMR magnetic radiation is not limited to our health and they've already listed the sleep disturbance ... Symptoms of electro-hydro sensitivity for radio sickness and there can be pains in all kinds of parts of your body, and the magnetic hypersensitivity can make people ill" (CIS T3 (Kelowna): 31).

- "Health Canada's safety limits for EMF are based on the thermal effects of radiation on human cells. New studies by scientists around the world are questioning the assumption that thermal effects are the only hazard to humans and are suggesting that biologically based guidelines should be used since the human cell is influenced by more than just heating" (CIS T1(Trail): 55).
- "Well, what about sleeplessness and anxiety and nausea and headaches which have been suffered as a result of people exposed to a smart meter?" (CIS T1(Trail): 101)
- "the radiation emitted from smart meters, routers and cell towers seriously interfere with medical devices such as pacemakers and several medical conditions, for example positional, benign positional vertigo, otherwise known as Ménière's disease, the problem in the inner ear, and many many more" (CIS T2(Osoyoos): 26).
- "I am not concerned with only radiation that will be emitted by the smart meter on my house; I am deeply concerned about the combined emissions from the meters on every house around me and the mesh grid network that will result" (CIS T1(Trail): 96).

on privacy:

- "There's also a privacy issue in regards to the protection of that information collected and who has access to that information. Can some or all of that information be sold or shared? Who owns that information once it's collected and in the possession of the utility company? I have a hard time trusting corporations that are profit driven ..." (CIS T3 (Kelowna): 66)

on wireless technology:

- I am able to regulate my electricity use responsibly without an in-home device and do not want the ZigBee chip on my house. I have no wireless devices nor cell phones in my home and I wish to keep it that way (CIS T1(Trail): 18).

on cost:

- "Now, it seems that the smart meters are just another way customers will be forced to pay more for the same product, in this case electricity" (CIS T2(Osoyoos): 29).

on benefits:

- "Fortis also states immediate detection of power outages, therefore allowing for more effective restoration of electricity to customers. My goodness we're doing just fine with this, it doesn't seem that we need a smart meter for that" (CIS T2(Osoyoos): 36).

on safety and fires:

- "Let's talk about fire liability. There have been numerous fires from faulty connections after the installation of smart meters in California and Ontario" (CIS T3 (Kelowna): 55).

on the economy and jobs:

- "Our concern is for the many individuals who are and have been employed by Fortis in the reading, et cetera, of meters. These individuals may no longer be needed to perform their historic roles in the power company's business, and will now be obliged to seek other employment, either within or without the company, and perhaps to lose their jobs at a time when job loss is of paramount importance" (CIS T3 (Kelowna): 29).

8.0 ECONOMIC ANALYSIS AND RATE IMPACT OF THE PROJECT

In this Section, the Panel analyzes the economic value of the Project relative to maintaining the Status Quo. Briefly, Status Quo is defined as retaining the current metering technology and the accelerated replacement of that technology over a 20-year period to remain in compliance with Measurement Canada regulations. The Status Quo is discussed in Section 9.1. In addition to determining whether the Project has a positive or negative economic value the impact on customer rates will also be assessed.

The CPCN Guidelines outline the following CPCN Application Requirements under Section 2 of Appendix A, "Project Need, Alternatives and Justification":

> "(iii) A schedule calculating the **revenue requirements** of the project and feasible alternatives, and the resulting impacts on customer rates; and
>
> (iv) A schedule calculating the **net present values of the incremental cost and benefit cash flows** of the project and feasible alternatives, and justification of the length of the term and discount rate used for the calculation" [Emphasis added]

In the view of the Panel, the Economic Analysis and the Revenue Requirements Analysis are two distinct schedules that should be considered in the evaluation of the Project. The Panel considers the Economic Analysis the appropriate schedule for the examination of the overall economics of the Project over the life of the Project while the Revenue Requirements Analysis is the appropriate schedule for the examination of the expected impact on customer rates in the short-term.

The financial analyses of the Project provided by FortisBC in the Application (Exhibit B-1, p. 69), Errata No. 1 to the Application (Exhibit B-1-1, p. 69), and Addendum to the Application (Exhibit B-1-2, p. 3; Exhibit B-1-3) represent the net present value of the incremental revenue requirements of the proposed Project, as compared to the Status Quo alternative, over twenty years (Revenue Requirements Analysis). Using the same data and assumptions as provided by FortisBC in the Revenue Requirements Analysis, Commission staff also prepared an analysis that separated the calculation of the revenue requirements of the Project from the calculation of the impact of the Project on customer rates (BCUC Staff Model).

The Revenue Requirements Analysis prepared by FortisBC calculates the NPV of the incremental revenue requirements of the Project, as compared to the Status Quo, over the life of the Project (i.e. 20 years). In the view of the Panel, it is not appropriate to examine the revenue requirements of the Project over a period of 20 years. Although this is an appropriate period over which to analyze the Economic Benefit, the revenue requirements should be examined over the short-term in order to determine the expected impact on customer rates. The Panel discusses the expected rate impact and the Revenue Requirements analysis further in this Section.

The majority of the information requests and Final Submissions from Interveners on the financial aspects of the Project focused on the Revenue Requirements Analysis provided by FortisBC, rather than the Economic Analysis. However, the Panel notes that the majority of the data and assumptions are the same in the two tests and accordingly much of the evidence filed in relation to the Revenue Requirements Analysis is also applicable for the examination of the Economic Analysis.

CEC submits that the proposed Project is in the public interest based on the cost effectiveness and positive rate impact of the Project. With respect to the Revenue Requirements Analysis submitted by FortisBC, CEC states that “the FortisBC Application understates the benefits and overstates the risk of the AMI implementation to a significant degree” (CEC Final Submission, p. 5) and the “FortisBC Application could be reasonably considered to have a probable Net Present Value of $80 million and a maximum Net Present Value of up to $350 million” (CEC Final Submission, p. 11).

BCPSO states that “some of the underlying assumptions contained in the cost benefit analysis may be optimistic .... BCPSO has reservations about accepting FBC’s NPV analysis” (BCPSO Final Submission, p. 18).

8.1 Net Present Value Analysis of Costs and Benefits (Economic Analysis)

In response to BCUC 1.96.1 (Exhibit B-6-5) and BCUC 3.6.1 (Exhibit B-50), FortisBC provided a schedule of the net present value of the incremental cost and benefit cash flows of the Project, as compared to the Status Quo alternative, over twenty years (Economic Analysis). The schedule included the following assumptions:

- Project and sustaining capital costs are included in the year in which they are expected to be incurred.
- No financing or depreciation expense is included.
- Sunk costs are excluded.
- The discount rate is 8 percent.
- The term of the analysis is 20 years. (Exhibit B-50, BCUC 3.6.1)

The Panel considered each cost and benefit item included in the Economic Analysis individually below.

In the economic analysis, Net Present Value (NPV) is used as a reasonable method to compare alternatives that have quantified costs and benefits extending up to 20 years into the future. In order to carry out the analysis and determine rate impacts certain assumptions must be made. The first sub-section makes determinations on these assumptions which include Discount Rate; Inflation; Term; and Taxes.

8.1.1 Key Assumptions

8.1.1.1 Discount Rate

FortisBC used a discount rate of 8 percent to calculate the NPV of the incremental cost and benefit cash flows of the Project in the Economic Analysis (Exhibit B-1, p. 75). FortisBC states:

> "The Company had used a nominal discount rate of ten percent in its rate impact and economic analysis impact studies for a number of years based on the Company's 25 year weighted average cost of capital. The eight percent discount rate is meant to represent a lower long-term after-tax weighted average cost of capital based on an expected lower cost of debt over the study period. The Company is of the opinion that the current low weighted average cost of capital reflects the current anomalous economic conditions and does not reflect the

> average long-term cost of capital that would be expected over the study period. The reduction from the historic ten percent to an eight percent discount rate recognizes that lower rates are expected for the near term but would not be expected over a 20 year period." (Exhibit B-6, BCUC 1.52.2)

BCSEA and CEC both accept the use of a discount rate of 8 percent (BCSEA Final Submission, p. 12; CEC Final Submission, p. 41). No Interveners take the position that a different discount rate should be used.

Commission Determination

The Panel accepts FortisBC's assertion that a discount rate of 8 percent recognizes that "lower rates are expected over the near term, but would not be expected over a 20 year period." The Panel agrees that the selection of a discount rate is a matter of judgement and for these reasons the Panel accepts FortisBC's use of a discount rate of 8 percent as reasonable.

8.1.1.2 General Inflation and Escalation Rate

FortisBC uses a general inflation rate of 1.8 percent for the project costs and benefits, based on a Conference Board of Canada Provincial forecast of BC Consumer Price Index for the period 2012-2016 inclusive (Exhibit B-1, p. 75). The CEC supports the use of a general inflation rate of 1.8 percent, but notes that "...3 percent could be a reasonable estimate of inflation into the future particularly if central bank expansion of money supply continues to be required to support western economics" (CEC Final Submission, pp. 23, 41).

The CPCN Guidelines state the project cost estimate should include escalation (including inflation) amounts. This is intended to deal with situations where future costs of specific capital items may vary at a rate different than a general inflation index. FortisBC states the estimate includes inflation at 1.8 percent per year on all aspects of the Project not covered by fixed unit or fixed price contract and no additional escalation is included. The Project costs include substantial components (approximately 55 percent) covered under fixed price or fixed unit price contracts (Exhibit B-6, BCUC 1.49.1).

CEC considers 1.8 percent to be the likely and the most conservative estimate for all inflationary escalations and that 3 percent could be a reasonable estimate of inflation into the future (CEC Final Submission, p. 23).

Commission Determination

The Panel finds that a 1.8 percent escalation of costs not covered by the Itron contract is reasonable to include in the estimate of project costs. The Panel recognizes the uncertainty in forecasting inflation factors; however, using the Conference Board of Canada inflation forecast for British Columbia is a reasonable approach. While the Panel assessed the use of 3 percent for inflationary cost escalation, the Panel finds no evidence that the 1.8 percent inflation forecast put forward by the Conference Board of Canada is inappropriate. Hence, the Panel accepts the estimate as put forward by FortisBC.

The Panel accepts FortisBC's use of a 1.8 percent general inflation rate, based on the Conference Board of Canada's forecast for British Columbia.

8.1.1.3 Term of 20 Years

FortisBC states that "[t]he 20 year study period was chosen in order to reflect the 20 year economic life of the meters (which are the most significant project expense)" (Exhibit B-6, BCUC 1.52.2).

CEC submits that a 20 year term is conservative and "...FortisBC has also unnecessarily curtailed the attribution of many of the financial benefits from the FortisBC Application by assuming a 20 year economic life of the project and matching the financial benefit stream to the service life of the smart meters" (CEC Final Submission, p. 24).

Commission Determination

The Panel acknowledges that some of the benefits of the proposed Project may extend beyond 20 years; however, in the Panel's opinion, the certainty with which the costs and benefits attributable to the Project can be reasonably estimated diminishes beyond a 20 year time frame. This matter is discussed in further detail in the section covering depreciation rate for project equipment.

In Section 8.5.3 the Panel reviews the evidence for the depreciation rate for the AMI meters. The Panel considers the life determined for depreciation is also appropriate for the Economic Analysis. Accordingly the Panel accepts the estimated economic life of the AMI meters to be 20 years. In the Panel's view, the estimated economic life of the AMI meters is a reasonable means of determining the appropriate timeframe to assess the costs and benefits of the proposed Project. **Accordingly, the Panel accepts FortisBC's use of a 20 year term for the Economic Analysis.**

8.1.1.4 Income Taxes

The Economic Analysis includes an NPV cost of $4.5 million related to income taxes. No Interveners took issue with the forecast cost for income taxes.

Commission Determination

The Panel reviewed FortisBC's calculation of income taxes, including the combined income tax rate and the composite Capital Cost Allowance (CCA) rate. **The Panel accepts the Income Tax and CCA rate assumptions used by FortisBC, and its calculation of income taxes, as being reasonable.**

8.1.2 Project Costs and Benefits

The following subsections summarize the financial costs of the Project found in the evidence, as well as the economic benefits that are expected to flow as a result of the Project. While a significant amount of detail is included to describe both the costs and benefits and how they are developed, it is not the Panel's intention to reproduce the large volume of detailed information that was filed in both the Application and the responses to information requests. Where specific issues of concern were identified by Interveners or the Panel, more detailed information is included. Unless specifically stated the costs and benefits referred to will include the costs and benefits that are associated with the installation of meters in the City of Kelowna.

In reviewing the financial estimates, the Commission Panel considered the CPCN Guidelines, which state that cost estimates used in the economic comparison should have, at a minimum, a Class 4 degree of accuracy. This is defined in the Advancement of Cost Engineering (AACE International) Recommended Practice No. I0S-90 as "generally prepared based on limited information and subsequently have fairly wide accuracy ranges." Further the CPCN Guidelines state that cost estimates for proposed CPCN project costs should have at a minimum a Class 3 degree of accuracy.

Class 3 estimates are typically prepared to support full project funding requests, and become the first project phase "control estimate" against which all actual costs and resources will be monitored for variations to the budget. (CPCN Guidelines, Appendix A, p. 10 of 12)

The high-level assumptions, in addition to those previously described, included in these subsections are:

- Positive BCUC decision by mid-July 2013, ensuring that the contract with Itron need not be renegotiated or canceled;
- Project implementation begins as per preliminary project plan, in Q3 2013;
- Implementation proceeds as per schedule in preliminary project plan, completing in the fourth quarter of 2015;
- Post-AMI manual meter reading for no more than 1 percent of customer base;
- Customer AMI meter refusals do not exceed 0.5percent of customer base;
- Regulatory costs do not exceed $2 million; and
- Cost of the existing meter disposal, included in the meter deployment estimate, will be offset by the scrap value of those meters. (Exhibit B-6, BCUC 1.53.8; Exhibit B-1, p. 56; Exhibit B-6, BCUC1.39.2)

8.1.2.1 Project Capital Costs

A summary of the expected costs for the Project as described in the Application is shown in Table 8-1 below. The Project Development and Regulatory Costs are included because typically, if approved, such costs are capitalized.

Table 8-1

Summary of Project Costs				
AMI	Activity	Pre-Deployment Costs	Deployment Costs	Total
		($000s)		
AMI Project Development and Regulatory Costs				
	Total	4,915		4,915
Capital Costs				
1	Third Party Software and Services		5,830	
2	Meters (including Deployment)		22,941	
3	Network Infrastructure		4,650	
4	System Integration		2,377	
5	Theft Detection		1,100	
6	Project Management		3,355	
7	Capitalized Overhead, AFUDC, PST		6,005	
	Total Capital Expenditure		46,258	46,258
	Total Deployment Capital (Development + CAPEX)			51,173

(Exhibit B-6, BCUC 1.50.1**,** 1.53.1; Exhibit B-1-2, Table 2.1.b, p. 4)

The NPV of the capital cost estimate of $46.258 million is $39.074 million (Exhibit B-50, BCUC 3.6.1).

Apart from the Intervener submissions on the assumption discussed above, no Intervener challenged the capital cost estimate.

8.1.2.2 Contingency Allowance and Accuracy of the Project Cost Estimate

Each of the deployment costs in Table 8-1 above includes a contingency. The total contingency is $2.689 million or approximately 5.8 percent of the total Capital estimate of $46.258 million (Exhibit B-6, BCUC 1.53.4; Exhibit B-1-2, Table 2.1.a, p. 4). FortisBC states this is reasonable as it falls within the estimate accuracy range of -20 percent / +30 percent for a Class 3 estimate based on the AACE guidelines (Exhibit B-6, BCUC 1.53.3).

In its evidence, (excluding the City of Kelowna) FortisBC estimates about 2.6 percent of project costs meet Class 1 estimate criteria (highest accuracy) and are given a contingency factor of 1.2 percent, about 40 percent of costs meet Class 2 estimate criteria and are assigned a 3.65 percent contingency factor. Class 3 estimate costs represent about 26 percent of project costs and are given a 13.16 percent contingency factor and about 2.6 percent of costs fall in the Class 4 estimate criteria and are assigned a 10 percent contingency factor. (Exhibit B-6, BCUC 1.53.4)

There was no evidence provided by Interveners that challenged the contingency amount provided.

Commission Determination

For the reasons outlined above, the Panel accepts for the purposes of the economic analysis, Project capital costs of $46.258 million, excluding CPCN Development costs, but including contingency amounts as described above, in nominal dollars over the period 2013-2015. **Accordingly, the Panel accepts the NPV amount of the Project capital costs of $39.074 million.**

8.1.2.3 CPCN Development Costs

Although not directly related to this section, having made the decision on project capital costs, the Panel will deal with CPCN Development Costs here.

The CPCN development costs are estimated to be $4.915 million (Exhibit B-1-1, p. 73). The CPCN development costs are included in the Project capital cost.

Table 8-2 shows the summary of the AMI development and regulatory costs.

Table 8-2

Table 5.1.1.a - AMI Project Development and Regulatory Costs

	Activity	Cost
	($000s)	
1	2007 AMI Application	275
2	2012 AMI Application	2,217
3	Consultants	423
4	Regulatory Process (forecast)	2,000
5	**Total**	**4,915**

(Exhibit B-1-1, p. 73)

Part of the CPCN development cost in the Application is the 2007 AMI CPCN application cost of $275,000. In the 2008 AMI Decision, the Commission denied FortisBC's 2007 AMI application. The Commission was of the view that FortisBC should explore opportunities with BC Hydro in several areas, improve consultation, develop an overall vision of the complete program, coordinate its efforts with other utilities, and reapply with another application.

FortisBC requests approval to recover the 2007 AMI CPCN application costs as part of the costs of the Project (Exhibit B-14, BCUC 2.46.1.1, p. 94).

No Intervener expressed support for FortisBC's request.

Commission Determination

As the FortisBC 2007 AMI CPCN application was denied, the Panel finds that the cost of the 2007 AMI proceeding should not form part of this Proceeding. FortisBC is directed to apply for recovery of the 2007 AMI costs in its next Revenue Requirement Application. At this time the Panel accepts the estimate for the current Application and regulatory costs (excluding the 2007 AMI CPCN application costs) for the purpose of establishing the capital budget for the Project. The majority of the CPCN Development Costs are retrospective costs that have already been incurred and accordingly these costs should be excluded from the Economic Analysis.

8.1.2.4 Sustaining Capital, Project Operating Costs and Benefits

In the following subsections, the operating costs and benefits that FortisBC expects to flow from the implementation of the Project are described and assessed. As in the cost subsection, sufficient detail has been included to allow an understanding of the ongoing costs and benefits that are described in the Application. Greater detail is available in the Application itself and in the responses to information requests; however, it should be noted that the financial spreadsheets provided by FortisBC were revised and updated throughout the proceeding through errata, addendum and response to information request filings. The latest version of the FortisBC financial spreadsheet can be found in Exhibit B-50, Electronic Attachment BCUC 3.6.1. Where quantification of certain benefits have been challenged by Interveners or found to be of concern to the Panel, greater detail is provided to allow understanding of the decisions made by the Panel in specific areas. In addition to quantified benefits, the Panel also discusses potential or unquantifiable benefits that could be expected to flow from the implementation of the Project.

Table 8-3 below shows the FortisBC calculated net cost or (benefit) of the Project excluding any theft benefit relative to the current system, or Status Quo over the life of the Project. Both nominal and present value dollars are shown. NPV will be used when comparing alternatives.

Table 8-3

AMI	Activity	Nominal Post Deployment Costs (Benefits)	NPV Post Deployment Costs (Benefits)
		$000s	
Sustaining Capital			
	Meter Growth and Replacement	4,941	1,972
	Handheld Replacement	(1,149)	(581)
	IT Hardware, Licensing, and Support Costs	12,864	5,688
	Measurement Canada Compliance	(20,490)	(10,808)
	Total Sustaining Capital	(3,834)	(3,729)
Operating Expenses			
	New Operating Costs	32,400	14,411
	Meter Reading	(64,609)	(26,444)
	Disconnect/Reconnect	(14,938)	(6,155)
	Meter Exchanges	(1,942)	(1,610)
	Contact Centre	(1,317)	(507)
	Total Operating Expenses	(50,406)	(20,305)
	Total	(54,240)	(24,034)

(Extracted and calculated from Exhibit B-50, Electronic Attachment BCUC 3.6.1)

A more detailed discussion of these benefits is provided in the subsections that follow.

8.1.3 Quantifiable Operational Costs and Savings

Table 8-3 above shows a net ongoing sustaining capital and operating expenses savings of $20.3 million not including theft reduction savings for the Project relative to the Status Quo. FortisBC states there will be new costs involved with the Project and changes to some existing operating costs. Significant costs of the Project include the higher cost per advanced meter for ongoing meter growth and replacement, higher Information Technology costs for hardware, software licensing and new operating costs including an additional 9.5 persons to support the AMI system and new processes. (Exhibit B-1, p. 74)

A further break-down of each individual benefit is discussed below.

8.1.3.1 Meter Reading

Status Quo meter reading expenses are primarily made up of labour costs (including employee benefits) for a workforce of approximately twenty-one and a half full time equivalent employees and one supervisor. They also include vehicle and administrative expenses as well as the cost of hand-held meter reading devices (Exhibit B-1, pp. 78, 80; Exhibit B-11, CEC 1.70.2). FortisBC estimates the NPV of meter reading savings of the proposed AMI system over the Status Quo for the life of the Project to be $26.44 million (Exhibit B-50, BCUC 3.6.1, Net AMI DCF spreadsheet). This estimate is based on actual annual meter reading expenses of between $2.1 million and $2.4 million for the years 2008 through 2011 (Exhibit B-1, p. 80) to establish a value of $2.879 million for December 2013 (Exhibit B-1-3, NPV spreadsheet, Tab Status Quo, Line 47).

This amount is then escalated at approximately 3 percent annually to account for inflation and the expected growth in the number of meters to be read. The savings or benefit NPV is calculated by the difference between the Status Quo meter reading expenses and the meter reading expenses under AMI over the life of the Project. Meter reading expenses under AMI assumes that one percent of meters will still require manual meter reading. For example, in 2016 meter reading costs under Status Quo are projected as $3,155,000 and under AMI are projected as $268,000, or approximately eight percent of the Status Quo expense to read one percent of the meters. FortisBC also provided an estimate that would reduce the NPV savings by $5.7 million over the life of the Project if five percent manual meter reading is required (Exhibit B-50, BCUC 3.9.2).

While not disagreeing with the proposed savings, BCPSO express concern that the savings claimed be realized and stated “the savings in this area should be closely monitored and FBC held accountable for any material reduction from the level of savings anticipated” (BCPSO Final Submission, pp. 10-11). No other Intervener commented on estimated meter reading savings for the proposed Project.

Commission Determination

The Panel accepts the basis and assumptions for the calculation to be reasonable and therefore finds the estimated NPV savings of $26.44 million from reduced meter reading expense to be reasonable over the life of the Project. However, the Panel notes this potential saving is sensitive to achieving the assumed 99 percent conversion of current manually read meters.

8.1.3.2 Remote Disconnect/Reconnect

This topic raises both cost/benefit and customer service/policy issues. As these matters are related they will both be discussed here.

The Application includes the provision of a remote disconnect/reconnect switch integral to the AMI meter. The switch is capable of remotely disconnecting or reconnecting electric service without FortisBC having to physically access a customer's premise (Exhibit B-1, pp. 89-91). FortisBC forecasts the NPV savings from the AMI remote disconnects and reconnects as $6.155 million over the 20 year cost benefit analysis period (Exhibit B-50, BCUC 3.6.1, Net AMI DCF Excel spreadsheet).

FortisBC calculated this benefit reflecting a fully avoided cost of all disconnects and reconnects as if these are all done remotely and included an avoided cost of unbilled consumption used at vacant sites (Exhibit B-11, BCPSO 1.47.3) where a disconnect is delayed. In practice FortisBC will conduct visits to 50 percent of vacant sites being disconnected and 100 percent of non-pay sites. These disconnection visit costs have been included in the AMI New Operating Costs line (Exhibit B-11, BCPSO 1.47.4).

FortisBC states it 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 its existing policies concerning disconnection and will continue to maintain processes directing how contact will be made before a disconnection for non-payment is made. (Exhibit B-1, pp. 139-142)

Once the Project is completed, the marginal cost of a remote reconnection is likely to be less than $10, meaning that in theory the reconnection fee could be dropped substantially. However, FortisBC proposes to maintain the current reconnection charge until the next cost of service application (COSA) in order to better understand all costs associated with the new processes. (Exhibit B-6, BCUC 1 92.2.1)

FortisBC states that in 2011 it dispatched nearly 7,700 service calls to disconnect or reconnect customer services. FortisBC does not expect the total number of disconnects and reconnects to be materially different in the Status Quo and AMI scenarios. (Exhibit B-6, BCUC 1.91.2)

In its Final Submission, CEC does not accept continuing to charge the current reconnection charge of $100 until the next COSA in 2017 and recommends that FortisBC be directed to reduce the reconnection fee to $10 or apply for and justify an alternative amount more in keeping with the actual costs. (CEC Final Submission, p. 120)

CEC believes that the process outlined by FortisBC provides sufficient protection for customers in that site visits will be required for 100 percent of disconnections for non-payment. (CEC Final Submission, p. 120)

BCPSO notes inconsistencies and submits that the savings from remote disconnects/reconnects are likely overstated. (BCPSO Final Submission, pp. 12-13) It identifies three issues with regard to the remote disconnects/reconnect:

1. FortisBC needs to clarify its planned approach to reconnection charges;
2. What will be the charge to those that are not switched to AMI meters through no choice of their own; and
3. It disputes the assertion that a higher reconnection charge deters disconnections and a reconnection charge above the cost of service is unduly punitive.

(BCPSO Final Submission, pp. 11-12)

BCPSO further submits that FortisBC's policy on disconnections for nonpayment should be amended to require personal contact with the customer prior to disconnecting service in all but exceptional circumstances. (BCPSO Final Submission, p. 26)

In its May 2 Reply, FortisBC states it will maintain the current disconnection process, retain the current standard charge for the physical disconnection of a meter and its subsequent reconnection until the next Cost of Service application (COSA), and found nothing to reconcile with regards to the request from BCPSO. (FortisBC May 2 Reply, pp. 68-69)

Commission Determination

The Panel accepts FortisBC's forecast of the NPV savings from the AMI remote disconnect/ reconnect savings of $6.155 million over the life of the Project. This amount provides for both the reduction in workload without contemplating any changes to the current policy for communication and contact with customers related to disconnection. The Panel will not consider a change to the customer charge for disconnection/reconnection as this matter is not within the scope of this Proceeding.

8.1.3.3 Measurement Canada Compliance

FortisBC states that effective January 1, 2014, Measurement Canada will require compliance with the new S-S-06 sampling plan for meters installed in Canada, and that this new sampling plan will increase compliance costs of the current meter fleet (Exhibit B-1, p. 93). FortisBC estimates the NPV of compliance savings compared to the proposed AMI system over the Status Quo over the life of the Project to be $10.8 million (Exhibit B-50, BCUC 3.6.1, Net AMI DCF Excel spreadsheet).

FortisBC calculates replacing all 115,000 meters (not including Kelowna) would result in an avoided cost under the Status Quo of not having to replace approximately 88,000 meters that will fail under the new Measurement Canada regulations over the 20 year project life. In the financial analysis of calculating the NPV avoided cost benefit, FortisBC states that it only accounted for the incremental number of meters above the ongoing meter exchange process that are replaced or exchanged as a result of S-S-06. (Exhibit B-1, p. 93)

These compliance costs that the Project would avoid, include and are driven by:

1. Fewer meters will have to be tested each year.

   FortisBC states that the current fleet of meters is comprised of many different 'compliance groups' or 'batches' with each batch requiring that a sample size be removed from service and tested. Under AMI there will be fewer batches of meters which will require fewer meters to be removed and tested every year as compared to the Status Quo (Exhibit B-1, p. 92). Under the new Measurement Canada S-S-06 regulations, the AMI compliance group would require approximately 6,600 meters be exchanged and tested compared to 18,000 under the Status Quo (Exhibit B-1, p. 94).

2. Fewer meters will fail testing and have to be replaced with new meters.

   The Measurement Canada S-S-06 sampling plan includes tighter tolerances for compliance testing which in FortisBC assessment will result in higher failure rate of existing meters compared to solid-state digital meters. For example FortisBC looked at testing results between 2006 and 2010 under the current EG-04 regulations where only 1 out of 92 tested groups failed and applied the new S-S-06 requirements to determine that 12 of 92 groups would have failed (Exhibit B-1, p. 93). In the event of failure of sampled meters, the entire batch of meters is considered to be non-compliant and must be removed and replaced.

Based on the new S-S-06 regulations, FortisBC anticipates increased failures, shorter seal extensions, and an increase in compliance sampling costs and as a result expects an accelerated replacement (shorter lifespan) of approximately 80,000 electro-mechanical meters and 8,000 digital meters (not including Kelowna). FortisBC builds these expectations into the financial model to calculate the NPV of these incremental Measurement Canada Compliance Costs for the Status Quo (under S-S-06) over the life of the Project compared to lower Compliance costs for the proposed Project. (Exhibit B-1, p. 93)

No intervener raised concerns regarding the estimated Measurement Canada compliance savings.

Commission Determination

The Panel accepts the calculation of the avoided cost benefit for Measurement Canada compliance and therefore finds the estimated NPV savings over the life of the Project of $10.8 million to be reasonable.

8.1.3.4 Meter Exchanges

The replacement of nearly all existing meters with new AMI meters will avoid operating costs that would have been incurred for meter sampling, exchanges and testing for six years after deployment (Exhibit B-1, p. 94). FortisBC calculates the avoided operating costs compared to the Status Quo have an NPV of approximately $1.6 million (Exhibit B-1-2, p. 7) over the life of the Project. FortisBC states that new meters have an initial Measurement Canada seal period of 8 to 12 years (the period that the meters do not need to be tested) (Exhibit B-1, p. 92). FortisBC also states that experience shows that solid state digital meters exhibit better test results and are typically granted longer seal extensions by Measurement Canada (Exhibit B-1, p. 93), though it does not appear FortisBC included any benefit from longer seal extensions since it also says that the cost of meter exchanges is expected to begin returning to the pre-AMI deployment levels (Exhibit B-1, p. 94).

BCPSO states: "In principle the savings related to deferred exchange and compliance testing costs should reflect the full savings to be achieved, i.e. both the savings related to the actual removal of the meters involved as well as any savings in actual testing costs. However it is not clear from the evidence provided that this is the case." (BCPSO Final Submission p. 13)

Commission Determination

The Panel accepts the NPV estimate of $1.6 million in savings over the life of the Project compared to not having to perform meter exchanges for six years following the AMI deployment. The Panel views this to be a conservative estimate considering the evidence concerning longer seal extensions for solid state digital meters provided by FortisBC.

8.1.3.5 Contact Centre

In 2011 FortisBC reports that over 19,000 unscheduled meter reads ("soft reads") were processed through its contact center to handle customer moves or verification of readings by customer request or as part of the billing process (Exhibit B-1, p. 95). Labour savings, which include savings from not having to manually input data from unscheduled soft reads of meters over the life of the Project, are estimated to be $507,000 on an NPV basis (Exhibit B-50, BCUC 3.6.1, Net AMI DCF spreadsheet).

FortisBC expects an increase in Contact Centre call volume during the implementation phase of the Project, which it accounts for, followed by reduced call volumes, resulting in savings from reduced labour costs.

BCPSO commented on the labour savings as difficult to estimate but it did not challenge FortisBC's estimated benefit. No other interveners challenged the FortisBC estimate.

Commission Determination

The Panel accepts the evidence put forward by FortisBC that there will be labour savings in the Contact Centre of about $507,000 on an NPV basis over the life of the Project.

8.1.4 Soft Benefits

FortisBC states there are non-financial benefits that all customers, including industrial customers, will realize. FortisBC categorizes these as customer service, operational efficiencies and environmental benefits (FortisBC Final Submission, p. 74). In some cases these non-financial benefits have been assessed in financial terms through the information request process. However these amounts have not been included in the financial justification for the Project. Table 8-4 sets out the soft benefits from the Project as estimated by FortisBC.

Table 8-4

Functionality	*Means*	*Benefit*	*Notes*	*Reference*	*Duration Note 1*
Transition from existing analogue and digital meters to AMI meters	Installation of 115,000 new AMI meters throughout FortisBC territory	1.Improved accuracy of metered consumption, improved billing accuracy	1.Fairness for all rate payers	1.B-1 Appl p.2 and p.33	1.***
Energy balancing and loss management; Increased granularity and synchronicity of customer electricity consumption information; multiple attribute sensing	Feeder, transformer and portable meters	1.Improved system planning	1.May have $ value	1.B-1 Appl p.35	1.***
	Customer meters with near real-time information recording	2.Improved financial reporting/fcsting	2.Public interest	2.B-1 Appl p.36	2.***
	Software infrastructure;	3.Enhanced billing options such as flexible dates and consolidated bills	3.Customer service	3.B-1 Appl. p.33 and p.34	3.***
	additional sensors	4.Customer portal benefits and IHD information for customers	4. Estimated savings of $3.8 million NPV for CIP and $9.8 million NPV for IHD	4.B-11 CEC IR 1 61.1	4.***
		5.Improved power quality monitoring	5.May have $ value	5.B-1 Appl p.39	5.***
		6.Improved outage management /restoration	6.Customer service	6.B-1 Appl p38	6.***
		7.Theft and grow op deterrence	7.Health and public safety	7.B-1 Appl p 83	7.***
Two way communication between the customer and utility	Radio signal	1. Reduction of 171 tonnes of GHG per year during project life, and enduring thereafter	1.Environment and public health	1.B-11 CEC IR 1 25.1	1.***
		2.Facilitation of Conservation rate structures with IHD	2. Est.$9.8 million NPV	2.B-11 CEC IR 61.1 & Appl p.31	2.***
		3.Reduced need to access customer premises	3.Customer service	3.B-1,Appl pg.34	3.***
		4.Improved safety	4.Safety and public health derived from vehicle use	4.B-1 Appl p.36	4.***

Note 1: *One time reduction ** Reduction over project life *** Enduring benefit
(Exhibit B-15, CEC 2.1.1)

8.1.4.1 Customer Service and Satisfaction

Billing and Access to Customer Premises

FortisBC reports that in 2011, 25 percent of all Contact Centre calls were related to billing queries and that it received over 20 customer complaints regarding private property access issues (Exhibit B-1, pp. 33-34). FortisBC expects these issues to be mitigated by customer service benefits resulting from the Project. These benefits include improved billing accuracy, consolidated billing for multiple accounts, ability to offer flexible billing dates, and reduced need for FortisBC to access customer premises (FortisBC Final Submission, p. 74). Consumption estimates for billing will be eliminated and FortisBC states it plans to allow customers to choose billing dates that meet their needs (Exhibit B-1, pp. 33-34).

Provision of better customer information

FortisBC states that the Project allows for the provision of more detailed information for customers about their energy consumption (including both the timing and amount of energy consumed), for example through an online customer information portal or an optional in-home display (Exhibit B-1, p. 32).

FortisBC estimates that the energy savings from an online customer information portal would have a NPV benefit to customers of $3.8 million and from an IHD a NPV benefit of $4.6 million (Exhibit B-14, BCUC 2.72.2).

The CEC considers the online customer information portal will provide immediate information to customers about their energy use, and that the IHD will be valuable to customers in enabling them to monitor their energy consumption. CEC considers that these initiatives will contribute to a culture of conservation. (CEC Final Submission, pp. 34-35) The FortisBC 2010 Conservation and Demand Potential Review, filed as Appendix C of the 2012 Integrated System Plan, indicated that 116 GWh of Achievable Potential energy savings were possible through Behavioural Programs (BCUC 2.70.2).

BCPSO expects that the additional cost of providing a customer information portal is cost effective (BCPSO Final Submission p. 15). BCSEA consider that the web portal and IHD will result in energy and capacity savings, to the benefit of all FortisBC ratepayers (BCSEA Final Submission, p. 14).

The Panel also heard from certain interested parties that they are already conserving as much energy as possible (T2(Osoyoos): 33).

Reduced Safety Incidents

FortisBC reports that between 2006 and 2011 there were 93 safety incidents in the meter reading department related to vehicular incidents, falls, animals, weather or property access incidents. AMI will help to minimize these incidents. (Exhibit B-1, p. 37)

Commission Determination

The Panel accepts that there are soft benefits from the Project, although they are not included in the economic cost benefit analysis. The Panel supports this conservative approach to estimating benefits. However, the Panel makes no determination on the quantum of these benefits.

The Panel agrees with FortisBC and Interveners CEC and BCPSO that the Project allows for the provision of more detailed information to customers, and that this could contribute to a culture of conservation. The Panel considers that providing customers with better information on the quantity of electricity they consume could provide benefits to customers over the longer term.

8.1.4.2 System Efficiency and Reliability

FortisBC already has detailed, timely and accurate information on power supplied into the electrical network from generation and transmission to the substation level (Exhibit B-1, p. 35). It further states that the Project will not directly benefit the monitoring or visibility of this portion of the systems. However, the Project will enable improved distribution system modelling, accuracy and potential optimizations (Exhibit B-1, p. 35).

The Panel considers this to be a potential future benefit.

8.1.5 Other Potential and Future Benefits

FortisBC provides a description of other possible benefits that the Project enables, subject to potential additional capital expenditures. These potential expenditures and future benefits are not included in the financial justification. Table 8-5 sets out the potential future benefits from the Project as estimated by FortisBC.

Table 8-5

Functionality	*Means*	*Benefit*	*Possible Benefit*	*Reference*	*Duration*
Transition from existing analogue and digital meters to AMI meters	Installation of 115,000 new digital meters	foundational for all benefits			
Energy balancing and loss management via Increased granularity and synchronicity of customer electricity consumption information;	Customer, Feeder, and transformer meters; Meters with near real-time electricity consumption recording	1. Distribution loss reduction	1.May have $ value	1.B-1 Appl. P.97	1.***
multiple attribute sensing	Tap changers, voltage regulators,	2.Conservation Voltage Regulation	2.May have $ value	2.B-1 Appl p.98	2.***
	Software infrastructure; addit'l sensors	3.Distribution automation	3.May have $ value	3.B-6 BCUC 1.12.3	3.***
		4.Real time transmission line rating	4.May have $ value	4. B-6 BCUC 1.12.3	4.***
Two way communication between the customer and utility	Radio signal	1.Future conservation rate structures	1.May have $ value	1.B-1 Applic p.103	1.***
		2.customer pre-pay	2.May have $ value	2.B-1 Applic p.103	2.***
		3.Improved outage management	3.May have $ value; customer service	3.B-1 Applic p.101	3.***
		4.Distribuion generation	4. May have $ value; customer service;env't;	4. B-6 BCUC 1.12.3	4.***
		5.Electric vehicle integration	5.env't; cust. Service;may have $ value	5. B-6 BCUC 1.12.3	5.***
		6.HAN (Zigbee)	6.cust. service	6.B-11 CEC 1.51.1	6.***
		7.Demand Response	7.$ value; customer service	7.B-11 CEC 1.23.5	7.***

Note: *One time reduction; ** Reduction over project life; *** Enduring benefit
(Exhibit B-15, CEC 2.3.1)

8.1.5.1 <u>Voltage Optimization</u>

FortisBC states:

> "Conservation Voltage Regulation (CVR) techniques control field devices such as...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." (Exhibit B-1, pp. 98-99)

FortisBC further states that all forms of Conservation Voltage Regulation currently show a negative payback for customers and therefore no form of Conservation Voltage Regulation is proposed at this time. FortisBC states it will continue to study the potential to implement Conservation Voltage Regulation and may propose a solution if higher power purchase costs or lower implementation costs make the project economic. (Exhibit B-1, p. 101)

Commission Determination

The Panel acknowledges that AMI is an enabling technology to realize any future potential benefits and finds it appropriate that any benefit is not included in the financial analysis.

8.1.5.2 Outage Management

Outage data from an Outage Management System (OMS) can be used to map outages and determine location and number of customers without service. The information provided by the OMS will improve identification of the scope of the outage, assist with prioritizing the restoration of service and reduce the field crews' response and repair times. FortisBC states:

> "Outage data from the AMI system can be used to map outages and determine location and number of customers without service. Disruptions in power deliver can be detected at specific transformers, down to individual metering endpoints with full visibility provided back to the System Control Center .... Armed with this information, field crews' response and repair times will be reduced .... More accurate and timely outage information and the resultant restoration of those outages will result in an increase in customer satisfaction, comfort and safety." (Exhibit B-1, pp. 101-102)

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 2014/2015 (Exhibit B-1, p.102; Exhibit B-6, BCUC 1.102.3). The estimated cost of the OMS is $830,000. The net forecasted savings of an OMS over the term of the Project is $1.957 million (Exhibit B-1, Section 6.3 Outage Management, Table 6.3.a, p. 102).

BCPSO questions the benefit of an OMS as there may be a several hour delay (in real time) between actual downloads of AMI data and power restoration (BCPSO Final Submission, p. 16).

CEC notes improvements in outage identification and management (CEC Final Submission, p. 11).

Commission Determination

The Panel acknowledges that AMI is an enabling technology to realize any future potential benefits and finds it appropriate that any benefit is not included in the financial analysis.

8.1.5.3 Development of Future Rates

FortisBC states that AMI allows it to remotely and economically apply time-varying rate structures to selected meters (Exhibit B-1, p. 103). These could include time-of-use rate (where rates vary based on the time period); critical peak pricing rates (where customers are charged higher rates during critical peak periods and lower rates during non-critical periods); and critical peak rebates (where customers receive rebates for reducing consumption during critical peak periods) (Exhibit B-1, Appendix C-1, p. 6). These are collectively referred to as time-of-use rates.

FortisBC considers that time-of use rates can provide benefits such as:

- Delaying requirement for new generating facilities and transmission and distribution infrastructure, lowering costs for all customers;
- Reducing future power purchase expense;
- a reduction in reliance on alternative fossil fuel based energy supply, will result in an environmental benefit.

(Exhibit B-6, BCUC 1.107.1)

FortisBC estimated the uptake and response to these rates; however, it did not rely on these estimated benefits in its AMI cost benefit analysis (Exhibit B-1, pp. 103, 104).

Interveners made submissions for and against time-of-use rates.

Commission Determination

The Panel acknowledges that AMI is an enabling technology that could facilitate time-of-use rates. Whether these potential rate structures provide an overall benefit to ratepayers has not been established in this Proceeding. The Panel will not consider this matter further.

8.2 Policy/Environmental Benefits

FortisBC states that the Project is consistent with the applicable of BC's energy objectives and specifically:

a) "to take demand-side measures and to conserve energy";

b) "to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources"; and

c) "to reduce BC greenhouse gas emissions."[8]

(FortisBC Final Submission, p. 39)

8.2.1 Clean Energy Act – GHG Reductions

FortisBC considers that the Project will have a positive environmental impact by reducing emissions from meter reading vehicles. FortisBC meter reading vehicles drive approximately 500,000 kilometres per year consuming approximately 80,000 litres of gasoline and emitting up to an estimated 234 tonnes of carbon dioxide per year based on GHGenius v4.0 modeling software. (Exhibit B-11, BCSEA 1.48.1) Over a 20 year Project life, FortisBC estimates the cumulative GHG emission reduction of 4,996 tonnes. FortisBC also points to additional vehicle emission reductions of future smart grid capabilities such as an outage management system that will assist crews in locating failed equipment compared to having to drive searching for the location of outages (Exhibit B-11, BCSEA 1.3.3).

BCSEA, however, states that these vehicular GHG emission reductions, while directionally supportive, are minor. BCSEA consider it is instead "crucial that marijuana grow-operations are not allowed to switch to diesel generation as an alternative to using stolen electricity" - the GHG emissions from grow-ops switching from grid electricity to diesel-fuelled generation could be greater than the GHG reduction benefits from meter reading vehicles (BCSEA Final Submission, p. 15).

[8] CEA, s. 2(b),(d) and (g).

Commission Determination

The Panel agrees with FortisBC's calculation of the GHG reductions that the Project provides. The Panel makes no determination on BCSEA's submission concerning fuel switching as no evidence was put forward on whether there would or would not be fuel switching to diesel fuel by marijuana grow-ops.

The Panel determines that the Project, by providing more detailed and timely information to customers about their energy use, supports BC's energy objectives, specifically the objectives found in CEA sections 2(b) to take demand-side measures to conserve energy; and 2(d) to use and foster the development in BC of innovative technologies that support energy conservation and efficiency. The Panel also finds that the Project supports energy objective 2(g) to reduce greenhouse gas emissions.

8.3 Theft Reduction Benefit

Power theft, primarily by illegal marijuana grow-operations, increases costs for all paying FortisBC electricity customers. Reduction of power theft resulting from the Project is estimated by FortisBC to be a significant benefit. FortisBC estimates the NPV benefit to be approximately $43 million over the life of the Project (Exhibit B-1-2, p. 3). Given the significance and complexity of this issue it is dealt with in its own section here.

In its analysis for the Project, FortisBC includes three components of the forecast theft reduction benefit. The first is a forecast increase in energy sales to paying illegal marijuana grow-operations. The second is a decrease in network electricity losses resulting from a reduction in theft of electricity by illegal marijuana grow-operations. The third is the recovered revenue from theft identification. The three components are broken out as follows:

Table 8-6

	($millions)
Revenue margin from paying sites	(16)
Power purchase costs from theft sites	(29)
Recovered revenue from theft identification	2
Total Theft Reduction Benefit	**(43)**

(Exhibit B-1-3, Excel Attachment, Tab "Theft Reduction")

Commission Determination

In the view of the Panel, the Economic Analysis should include the Theft Reduction Benefit to FortisBC's ratepayers. Accordingly, the Panel considers the $43 million to be the appropriate starting point for the examination of the Theft Reduction Benefit to be included in the Economic Analysis. The Panel has considered the three components that make up the Theft Reduction benefit of $43 million separately below. In addition the Panel will consider other issues, if any, from the effect of the Project on illegal grow-operations.

8.3.1 Theft Reduction – Revenues

This Section deals with the forecast increase in revenues by converting non-paying illegal marijuana grow operators to paying customers. The Panel will consider whether this portion of the benefit (to the extent it exists) should be included in this evaluation.

FortisBC put forward the following argument in support of inclusion of this benefit:

> "If the AMI project is implemented as proposed real financial benefits will occur due to illegal marijuana grow-operations being incented to pay for their electricity. It would seem disingenuous and improper not to attribute those financial benefits to the capital investment from which they are derived. In addition, the Company is not aware of any authoritative texts or guidelines for preparing financial analyses that suggest cash flows or other financial consequences of illegal activities are to be ignored when performing an analysis." (Exhibit B-14, BCUC 2.58.2.1)

In contrast, FortisBC also recognises that illegal activities are not a societal benefit, stating:

> "[FortisBC] doubts that Section 2 of the Clean Energy Act was intended to encourage economic development through illegal activities" (Exhibit B-14, BCUC 2.58.1)

In addition, a 2011 study authored by Diplock & Garis and led by Dr. Darryl Plecas, RCMP University Research Chair at the University of the Fraser Valley titled "Commercially Viable Indoor Marijuana Growing Operations in British Columbia: What Makes Them Such A Serious Issue?" (Plecas, Diplock & Garis Report) states:

> "[Commercially viable indoor marijuana growing operations] are harmful operations intended to generate on-going tax free profits for those who own them. Collectively across the province of British Columbia commercial [marijuana] growers take money out of the pockets of every taxpayer and worse and increasingly so, facilitate the ability of organized crime to become richer, stronger, and more pervasive." (Exhibit B-14, Appendix 3 to BCUC 2.59.0, p. 26)

CEC agrees with FortisBC that including the increase in net billable load of grow-operations paying for electricity is a reasonable assumption (CEC Final Submission, p. 16). BCSEA considers that additional revenue from paying illegal grow-operations should be included in the NPV analysis on the basis that 'but for the project' the additional revenue would not be received (BCSEA Final Submission, p. 11).

Commission Determination

The Panel considers that this illegal activity cannot, by its very nature, be considered to have a public interest benefit. **The Panel therefore disagrees with FortisBC's position that an increase in sales to illegal grow-operations can be considered a net benefit of the Project.** While it may be true that some marijuana growers may shift from stealing electricity to paying for it as a result of AMI due to improvements in theft detection provided by AMI, to base a decision on the merits of installing meters on the expectations of gains from an illegal enterprise is, in the Panel's view, inappropriate. For this reason no such benefit is included in the Panel's economic analysis of the Project.

8.3.2 Decrease in Network Electricity Losses

This Section deals with the reduction in theft of electricity by illegal marijuana grow-operations and the related decrease in network electricity losses. The following subsections discuss the key assumptions and methodology used in arriving at the Panel's determination to attribute a NPV benefit of $33.5 million to the Project.

8.3.2.1 Treatment of Uncertain Benefits

FortisBC acknowledges that there is uncertainty in forecasting the result of the Project on electricity theft (FortisBC Final Submission, pp. 45-46).

BCPSO submits that the benefit from theft reduction is entirely speculative, and granting a CPCN based on a financial analysis that is based on such speculative estimates may not be prudent (BCPSO Final Submission, p. 10). CEC and BCSEA consider adoption of a conservative approach in estimating the benefit is sufficient to address the uncertainty risk. The CEC also submits that the Commission should consider the possible upside as well as the possible risk in evaluating the benefit (CEC Final Submission, pp. 15-16; BCSEA Final Submission, pp. 12-13). FortisBC states that the fact that there is never absolute certainty should not be a reason for rejecting a project, otherwise the electrical grid would simply stagnate (FortisBC May 2 Reply, p. 14).

Commission Determination

The Panel considers that benefits which are uncertain should be estimated conservatively, such that the estimated benefit is more likely to be understated than overstated. The Panel notes that any economic benefit from reduced system losses will accrue to FortisBC's ratepayers as they are the ones who pay these costs.

8.3.2.2 Identification of Key Assumptions used to Estimate the Theft Benefit

The Commission Panel will review each of the key assumptions made by FortisBC in arriving at the probable theft benefit estimate to determine if, when considered together, they are more likely to result in a theft benefit estimate that is understated rather than overstated.

To capture the range of possible results, FortisBC prepared four possible scenarios for calculating the theft benefit, and put forward a 'probable AMI forecast' as a conservative estimate of the benefit. FortisBC states that Table 8-7 provides a reasonable summary of the key assumptions made by FortisBC in estimating electricity theft by illegal marijuana grow-operations.

Table 8-7

	FortisBC Status Quo	**FortisBC AMI Probable**
Current estimated number of illegal marijuana sites in FortisBC service area	927	927
Annual change in total number of sites	2 percent increase each year	1 percent increase each year
Annual energy use per site	151,200 kWh	151,200 kWh

	FortisBC Status Quo	FortisBC AMI Probable
Percentage sites stealing electricity	25 percent, increasing to 30percent by 2017	25 percent decreasing to 5percent by 2021
Theft detection rate	8 percent	Increasing from 8 percent to 25 percent by 2016
Recovered revenue from theft detection	Each theft site is billed for an average 1 year loss with collection success rate of 20 percent	

(Exhibit B-14, BCUC 2.62.2 – modified to include Kelowna)

FortisBC filed a letter from Professor Neil Boyd, a Professor at the School of Criminology, Simon Fraser University. Professor Boyd raised concerns that future government policy changes and lighting technology improvements could significantly decrease or increase the forecast theft benefit from AMI. He states that marijuana legalization and technology changes to more efficient LED lighting are entirely within the realm of possibility and could dramatically affect the validity of the projections. (Exhibit B-6, Appendix to BCUC 1.86.1, p. 6) FortisBC considers that there is little credible evidence to support a current trend towards LED use by marijuana grow-operations. (Exhibit B-6, BCUC 1.83.4.1)

FortisBC considers that regulation of marijuana production in BC will not result in a reduction in electricity theft as 90 percent of marijuana is exported and the regulated marijuana product may be of a lower potency than that offered in the illegal market (Exhibit B-14, BCUC 2.63.1).

Professor Boyd considers that there could be significantly higher theft levels under the Status Quo if local governments embraced the Safety Standards Amendment Act of 2006 by using electricity consumption data to identify potential illegal grow-operations. Professor Boyd considers that a worst case scenario could emerge, where the number of growers in the region would increase (given knowledge of the lack of AMI deployment) and the majority would steal electricity. (Exhibit B-6, Appendix to BCUC 1.86.1, p. 6)

FortisBC states that there have been no signals from local governments indicating an interest in engaging under the Safety Standards Amendment Act. However, FortisBC notes that, if such a scenario were to occur, the theft benefit will increase beyond that submitted in the Application. (Exhibit B-14, BCUC 2.63.4, 2.63.4.1)

Commission Determination

The Panel agrees with Professor Boyd that legalization of marijuana, LED changes and municipal use of the Safety Standards Amendment Act could significantly increase or decrease the theft benefit from AMI. However, the Panel considers that these potential impacts are hard to predict. The Panel will consider these possibilities when evaluating whether the theft benefit estimate put forward by FortisBC is sufficiently conservative.

8.3.2.3 Review of Key Assumptions in the theft benefit estimate

8.3.2.3.1 Number and growth rate of marijuana grow sites on FortisBC's network

FortisBC used a 2011 study authored by Diplock & Plecas titled "The Increasing Problem of Electrical Consumption in Indoor Marihuana Grow Operations in British Columbia" (Plecas Report, Exhibit A2-1) as its starting point in estimating the number of illegal marijuana sites in FortisBC's service area. This study estimated that there were 13,206 indoor marijuana grow premises in BC in 2010. (Exhibit B-1, p. 82)

As FortisBC serves approximately 6 percent of residential electric customers in BC, FortisBC estimated that 792 sites existed in the Company's service area. This figure was 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. (Exhibit B-1, p. 82) Professor Boyd supports FortisBC's estimate. (Exhibit B-6, Appendix to BCUC 1.86.1, p. 2) FortisBC subsequently scaled the number of sites up to 927 to include Kelowna (Exhibit B-1-3, AMI Excel NPV Analysis – CoK Addendum, Theft Reduction sheet).

FortisBC also assumes (i) a 2 percent/year increase in the number of illegal marijuana grow-operations without the Project, and (ii) a 1 percent/year increase in the number of illegal marijuana grow-operations year if the Project is installed (Exhibit B-1, pp. 82, 83). Professor Boyd's opinion is that the increase in illegal grow-operations is likely to be greater than estimated by FortisBC without the Project (10 percent increase by 2016 was provided as a low estimate), and if the Project results in a theft ratio of 5 percent, the total number of sites may not increase but may even decrease (Exhibit B-6, Appendix to BCUC 1.86.1, pp. 6, 7). No interveners disputed FortisBC's assumptions regarding the number and growth rate of marijuana grow sites.

Commission Determination

Based on the evidence provided in the report and letter, the Panel accepts (i) FortisBC's estimate of the number of marijuana grow sites as reasonable, and (ii) FortisBC's estimate of the annual increases in the number of theft sites with and without AMI as conservative.

8.3.2.3.2 Average Energy Use per Site

FortisBC estimates that each marijuana grow-operation uses on average thirty 1000 Watt lights per site. This is taken from data compiled by FortisBC of investigations undertaken between 2006 and 2012, and is lower than the estimate of 36 lights per site used in the Plecas Report. Professor Boyd states that he has no reason to doubt this estimate. (Exhibit B-1, p. 82; Exhibit B-6, Appendix to BCUC 1.86.1, p. 3)

A 2011 study titled "The Nature and Extent of Marihuana Growing Operations in Mission British Columbia" (Exhibit A2-7) found that grow-operations involving electricity theft have been consistently larger than operations that do not involve electricity theft (Exhibit A2-7, p. 6).

FortisBC estimates that each marijuana grow-operation uses 151,200 kWh/year based on an assumption of four grow cycles per year used in the Plecas Report (Exhibit B-1, p. 82). FortisBC states that it has consistently assumed and invoiced for four annual grow cycles when theft is detected, and this assumption has not been challenged by producers (Exhibit B-14, BCUC 2.62.3). However, Professor Boyd states "the Plecas Report calculations of 90 days in the grow cycle and 4 grow cycles per year likely assume a degree of organization that does not exist with most grow-operations." Professor Boyd instead supports a more conservative estimate of three grow cycles per year (113,400 kWh per site) (Exhibit B-6, Appendix to BCUC 1.86.1, p. 3). No interveners made submissions regarding FortisBC's assumptions of the average energy use per site.

Commission Determination

The Panel accepts FortisBC's assumption, supported by Professor Boyd that each marijuana grow-operation uses on average thirty 1000W lights per site. The Panel accepts that although some grow-ops may average four grow cycles per year the evidence of Professor Boyd is that a more conservative approach is to assume three grow cycles each year. **The Panel therefore accepts Professor Boyd's conservative approach of three grow cycles per year as being reasonable. This**

reduces the assumed annual energy use per site from FortisBC's estimate of 151,200kWh/year to 113,400/kWh.

8.3.2.3.3 Percentage of Sites Stealing Electricity

FortisBC assumes that 25 percent of illegal marijuana grow sites are stealing electricity, and that this increases to 30 percent by 2017 under the Status Quo, and decreases to 5 percent by 2021 if AMI is installed. FortisBC states that the revenue protection program has identified an average 25 percent of known or suspected marijuana sites as diverting electricity (theft) from 2009 to 2011. (Exhibit B-1, p. 83)

The Plecas Report found that the proportion of growers stealing power appears to be approximately 52 percent, and stated that this figure is nearly identical to the estimate provided to the authors from BC Hydro (51 percent). The Plecas Report also states that this estimate is nearly identical to the estimate provided by individuals who have operated illegal grow-operations and who have a broad knowledge of the industry. These individuals reported that generally "half" of all operators today steal electricity. (Exhibit A2-1, p. 2)

Professor Boyd considers that the higher theft estimates by Plecas could result from approaches taken by some Lower Mainland municipalities to use the provisions of the Safety Standards Amendment Act of 2006 to identify and target high use customers. Professor Boyd notes that no local governments serviced by FortisBC require disclosure of account information of customers with high loads, and this could result in marijuana producers on FortisBC's network being less likely to steal. (Exhibit B-6, Appendix to BCUC 1.86.1, p. 5)

Professor Boyd cites a province-wide 2005 report of theft which found electricity theft in an average of 20 percent of 25,000 cases, and considered it was reasonable to assume an increase in theft levels since that date as a result of an unintended consequence of the Safety Standards Amendment Act of 2006. Professor Boyd considers that there will be some further increase in theft from current levels under the Status Quo due to an influx of growers; however, while he considers it is virtually certain theft will decrease markedly under the Project, it may not drop as low as 5 percent. (Exhibit B-6, Appendix to BCUC 1.86.1, pp.5, 7)

Commission Determination

The Panel accepts FortisBC's evidence of a 25 percent grow-op theft rate, increasing to 30 percent under the Status Quo as conservative.

8.3.2.3.4 Theft Detection Rate and Recovered Revenue

FortisBC states in the Application that revenue protection investigators have discovered an average of 8 percent of the total estimated theft sites annually. Its analysis assumes this 8 percent theft detection rate will increase to 25 percent by 2016 under the Project. (Exhibit B-1, pp. 83, 84) FortisBC considers this to be a conservative assumption (Exhibit B-6, BCUC 1.87.1.4).

FortisBC states that theft reduction following AMI will be achieved in two phases. Phase I will focus on tamper detection, improved data quality and non-demand meter readings. Phase II involves the installation of feeder meters at key points on FortisBC distribution feeders. These meters will measure the total electricity supplied to a specific area and can be used to target areas with higher than expected line losses. The capital cost of installation and operation of Phase II is included in the Project budget. (Exhibit B-1, pp. 87, 88)

FortisBC states that once the Phase I theft detection results are evaluated it will determine if there is a business case for an increase in the Phase II budget to further increase the theft detection rate (Exhibit B-14, BCUC 2.62.5). FortisBC also estimates in the Application that theft sites will be billed for an average one year loss, with a success rate of 20 percent, which is lower than the 50 percent actual recovery rates obtained during 2006 to 2011 (Exhibit B-14, BCUC 2.62.4). No interveners disputed FortisBC's assumptions regarding the theft detection rate and recovered revenue.

FortisBC considers that it has achieved a noteworthy reduction in theft with limited resources, technology and data quality, and considers it is reasonable to predict an additional 20 percent reduction in theft from AMI (Exhibit B-14, BCUC 2.62.3). No interveners disputed FortisBC's assumptions regarding the percentage of sites stealing electricity or the reduction esitmates.

Commission Determination

The Panel accepts FortisBC's assumption regarding the theft detection rate and recovered revenue as conservative. **The Panel accepts FortisBC's evidence that it will be able to yield an additional 20 percent reduction in the theft ratio under AMI as reasonable.**

8.3.2.4 Valuing the Decreased Network Electricity Losses from the Project

FortisBC valued the electricity theft from marijuana grow-operations at its short-term avoided cost using the estimated BC Wholesale Market Energy Price ($54.68 per MWh for 2012) (Exhibit B-6, BCUC 1.81.2). FortisBC states that it elected to use the short-term avoided cost as part of its overall conservative approach to modelling the benefits associated with the AMI Application, and believes this to be an appropriate approach. However, FortisBC states that it would not object to valuing the energy lost due to theft at the full long-run marginal cost of acquiring energy from new resources (Exhibit B-14, BCUC 2.61.2.1). FortisBC estimates the long-run marginal cost for acquisition of new resources is $111.96/MWh. Adding 11 percent FortisBC system losses increases the estimate to $125.80/MWh (Exhibit B-14, BCUC 2.61.1).

Commission Determination

In valuing the reduction in electricity lost to theft, the Panel does not consider that the decision should be based on picking whichever of the short-run or long-run cost estimate happens at that time to provide the lowest benefit estimate. The Panel considers that a matching principle should apply. Where the energy saving benefit occurs over the long-term, a long-term cost of energy should be used to calculate the value of that benefit.

The Panel considers that the reduction in energy lost to theft as a result of AMI provides a long-term benefit to customers. Accordingly, in examining the Project over the long-term in the Economic Analysis, the Panel considers that the cost of energy should be valued at FortisBC's long-run marginal cost of $125.80/MWh.

The Panel considers that while using the long-run marginal cost of energy is appropriate to measure the long-term benefit in the Economic Analysis, this is not appropriate to use when examining the short-term rate impact of the Project. Accordingly, for the purposes of determining the rate impact of the Project over the short-term, the Panel has used the short-term avoided cost using the estimated BC Wholesale Market Energy Price. The rate impact of the Project is discussed in Section 8.5 of this Decision.

8.3.3 Are There Lower Cost Ways of Obtaining the Theft Benefit?

BCPSO submits that if theft reduction was the primary need to be addressed in this project, then simpler, lower cost systems exist (BCPSO Final Submission, p. 9).

FortisBC does not consider that an expansion of the Revenue Protection Program coupled with only advanced feeder level meters would not increase the number of leads nor improve the quality of tips; both of which are possible with AMI deployment (Exhibit B-6, BCUC 1.85.5). FortisBC states it tested a manual approach to energy balancing at the feeder level and has concluded that the installation of feeder meters without the accompanying advanced meters is not practical as the readings will occur over different time periods and manual readings may contain inaccuracies (Exhibit B-6, BCUC 1.82.4).

Commission Determination

The Commission Panel accepts that advanced meters at the feeder level only would not be a practical means of identifying theft as data obtained would not be time synchronised.

8.3.4 Theft Reduction Benefit – Other Considerations

The Panel previously determined that AMI should result in a reduction in the number of illegal marijuana grow-operations on FortisBC's network compared to the Status Quo. FortisBC considers that this will provide communities with health and safety benefits, and states that it is particularly concerned with the existing risk of electrical fires associated with theft sites. An August 2012 report by Surrey Fire Chief Len Garis and Dr. Joseph Clare found a 36 percent decrease in the frequency of residential fires associated with marijuana grow-operations following deployment of smart meters on BC Hydro's network. (FortisBC Final Submission, pp. 212-213; Exhibit B-14, BCUC 2.58.6)

The Plecas, Diplock & Garis Report, (titled 'Commercially viable indoor marihuana growing operations in British Columbia: what makes them such a serious issue?' states that a reduction in the overall number of illegal marijuana grow-ops on FortisBC's network should provide community health and safety benefits. These include: reduced fire and other health risks to house occupants (including children) of current grow-operations; reduced health risks to house occupants of past undetected grow-operations; reduced risk of drinking water contamination in the neighbourhood as a result of grow-operation back flushing; and enhanced community safety resulting from a reduction in criminal activity. (Exhibit B-14, Appendix 3 to BCUC 2.59.0)

Professor Boyd states "... the material provided to me by Fortis does not quantify the potential public safety benefits of AMI (in relation to the dangers in theft of electricity). More specifically, the avoidance and/or limitation of fatalities and serious injuries to citizens have economic costs that should be considered." (Exhibit B-6, Appendix to BCUC 1.86.1, p. 8)

Commission Discussion

The Panel is of the view that a reduction in illegal grow-operations resulting from AMI should provide community health and safety benefits, in particular through a reduction in number of residential fires caused by illegal grow-operations. No determination is made on the quantum of these net benefits.

8.3.5 Summary

In summary, the Panel concludes that the total theft reduction benefit should be adjusted for the following items:

- No allowance for increases in sales to illegal grow-operations;
- Annual energy use per site reduced from 151,200 kWh to 113,400 kWh; and
- Short-term avoided cost of energy replaced with the long-run marginal cost of energy.

Using FortisBC's financial model (included in Exhibit B-1-3, Attachment, Tab "Theft Reduction") to make these adjustments results in an estimated net present value benefit of theft reduction of $33.463 million. The Panel considers this to be the appropriate Theft Reduction Benefit to include in the Economic Analysis of the Project.

8.4 Economic Analysis – Summary

For the reasons outlined above in this Section, the Panel accepts a net benefit of $13.876 million on a NPV basis over 20 years for the Project Economic Analysis. This is summarized as follows:

Table 8-8

	NPV ($000s) Net AMI
Operating Expenses:	
New Operating Costs	14,411
Meter Reading	(26,444)
Disconnect / Reconnect	(6,155)
Meter Exchanges	(1,610)
Contact Centre	(507)
Total Operating Expenses	**(20,305)**
Sustaining Capital:	
Meter Growth and Replacement	1,972
Handheld Replacement	(581)
Measurement Canada Compliance	(10,808)
IT Hardware, Licensing and Support Costs	5,688
Total Sustaining Capital	**(3,729)**
Income Taxes	4,547
Project Capital	39,074
CPCN Development Costs	-
Theft Reduction Benefit	(33,463)
Total	**(13,876)**

Given the expected economic benefit of the Project, the Panel expects that the Project will also have a positive impact on rates over the life of the Project.

8.5 Rate Impact of the Project

The Panel does not consider it appropriate to evaluate the customer rate impact over the life of the Project (i.e. 20 years). Instead, the Panel has considered the expected rate impact over the short-term. In the Panel's opinion a period of five years is appropriate given that FortisBC's current Revenue Requirements Application is for the period 2014-2018.

The Revenue Requirements Analysis submitted by FortisBC has a cumulative incremental rate impact over the next five years as follows:

Table 8-9

Cumulative Incremental Rate Impact (Net AMI)					
2014	2015	2016	2017	2018	Reference
1.76%	1.66%	-0.38%	-0.46%	-0.69%	Exhibit B-1-3, Tab "Net AMI", Line No. 14

The Panel has used this Revenue Requirements Analysis (Exhibit B-1-3) as the basis for determining the expected rate impact of the Project. The majority of the project costs and benefits included in the Revenue Requirements Analysis are the same as in the Economic Analysis and accordingly, they are not re-examined here. There are, however, several items that are specific to the calculation of the expected rate impact of the Project that are examined in the sections that follow.

The Economic Model has been adjusted for the following items:

1. Theft Reduction Benefit
   - No allowance for increases in sales to illegal grow-operations;
   - Annual energy use per site reduced from 151,200 kWh to 113,400 kWh.
2. Write-off of the Existing Meters
   - Amortized over a period of 5 years

Making these adjustments, the Panel has summarized below the expected rate impact of the Project over the next five years. The Panel notes that the cumulative incremental rate impact of the Project in any given year is less than 0.9 percent.

Table 8-10

Cumulative Incremental Rate Impact (Net AMI)				
2014	2015	2016	2017	2018
0.39%	0.87%	0.46%	0.54%	0.39%

8.5.1 Carrying Costs

The Panel has reviewed FortisBC's calculation of carrying costs included in the Revenue Requirements Analysis, including the following inputs: deemed capital structure; cost of debt; and cost of equity. The Panel accepts FortisBC's calculation of carrying costs as being reasonable.

8.5.2 Theft Reduction Benefit

The Panel has examined the Theft Reduction Benefit specifically in Section 8.3 of this Decision. In summary, the Panel concluded that the total Theft Reduction Benefit of $43 million should be adjusted for the following items:

- No allowance for increases in sales to illegal grow-operations;
- Annual energy use per site reduced from 151,200 kWh to 113,400 kWh; and
- Short-term avoided cost of energy replaced with the long-run marginal cost of energy.

In order to determine the appropriate theft reduction benefit to use in the determination of the rate impact of the Project, the adjustments above are also applicable except for the cost of energy. The Panel notes that while using the long-run marginal cost of energy is appropriate to measure the long-term benefit in the Economic Analysis, this is not appropriate to use when examining the short-term rate impact of the Project. Accordingly, for the purposes of determining the rate impact of the Project over the short-term, the Panel has used the short-term avoided cost using the estimated BC Wholesale Market Energy Price.

8.5.3 Depreciation

The depreciation expense included in the Revenue Requirements Analysis represents the incremental expense under the Project, as compared to the Status Quo scenario. For ratemaking purposes, depreciation expense is the allocation of the cost of assets to periods in which the assets are used. The depreciation expense for both the Project and the Status Quo scenario is calculated using the capital costs and applicable depreciation rates.

With respect to depreciation rates, FortisBC provided a summary of the Project capital costs and the proposed depreciation rates excluding the City of Kelowna in Exhibit B-6 (Exhibit B-6, BCUC 1.90.1). The Panel recalculated the summary with the project capital costs for the City of Kelowna using the data provided in the Addendum to the Application (Exhibit B-1-2).

Table 8-11

	Item	Total 2013 - 2015 (A)	% of Total (B)	Depreciation Category (C)	Depreciation Rate (C)	Portion of Total Composite Depreciation Rate (B)
		($000s)				
1	Third Party Software and Services	5,830	11%	Software	5.01%	0.6%
2	Meters (Including Deployment)	22,941	45%	Meters	5.00%	2.2%
3	Network Infrastructure	4,602	9%	Comm Structure & Equip	8.05%	0.7%
4	Network Infrastructure	48	0%	Software	5.01%	0.0%
5	System Integration	2,377	5%	Software	5.01%	0.2%
6	Theft Detection	1,100	2%	Meters	5.00%	0.1%
7	Project Management	3,355	7%	Average	5.38%	0.4%
8	CPCN Development / Approval Costs	4,915	10%	Average	5.38%	0.5%
9	Capitalized Overhead, AFUDC, PST	6,005	12%	Average	5.38%	0.6%
10	**Total**	**51,173**	**100%**			**5.38%**
A	Agreed to Exhibit B-1-2, p. 4					
B	Recalculated					
C	Agreed to Exhibit B-6, BCUC IR 1.90.1					

FortisBC requests approval of a depreciation rate of 5 percent for the meters to be installed as part of the Project, based on an estimated economic life of 20 years. With respect to the Project capital costs other than the Meter asset class, specifically the Computer Equipment and Software and Communication Structures and Equipment, FortisBC proposes depreciation accrual rates based on the 2011 Depreciation Study.

Regarding accrual rates, the 2011 Depreciation Study notes the following:

> "The annual depreciation accrual, and cost of removal rates and the related calculated requirement for accumulated depreciation and cost of removal were calculated using the straight line method, the remaining life basis and the average service life (ASL) procedure. The calculation was based on the attained ages and estimated service life and net salvage characteristics for each depreciable group of assets."

With respect to survivor curves, the 2011 Depreciation Study notes the following:

> "The use of an average service life for a property group implies that various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages."
> (Exhibit B-6, Appendix BCUC 1.69.4)

8.5.3.1 AMI Meters

FortisBC states in the Application that "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 manufacturer's recommendations" (Exhibit B-1, p. 76).

The 2011 Depreciation Study designates a survivor curve of 20 years to FortisBC's existing meter population, comprised of both electric and electromechanical meters (Exhibit B-6-5, BCUC 1.89.1). FortisBC submits that the "...Centron meter product was introduced to the marketplace in 1998, so no Centron meters have yet been operating in the field for 20 years" (Exhibit B-11, CEC 1.6.1), However, the Accelerated Life Testing document provided by Itron also indicates that the AMI meters have a "...15 or 20 year life expectancy" (Exhibit B-6, BCUC 1.69.1).

In support of the "manufacturer's recommendations" FortisBC provided an Itron document that summarizes the accelerated life testing performed at the Oconee electric meter manufacturing facility. The testing summary notes the following:

> "Many meters will last beyond their 15 or 20 year life expectancy. Each stress test lasts the equivalent of the product lifespan. The tests show that the product must maintain a <= 0.5% yearly failure rate over the product life expectancy. In other words, if we have 0.5% * 20 years = 10% of the meters can fail, but 90% are still operational. From the accelerated life testing, we calculate what the yearly failure rate; we can validate that the failure rate is less than the 0.5%." (Exhibit B-6, BCUC 1.69.1)

FortisBC also provided an email from Itron which stated that "Itron does not provide guidance on depreciation schedules, as those decisions are a function of utility policy" and "Several utilities have determined that for their purposes the OpenWay CENTRON Meter has a useful life expectancy of 20 years. This is based on a failure rate of less than 0.5% for single-phase meters ... With more than 9 million meters deployed, we also have access to field data to determine the failure rates and reliability of the product. Currently, Itron can demonstrate field failure rates well below 0.5% for the [product(s)]." (Exhibit B-14, Attachment BCUC 2.37.1)

The implementation of AMI meter technology in Canada has been a relatively recent development. In Ontario, legislation was introduced in 2005 to start the process of installing "smart meters" in every home and small business in the province by 2010.[9] Under BC Hydro's Smart Metering Program, the installation of "smart meters" began throughout British Columbia in 2011 and 2012 (Exhibit B-1, Exhibit C-4, BC Hydro Smart Meter Business Case). Most recently in October 2012, the Régie de l'énergie [Québec energy board] issued Decision D-2012-127 approving Phase 1 of Hydro-Québec's Smart Meter Project (Exhibit B-14, Appendix BCUC 2.84.1).

With respect to assumptions made in other Canadian jurisdictions regarding the economic life of AMI meters, the Ontario Energy Board notes the following in their 2010 "Accounting Procedures Handbook Frequently Asked Questions" document:

> "For regulatory accounting purposes, 15 years useful life on a straight-line basis is used to calculate and record depreciation of in-service smart meters ... This applies until such time as the distributor presents an independent depreciation study and the Board accepts a different useful life as more appropriate."
> (Exhibit B-6, BCUC 1.69.1)

With respect to "industry experience", FortisBC notes that "Currently the only other jurisdictions known to FortisBC using an economic life other than 20 years are FortisAlberta (at 25 years) and Ontario (at 15 years)" (Exhibit B-6, BCUC 1.89.5).

The CEC supports a revised depreciation rate of 5 percent for the AMI meter asset class and recommends that this revised rate be approved for the duration of the proposed Project (CEC Final Submission, p. 42). No other Interveners took a position on this issue.

BC Hydro indicated that the amortization period for its smart meters is 20 years (Exhibit B-1, Appendix C4, p. 32).

Commission Determination

For the Revenue Requirement Analysis the Panel accepts the same capital costs as it did for the Economic Analysis, as both analyses concern the same Project and the same set of capital assets.

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9 http://gridsmartcity.com/smart-grid-defined/smartgrid-and-green-energy-timeline/

Given the recent implementation of AMI technology in other Canadian jurisdictions, the Panel is of the view that the economic life of AMI meters based on industry experience is not well established. However, the Panel also recognizes that depreciation rates are based on estimates and consequently assumptions must be made in order to determine appropriate depreciation rates.

The Panel acknowledges that the economic life of AMI meters may differ from that of the existing meter population; however, in the absence of historical data and established industry experience to support the estimated economic life of the AMI meters, the Panel is of the view that the survivor curve of the existing meter population provides support for the expected useful life of meter technology in general.

Based on the evidence set out above, the Panel considers there to be an acceptable range of between 15 and 20 years for the estimated economic life of AMI meters. **Accordingly, the Panel approves a depreciation rate of 5 percent for the AMI meters, based on an estimated economic life of 20 years until the next depreciation study is completed and approved.**

8.5.3.2 Other Project Asset Classes

FortisBC proposes depreciation rates for the Computer Equipment and Software and Communication Structures and Equipment asset classes of 5.01 percent and 8.05 percent respectively based on the recommendations in the 2011 Depreciation Study (Exhibit B-1-1, Updated Application, p. 76). FortisBC submits that this is appropriate for the following reasons:

> "The Company is of the opinion that given that the Computer Hardware and Software in the AMI project is very similar to the Computer Hardware and Software that the Company uses in its operations today, the useful lives of the existing Computer Hardware and Software would be similar to that associated with the AMI project." (Exhibit B-6-5, BCUC IR 1 (Revised Responses), p. 10)
>
> "The communication equipment, software, and structures in the AMI project is very similar to the communication equipment, software, and structures that the Company utilizes in its operations today. The communication equipment, software, and structures would be added to the same asset classes as are found in the depreciation study but the current depreciation rates by asset class would continue to be applied to all assets until a new depreciation study was completed." (Exhibit B-6, BCUC 1.69.4)

The 2011 Depreciation Study recommended the following accrual rates and survivor curves (Exhibit B-6, Appendix BCUC 1 69.4, 2011 Depreciation Study):

Table 8-12

Asset Class	Accrual Rate	Survivor Curve
Computer Equipment and Software	5.01 percent	10 years
Communications Structures and Equipment	8.05 percent	15 years

The CEC agrees with FortisBC's approach in determining the composite depreciation rates for the Project capital costs (CEC Final Submission, p. 42). No other Interveners took a position on this issue.

Commission Determination

The Panel notes that the attained ages of the assets within each asset class, based on data through 2009, forms part of the basis for the calculation of the accrual rates recommended in the 2011 Depreciation Study. Accordingly, the addition of significant, new capital costs to the existing asset classes could render the existing accrual rates inappropriate by changing the overall composition of the asset class.

Considering the impact that the new AMI capital costs could have on the overall composition of the existing asset classes, the Panel concludes that it is more appropriate to use the survivor curves, rather than the accrual rates, recommended in the 2011 Depreciation Study to determine the appropriate depreciation rates for the AMI Computer Equipment and Software and Communication Structures and Equipment. **FortisBC is directed to use a depreciation rate of 10 percent (1 divided by a 10 year survivor curve) for the AMI Computer Equipment and Software and 6.67 percent (1 divided by a 15 year survivor curve) for the AMI Communications Structures and Equipment until the next depreciation study is completed and approved.**

FortisBC has not had the opportunity to recalculate the Revenue Requirements Analysis and the expected impact of the Project on customer rates using the depreciation rates for the AMI Computer Equipment and Software and AMI Communication Structures and Equipment ordered by the Panel in this Decision. However, in the Panel's opinion, this is not expected to have a material impact on the expected impact on customer rates, given that the revised depreciation rate of 5 percent for the AMI meters has been approved, and the capital costs associated with meters (including deployment) represent 45 percent of the total Project capital costs. (Exhibit B-1-2, p. 4)

8.5.4 Accounting Treatment of the Existing Meters

The accounting treatment for the write-off of the existing meters for ratemaking purposes is an important consideration in the Revenue Requirements Analysis. The unamortized balance of the existing meter population including the former City of Kelowna service territory is $10.3 million (Exhibit B-1-3, Tab "Net AMI", Line No. 64-65). FortisBC has considered three options for the regulatory accounting treatment of the existing meter population (Exhibit B-1, p. 77):

1. Write-off the existing meter population as they are removed from service and replaced with AMI meters over 2014 – 2015.
2. Continue to depreciate the existing meter population based on the depreciation rates set by the 2011 Depreciation Study.
3. Depreciate the existing meters over a period longer than proposed in Option 1 and 2 above.

FortisBC has proposed Option 1, as it does not require a departure from US Generally Accepted Accounting Principles (US GAAP).

Under US GAAP the write-off of the existing meters would normally be expensed as a current period charge as the existing meters are removed from service. Consequently, a variance from US GAAP is required under Option 2 and Option 3. FortisBC submits that "US GAAP recognizes that rate regulated entities might request or be ordered to account for costs in a manner not consistent with US GAAP and allows for the variance in the accounting treatment." (Exhibit B-15, CEC 2.19.2)

BCPSO supports Option 3 considered by FortisBC, given that "... the longer amortization period is in the customers' best interest." (BCPSO Final Submission, p. 19)

CEC supports the accounting treatment proposed by FortisBC on the basis that it is in accordance with US GAAP and accurately reflects the costs of the Project. (CEC Final Submission, p. 42)

Commission Determination

FortisBC is directed to record the cost of these meters in a rate base deferral account attracting FortisBC's weighted average cost of capital (WACC) as they are removed from service. Additions to the deferral account are to be amortized over a period of five years, commencing the year following their addition.

The Panel is in agreement with CEC that Option 1 most accurately reflects the costs of the Project. In addition, this option is advantageous in that it does not require a variation from US GAAP. However, the Panel is of the view that the rate impact must also be considered in determining the appropriate regulatory accounting treatment for the existing meters. Option 1 has the most significant annual rate impact as it proposes the shortest amortization period.

Option 3 results in the lowest annual rate impact of all three deliberated by FortisBC as it proposes the longest amortization period. In the Panel's view this option increases intergenerational inequity with respect to the cost of service impact of the existing meter population. In addition, it results in the most significant ultimate cost to ratepayers due to the amount of financing charges that the balance would attract over the extended amortization period. Accordingly, the Panel does not consider it appropriate to extend the amortization period of the existing meter population beyond what was recommended in the 2011 Depreciation Study.

The Panel considers that an accounting treatment derived from Option 2 proposed by FortisBC appropriately balances the benefit of rate smoothing with the benefit of reducing both intergenerational inequity and the financing costs that deferred expenses attract. As Option 2 requires a variance from US GAAP, the Panel has considered two additional issues with respect to the recovery of the unamortized balance of the existing meters:

1. Amortization Period

> With respect to Option 2, FortisBC notes that "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." (Exhibit B-1-1, Updated Application, p. 77) In the absence of a more current depreciation study, and in order to account for the two years (i.e. 2012 and 2013) that have passed since the 2011 Depreciation Study, the Panel considers the appropriate amortization period to be 5 years.

2. Financing Costs

Given that the deferral account relates to expenditures that are capital in nature, the Panel considers it appropriate for the deferral account to attract FortisBC's WACC.

Option 2 was used by BCUC staff, in calculating the rate impact.

8.5.5 BCUC Staff Model

Using the same data and assumptions as provided by FortisBC in the Revenue Requirements Analysis, Commission staff also prepared an analysis that separated the calculation of the revenue requirements of the Project from the calculation of the impact of the Project on customer rates (BCUC Staff Model).

FortisBC acknowledges in its Final Submission that:

> "An alternative means of looking at this calculation was provided by Commission Staff in Appendix 1 to Exhibit A-15 (the BCUC Staff Model). In the BCUC Staff Model, the impact of the proposed AMI Project was considered on the revenue requirement using only the portion of the theft reduction benefit that directly impacts the revenue requirement. Unlike FortisBC's calculations, the BCUC Staff Model excluded the portion of the benefit related to an increase in net billable load. This benefit was instead reflected in determining the impact of the proposed AMI Project on customer rates." (FortisBC Final Submission, p. 44)

BCSEA states that "Using the BCUC Staff Model, FortisBC's estimate of the AMI NPV is -$10.8 million -- meaning the financial benefits exceed the financial costs by $10.8 million" (BCSEA Final Submission, p. 12).

Although the CEC agrees with FortisBC that including the increase in net billable load of grow-operations paying for electricity is a reasonable assumption, it "submits that a positive net present value of $10 million remains a valuable contribution" (CEC Final Submission, p. 16).

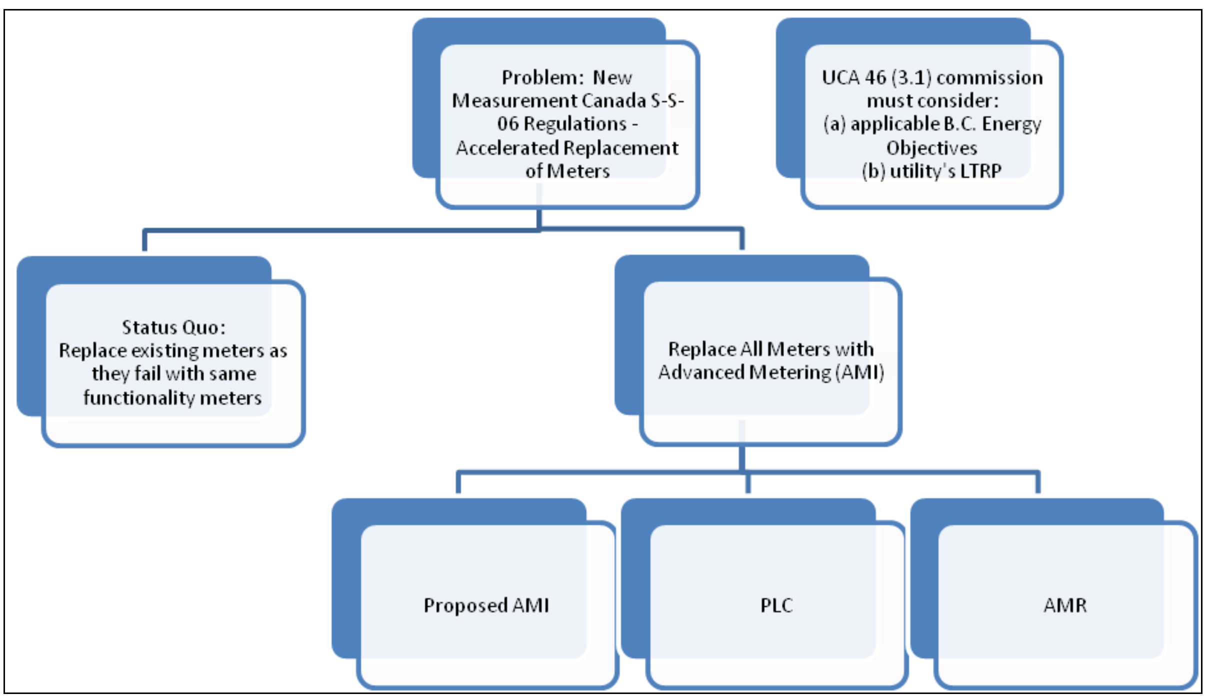
Commission Panel Discussion

The Panel notes that Part 2 of the BCUC Staff Model calculates the expected customer rates impact of the Project, including the Theft Reduction Benefit related to the increase in billable load from marijuana sites. The Panel has examined the Theft Reduction Benefit specifically in Section 8.3 of this Decision and has not approved the portion of the Theft Reduction Benefit related to the increase in billable load from marijuana sites. Accordingly, while the Panel recognizes that the BCUC Staff Model represents another method of calculating the revenue requirements and customer rates impact of the proposed Project, the Panel has not examined the model further in this Decision.

9.0 PROJECT ALTERNATIVES CONSIDERED

The following figure provides an overview of the considerations and alternatives evaluated in the Application.

Figure 9-1



9.1 Status Quo

Status Quo defines the case of the accelerated replacement of an estimated 88,000 meters (not including Kelowna) to remain in compliance with new Measurement Canada S-S-06 regulations over a 21 year period with similarly functional meters (i.e. not advanced meters) (Exhibit B-1, p. 105). The financial analysis only accounted for the predicted incremental number of meters exchanged and replaced as a result of the new S-S-06 regulation, above the current number of meter exchanges and replacements (Exhibit B-1, p. 93). FortisBC chose to use the Status Quo as a baseline despite determining that the Status Quo alternative was a non-feasible alternative based on:

1) Not providing quantified benefits of an AMI system;
2) Not providing non-quantified (soft) benefits of AMI system;
3) Not supporting innovative rate structures, efficiency and conservation;
4) Not consistent with supporting British Columbia's energy objectives; and
5) Not consistent with the system and services available to 1.8 million BC Hydro customers.

(Exhibit B-1, p. 108)

9.2 Automated Meter Reading

Automated Meter Reading (AMR) is a system that allows meter readings from a 'drive-by' vehicle thus improving the productivity of the meter reading function. This alternative still requires the replacement of existing meters with wireless meters and would reduce the number of meter readers from 20 to approximately 8 (Exhibit B-1, p. 108). New project capital would include the replacement of meters with new wireless AMR meters and related vehicle mounted reading equipment. Incremental Measurement Canada Compliance costs are avoided, though drive-by meter reading, disconnect/reconnect and off-cycle reads would still require manual processes. AMR does not significantly increase the frequency or quantity of information collected to allow for better management of the cost of electricity (FortisBC Final Submission, p. 223).

9.3 Power Line Carrier AMI

A Power Line Carrier (PLC) system utilizes existing electrical distribution wires for two-way communication with the advanced meters. Collectors at distribution substations transmit data to the Utility through a separate WAN solution. The method and technologies of transmitting data through the electrical wires varies as does speed and amount of data that can be transmitted at any given time. Costs are dependent on number of endpoints per substation and distance along the distribution lines. (Exhibit B-1, p. 112) FortisBC submits that operating costs are lower than the AMI alternative due to lower WAN backhaul costs from the substation to the utility but the capital costs would be higher with a net result of being less cost competitive than the AMI alternative. FortisBC also states that PLC does not allow all of the future benefits of the AMI alternative. (Exhibit B-1, pp. 114, 115)

9.4 Alternative Evaluation

FortisBC provided an assessment of the alternatives considered and concluded that the Project as proposed provides the most financial, non-financial and future potential benefits of the alternatives examined. (Exhibit B-1, p. 123) A summary of the estimated cost of the four alternatives is provided in Table 9-1.

Table 9-1
Alternatives Cost Comparison – w/o Kelowna ($ x 1000)

Analysis Period 2013 – 2032	**Status Quo**	**AMI**	**AMR**	**PLC**
New Project Capital	-	$47,689	$28,270	$66,351
Sustaining Capital Total	$23,209	$20,558	$7,736	$20,511
Meter Growth/Replacement	$3,505	$7,791	$6,479	$7,791
Measurement Canada Compliance	$18,556	-	-	-
Sustaining Capital Other	$1,149	$12,767	$1,257	$12,720
Operating Expenses Total	$107,313	$65,167	$70,036	$61,601
New Operating	-	$32,196	$3,509	$28,631
Meter Reading	$72,896	$14,779	$33,813	$14,779
Operating Other	$34,417	$18,192	$32,714	$18,191
Total Capital and Operating Cost	**$130,522**	**$133,414**	**$106,042**	**$148,463**

(Reproduced from Exhibit B-1-2, Errata Tables 7.1.a, 7.2.1, 7.3.a, 7.4.a, 7.5.a)

The FortisBC assessment of alternatives also includes an estimated Theft Reduction Benefit for the AMI and PLC alternatives that is over $90 million greater than for the AMR or Status Quo alternative. Table 9-2 shows the magnitude of the expected difference in this benefit.

Table 9-2
Alternatives Benefit Comparison – w/o Kelowna ($ x 1000)

Benefits	Status Quo	AMI	AMR	PLC
Estimated Theft Reduction	(127,218)	(220,923)	(127,218)	(220,923)

(from Exhibit B-1-2, Errata Table 7.5.a)

FortisBC also provided Net Present Value, Annual and Cumulative rate impact and current and future functionality assessments to conclude that the Project provides the most financial, non-financial and future potential benefits of available technology solutions. FortisBC states that its selection of the AMI technology alternative is supported by a fair and transparent RFP process that included functional requirements and not specific technology solutions and that only RF AMI proposals were received from vendors.

RDCK specifically provides the following challenges:

1. The RFP process used by FortisBC not including bids for different technologies. (RDCK Final Submission, p. 4)
2. The credibility of FortisBC's PLC cost estimates given the costs for PLC alternatives in similar, nearby jurisdictions are considerably lower than the FortisBC estimates on an installed meter basis. (RDCK Final Submission, pp.7, 8, 9)
3. Given the lower costs of PLC alternative in other jurisdictions, the AMI costs proposed by FortisBC for its AMI Project would lead to unjust and unreasonable rates, contrary to UCA section 59 and competitive concerns for local businesses. (RDCK Final Submission, pp.7, 8, 9)
4. Functionality gaps between PLC and RF AMI systems are overstated and not sufficiently assessed by FortisBC with PLC capabilities proven and improving in other jurisdictions. (RDCK Final Submission, pp. 11-19)
5. The fact the BC Hydro has installed RF based smart meters should not be a determinative factor in the selection of an advanced meter alternative. (RDCK Final Submission, p. 3)

RDCK further submits that the PLC solution would eliminate RF emissions that concern some customers and interveners. RDCK refers to comments provided by the Kaslo and Area Chamber of Commerce which supports the benefits of advanced metering but states in part,

> "...we are very concerned that the above application is going forward without requiring that FortisBC provide an appropriate and verifiable wired option for consideration by the commission. In light of the strong public opposition to the

> wireless option, issues surrounding interference with rural Internet reception and the higher costs associated with the wireless option...it would seem counter intuitive to not give serious consideration to a wired option..." (Exhibit E-95)

FortisBC provided a further breakdown of the PLC cost estimate showing that the roughly $19 million estimated higher cost was mostly due to higher network infrastructure and installation costs ($14 million), third party software and services ($2 million) and resulting financing and tax costs ($2.5 million) (Exhibit B-14, BCUC 2.34.2). RDCK provided Idaho commission and utility company documents that showed an installed per meter cost for a recent Idaho Power Company PLC AMI project of $193.81 for a deployment of 485,000 meters. RDCK uses the Idaho cost figures to estimate a PLC alternative cost of $22 million ($193.81 x 115,000) compared to the $66 million FortisBC estimate. RDCK further argues that FortisBC has been unable to explain why its AMI cost estimate is roughly double the Idaho PLC-AMI cost at approximately $415 per meter for a deployment of (115,000) meters. (RDCK Final Submission, pp. 7, 8) FortisBC argues that without having received an RFP response for a PLC-AMI system a comparison of included items and functionality is difficult (FortisBC May 2 Reply, p. 18). FortisBC does provide other comparisons such as the FortisAlberta PLC-AMI system which resulted in a cost of approximately $286 per customer for a deployment of 470,000 meters. If corrected to include HES and MDMS servers, additional functionality (though still not equivalent to the FortisBC RFP) and incidental costs that were not included in the FortisAlberta cost, would result in a PLC-AMI estimate of $55 million or $478 per installed meter (Exhibit B-14, BCUC 2.32.2.1).

9.4.1 AMI RFP Process and Credibility of PLC estimate

FortisBC states that the RFP included functional requirements and did not specify the type of meter to collector communication technology (Exhibit B-1, p. 55). FortisBC provided the complete RFP in this proceeding (Exhibit B-11, Appendix BCSEA 1.8.1). The RFP was sent to eleven vendors and two integrators with seven responding with proposals. Four of the vendors that received the RFP document offer PLC or wired technologies including Aclara Technologies, the vendor that supplied Idaho Power's PLC system but who declined to submit a proposal. FortisBC states that only wireless technologies were proposed. (Exhibit B-34, BCSEA 3.107.4; FortisBC May 2 Reply, p. 16) FortisBC further states that the RFP process completed was fair and that compelling FortisBC to seek PLC-AMI bids would be unfair to those that participated in good faith in a fair process (FortisBC May 2 Reply, p. 17).

Commission Determination

The Panel is satisfied that FortisBC has adequately met the CPCN requirements to consider and evaluate reasonable project alternatives. FortisBC established functional requirements without specifying the type of technology to be used. Vendors responded with RF based AMI solutions. The Panel is satisfied that the RFP process was fair. The fact that certain technologies were not proposed or that certain vendors declined to quote would indicate that these vendors self-selected the technology and that for various possible reasons only RF AMI proposals were submitted. The Panel agrees that compelling FortisBC to seek PLC quotes would not be fair to those who participated in a fair RFP process and would add risk and delay to the Project. The Panel is of the view that the cost comparisons to other jurisdictions, though informative, should not over-ride a fair and reasonable RFP process. The Panel accepts that there will be a broader range of accuracy on the PLC estimate since no proposals were received for this alternative, but that the cost of either $55 million or $66 million for the PLC alternative would not change the outcome of the alternative analysis. **For the above reasons, the Panel finds that FortisBC has adequately considered alternatives.**

10.0 RADIO FREQUENCY EMMISSIONS AND HEALTH

10.1 Introduction

The proposed AMI system transmits data wirelessly at Radio Frequencies. RF emissions and potential impacts on health was a key matter of concern raised at the Community Input Sessions and at the Oral Hearing.

In hearing evidence on the potential human health effects of AMI meters, the Panel sought to ensure that the concerns expressed by the general public and registered interveners were addressed through the evidentiary record. The goal of the Panel was to arrive at a decision that considers, in the words of Mr. Flynn, "… independent, science-based evidence" (J. Flynn Final Argument, p. 1).

One of a series of safety codes prepared by the Consumer and Clinical Radiation Protection Bureau, Health Canada is 'Safety Code 6: Limits of Human Exposure to Radiofrequency Electromagnetic Energy in the Frequency Range from 3 kHz to 300 GHz' (Safety Code 6). Safety Code 6 specifies the requirements for the safe use of, or exposure to, radiation emitting devices (Exhibit B-1,

Appendix B-6, p. 5 of 30). According to Safety Code 6, "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. This code has also been adopted as the scientific basis for the equipment certification specifications outlined in Industry Canada's regulatory compliance documents that govern the use of wireless devices in Canada, such as cell phones, cell towers (base stations) and broadcast antennae." (Exhibit B-1, Appendix B-6, p. 3)

In order to make its determination on matters related to health and safety, the Commission Panel must weigh several inter-related issues. Over the course of several days of Community Input Sessions, a two-week Oral Hearing, and from nearly two hundred Letters of Comment, the Commission Panel has distilled the many issues related to health down to two key points:

- Is Health Canada's Safety Code 6 applicable to the type of technology used in the proposed Project?
- Are the emission standards set out in Safety Code 6, if they are applicable to AMI meters, sufficient to protect the health of FortisBC's customers. Alternatively, are they flawed to the extent that the Commission must set its own exposure standards?

The Panel recognizes that many individuals expressed concerns, both general and specific, about the potential impacts on their health from the proposed Project. The Panel addresses those concerns below.

10.2 Does Safety Code 6 Apply To FortisBC's AMI Program?

The proposed Project will operate in the 900 MHz range (for the AMI infrastructure) and also at the 2400 MHz range (for the optional Zigbee system) (Exhibit B-1, Appendix C-5, p. 42).

Regarding the applicability of Safety Code 6, CSTS argues:

> "The guidelines contained in this document [Safety Code 6] are brought into effect through Industry Canada's licensing procedures….Industry Canada's licensing procedures do not apply to the proposed AMI meters, so Safety Code 6 does not apply."

CSTS further submits that the proposed AMI technology operates at a frequency that is exempted from Industry Canada licensing procedures, which renders the requirement to meet Health Canada Safety Code 6 guidelines inoperative (CSTS Final Submission, p. 45).

Dr. Shkolnikov illustrated the relationship between Health Canada and Industry Canada during his testimony at the Oral Hearing:

> "I have actually specifically called Industry Canada with the parameters that we're working with to identify if there was a standard testing method covering calculating the exposure from these devices. And I was directed -- I was told yes and directed to use Industry Canada's RSS 102 as a method for calculating the exposure as it relates to Safety Code 6 compliance." (T5: 884-885)

FortisBC argued that Safety Code 6 is, in fact, applicable to the operation of the proposed AMI technology, stating:

> "CSTS is correct that the AMI meters are exempt from licensing requirements, as they operate on the 902-928 MHz band. However, this exemption is a qualified one which does not relieve the AMI meters from the burden of compliance with Safety Code 6 through the requirements of the above-mentioned Industry Canada Radio Standards Specifications (certification is also required but no Intervener has taken issue with FortisBC's compliance in that regard)." (FortisBC May 2 Reply, p. 37)

FortisBC adds:

> "CSTS does not address Industry Canada's RSS-Gen, RSS-102 or RSS-210 in its flawed analysis of the application of Safety Code 6, despite the fact that each is expressly discussed in FortisBC's Main Submission as part of the legal framework binding the operation of the AMI meters. Nor does CSTS address the testimony of its expert witness, Dr. Maisch, who was qualified as an expert in health standards relating to exposure to electromagnetic radiation and agreed that FortisBC is bound to follow national official standards such as Safety Code 6." (FortisBC May 2 Reply, p. 40)

Industry Canada RSS-Gen, RSS-102 states:

> "It is the responsibility of proponents and operators of antenna system installations to ensure that all radiocommunication and broadcasting installations comply at all times with Health Canada's Safety Code 6, including the consideration of combined effects of nearby installations within the local radio environment." (Exhibit A2-8, Industry Canada RSS-102, p. 3 of 16)

RSS-102 further states:

> "It must be emphasized that the above exemption from routine evaluation is **not** an exemption from compliance." (Exhibit A2-8, Industry Canada RSS-102, p. 4 of 16, emphasis in original)

FortisBC provided evidence of Industry Canada (IC) certification (Exhibit C9-19).

Commission Determination

Upon review of the contents of Industry Canada's RSS-102 specifications, the Panel agrees with FortisBC that while the proposed AMI technology is exempted from the routine evaluation as laid out in RSS-102, it is *not* exempt from compliance with Safety Code 6. Safety Code 6 remains the relevant standard for health effects from radio-frequency EMF. Further, the Panel finds that the frequency of the RF emissions from the Project are within the range of frequencies addressed by Safety Code 6.

Accordingly, the Panel finds that Safety Code 6 applies to FortisBC's AMI Program and emissions from the proposed AMI meters must comply with the requirements of Safety Code 6.

10.3 Do the Emission Standards Set Out in Safety Code 6 Adequately Protect FortisBC Customers?

There were three issues raised with respect to the adequacy of Safety Code 6. These are:

- The treatment of thermal effects;
- The treatment of non-thermal effects; and
- Whether the precautionary principle is adequately embodied.

10.3.1 Thermal Effects

RF signals above a certain intensity are known to heat body tissue, which can pose a health risk. Safety Code 6 provides the following comments on thermal effects:

> "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. 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."
> (Exhibit B-1, Appendix B-6, p. 9)

There were no submissions that thermal effects were not adequately covered by Safety Code 6.

10.3.2 Non-Thermal Effects

Exposures at a level below which tissue heating occurs, other biological effects have been investigated.

CSTS argues that Safety Code 6 is fundamentally flawed in that it does not account for these potential *non-thermal* health effects from EMF energy emitted by devices like the proposed AMI meters. It argues that there is some scientific evidence of negative health effects from exposures below the level at which tissue heating occurs, which makes the Safety Code 6 threshold insufficient to protect the public. CSTS submits:

> "In relation to RF exposure, Safety Code 6 does not go so far as to say that tissue heating is the only health effect to be avoided. Indeed, the language of Safety Code 6 implies that there are effects, other than tissue heating, to be avoided. This interpretation was affirmed by Dr. Bailey in cross-examination. (T5:896)
>
> Nevertheless, there is not a specification in Safety Code 6 to identify non-thermal adverse bioeffects within the frequency range emitted by AMI meters. Dr. Bailey confirmed that the basic restrictions in Safety Code 6 are designed to limit temperature increases in tissues." (CSTS Final Submission, pp. 47-48)

CSTS further argues:

> "Health Canada and ICNIRP, through the weight of evidence process, have concluded that adverse health effects are not established - despite the existence of a large number of studies that show an adverse effect.

The problem with FortisBC's reliance on the positions of Health Canada and ICNIRP is that the subjective determination behind this weight-of-evidence analysis occurs behind closed doors without the subsequent publication of explanations or reasons. There is no transparency as to which scientific studies were accepted/rejected by Health Canada or ICNIRP and what are the reasons for same.

In cross-examination, Dr. Bailey admitted that Health Canada's review process involves the exercise of subjective judgment and that nobody outside of Health Canada is privy to the reasoning behind that judgment, and Dr. Bailey, in cross examination, could offer no evidentiary basis upon which to conclude that that judgment was properly made." (CSTS Final Submission, p. 25)

Dr. Sears presented the same view in her report:

"Bulk heating has been a convenient experimental measurement as technology has been available to quantify temperature for decades, but bulk heating is in no way a sensitive indicator of molecular effects of radiofrequency radiation. Indeed, contrary to the opinion expressed in the Exponent report that heating is a sensitive measure of potential harm, bulk heating could be considered an end-stage, least-sensitive measure of molecular perturbations caused by radiofrequency radiation." (Exhibit C9-8, Tab 7B, p. 13)

In response, FortisBC argued that Safety Code 6 does, in fact, specifically address non-thermal health effects, and therefore is still the appropriate regulatory standard governing the use of radio-frequency technology like AMI meters:

"While CSTS also alleges, on page 48 of its submissions, that "Dr. Bailey confirmed that the basic restrictions in Safety Code 6 are designed to limit temperature increases in tissues", the evidence clearly is that Safety Code 6 is intended to protect against all adverse effects. For the frequencies utilized by AMI meters, the adverse effects with the lowest thresholds are for thermal induced effects; other effects (such as stimulation) require much greater exposure. Therefore, protection against adverse thermal effects protects against both thermal and non-thermal effects, as confirmed by the introduction to Safety Code 6 itself." (FortisBC May 2 Reply, p. 33)

The relevant passage from Safety Code 6 states:

"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. 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." (Exhibit B-1, Appendix B-6, p. 7)

In addition to the above reference in Safety Code 6 to Health Canada's consideration of potential non-thermal effects, the Panel reviewed the transcripts of the testimony from *White v. Chateauguay* (referred to in CSTS documents as *Chateauguay v. Rogers*) that both FortisBC and CSTS have referenced at the Oral Hearing and in their respective Final Submissions. In particular, the Panel notes the testimony of Dr. James McNamee of Health Canada regarding scientific evidence of potential non-thermal effects:

> Q. And do I understand that, even though there is out there some studies regarding non-thermal effects for our frequency, the position of Health Canada is that none of these studies, because it's what it's saying in Safety Code 6, is relevant and there's no change?
>
> A.: We recognize that there are a large number of studies assessing virtually every health endpoint there is. There are a large number that show an adverse effect here, an adverse effect there. So, I'm not denying that there are studies showing effects, no question. There are also a large number of studies that don't show effects, and generally, a much larger number of studies, in many cases much more thorough and much more well-conducted. (Exhibit B-46, pp. 69-70)

10.3.3 Does Safety Code 6 take the 'Precautionary Principle' Into Account?

There is conflicting evidence as to the definition of the precautionary principle, and whether or not Safety Code 6 adequately embodies the precautionary principle. While some interveners and expert witnesses described the precautionary principle, there was no general agreement on a specific definition.

CSTS argues that the precautionary principle requires the denial of the CPCN application on the basis that any potential risk is unacceptable:

> "If there is evidence that AMI meters "could be a risk", it would be unconscionable to impose those meters on customers at their residential dwellings against their will." (CSTS Final Submission, p. 10)

This view is echoed in Dr. Sears' report:

> "The position that effects must be proven to a very high standard before action is taken is characterized as devices being "innocent until proven guilty" and is counter to the Precautionary Principle to which Health Canada claims to ascribe" (Exhibit C9-8, Tab 7B, p. 20).

FortisBC argues that the precautionary principle is already built into Safety Code 6, citing Health Canada's 50-fold safety threshold as evidence of a proactive, precautionary stance built into the guidelines; furthermore, that even by the stringent standards set by Health Canada, the proposed Project's emissions are far below the Safety Code 6-mandated threshold (FortisBC May 2 Reply, pp. 35-36).

During the Oral Hearing, FortisBC's expert witness, Dr. Bailey, stated:

> "I think scientific agencies, particularly dealing with health, are extraordinarily cautious, and exercise prudency in their assessments. And have at various times set into place in their deliberations ways that would err on the side of caution. And the fact that we have safety factors in these guidelines and Safety Code 6 and the FCC guideline and the ICNIRP guideline, is part of that precautionary basis." (T3:554, lines 18-26)

Dr. McNamee of Health Canada describes how precaution is taken into account:

> "Safety Code 6, when we developed the limits, when we're establishing the basic restrictions, we're sort of using the worst-case scenarios for both the development of the basic restrictions and then the derived reference limits that go with them. So, that's the worst-case body size, worst-case frequency, worst-case orientation with the field, standing on, you know, bare foot on a wet surface. All of these worst-case scenarios are taken into account to establish the envelope of the lowest exposure level which is allowable. So, there's precaution taken into account there.
>
> Beyond that, we then apply a safety margin of 50-fold for the general public as another precautionary measure. So, precautionary measures are already taken into account and we do other measures such as ongoing review of the science, ongoing studies, research studies. This is not something that we pick up and drop and move on to something else, this is something we do all the time."
> (Exhibit B-46, pp. 50-52)

In considering the various views on the precautionary principle and its application to Safety Code 6, the Panel was informed by Health Canada's publication, "Health Canada Decision-Making Framework for Identifying, Assessing, and Managing Health Risks (2000)", which was referenced in Dr. Sears' evidence (Exhibit C9-8, Tab 7B, p. 20). The Health Canada document states:

> "There is considerable debate, both nationally and internationally, over the use of the phrases 'precautionary approach' and "precautionary principle." No definition is universally accepted. The Health Canada Decision Making Framework treats the concept of precaution as pervasive. As such it does not require extremes in the actions taken. Instead, risk management strategies reflect the context and nature of the issue, including the urgency, scope and level of action required." (p. 8)

In endorsing Safety Code 6, the Chief Medical Health Officer at Vancouver Coastal Health stated that "[t]he current Canadian (Safety Code 6 revised 2009)…standards provide significant safety margins for public exposure to RF" (Exhibit B-15-1, Attachment BCH 2.1 p. 6)

Commission Determination

The Panel notes in reviewing the evidence that there was general agreement during cross-examination of experts that the role of Health Canada is to protect the health of Canadians. Safety Code 6 is the result of the ongoing study by Health Canada on the health effects of RF emissions. With regard to thermal effects there is no evidence that Safety Code 6 does not adequately protect

FortisBC customers. While there was disagreement over the adequacy of Safety Code 6 in dealing with non-thermal effects, the Panel agrees with FortisBC that the exposure limits in Safety Code 6 were established based upon a thorough evaluation of the scientific literature including potential non-thermal effects. No intervener provided scientific evidence that persuaded the Panel that Safety Code 6 fails to adequately protect FortisBC customers from non-thermal effects. Safety Code 6 has applied a significant safety factor to the allowable exposure levels and is subject to an ongoing evaluation of scientific literature by Health Canada. **For these reasons, the Panel finds that Safety Code 6 provides protection from thermal effects, non-thermal effects and incorporates an adequate degree of precaution.**

10.4 Other Issues

10.4.1 What Will I *Actually* Be Exposed To From FortisBC's AMI Equipment?

Concern was expressed at the Community Input Sessions, in Letters of Comment and during the course of the Oral Hearing over the actual RF exposure FortisBC customers could experience from the proposed AMI meters.

Table 10-1 below is drawn from BC Hydro material placed in evidence by the CEC. It shows the power density of RF radiation in the 900-range frequency and at various distances from the source. It refers to "smart meters", which the evidence from this hearing shows to be the same Itron meters proposed by FortisBC for its Project.

Table 10-1
Comparison of smart meter emissions to Health Canda Safety Code 6
Limits for public environment

Distance from smart meter	Time-averaged Power Density S 1 operating smart meter (µW/cm^2)	Time-averaged Power Density S 10 operating smart meter (µW/cm^2)
30 cm	0.0022 (0.00037 % of SC 6 Limit)	0.0028 (0.00047 % of SC 6 Limit)
1 meter	0.0011 (0.00018 % of SC 6 Limit)	0.0018 (0.00030 % of SC 6 Limit)
3 meters	0.0008 (0.00013 % of SC 6 Limit)	0.0012 (0.00021 % of SC 6 Limit)

Source: Exhibit B-15-1, BCH 2.2.2 Attachment, p. 6

Safety Code 6 is based on calculating exposure at 20 centimeters away (Exhibit B-1, Appendix B-6, p. 11). However, FortisBC states that the signal strength “drops off [with] the square of the distance” between the meter and an individual (T6:1186). Further, FortisBC states that the “signal gets weaker as it goes through different media” such as walls (T6:1182,). As stated in the Exponent Report:

> “In a typical installation, the advanced meter is installed on the outside wall of the residence, mounted on a metal enclosure, and has a faceplate pointing away from the house. In such a configuration, the signal sent by the advanced meter toward the house is 1/10th of the signal sent away from the house. Moreover, the RF signal from the advanced meter is greatly reduced by reflection and absorption from the metal enclosure and the structural materials of the residence walls.” (Exhibit B-1, Appendix C-5, p. 43)

With respect to RF emissions from neighbouring meters, the Exponent Report states:

> “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. [An] 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.” (Exhibit B-1, Appendix C-5, p. 44)

Commission Determination

The Panel notes the usefulness of Table 10-1 as a guide in understanding the level of exposure to RF from an advanced meter in a variety of scenarios. In all scenarios, the Table indicates that the levels of RF emissions are significantly below those allowed by Safety Code 6. Letters of Comment expressed concern where individuals would be sleeping next to a wall and an AMI meter was located on the outside of the wall. In this scenario, the evidence shows that the level of RF exposure would be even lower than set out in the Table due to the attenuating effect of different media such as walls. The Panel concludes, based on the scientific evidence, that FortisBC customers would experience RF exposure from AMI meters far below the limits of Safety Code 6.

10.4.2 <u>What are the concerns arising from RF emissions being classified as a "Possible Carcinogen"?</u>

A number of parties expressed concern about the World Health Organization International Agency for Research on Cancer (IARC) 2011 classification of radiofrequency electromagnetic fields (EMF) as "possibly carcinogenic to humans (Group 2B)" (Exhibit C9-25, p. 421). The following submission at the Trail Community Input Session is an example:

> "Emission[s] given off by the smart meters have been classified by the World Health Organization International Agency on Research of Cancer as possibly human carcinogens" – (CIS T1(Trail): 115)

While a summary of the views and expert opinions of the IARC Working Group investigating a possible linkage between RF emissions and cancer, was made available in the British medical journal *The Lancet,* and referred to in the information request process and at the Oral Hearing, their full report (IARC Report) was not released until after the close of the evidentiary record.

CSTS filed a copy of the IARC report along with a motion requesting that the Panel amend the regulatory timetable to reopen the evidentiary record to allow the IARC Report into evidence, and that the Panel also allow submissions on the report. By Order G-80-13 the Panel granted the CSTS request, reopened the evidentiary record admitting the IARC Report into evidence and further allowing FortisBC and Interveners to file limited supplemental Submissions on the IARC Report. The IARC Report was filed as CSTS Exhibit C9-25.

Interveners were primarily of the opinion that the full contents of the IARC Report did not significantly alter the evidentiary record, and the submissions on this topic were, for the most part, limited.

BCSEA notes:

> "The full Report adds considerable detail to the summary report. However, it is the Working Group's findings that are important for the Commission's purposes in this proceeding. The Working Group's findings are the same in the full Report as they are in the 2011 summary report, which was relied upon by the expert witnesses during the proceeding. Accordingly, the full Report does not change the weight the Commission should give to the existing evidence based on the summary report." (BCSEA Supplementary Submission, p. 1)

BCPSO concur with BCSEA's submission:

> "BCPSO et al. agrees with the submission of B.C. Sustainable Energy Association and Sierra Club British Columbia, dated May 16, 2013. The full IARC Report adds detail to the evidence found in the 2011 summary report, but does not alter the findings set out in the summary report and does not change the weight that should be accorded to those findings." (BCPSO Supplementary Submission)

CEC similarly view the full Report as adding little in the way of new evidence:

> "In summary, the CEC submits that there is no material new evidence in the Report which should affect the weight, if any, the Commission should give the other evidence on the record relating to the previously published summary of the views and expert opinions of the IARC Working Group. There is nothing new of a material nature in the Report which was not available to be considered during the course of the hearing or argued in the Final Submissions." (CEC Supplementary Submission, p. 1)

Mr. Atamanenko expressed concern that the IARC Report indicated a lack of clear scientific evidence on human health effects (BCSI Supplemental Submission, pp. 2, 3).

CSTS highlight numerous specific points raised by the IARC Working Group with respect to certain studies showing possible human health effects. In summation, CSTS states:

> "No evidence exists with respect to the deliberations or reasoning of Health Canada, IEEE and ICNIRP in dismissing the body of scientific evidence that affirms the existence of adverse effects at non-thermal exposure levels. In that regard, the findings of those bodies are incapable of scrutiny.
>
> In contrast, the IARC monograph carries weight in that it sets out a detailed, transparent analysis in support of its conclusion of risk - a conclusion which is consistent with the evidence provided by CSTS witnesses in these proceedings." (CSTS Supplemental Submission, p. 6)

CSTS also states:

> "FortisBC's argues that coffee is among the various substances listed by IARC as a class 2B possible human carcinogen however it is silent about the fact that DDT and lead are also included in the classification. FortisBC compares coffee to RF emissions in an attempt to characterize the latter as benign, which it is not. If RF emissions were benign, they would be under IARC classification 4.

In further reply to the point on coffee, we say that there is no evidence before the Commission as to the health risk of coffee consumption and, as a result, the comparison is a hollow one.

Furthermore, we question: what civil liberties implications would result from a regulatory decision that forces all persons, including babies, to consume coffee? What if the suspected carcinogen was to be imposed on a continuous basis: all day, all night, every day, for an indefinite period of time? Even where the scientifically discernible risk of adverse effects is only a possibility, surely people - in their own homes - have the right to choose." (CSTS Supplementary Submission, pp. 6-7)

Mr. Bennett's submission fell out of the scope that the Commission established in allowing Supplemental Submissions in Order G-80-13.

In reply, FortisBC submits:

"As to relative weight between the IARC Working Group's findings and other health-related information before the Commission, the IARC Monograph reinforces the primacy that should be given to the conclusions of Canadian health authorities, and in particular Safety Code 6, in relation to safe exposure levels. The IARC Working Group acknowledges in the IARC Monograph the limited role it is to play. The IARC Working Group recognizes in the IARC Monograph (as quoted by CEC at page 5 of its Schedule "A") that its evaluations 'represent only one part of the body of information on which public health decisions may be based' and do not constitute a recommendation with regard to regulation or legislation, 'which are the responsibility of individual governments and other international organizations.'" (Fortis Supplemental Reply, p. 1)

FortisBC also notes that Dr. James McNamee was a member of the IARC working group, indicating Health Canada was well aware of the research and findings of the IARC Working Group.

The IARC Report does list EMF radiation as a Class 2B agent (Exhibit C9-25, p. 421).

IARC's definition of what criteria are used in making a determination about Class 2 status informed the Commission's determination on weighting the IARC classification:

"This category includes agents for which, at one extreme, the degree of evidence of carcinogenicity in humans is almost sufficient, as well as those for which, at the other extreme, there are no human data but for which there is evidence of carcinogenicity in experimental animals. Agents are assigned to either Group 2A

> (probably carcinogenic to humans) or Group 2B (possibly carcinogenic to humans) on the basis of epidemiological and experimental evidence of carcinogenicity and mechanistic and other relevant data. The terms probably carcinogenic and possibly carcinogenic have no quantitative significance and are used simply as descriptors of different levels of evidence of human carcinogenicity, with probably carcinogenic signifying a higher level of evidence than possibly carcinogenic." (Exhibit C9-25, Non-ionizing Radiation, Part 2: Radiofrequency Electromagnetic Fields, IARC Monographs on the Evaluation of Carcinogenic Risks to Humans- Preamble, p. 22)

In addition, in *White v. Chateaguay*, Dr. James McNamee gave the following evidence:

> "In 2011, an expert panel was composed to assess the possible cancer risks of radiofrequency energy. I was actually a member of that expert panel... This classification [2B] is meant to reflect there is some evidence, from human studies and from animal studies, that could be used to formulate a decision of carcinogenicity. But it's also an acknowledgement that there's a much greater... or there's a large number of other evidence that doesn't support that. So, essentially, Class 2B is a category for additional study. It means there is evidence, it doesn't necessarily mean the evidence is strong or causal. Most agents that are studied by this group end up in Class 2B." (Exhibit B-46, pp. 12-13)

Commission Determination

Upon review of the IARC Report and having considered the submissions of the parties on the IARC Report, the Panel agrees with BCSEA and BCPSO that the IARC Report adds detail to the evidence found in the 2011 summary report, but does not alter the findings set out in the summary report and does not change the weight that should be accorded to those findings.

The IARC Report states that categorization as Class 2B has "no quantitative significance." This categorization includes other substances such as coffee, pickled vegetables, some uses of talcum power and nickel alloys (IARC Monographs on the evaluation of carcinogenic risks to humans, http://monographs.iarc.fr/ENG/Classification/, Referenced on page 26 of C9-25). The very breadth of substances under this category lends weight to the view that this designation, in and of itself, is of no quantitative significance. The Panel is not persuaded that this designation is sufficient to undermine the validity of Health Canada's research in establishing the Safety Code 6 limits for human exposure.

10.4.3 What If I Live Near A Bank Of Meters?

The Commission heard from some individuals in the FortisBC service area who live in multi-family dwellings such as apartments and condos, and who are concerned that living near a bank of advanced meters will result in higher exposure to EMF. The Panel gave leave to one such individual, who had not registered as an intervener, Ms. Enns, to question the FortisBC expert witness panel at the Oral Hearing on this subject. The Panel thanks Ms. Enns for her participation in the process, as it believes that the questions she asked of the expert witnesses and the responses she received to her questions have informed the Panel on this matter quite effectively:

> MS. ENNS: Q: Well, thank you to the Commissioners and to the panel. As I say, I'm a lay person and all these technical -- so much of the information was technical, and it was just way beyond my understanding. So I've only got a few questions to confirm or clarify a few things. Mostly regarding involuntary and/or uncontrolled exposure. First off, could you please confirm the emissions from one meter? Is it 0.006, is that what -- or 0.002 3?
>
> DR. SHKOLNIKOV: A: Sorry, I just want to cite the correct number. So, a single smart meter will -- sorry, a single AMI meter will, under mean duty cycle, which is a typical one, at half a metre, will produce an exposure of 0.000056 milliwatts per centimetre squared.
>
> MS. ENNS: Q: Four zeroes, five six?
>
> DR. SHKOLNIKOV: A: Yes. So, zero, point, then four zeroes, five six.
>
> MS. ENNS: Q: Okay. And that's, you said, at a -- okay. Well, that's okay, it's getting too technical. So, two meters, then, would be double that? Is that how it works?
>
> DR. SHKOLNIKOV: A: It will be slightly less, because by necessity you can only be in front of one of the smart meters. So as you start adding smart meters, the distance to them, effectively means to increase. But for two meters, it's roughly double.
>
> MS. ENNS: Q: Okay. Let's assume there is two meters side by side.
>
> DR. SHKOLNIKOV: A: Yeah. It's roughly double.
>
> MS. ENNS: Q: Double. So then if you have a bank of 16 meters, all side by side, and in rows, that would be 16 times that?
>
> DR. SHKOLNIKOV: A: No, because at that point the distance to the meters that are not in the centre becomes substantial enough to reduce the exposure from those.

Because you're physically farther away from them.

MS. ENNS: Q: From some of them than you are from others.

DR. SHKOLNIKOV: A: Yes.

MS. ENNS: Q: Okay.

MR. WARREN: A: I should add that -- and this may be helpful, is that there is some evidence in the filing itself -- it didn't come out during this oral hearing, but in filed evidence that from actual measurements on multiple meter banks, Mr. Loski has some of that.

MR. LOSKI: A: So I can go there. I'll state the exhibit number here. It's Exhibit B-15, and this is a response we had to a B.C. Hydro IR No. 2, question 2.2. And there is an attachment there that is from the B.C. Centre for Disease Control. And what they did in this study, they compared the emissions from a single meter with a bank of ten meters. (see Table 10-1 above in Section 10.4.1)

MS. ENNS: Q: Okay.

MR. LOSKI: A: Okay? And there, I'll -- I guess in Table 3 on page 6 of that report, but just to give an example here, that they measured the emissions at different distances. So 30 centimetres, 1 metre and 3 metres. And then compared one meter versus ten. And I'll just pick one of the numbers out of here from --

MS. ENNS: Q: Could we do the three-metre distance?

MR. LOSKI: A: Three metres, sure. And so the emissions here for one meter, as it says in this table -- first of all, I'll do it in terms of the percentage of the Safety Code 6 limit, was 0.00013 percent of Safety Code 6 limit. So that's 1 meter at 3 metres away. And then the 10 meters at that same distance was 0.00021 percent of Safety Code 6 limit. So definitely is not a matter of simply multiplying 1 by 10.

MS. ENNS: Q: No, I understand.

MS. ENNS: Q: Okay, and what is the furthest distance that's in that chart?

MR. LOSKI: A: Well, that was it, so it just had those three distances, 30 centimetres, 1 metre and 3 metres.

MS. ENNS: Q: And up to 3 metres.

MR. LOSKI: A: That's correct.

MS. ENNS: Q: Okay. So then a bank of 16, you wouldn't know unless you did a calculation, which I won't ask you to do. So perhaps now this is not an appropriate question to ask, but I was wondering what is the aggregate or cumulative exposure from those -- was it 10 or 3 that you were giving me the numbers for?

MR. LOSKI: A: That was a bank of 10 meters.

MS. ENNS: Q: Bank of 10, mm-hmm.

MR. LOSKI: A: Correct.

MR. WARREN: A: You may also find it helpful to note, like, Health Canada has also commented on this issue of multiple meter banks in their document that's in evidence called "In Your Health, It's Your Health 2011", and it arises in Exhibit B-15, B.C. Hydro IR 2, question 2.4, and they stated in part: "In cases where smart meters, AMI meters, are installed together, the total exposure will still be far below Health Canada's radio frequency limits."

MS. ENNS: Q: Okay, thank you. Is it true -- my understanding is that these emissions are not blocked by walls, like they travel right through. Is that correct?

DR. SHKOLNIKOV: A: The term that people use is "reduced". So the walls won't necessarily block the signal but they will strongly reduce the amplitude that makes it through.

MS. ENNS: Q: Okay, but some of it gets through.

DR. SHKOLNIKOV: A: Yes.

MS. ENNS: Q: So where you've got 16, of course, more, what's the word, amplitude, would get through than if you had one or two or three meters.

DR. SHKOLNIKOV: A: Actually, one of the difficulties when you have multiple smart meters in a bank, they're close by, and what they do is they form effectively --one of the reasons why the signal from a single smart meter makes it back into the house is that some of the signal travels around the meter panel. If you have a bank of smart -- of advanced meters side by side, then there's actually -- they have to travel much farther to make it around. So typically you would expect even less of the signal to go behind the meter bank. So in the single meter you'd expect one tenth to go back roughly. In the larger meter bank you'd expect substantially less than one-tenth to make it around -- just the meter panels, not including the building continuation.

MS. ENNS: Q: Sure. Okay, but there would be a transfer or travelling of those emissions beyond the walls.

> DR. SHKOLNIKOV: A: Some signal will make it inside the residence.
>
> MS. ENNS: Q: Okay.
>
> MR. WARREN: A: Which is why those numbers that Mr. Loski cited were without anything in between them, right, so there was just air in between the meters --
>
> MS. ENNS: Q: Right.
>
> MR. WARREN: A: -- and the measuring device. And so in a real situation, especially where in a lot of apartment buildings the meter room -- not all of them but a lot of the meter rooms they have at minimum a wall but often a concrete wall as well, right, and so you may get quite significant attenuation or reduction in the signal out of the meter room. (T7:1366-1372)

The Panel heard no evidence from any party that contradicted the information provided in response to Ms. Enns' questions on the subject of multiple meters or the information provided on that subject in the Exponent Report.

Commission Determination

The Panel agrees that proximity to multiple meters in a bank results in exposure that is below, (and in the example provided by BC Hydro, and reproduced here in Table 10-1, is considerably below) the maximum allowable exposure of Safety Code 6.

10.4.4 What about My Total Exposure to EMF from all Sources?

Many individuals who spoke at the Community Input Sessions or wrote to the Commission expressed their concern that they are already being exposed to an unhealthy level of EMF from various sources present in modern society, and that the proposed Smart Meter system would add to the aggregate exposure. The author of a Letter of Comment expresses the concern this way:

> "I'm not concerned with only the radiation that will be emitted by the Smart Meter on my house - I'm deeply concerned about the combined emissions from the meters on every house around me and the mesh-grid network that will result. Not only will our homes and work places be blanketed under an unknown level of toxic microwave radiation, so will our entire communities! I found no information that any utility actually knows what aggregate levels of highly toxic pulsed-microwave radiation any community could experience from a meshed-

> grid network. Start adding pulsed-microwave devices in our homes and communities, like WiFi, routers, cell phones, cell phone towers, iPhones, Smart phones, lap top computers, Blue Tooth, and GPS, to name a few, and top it off with Smart Meters which are in constant communication with each other and the towers that serve those Smart Meters and we could have a deadly mixture." (Exhibit E-9)

In response to this concern, the Panel asked Dr. Shkolnikov to provide calculations based on a number of typical exposure scenarios, including emissions from AMI systems. These exposure scenarios included individuals living in dense urban settings and in buildings with banks of smart meters, as well as individuals living in rural areas. (Exhibit B-52, Undertaking No. 9, p. 2) No parties challenged this information in their Final Submissions. Table 10-2 presents Dr. Shkolnikov's calculations.

Table 10-2

RF Exposure by Scenarios[i]	All Sources	Dense Urban Environment	Rural Environment (No AMI)	Rural Environment (with AMI)	Rural Environment (with AMI Bank)	Cordless Phone & AMI Bank
Radio Frequency Exposure Sources	**Per Cent of Safety Code 6 Limit**					
Cell Phone (In Use)	10%	10%	-	-	-	-
Microwave Oven (In Use)	2.3%	2.3%	-	-	-	-
Cordless Phone (In Use)	1.25%	-	-	-	-	1.25%
TV and Radio Antenna	0.53%	0.53%	-	-	-	-
Cellular Base Station Antenna	0.16%	0.16%	-	-	-	-
Human Body	0.018%	0.018%	0.018%	0.018%	0.018%	0.018%
Natural Background	0.013%	0.013%	0.013%	0.013%	0.013%	0.013%
Man Made Background	0.005%	0.005%	0.005%	0.005%	0.005%	0.005%
Wi-Fi	0.0045%	0.0045%	-	-	-	-
Cordless Phone Base Station (In Use)	0.0038%	-	-	-	-	-
ZigBee In-Home Display	0.0024%	0.0024%	-	-	-	-
FortisBC AMI Meter Bank (No Wall)	0.0019%	-	-	-	-	-
Cordless Phone Base Station (Not in Use)	0.00076%	0.00076%	-	-	-	-
FortisBC AMI Meter Bank (Separated by Wall)	0.00032%	0.00032%	-	-	0.00032%	0.00032%

FortisBC Advanced Meter (No wall)	0.00025%	-	-	0.00025%	-	-
FortisBC Advanced Meter (Separated by Wall)	0.000041%	-	-	-	-	-
Zig Bee Radio in AMI (Turned On)	0.000024%	0.000024%	-	-	-	-
Total Sum of RF Exposure by Scenario		13.034004%	0.036%	0.03625%	0.03632%	1.28632%

[1] Commission Staff created this table based on the typical values for estimated RF energy exposure scenarios as described in **Exhibit B-52, Undertaking No. 9**. The assumptions used to calculate typical RF exposures from each source are also described **Exhibit B-52.** For example, a **FortisBC Meter Bank** assumes a bank of 45 Advanced Meters. Commission Staff also added the "Human Body" as a source of RF exposure to some of the scenarios.

Commission Determination

Based on the evidence summarized in the table above, the Panel is satisfied that RF emissions from the proposed AMI system add a small fraction to the overall RF exposure of an individual, and this aggregate exposure is significantly below the limit established in Safety Code 6.

10.4.5 How Frequently do AMI Meters Transmit and does this Create a Chronic Health Problem?

Another issue in the Proceeding was whether or not the transmissions produced by the AMI meters constituted 'chronic exposure', and whether or not 'chronic' exposure differed in any way from the type of exposure calculated by Safety Code 6. Central to this issue is how frequently the meters transmit. A Letter of Comment describes the concern as follows:

> "One final fact.
> If the human physiology is subjected to high doses of EMF's (sic), over an extended period of time, there is naturally an "accumulative" effect of EMF's (sic) being "radiated" into the human physiology which creates a favourable environment, within the human physiology, for cancerous tumours."
> (Exhibit E-97)

At the Community Input Sessions a request was made:

> "to deny Fortis their application to install the radiating smart meters in our home environment. There would be a constant high level of wireless pulsed microwave radiation that is know by independent experts to be harmful to the body." (T2 CIS (Osoyoos):53)

The issue of how often the AMI meters transmit, and at what strength, was addressed by a number of parties in IRs and at the Oral Hearing. The Panel found the following exchange from the Oral Hearing to be particularly illustrative of this topic:

> MR. AARON: Q: Okay. Mr. Warren, in being crossexamined by Mr. Miles, and I don't need to take you there, I think we could -- possibly we could agree that you said there's no ability to turn them off, or Mr. Miles said these things are on all the time, and you said, "Well, that might be true, there's no ability to turn them off, but they're only on for .06 of the time for those 20 years." Could you agree to having said that or do I need to go to the transcript?
>
> MR. WARREN: A: I do not believe I said that they can't be turned off, but I did say that they were active on average about .06 percent of the time.
>
> MR. AARON: Q: Okay, well, we could agree that they can't be turned off, correct? They're operating all the time. The customer can't turn them [off]. Fortis doesn't intend to turn them off. Correct?
>
> MR. WARREN: A: You're correct that we don't intend to turn them off, correct.
>
> MR. AARON: Q: All right, so that's not an issue. And you said they're operating for only .06 percent of the time.
>
> MR. WARREN: A: On average, yes.
>
> MR. AARON: Q: For 20 years.
>
> MR. WARREN: A: Correct.
>
> MR. AARON: Q: Okay. But you admit that the maximum duty cycle is 5 percent.
>
> MR. WARREN: A: As I said earlier, the theoretical maximum duty cycle is 5 percent. The maximum duty cycle that was measured in a study performed by Itron in their white paper showed a maximum duty cycle of .58 percent.
>
> MR. AARON: Q: And so let's see, what does that amount to, 5 percent of 20 years? Can you calculate that? Mr. -- there you go, I knew you could. You know what? I did it in advance. It's one year, isn't it?
>
> DR. SHKOLNIKOV: A: Yes.
>
> MR. AARON: Q: So the exposure over 20 years would be a one year of continuous exposure to these emissions that were grossly similar to those in the Sommer study, correct?

MR. WARREN: A: No, I would not agree with that. That would be at the theoretical maximum exposure.

MR. AARON: Q: Okay, well, let's just qualify it like that. Theoretically the maximum exposure would be --well, you know. I know you're talking amongst yourselves and I just want to put the question to you.

DR. SHKOLNIKOV: A: I would like to caution here, if we're going to be talking about cumulative exposure over 20 years --

MR. AARON: Q: Yes.

DR. SHKOLNIKOV: A: -- the appropriate metric to use is average duty cycle --

MR. AARON: Q: Okay.

DR. SHKOLNIKOV: A: -- because it is basically impossible to have smart meter, as I would say, continuously win the lottery by always communicating at 5 percent. So the appropriate value, if you're looking at the cumulative exposure, which I think is the question here, is to use 0.06 percent value.

MR. AARON: Q: All right, well, for some reason Health Canada wants you to calculate the theoretical and limits you in that regard, and the theoretical is 5 percent. And I don't hear anyone telling me that the theoretical maximum duty cycle is not more than 5 percent. Nobody's saying that, are they?

DR. SHKOLNIKOV: A: I think that we are mixing here a compliance question versus exposure question. For compliance purposes, Industry Canada doesn't even allow you to use a 5 percent value, but that's really for purposes of compliance. The question you're asking is for comparing to exposure, which is a separate question, and then for exposure the relevant question is what is a -- and especially for the questions of cumulative exposure, the question would be the average value. Because the idea is that, you know, in the long term the value you're going to get averaged over many years is the average value, and therefore 5 percent would be improper to use.

MR. AARON: Q: Okay. So if we use the average, .006, so that would be .0006 times 20 years, you'd be exposed for something like one month of continuous exposure.

MR. WARREN: A: That's roughly correct, I think, yes.

MR. AARON: Q: So on the average duty cycle you've got one month of continuous exposure. On the theoretical maximum duty cycle you've got a year of continuous exposure to the emissions that were grossly similar to those in -- studied in the Sommer study, correct?

DR. BAILEY: A: Yeah.

DR. SHKOLNIKOV: A: And the key thing here would be if we are counting exposure as total duration rather than volume, because this is -- the actual -- so this is true for duration of exposure, I should say.

MR. AARON: Q: Okay. It's not clear to me the ZigBee emissions, it's a whole different kind of emission. Will the smart meter as it is installed, if this application is approved, will it be installed with the ZigBee emission being in a state of emission regardless of whether the ZigBee chip is opted into by the customer?

MR. WARREN: A: No, we intend to install the meters with the ZigBee radios in what's called "quiet mode", in which there are no transmissions.

MR. AARON: Q: All right. And so, unless a customer consents to the ZigBee, there will be no ZigBee transmissions.

MR. WARREN: A: That's correct.

MR. AARON: Q: All right. Well, that satisfies me with respect to the health issues concerning the ZigBee matter.

DR. SHKOLNIKOV: A: I am sorry, I just did the calculation and maybe I am incorrect. For 20 years, 12 month use per year, and 0.06 percent, you are getting -- I am getting about 0.15 of a month instead of one month.

MR. AARON: Q: Isn't it years? It's 20 years, right?

DR. SHKOLNIKOV: A: Yes. So, 20 years, 12 months a year --

MR. AARON: Q: Yes.

DR. SHKOLNIKOV: A: -- times 0.06 divided by 100, I'm getting 0.144 months.

MR. AARON: Q: Oh, okay. I'm not going to query you on the calculation. Why don't you just read into the record your formula for getting to that? To your calculation.

DR. SHKOLNIKOV: A: Yes. So, 0.06 divided by 100, times 20, times 12. (T5: 863-868)

The subject of whether or not the periodic 'check-in' transmissions sent by the proposed AMI devices qualify as 'constant transmissions' was also addressed at the Oral Hearing by Dr. Shkolnikov in response to a question from Mr. Aaron:

> "The cell phone that you have, whether you use it or don't use it, actually continuously transmits. On that definition of word continuously transmits, the signal. About 30 times a minute, your phone in your pocket communicates with a tower. It does it for purposes of notifying that you're still available to receive phone calls, to receive control information to know how to communicate with the network. And so from that perspective, if you were to use that definition of "continuous", there are a lot of technologies that do it. Say cordless phones, cellular phones." (T4:765)

FortisBC provided evidence showing that the typical duty cycle for an AMI meter amounted to 52 seconds of total transmission per day; beyond that, the maximum theoretical duty cycle over an entire 24 hour period amounts to approximately 5 percent of the day (Exhibit B-47, p. 3). However, as noted in the above transcript excerpt, FortisBC took the position that it is inappropriate to calculate exposure based on the maximum theoretical duty cycle, but rather that the typical duty cycle should be used.

CSTS submits that at the maximum theoretical duty cycle of 5 percent exposure to the AMI meter over 20 years would result in one year of continuous exposure (CSTS Final Submission, p. 49).

The Exponent Report, states: "[a]cute effects typically occur from relatively high exposures, and chronic effects, such as cancer, are typically linked to long term exposures at low levels." (Exhibit B-1, Appendix C-5, p. 10 of 47) Dr. Bailey commented on this statement during cross-examination:

> "That's been the pattern that's been observed for many chemicals, and so that same kind of observation has been made with regard to radio frequency fields. That very intense high exposures can lead to immediate effects and to evaluate effects that might take a longer period of time that occur at lower levels, you would have to look over a longer period of time." (T4:744)

CSTS is concerned that the "long term effect is a critical factor in risk assessment." In support it cites Dr. Bailey's testimony:

> "For some types of diseases we have –there's not been enough, a long enough time to exhaust all possibility of assessing the risk, because the time frame is -- for which we have good data anyway, is probably 15 years or so. And some types of tumours might take longer to develop than 15 years...for some types of diseases, there may not have been long time enough for these potential effects to be fully investigated."

CSTS submits that, "[t]he failure of Health Canada to specify any limit on exposure duration clearly fails to consider that the passage of time is a key factor in the assessment of the adverse bio-effects from RF exposure" (CSTS Final Submission, p. 53).

Dr. Bailey pointed out that the fact that Safety Code 6 did not set out a standard for chronic exposure,

> "reflects the scientific consensus that there is not a sufficient scientific basis to develop such a standard…[t]he standard bodies and agencies can only review evidence that they have, and they have assessed the evidence and concluded that based upon what is available to date and the latency periods evaluated, that there is not a basis to conclude that there are adverse long-term health effects including cancer." (T4:752)

FortisBC states:

> "Safety Code 6 take[s] into account all studies and literature that are relevant to setting the Code, and the Code is absent a duration limitation, and therefore one isn't necessary." (T5:792)

In its Final Submission, CSTS submits:

> "FortisBC should not be allowed to subject their customers to these uncertainties, particularly when there are alternative (non-wireless) means of achieving the objectives of the AMI program. At the very least, customers wishing to opt-out should have the right to do so." (CSTS Final Submission, p. 54)

Safety Code 6 states, "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" (Exhibit B-1, Appendix B-6, p. 11 of 30).

Commission Determination

The Panel notes that the issue of cumulative health risks is addressed in Safety Code 6. **The Panel is not persuaded by the evidence provided that Safety Code 6 fails to protect the public from cumulative or chronic health risks from RF emissions.**

10.4.6 Will AMI Meters Interfere With My Medical Device?

A number of parties raised the question of whether or not the proposed AMI system would interfere with medical devices, such as pacemakers and insulin pumps.

CSTS directly raised the issue of medical device interference in an information request to which FortisBC responded:

> Q: "Is FortisBC aware that there have been concerns about the potential impact of RF communication technology on pacemakers and other medical equipment?"
>
> Response:
>
> "Medical equipment such as pacemakers are designed to operate in 900 megahertz and 2.4 gigahertz RF environments since these are common frequencies for baby monitors, cordless phones, and WiFi routers, for example. These are the same frequencies on which advanced meters transmit and receive, so FortisBC believes any concerns would be unfounded."
>
> (Exhibit B-11, CSTS 1.34.5)

The issue was further explored during the Oral Hearing by Mr. Atamanenko:

> "So, the question [...] for Fortis, is what actions would Fortis think to undertake to address [concerns about medical device interference]?" (T5:1003)

Dr. Shkolnikov responded to the question as follows:

> "... all the medical manufacturers that I'm familiar with, and I don't know the manufacturer you're working with, diligently evaluate what are the common sources of RF exposure, and design a device to protect it and do very rigorous testing to verify it." (T5:1004)

Later, during cross-examination by Ms. Enns, Dr. Shkolnikov provided the following evidence on pacemakers and other implants:

> "... And usually if you look at inserts for different medical devices, they will tell you what is a minimum recommended distance. And typically the number they cite is roughly six inches ... So I would say, you know, people need to be prudent and follow their instructions from their medical device manufacturer. If they are concerned they should talk to the doctor. But this device doesn't produce anything unusual that wouldn't be experienced by a person who has a cordless phone or a cell phone or a WiFi router. It's similar issues. There's not – with the

> only difference is that these devices will typically be installed at a substantial distance from your body, so that effectively reduces the likelihood of interference." (T7: 1375)

Commission Determination

While the Commission is satisfied on the evidence in this Proceeding that the Project will not increase the current risk to owners of these medical devices, it also agrees with Dr. Shkolnikov that patients using such devices should always consult with the device manufacturer and their physician to obtain specific guidance.

10.4.7 What About People Concerned about Electromagnetic Hypersensitivity?

The issue of electromagnetic hypersensitivity was of great concern to some of the Interveners and members of the public who wrote to the Commission or participated in the Community Input Sessions.

RDCK submits that:

> "EMF and EMR sensitivity describes persons with an often multi-faceted illness that ranges from acute, requiring hospitalization, to ongoing chronic, often leaving the patient unable to work and financially unable to support themselves." It further submits that "critiquing the scientific basis of the disability and its symptoms fails to come to grips with the very real and practical problem which physicians face in having to treat people presenting themselves with EHS symptoms." (RDCK Final Submission, p. 28)

Dr. Sears testified that:

> "The individual finds that their symptoms occur with an exposure, and that when that exposure is removed they get better, and that when they rechallenge themselves they experience the same symptoms. So it's not a question of, oh, this happened once. It's a question of every time I go to this particular location where there is a high level of WiFi, or every time I use this device, and in between I go away to my cottage and I'm fine, or I turn off this device and I'm fine. So it's a lot stronger than simply, "oh, I think that it's this."
>
> And so the physician first of all has ruled out other possibilities, and then it's a repeatable phenomenon that you get these symptoms in association with the exposure. The Austrian doctors also say that along with that there is a suite of

> biochemical markers, and then we have animals' evidence that there are a lot of stressed proteins, and then we also have the in vitro evidence. And so it's not simply one --you know, there isn't just one piece, but it's putting together the entire fleet of what we know about biochemistry and all the way up to the patient's experience.
>
> The other one comment I would make in terms of self-reports is that a huge amount of medicine is based on self-reports. Pain is based on self-report. Psychiatry, psychology, all of that is based on self report. There's a huge amount of medicine that is self-report. So saying that shouldn't be used as something to kind of minimize this type of assessment." (T9:1824-1825)

The American Academy of Environmental Medicine (AAEM) recommends:

> "Because Smart Meters produce radiofrequency emissions, it is recommended that patients within the above conditions and disabilities be accommodated to protect their health. The AAEM recommends: that no Smart Meters be on these patients' homes, that Smart Meters be removed within a reasonable distance of patients' homes depending on the patients' perception and/or symptoms, and that no collection meters be placed near patients' homes depending on patients' perception and/or symptoms." (Exhibit C11-6, Attachments, American Academy of Environmental Medicine Regarding Electromagnetic and Radiofrequency Exposure, July 12, 2012, p. 2, para. 1)

When asked during cross-examination by Mr. Miles about the AAEM recommendation, Dr. Bailey stated that there is no indication about what kind of assessment or review and what studies were considered, or not studied. It appeared to him that it was only designed to put forth and identify studies that AAEM believed were potentially harmful. In his view it did not represent a valid weighting of the evidence in which one looks at all of the evidence, looks at the strength and quality of those individual studies, and then comes to a reasoned conclusion about what that evidence means. (T3:496-497)

Dr. Carpenter acknowledged that the existence of EHS is widely debated. Dr. Carpenter's definition of EHS is that symptoms are *reported* to be associated with EMF exposure; not that symptoms are *caused* by EMF exposure, although he notes that it is this causal relationship which has been widely debated. He also confirmed that there are many potential causes of symptoms such as headache, fatigue, tinnitus, disruption of sleep, mental dullness and a general feeling of ill health. In the 2012 BioInitiative Report, Dr. Carpenter stated that "it remains unclear whether EHS is actually caused by RF/EMF exposure, or rather is a self-identifying syndrome of excessive responsiveness to a variety of stimuli." (Exhibit C9-8, Attachment 6C, p. 8; Exhibit C9-12-3, BCSEA 9.1-9.3; T11:2133; Exhibit C9-12-3, BCSEA 1 11.6)

On this subject, Commission staff made the following information request to FortisBC:

> "Does FortisBC consider the 'nocebo effect', as referenced in the Exponent report and in other academic studies of the potential link between RF/EMF radiation and human health, to be a significant source of negative effects for some of these concerned stakeholders? If not, please explain why not."

To which FortisBC responded:

> "Yes. Scientific research on radio frequency fields and assessments of this research by health and scientific agencies has described the belief and perception of some individuals that they can detect or develop symptoms in the presence of these fields as unrelated to the physical stimulus itself (referred to as electromagnetic hypersensitivity). As stated by the World Health Organization 'The symptoms are certainly real and can vary widely in their severity. Whatever its cause, EHS can be a disabling problem for the affected individual. EHS has no clear diagnostic criteria and there is no scientific basis to link EHS symptoms to EMF exposure.'" (Exhibit B-14, BCUC 2.55.1)

According to the World Health Organization:

> "EHS is characterized by a variety of non-specific symptoms that differ from individual to individual. The symptoms are certainly real and can vary widely in their severity. Whatever its cause, EHS can be a disabling problem for the affected individuals. EHS has no clear diagnostic criteria and there is no scientific basis to link EHS symptoms to EMF exposure. Further, EHS is not a medical diagnosis, nor is it clear that it represents a single medical problem.
>
> Physicians: Treatment of affected individuals should focus on the health symptoms and the clinical picture, and not on the person's perceived need for reducing or eliminating EMF in the workplace or home. This requires: a medical evaluation to identify and treat any specific conditions that may be responsible for the symptoms,
>
> - a psychological evaluation to identify alternative psychiatric/ psychological conditions that may be responsible for the symptoms,

- an assessment of the workplace and home for factors that might contribute to the presented symptoms. These could include indoor air pollution, excessive noise, poor lighting (flickering light) or ergonomic factors. A reduction of stress and other improvements in the work situation might be appropriate.

- For EHS individuals with long lasting symptoms and severe handicaps, therapy should be directed principally at reducing symptoms and functional handicaps. This should be done in close co-operation with a qualified medical specialist (to address the medical and psychological aspects of the symptoms) and a hygienist (to identify and, if necessary, control factors in the environment that are known to have adverse health effects of relevance to the patient).

Treatment should aim to establish an effective physician-patient relationship, help develop strategies for coping with the situation and encourage patients to return to work and lead a normal social life."

(Exhibit B-15-1, Attachment BCH 2.6, p. 3, para. 1 and 5)

FortisBC asserts that while the *symptoms* of EHS are real, there is no clinical pattern to their diagnosis, nor any causal linkage to RF that has been established scientifically (FortisBC Final Submission, pp. 175-176).

RDCK raise the issue of Charter rights in relation to EHS:

"S. 7 of the Canadian Charter of Rights and Freedoms states:

> Everyone has the right to life, liberty and security of the person and the right not to be deprived thereof except in accordance with the principles of fundamental justice.

RDCK submits:

"…FortisBC's proposal to wantonly and deliberately expose its EMF and EMR sensitive customers to electromagnetic and radio frequencies detrimental to their health, and without even the slightest concession to due process in connection with that assault, is a clear and undeniable violation of those customers' s. 7 right under the *Charter* to security of the person. S. 15 of Charter further states:

> *Every individual is equal before and under the law and has the right to the equal protection and equal benefit of the law without discrimination and, in particular, without discrimination based on...mental or physical disability*." (RDCK Final Submission, p. 33)

NCGP, in its Final Argument, also makes the same argument:

> "NCGPCA submits that FortisBC's proposal to unilaterally and deliberately expose its EMF and EMR sensitive customers to electromagnetic and radio frequencies detrimental to their health, and without even the slightest concession to due process in connection with that exposure, are a clear and undeniable violation of those customers' Section 7 and Section 15 Charter rights." (NCGP Final Argument, p. 7)

FortisBC replies:

> "NCGPCA at page 7 and Mr. Shadrack at paragraphs 114-115 further suggest that FortisBC's proposal, particularly in relation to EHS and opt out, violates the Canadian Charter of Rights and Freedoms (the Charter). Again, these allegations are unfounded.
>
> First, setting aside for a moment the substance of the issues, as a matter of law FortisBC's proposal could not violate the Charter no matter what its content, as section 32(1) of the Charter limits its application to government actors:
>
> This Charter applies
>
>> (a) to the Parliament and government of Canada in respect of all matters within the authority of Parliament including all matters relating to the Yukon Territory and Northwest Territories; and
>>
>> (b) to the legislature and government of each province in respect of all matters within the authority of the legislature of each province.
>
> As a private company, FortisBC does not fall within this category. As such, the Charter does not govern its actions or proposals.
>
> Second and more fundamentally, even if the Charter were to apply, FortisBC's proposal does not constitute a breach, for all the reasons set out in the Main Submission and in this reply." (FortisBC May 2 Reply, pp. 72-73)

Commission Determination

With respect to the issue raised by RDCK and NCGP in regards to the Charter of Rights and Freedoms, the Panel agrees with FortisBC that the Charter is limited to government actors and is therefore not applicable in this case. The Panel notes that the Interveners raising this issue do not indicate how they see the Charter of Rights applying in these circumstances.

The Panel recognizes that there are individuals who feel strongly that low-level EMF emissions will have a negative impact on their health. However based on the scientific evidence in this Proceeding, the Panel is not persuaded that there is a causal link between RF emissions and the symptoms of EHS. The Panel notes that according to the World Health Organization, there is "no scientific basis to link EHS symptoms to EMF exposure." While the Panel ascribes little weight to Dr. Carpenter's evidence, it is noted that he acknowledged that although EHS symptoms are reported to be associated with EMF exposure, whether this relationship is causal is widely debated.

11.0 OTHER KEY ISSUES ARISING

11.1 Privacy and Use of Data Collected

By Order G-177-12 the Privacy issue was defined as "the collection and use of information only for its intended and authorized purpose and what those intended and authorized purposes should be." The *Personal Information Protection Act* (PIPA)[10] governs the collection, use and disclosure of personal information by organizations in British Columbia in a manner that recognizes both the right of the individuals to protect their personal information and the need of organizations to collect, use or disclose personal information for purposes that a reasonable person would consider appropriate in the circumstances. FortisBC must comply with the PIPA and the *Personal Information Protection and Electronic Documents Act*.[11] (Exhibit B-1, p. 138) Section 5 of the PIPA requires an organization to "develop and follow policies and practices that are necessary for the organization to meet the obligations of the organization under this Act."

[10] SBC 2003, c. 63.
[11] S.C. 2000, c. 5.

FortisBC states that privacy and security are fundamental considerations in the design and planning of the Project and that it will be collecting the same information it does currently only more frequently (Exhibit B-1, p. 138). FortisBC provided its updated privacy policy and included notes on how its obligations under PIPA regarding the collection, use, disclosure and security of personal information are being met (Exhibit B-9, p. 2).

In response to public concern related to the BC Hydro smart meter implementation the Information and Privacy Commissioner for BC conducted a review and issued Investigation Report F11-03 in December 2011. The report identified several recommendations to BC Hydro for notifying customers of the purposes for collecting the information, the legal authority for the collection and providing contact information within BC Hydro for questions (Exhibit B-9, Attachment 1, p. 3).

In his report the Privacy Commissioner noted that hourly consumption data would not reasonably reveal what appliances are being used and when but could reveal whether people are at home or away. (Exhibit B-9, Attachment 1, para. 49) He also reported that the California Public Utilities Commission was the first state to adopt specific rules regarding the privacy and security of consumption information generated by smart meters (Exhibit B-9, Attachment 1, para. 45).

The concerns that have been raised in this Proceeding include:

- The amount of individual consumption data collected is enormous and not obviously necessary.
- Once collected it is potentially available to law enforcement, insurance companies, marketers, criminals and others through the data being stored in a different jurisdiction outside Canada or other statute or court order.
- The consumption data may provide information on the number of occupants, daily routines, when and potentially what appliances are being used or when people are home or away.
- The collection of usage data on an hourly basis is intrusive and unnecessary.

(BCPSO Final Submission, pp. 20-21; Keith Miles Final Submission, p. 2)

FortisBC's Privacy Policy includes the statement, "From time to time, we may store your Personal Information outside of Canada, where it may be subject to the lawful access requirements of the jurisdiction in which it is being held" (Exhibit B-8, p. 5 of 6, FortisBC Privacy Policy). When asked what purpose and under what circumstances would FortisBC store personal information of its BC customers outside of Canada, it responded that "[A]ny personal information from the AMI system will not be (not) *sic*. sent outside of Canada and will reside on FortisBC's servers located within British Columbia" (Exhibit B-14, BCUC 2.56.2). When asked what the business implications would be if this provision were removed from the FortisBC Privacy Policy, the response was that "[T]he legislative requirements under the Personal Information Protection Act are why FortisBC includes this statement in its Privacy Policy" (Exhibit B-14, BCUC 2.56.3).

BCPSO makes several submissions on the subject:

1) that FBC should identify the specific purposes for which hourly consumption data is being collected and strictly limit its use accordingly;
2) that FBC should conduct privacy impact assessments given the evolving functionality of smart meter and smart grid technology;
3) that non-FBC personnel should be provided only with de-identified consumption data and only pursuant to agreements placing clear limits on the use of such data by any third party; and
4) that restrictions should be placed on the collection and retention of information outside of Canada.

(BCPSO Final Submission, p. 23-24)

An example of the public concern can be found in the Community Input Sessions in Section 7 of this Decision.

Commission Determination

The Panel recognizes that the PIPA governs FortisBC's obligations related to the collection, use, disclosure and security of personal information of its customers. The Panel is not persuaded that collecting the same information more frequently increases the risk of privacy issues provided the other aspects of disclosure and security are maintained or improved and is satisfied that FortisBC understands its obligations to comply with the PIPA.

There is no evidence that there is a business need for storage of FortisBC customer information outside Canada. **Accordingly, the Panel directs FortisBC to store customer information only in Canada and update its Privacy Policy to reflect this.**

11.2 Wireless System Security

By Order G-177-12, the Panel adopted the definition of security as "the potential unauthorized interception of information (utility information, not just personal information) and includes interception by FortisBC of information belonging to a customer or by a customer of utility information not just interception by third parties" (Exhibit A-14, pp. 4, 5).

Mr. Flynn raised concerns related to the electrical grid security including international hacking and cyber-attacks in written and oral submissions (e.g. T2:310). The Panel clarified that issues of system-wide grid security were not within the scope of this Proceeding (T2:310). FortisBC does, however, state that it considered both the security of information and the security of the electricity grid (FortisBC Final Submission, p. 111).

FortisBC states it included AMI system security requirements including the North American Advanced Metering Infrastructure Task Force's AMI-SEC standards in its RFP to Vendors (T2:226). It further states that it will ensure third party audits are conducted at implementation and on an ongoing basis to ensure compliance with the AMI-SEC security standards (Exhibit B-1, p. 135). FortisBC confirms that the metering system proposed by Itron meets FortisBC's security requirements and provide end to end security including:

1) Preventing interception of transmissions (RF-LAN using frequency hopping spread spectrum technique);
2) Encryption of the data using state of the art encryption and signing keys for communications between meters and FortisBC's HES;
3) Security event software to analyze and detect possible intrusions or attacks into the system; and
4) Role based and authenticated user controls for access to the system.

(Exhibit B-1, pp. 136-138; FortisBC Final Submission, pp. 115-119)

FortisBC further states that "[t]he only personal information being transmitted wirelessly over the AMI system is a customer's aggregate consumption information and this reading is not linked to a customer name or address until it reaches FortisBC's internal system. Additionally, there are extensive security features of the AMI system that would be in place to prevent unauthorized interception of that information (i.e. encryption). That being said, even if a person were to intercept the data being transmitted over the AMI system, they would only have a number representing aggregate consumption and a FortisBC meter number, so for that person to link that to an individual customer they would need to know the customer's meter number. In other words, it is improbable that even if a person were to get past all of the security that that they would be able to identify the individual customer that the consumption information related to" (Exhibit B-9, p. 3). During cross-examination by CEC, Mr. Swanson gave evidence on behalf of FortisBC that an individual could physically read the meter number at the meter and thereby link it to the address manually, but that would still require them to hack the wireless transmitted data encryption. He also testified that it would be possible to simply walk up to the meter and read the consumption physically, which is the case now (T2:217-218). FortisBC argues that the security of the system will be at least as secure as it is today and in fact will be improved over the current system due to not having manual meter reads (T2:220-221; FortisBC Final Submission, p. 111).

During the Oral Hearing, questions related to the AMI meter's optical port were raised, specifically relating to security and unauthorized access. If left unsecured, this port could potentially be used to access some personal information of the customer. (T2:253)

FortisBC responded to Commission staff questions by stating that the optical port would be secured with a log-in system that would require a specialized tool, as well as a valid username and password. In addition to this, all attempts to access the secured optical port would be flagged by the meter and transmitted to FortisBC's information system, so that any access attempts that were not pre-cleared in the system as authorized would be immediately flagged for investigation. FortisBC also stated that the system could be configured to only allow access to the optical port during a set, pre-determined "service window" timeframe that would block any and all access outside of that window, allowing for an extra layer of security. FortisBC further elaborated that the final level of security would be determined over time by adjusting the level of sensitivity of these protocols, but that the initial security level would be set at a fairly conservative threshold, and that any adjustments would come later as the network architecture was finalized. (T3:357-361)

Commission Determination

The Panel finds that FortisBC has adequately considered and taken reasonable steps to address security issues related to the proposed Project. The Panel further finds that FortisBC not only considered interception of electrical consumption information but also security of customer information and other utility information that is maintained at FortisBC's internal systems. The Panel notes current internal initiatives to safeguard security and considers that it would be prudent for FortisBC to continue to do so.

11.2.1 ZigBee and Home Area Network

Each AMI meter will have two, two-way RF radios, one for communication to the LAN for communication to FortisBC's head-end system and a second that may be used to communicate with a HAN device such as In Home Display using the ZigBee protocol. The second RF radio is referred to as the ZigBee chip. FortisBC states that initially the meters will use ZigBee Smart Profile (SEP) 1.1 which supports a wide varied of commercially available IHD's. (Exhibit B-1, p. 43) ZigBee is currently developing Smart Energy (SEP) v2.0 with additional functionality, which the selected meters also support and could be upgraded "over-the-air" to all meters (Exhibit B-11, BCSEA 1.1.2). FortisBC agreed that the HAN could be a possible security issue that could allow others to intercept the customers' consumption data. FortisBC states this would not provide a means to get into the FortisBC AMI system (T3:321, 322).

BCSEA highlights this potential security threat to customer data and proposes that the ZigBee chip be configured to only communicate with a customer's IHD or Customer gateway and not other in-home devices in order to limit or put HAN security as the customers' responsibility (BCSEA Final Submission, pp. 20-22). BCSEA further states that since SEP v. 2.0 is a new version that could connect to a wide and expanding range of home automation and services which raises the potential security concerns, only SEP1.1 should be approved by the Commission and FortisBC could apply at a later date to switch protocol (BCSEA Final Submission, pp. 24, 25).

FortisBC confirmed that the ZigBee radio transmitter will be turned off at installation but could be turned on remotely by request to FortisBC to connect a device or a gateway. If the customer chose to connect a gateway device then multiple devices could be added to the customer's network. If the customer chose to associate multiple devices directly with the meter, they would have to contact FortisBC for each device (T3:372).

FortisBC argues that BCSEA's proposal to only allow IHD or gateway connections could limit customers' choice to easily connect other devices and that it would consider all customer benefits and concerns in deciding whether to implement SEP 2.0 (FortisBC May 2 Reply, p. 10).

Commission Determination

The Panel finds that the presence of the ZigBee chip does not provide an increased security risk to either FortisBC's head end system or to customer consumption information collected by the AMI meter. Unauthorized access to the ZigBee chip by way of a HAN, or an in-home device, will not compromise data in the FortisBC system. There is the potential for unauthorized access to a HAN through customer owned equipment over which FortisBC has no control. However, use of a HAN is entirely at the discretion of the customer.

The Panel has already accepted that one of the more visible potential benefits to customers is the capability to connect in home displays and potentially other devices to allow them to see and manage personal electric consumption. The level of interest and ability of these customers to manage their own wireless network and/or add devices will vary broadly. The Panel observes that allowing customers to connect multiple devices to the Zigbee portion of the meter affords customers this choice and adequate security protection. **FortisBC is directed to provide clear information to customers choosing to connect devices on the options and any potential security risks and precautions along with the level of security provided by the ZigBee RF system to a HAN.**

There is not enough evidence for the Panel to determine whether SEP 2.0 would alter the security or privacy related risks and therefore **the Panel directs FortisBC to seek approval from the Commission prior to releasing a version update to the ZigBee architecture that would affect the communication, devices or security of access to the information on the customers HAN.** As other RF related issues including health have been dealt with extensively in this Proceeding, the application on updates to ZigBee software should be limited to costs, benefits, security and privacy matters.

11.3 Fire Risk

In the information requests, some of the Interveners' questioned the fire safety and fire risk to customers referring to reports of fires allegedly occurring as the result of AMI meter installations in other jurisdictions, such as California, Florida, Texas and Ontario. (Exhibit C9-2, CSTS 1.13; Exhibit C9-4, CSTS 2.36.0; Exhibit C15-2, Tatangelo IR1, p. 6; Exhibit C4-4, BCSEA 1.49.1)

FortisBC states it has reviewed the reports of alleged smart meter fires in other jurisdictions and its investigations indicate "...the problems relate to faulty customer equipment and inadequate installation processes." (Exhibit B-15 CSTS IR2.36.3) In its response to BCSEA's query on whether "...the temperature reporting functionality is enabled prior to meter deployment will the AMI system prevent fires associated with cracked meter bases, remote disconnection of service?", FortisBC states "This functionality cannot be guaranteed to prevent fires associated with faulty meter bases." (Exhibit B-11, BCSEA IR1.49.1)

FortisBC states it "... has developed specific procedures for the implementation of the AMI Project, to avoid any installation or equipment related problems increasing the risk of fires." It further states: "During the installation of AMI meters, there is a risk that the FortisBC installer may damage the meter base. FortisBC plans to immediately remedy any damage caused to meter bases, and included in the budget for the AMI Project the cost of replacing over 1,000 meter bases." (FortisBC Final Submission, p. 214)

FortisBC states 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 (Exhibit B-1, pp. 55-56). FortisBC states the meter deployment is exempt from the BC *Safety Standards Act*[12] and therefore BC Safety Authority oversight (Exhibit B-6, BCUC 47.1.1). FortisBC has not completed the AMI Meter Deployment Training Manual (Manual) but states "The AMI Project Manager, in consultation with qualified personnel from within the Company, will approve the meter deployment training manual." FortisBC will review the Manual toward the end of the Define/Design stage, which is expected to be the fourth quarter of 2013 and approve the Manual one month after the final draft is complete (Exhibit B-14, BCUC 2 83.8.3, pp. 221-222).

CSTS, BCSEA and Mr. Talangelo do not address the fire issue further in their Final Submissions.

BCPSO accepts that the Project will not increase the fire risk associated with utility meters. Indeed, properly trained installers should be able to detect existing unsafe conditions in meter bases and eliminate some existing fire risks. (BCPSO Final Submission, p. 26)

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[12] SBC 2003, c. 39.

CEC submits “that the Commission determine that the evidence shows there is no increased fire hazard associated with the AMI meters or meter exchange process.” It further submits that electrical hazards may be associated with a damaged base plate which could either be pre-existing or occur at the time of meter exchange (CEC Final Submission, pp. 118-119).

In its Reply, FortisBC states:“None of the Interveners have made submissions as to fire safety except for CEC and BCPSO, which accept FortisBC’s position in this regard” (FortisBC May 2 Reply, p. 68).

Commission Determination

The Panel is of the view there is a low- risk of fires resulting from installation of the new meters. The Panel considers a properly developed and fully documented installation manual and deployment plan, and appropriately trained and supervised installers, will reduce this risk. - The Panel considers the costs included for the replacement of damaged customer meter bases to be a reasonable precautionary measure even though these are not FortisBC assets. **The Panel directs FortisBC to immediately report any meter/meter base incidents to the Commission and other authorities as required or appropriate.**

11.4 Opt-Out

Many of the Letters of Comment touched on the desire for a so-called “opt-out” provision, whereby individuals could choose to have a non-transmitting AMI meter installed on their property and have their meter read manually. The issue of whether or not to allow an opt-out was also addressed in the information request process, at the Oral Hearing and in Final Submissions.

In the Application, FortisBC did not propose an opt-out program of any kind, stating that it did not see a sufficient need for an opt-out to justify the increased cost that would be borne by the ratepayer:

> “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.” (Exhibit B-1, pp. 142-143)

However, FortisBC also acknowledged during cross-examination that there would be a large number of individuals who may refuse AMI meters entirely, leading to a scenario in which ratepayers were forcibly disconnected if they did not choose to accept an RF-enabled AMI unit on their property:

> “And then barring that, if that wasn’t going to be an option for the customer, then ultimately we would be looking at the last option available to us, which would be to disconnect the customer.” (T6:1039)

FortisBC also agreed that some individuals would develop symptoms as a result of believing their AMI meters were exposing them to dangerous levels of RF energy, despite there being no scientific or medical basis for such a belief (also called the ‘nocebo effect’).

> Question:
>
> “Does FortisBC consider the ‘nocebo effect’, as referenced in the Exponent report and in other academic studies of the potential link between RF/EMF radiation and human health, to be a significant source of negative effects for some of these concerned stakeholders? If not, please explain why not.”
>
> Response:
>
> Yes. Scientific research on radiofrequency fields and assessments of this research by health and scientific agencies has described the belief and perception of some individuals that they can detect or develop symptoms in the presence of these fields as unrelated to the physical stimulus itself (referred to as electromagnetic hypersensitivity). As stated by the World Health Organization “The symptoms are certainly real and can vary widely in their severity. Whatever its cause, EHS can be a disabling problem for the affected individual. EHS has no clear diagnostic criteria and there is no scientific basis to link EHS symptoms to EMF exposure.” (Exhibit B-14, BCUC 2.55.1)

When asked about a hypothetical model of cost-recovery that might be followed in the event of the AMI program allowing an opt-out, FortisBC responded, both in IRs and to questions at the Oral Hearing, by indicating they would seek to have the party opting-out pay for the entire incremental cost on the principle of 'cost causation':

> MR. AARON: Q: So, and that opt-out will cost the company nothing extra, and will cost the non-opting out customers nothing extra.
>
> MR. LOSKI: A: The incremental cost that would be borne by the company to implement the opt-out for the customer would be recovered from that customer. Again, with the principle of cost causation, then the remaining -- or the rest of the customers would, in effect, be kept whole. (T5:963)

CEC expressed concern about a potential opt-out reducing the projected future benefits of an AMI system, and wants a potential opt-out program to be limited in scope and duration. CEC submits that the goal of an opt-out program should be to smooth the eventual transition to nearly-universal use of AMI meters, and decisions about how to structure a potential program should reflect that goal. (CEC Final Submission, p. 126)

BCSEA supports an opt-out system, with cost recovery being at the customers's expense. BCSEA notes that some FortisBC customers are "deeply opposed" to having an AMI meter on their premises because of the RF transmissions. (BCSEA Written Argument, p. 26) BCSEA also wishes for the Panel to "...define the key elements of the opt-out tariff as part of this proceeding, so that only a compliance filing is required." (BCSEA Final Submission, p. 27)

BCPSO supports an opt-out, based on an individual cost-recovery basis, and with AMI meters being deployed in a transmit-off mode to individuals who opt-out so that most of the benefits of the AMI system can still be realized. BCPSO is also supportive of free opt-outs being granted to individuals who can demonstrate financial or medical hardship. (BCPSO Final Submission, p. 27)

CSTS also supports an opt-out, stating, "At the very least, customers wishing to opt-out should have the right to do so" (CSTS Final Submission, p. 54). However, CSTS requests a separate proceeding to be initiated to determine the parameters of an opt-out program (CSTS Final Submission, p. 71).

Mr. Miles indicates he is in favour of an opt-out provision, provided that, "…project costs should accommodate each complainant" (Miles Final Submission, p. 6). The Panel interpreted this to mean that Mr. Miles echoes BCPSO's position regarding reduced costs being borne by individuals with financial or medical reasons.

RDCK strongly supports an opt-out program (RDCK Final Submission, p. 36).

Commission Determination

In Section 6.5.2, the Panel identified a potential risk to the implementation schedule arising from a protracted difference of views concerning the Project. This risk could increase costs to and reduce potential benefits from the Project, which would be detrimental to all FortisBC ratepayers. The Panel is of the view that an opt-out program could mitigate these potential schedule impacts. On the issue of financial or medical hardship, the Panel is of the view that a properly designed opt-out program allows individuals to decide not to accept a transmitting AMI meter while protecting the remaining FortisBC customers from the increased costs associated with the opt-out Program.

Therefore, the Commission directs FortisBC to design and bring forward to the Commission for approval an opt-out program based on the following principles:

- **Customers may choose to opt-out of accepting a wireless transmitting meter.**
- **Customers who choose to opt-out will be provided with an AMI meter that has the wireless transmit functions disabled. Transmit functions on these meters will remain disabled until the individual chooses to opt back in to the AMI program; in the event that the customer moves to a new property, the opt-out choice will move with the customer.**
- **The incremental cost of opting-out of the AMI program will be borne by the individual choosing to opt-out.**

FortisBC states that if an opt-out program is required, enough information has been provided during the Proceeding to allow the Commission to set the detailed terms of an opt-out program. However, the Panel is not persuaded that this is the case because the terms and conditions of an opt-out provision were not within the scope of the Proceeding. **Accordingly, the Panel directs FortisBC to file an application for an opt-out program, based on the principles outlined above by November 1, 2013.** As RF-related issues, including health, security, and privacy have been dealt with extensively in this Proceeding, the opt-out application should be limited to the issues described above.

11.5 Environmental Impacts

Interveners raised concerns over potential impacts of RF emissions on wildlife, plants and man-made structures. Dr. Jamieson's report includes a section on environmental concerns including possible risk factors of different insects, birds, and plants. In the report Dr. Jamieson discusses the importance of pollinating insects and birds for our ecosystem and phenomenon such as declining numbers of honey bees, and then refers to studies to make an appraisal of possible links to increasing EMF exposure. He states: "The detailed literature review conducted as part of this appraisal, indicates that exposure to inappropriate electromagnetic field (EMF) regimes can adversely affect insects, including bees and other insect pollinators. Greatly reduced insect numbers and insect diversity can adversely affect Nature's food chain, and may partially explain reduced numbers of some bat and bird species." (Exhibit C9-10-1, p. 127)

One particular insect discussed by Dr. Jamieson is honey bees. He speaks to the importance of honey bees in terms of agricultural value of pollination and the concern of the phenomenon known as Colony Collapse Disorder. Dr. Jamieson states that numerous potential causes have been suggested (Exhibit C9-10-1, p. 129) including manmade EMF as one. Dr. Jamieson shares his opinion that a combination of these potential causes may be to blame (Exhibit C9-10-1, p. 129). Dr. Jamieson refers to studies (Sharma and Kumar (2010), Kumar *et al.* (2011) and Sahib (2011)), which he states indicate a reduction in colony strength and queen egg-laying rate. The Sharma and Kumar study observed a total of four colonies with two being exposed to [variables] 900 MHz radiation for 15 minutes twice per day at a reported power density of 8.549 uW/cm^2 (Exhibit C9-10-1, p. 130). Dr. Jamieson states that these findings "indicate the need for a full-scale study to be undertaken where greater numbers of colonies can be assessed and variables reduced" and refers to "confounding" variables in other studies, which he suggests warrants further study and attention (Exhibit C9-10-1, pp. 131, 140). Dr. Jamieson summarizes his basic approach in the report "to raise awareness of studies where it's been indicated that there may be a cause for concern, so that debate can be opened up with BCUC..." (T10:2008).

FortisBC's expert consultant, Exponent, states: "A claim that a cell phone affected bee behaviour has been reported without direct evidence that the radiofrequency field was involved (Shabib, 2011). In short, there is no clear, confirmed adverse effect of radiofrequency field on bird or bee health" (Exhibit B-15, CSTS 2.4.4). FortisBC further states that it is not aware of scientific evidence that confirms any adverse effect of RF fields on insects and/or birds at the frequencies and intensities of RF fields produced by the FortisBC AMI meters (Exhibit B-11, CSTS 1.27.2).

Plants

Dr. Jamieson's report also included photos of plant "die-off" to suggest "cause for concern." When asked by FortisBC if he had considered other factors that could have led to the plant death he responded that time did not permit him to. When asked if there are other observations of bushes perishing near advanced meter installations he responded not that he was aware of. Ultimately, Dr. Jamieson conceded that "there could be other factors that led to the observed die-offs being so acute." (Exhibit C9-10-1, p. 39)

CSTS adopts Dr. Jamieson's report on the environmental impacts of the proposed AMI meters (CSTS Final Submission, p. 72).

Man-made structures

WKCC states that RF emissions will radiate infrastructure and will accelerate corrosion and adversely affect municipalities, industries, crops, timber, spawning, health as well as building compliance with building code (WKCC Final Submission, p. 12). WKCC refers to the science of how "everything in the coverage area being electrical at the atomic and molecular levels isn't (sic) insulated or compatible with these man-made frequencies" (WKCC Final Submission, p. 1); however, no evidence from other jurisdictions with AMI or smart meters was brought forward demonstrating any adverse affects. Dr. Shkolnikov provided a number of examples demonstrating that RF signals, even those many orders of magnitude higher than from AMI, do not result in damage or destruction of materials. One such example was cup used in a micro-wave oven to boil water; another was that the force exerted on a wall by RF radiation from an AMI meter is "a millionth of ... the force of air pressure from a normal human conversation in a room" (T6:1187, 1189).

Commission Determination

There is a significant amount of research and opinion in evidence on the impact of RF emissions on the broad spectrum of the natural habitat including insects, birds and plants and the ongoing interest of study in this area. The Panel considered this evidence and in doing so took into account the conclusions it reached in Section 4 on the weight to be applied to evidence of the experts.

Based on the scientific evidence presented the Panel is not convinced that RF fields produced by the Project would have adverse effects on the natural habitat. In dealing with claims of damage to infrastructure and buildings by WKCC the Panel was not convinced of the science or the basis on which such claims are made and notes that in the many jurisdictions across North America where AMI type meters have been installed there is no evidence of any building code issues or reports of damage to structures. In reaching this conclusion the Panel also considered the determinations in Section 4 regarding the weight to be applied to Mr. Bennett's evidence.

The Panel is satisfied that FortisBC has considered these potential environmental concerns as well as the environmental benefits associated with reduced emissions from vehicles discussed in Section 8.2.1.

11.6 Higher Bills

Several Letters of Comment were received expressing concern over higher bills after smart meters were installed. Two examples are:

- 'There are numerous reports of skyrocketing hydro bills with these meters. As Michael Smyth stated (Vancouver Province, April 8, 2012, p. A3) "Hundreds of Province readers have contacted me with stories of BC Hydro bills that doubled, tripled, quadrupled or spiked even higher after receiving a new smart meter."' (Exhibit E-113, p. 2)
- "In my research for this presentation, I read dozens of complaints from BC Hydro customers over higher electricity bills after smart meters were installed on their homes. On March 6, 2012 News 1130 radio reporter Erin Loxam interviewed Vancouver homeowner Brad Hugel, who stated his electricity bill tripled after a smart meter installation. Hugel explained that his bills shot from "usually around $160 for two months" to one for "$515 for a two-month period", adding he also purchased a more energy-efficient washer/dryer during that same period." (Exhibit E-21)

FortisBC recognizes potential customer concerns regarding accuracy of the AMI meters and references "numerous media articles" detailing customer concerns in other jurisdictions that have implemented smart or advanced meters (Exhibit B-1, p. 131). FortisBC identifies a potential cause as manual meter reading errors during AMI deployment and its plan to tighten the tolerances used by the Company's billing software in order to identify and review any bills potentially in error prior to issue to the customer. FortisBC will use its existing process for handling high bill concerns through its Contact Centre. In addition it says it plans to use a certified electro-mechanical meter as the "parallel check metre" to be able to demonstrate the accuracy of digital AMI meters. (Exhibit B-1, p. 133)

FortisBC further states that all meters will continue to subject to the accuracy requirements and testing mandated by Measurement Canada (Exhibit B-1, p. 131).

Commission Determination

The Panel is satisfied that FortisBC plans to handle customer concerns and accuracy requirements for the AMI meters. **The Panel directs FortisBC to report on customer concerns regarding accuracy of the AMI meters in its project reporting process.**

12.0 COMMISSION DETERMINATION

In its Application FortisBC specifically seeks the following:

1) Pursuant to sections 45 and 46 of the UCA, an order issuing a CPCN for the Project at an estimated cost of $51.2 million, including salvage value (Exhibit B-1, p. 6; Exhibit B-1-4, p. 2 and);
2) Pursuant to section 56 of the UCA, an order approving a revised depreciation rate for the proposed meters of 5 percent until the next depreciation study is completed (Exhibit B-1, p. 6).

12.1 Public Convenience and Necessity

Previously in this Decision, the Panel has found the need for the Project is not singular, but flows from a number of needs, including: replace metering technology that is no longer supported and provide a foundation for future upgrades to the grid. In addition, the Project provides FortisBC with opportunities to reduce the amount of energy theft, reduce operating costs and improve customer service, all to the benefit of the customer. The Project results in a quantifiable benefit with a net present value of $13.9 million.

Further, the Panel has found that FortisBC has adequately analyzed the project alternatives and the project risk. In addition, the Panel is not persuaded that safety standards that apply to the RF radiation emitted by the AMI meters and associated infrastructure, and to which they conform, is inadequate to protect the health and safety of the public.

The Project advances the BC 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" as stated in section 17(6) of the CEA. The Project also supports BC's Energy Objectives, specifically CEA sections 2(b) (to take demand side measures to conserve energy); 2(d) (to use and foster the development in BC of innovative technologies that support energy conservation and efficiency) and 2(g) to reduce greenhouse gases. For these reasons, the Panel finds the Project to be in the public interest and also notes that it is provided for in FortisBC's most recent long term resource plan.

Accordingly, the Panel approves a CPCN for the Project with a capital budget, including approved CPCN Development Costs, of $50.898 million ($51.173 million - $275,000) as described in this Decision, subject to a condition that FortisBC must confirm by August 1, 2013, that it will file an application for an opt-out provision that follows the direction in Section 11.4. As previously outlined in this Decision, FortisBC is directed to bring forward a proposal for an opt-out provision by November 1, 2013. In approving the CPCN the Panel made other decisions, which are listed in Section 13.0.

12.2 Depreciation Rate for Proposed Meters

As set out in Section 8.5.3.1 a depreciation rate of 5 percent is approved for the advanced meters based on an expected economic life of 20 years.

13.0 SUMMARY OF DIRECTIVES

This Summary is provided for the convenience of readers. In the event of any difference between the Directions in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

	Directive	**Page**
1.	The Panel finds that the Project need has been established.	41
2.	The Panel finds that the consultation process to date has been reasonable and sufficient.	49

3.	The Panel accepts FortisBC's assertion that a discount rate of 8 percent recognizes that "lower rates are expected over the near term, but would not be expected over a 20 year period." The Panel agrees that the selection of a discount rate is a matter of judgement and for these reasons the Panel accepts FortisBC's use of a discount rate of 8 percent as reasonable.	56
4.	The Panel finds that a 1.8 percent escalation of costs not covered by the Itron contract is reasonable to include in the estimate of project costs.	57
5.	The Panel accepts FortisBC's use of a 1.8 percent general inflation rate, based on the Conference Board of Canada's forecast for British Columbia.	57
6.	The Panel accepts FortisBC's use of a 20 year term for the Economic Analysis.	58
7.	The Panel accepts the Income Tax and CCA rate assumptions used by FortisBC, and its calculation of income taxes, as being reasonable.	58
8.	The Panel accepts the NPV amount of the Project capital costs of $39.074 million.	61
9.	As the FortisBC 2007 AMI CPCN application was denied, the Panel finds that the cost of the 2007 AMI proceeding should not form part of this Proceeding. FortisBC is directed to apply for recovery of the 2007 AMI costs in its next Revenue Requirement Application.	62
10.	The Panel accepts the basis and assumptions for the calculation to be reasonable and therefore finds the estimated NPV savings of $26.44 million from reduced meter reading expense to be reasonable over the life of the Project.	64
11.	The Panel accepts FortisBC's forecast of the NPV savings from the AMI remote disconnect/ reconnect savings of $6.155 million over the life of the Project.	66
12.	The Panel accepts the calculation of the avoided cost benefit for Measurement Canada compliance and therefore finds the estimated NPV savings over the life of the Project of $10.8 million to be reasonable.	68
13.	The Panel accepts the NPV estimate of $1.6 million in savings over the life of the Project compared to not having to perform meter exchanges for six years following the AMI deployment.	69
14.	The Panel accepts the evidence put forward by FortisBC that there will be labour savings in the Contact Centre of about $507,000 on an NPV basis over the life of the Project.	69

15.	The Panel accepts that there are soft benefits from the Project, although they are not included in the economic cost benefit analysis.	72
16.	The Panel determines that the Project, by providing more detailed and timely information to customers about their energy use, supports BC's energy objectives, specifically the objectives found in CEA sections 2(b) to take demand-side measures to conserve energy; and 2(d) to use and foster the development in BC of innovative technologies that support energy conservation and efficiency. The Panel also finds that the Project supports energy objective 2(g) to reduce greenhouse gas emissions.	77
17.	The Panel therefore disagrees with FortisBC's position that an increase in sales to illegal grow-operations can be considered a net benefit of the Project.	79
18.	The Panel considers that benefits which are uncertain should be estimated conservatively, such that the estimated benefit is more likely to be understated than overstated. The Panel notes that any economic benefit from reduced system losses will accrue to FortisBC's ratepayers as they are the ones who pay these costs.	80
19.	The Panel therefore accepts Professor Boyd's conservative approach of three grow cycles per year as being reasonable. This reduces the assumed annual energy use per site from FortisBC's estimate of 151,200kWh/year to 113,400/kWh.	83
20.	The Panel accepts FortisBC's evidence that it will be able to yield an additional 20 percent reduction in the theft ratio under AMI as reasonable.	86
21.	The Commission Panel accepts that advanced meters at the feeder level only would not be a practical means of identifying theft as data obtained would not be time synchronised.	87
22.	Using FortisBC's financial model (included in Exhibit B-1-3, Attachment, Tab "Theft Reduction") to make these adjustments results in an estimated net present value benefit of theft reduction of $33.463 million. The Panel considers this to be the appropriate Theft Reduction Benefit to include in the Economic Analysis of the Project.	88
23.	The Panel approves a depreciation rate of 5 percent for the AMI meters, based on an estimated economic life of 20 years until the next depreciation study is completed and approved.	95
24.	FortisBC is directed to use a depreciation rate of 10 percent (1 divided by a 10 year survivor curve) for the AMI Computer Equipment and Software and 6.67 percent (1 divided by a 15 year survivor curve) for the AMI Communications Structures and Equipment until the next depreciation study is completed and approved.	96

25.	FortisBC is directed to record the cost of these meters in a rate base deferral account attracting FortisBC's weighted average cost of capital (WACC) as they are removed from service. Additions to the deferral account are to be amortized over a period of five years, commencing the year following their addition.	98
26.	The Panel finds that FortisBC has adequately considered alternatives.	105
27.	The Panel finds that Safety Code 6 applies to FortisBC's AMI Program and emissions from the proposed AMI meters must comply with the requirements of Safety Code 6.	108
28.	The Panel finds that Safety Code 6 provides protection from thermal effects, non-thermal effects and incorporates an adequate degree of precaution.	114
29.	The Panel is not persuaded by the evidence provided that Safety Code 6 fails to protect the public from cumulative or chronic health risks from RF emissions.	130
30.	The Panel directs FortisBC to store customer information only in Canada and update its Privacy Policy to reflect this.	139
31.	The Panel finds that FortisBC has adequately considered and taken reasonable steps to address security issues related to the proposed Project.	141
32.	FortisBC is directed to provide clear information to customers choosing to connect devices on the options and any potential security risks and precautions along with the level of security provided by the ZigBee RF system to a HAN.	143
33.	The Panel directs FortisBC to seek approval from the Commission prior to releasing a version update to the ZigBee architecture that would affect the communication, devices or security of access to the information on the customers HAN.	143
34.	The Panel directs FortisBC to immediately report any meter/meter base incidents to the Commission and other authorities as required or appropriate.	145

35.	Therefore, the Commission directs FortisBC to design and bring forward to the Commission for approval an opt-out program based on the following principles: • Customers may choose to opt-out of accepting a wireless transmitting meter. • Customers who choose to opt-out will be provided with an AMI meter that has the wireless transmit functions disabled. Transmit functions on these meters will remain disabled until the individual chooses to opt back in to the AMI program; in the event that the customer moves to a new property, the opt-out choice will move with the customer. • The incremental cost of opting-out of the AMI program will be borne by the individual choosing to opt-out.	148
36.	The Panel directs FortisBC to file an application for an opt-out program, based on the principles outlined above by November 1, 2013.	148
37.	The Panel directs FortisBC to report on customer concerns regarding accuracy of the AMI meters in its project reporting process.	152

Dated at the City of Vancouver, in the Province of British Columbia, this 23rd day of July 2013.

Original signed by:
L.F. Kelsey
Panel Chair/Commissioner

Original signed by:
N.E. MacMurchy
Commissioner

Original signed by:
D.M. Morton
Commissioner

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER NUMBER C-7-13

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

and

An Application by FortisBC Inc.
for a Certificate of Public Convenience and Necessity
for the Advanced Metering Infrastructure Project

BEFORE: L.F. Kelsey, Commissioner
D.M. Morton, Commissioner
N.E. MacMurchy, Commissioner

July 23, 2013

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

WHEREAS:

A. On July 26, 2012, FortisBC Inc. (FortisBC) applied to the British Columbia Utilities Commission (Commission or BCUC) pursuant to sections 45, 46 and 56 of the *Utilities Commission Act*, for approval of the Advanced Metering Infrastructure (AMI) Project (Project, Application);

B. By Order G-105-12, dated August 2, 2012, the Commission established a Preliminary Regulatory Timetable requesting comments on the regulatory process for the review of the Application, such as written, oral or both;

C. By Order G-135-12, dated September 26, 2012, the Commission established a Procedural Conference to take place in Kelowna to hear participant submissions on the regulatory process for the review of the Application. The Order also appended an Amended Preliminary Timetable;

D. By Order G-137-12, dated September 28, 2012, the Commission set November 6, 7 and 8, 2012, as the dates for Community Input Sessions on the Application in Trail, Osoyoos and Kelowna respectively. The Community Input Sessions took place on those dates;

E. The Procedural Conference took place in Kelowna on November 8, 2012;

F. By Order G-177-12, dated November 23, 2012, the Commission directed, among other things, that the review of the Application would proceed through a combination of a written and an oral hearing, with financial, operations, fire safety and privacy issues to be reviewed by way of a written process and health, security and environmental issues by way of an oral hearing. Among other matters, the Order also directed that the oral hearing take place in Kelowna commencing March 4, 2013, and concluding by no later than March 15, 2013. The Order also appended an Amended Regulatory Timetable;

G. On November 13, 2012, FortisBC filed a application with the Commission to purchase the electric utility assets of the City of Kelowna (CoK CPCN);

H. On November 16, 2012, FortisBC filed an Addendum to the Application, which described the impacts to the Application in the event the Commission approved the CoK CPCN. On November 20, 2012, FortisBC filed the Excel file containing the Net Present Value analysis in its November 16 Addendum filing;

I. The estimated cost of the AMI Project, including salvage value, is $51.2 million;

J. By Order G-198-12 dated December 20, 2012, the Commission denied the requests of two Interveners, Area D in the Regional District of Central Kootenay (RDCK) and the Nelson–Creston Green Party Constituency Association (NCGP), for a suspension of the proceeding and confirmed the Amended Regulatory Timetable established by Order G-177-12;

K. By Order G-11-13, dated January 18, 2013, the Commission denied the request of an Intervener, Mr. Jerry Flynn, to make a PowerPoint presentation at the oral hearing;

L. On January 22, 2013, FortisBC submitted an Evidentiary Filing on the Advanced Metering Initiative Market, technology and North American project costs;

M. By Order G-12-13, dated January 22, 2013, the Commission ordered that FortisBC's responses to certain Commission Information Requests were to be treated as confidential by the Commission, but did allow access to Intervener counsel and a limited group of Interveners upon the filing of an Undertaking of Confidentiality;

N. By Order G-17-13, dated February 1, 2013, the Commission, among other matters, granted a limited third round of Information Requests and one round of Confidential Information Requests to Interveners who qualified to make those requests pursuant to Order G-12-13 and issued a Further Amended Regulatory Timetable;

O. By Order G-21-13,dated February 7, 2013, the Commission denied RDCK's request for reconsideration and variance of Order G-177-12 to permit financial, operational, fire safety and privacy issues including wireless *vs*. wired meters in the oral hearing;

P. By Order G-24-13, dated February 13, 2013, the Commission allowed Commission staff and one Intervener, the British Columbia Pensioners' and Seniors' Organization, to submit additional Information Requests focussed on clarification and financial impacts of the Addendum and certain other evidence relating to the Addendum. In addition, the Commission allowed certain Information Requests delivered by another Intervener, BC; Sustainable Energy Association and the Sierra Club of BC, in the CoK CPCN proceeding to be filed as evidence;

Q. By Letter L-3-13, dated February 15, 2013, the Commission granted the request of the Citizens for Safe Technology Society (CSTS) to have certain of its expert witnesses cross-examined by video-conference at the oral hearing;

R. By Order C-4-13, dated March 1, 2013, another Panel of the Commission approved the CoK CPCN application with conditions, which were subject to acceptance by FortisBC by March 31, 2013;

S. The oral hearing took place in Kelowna from March 4 to March 15, 2013, as provided for by Order G-177-12. The evidentiary record was closed following the conclusion of the evidence on March 15, subject to the filing of outstanding undertakings made by witnesses the oral hearing;

T. FortisBC filed its Final Submissions on March 28, 2013;

U. On March 29, 2013, FortisBC advised the Commission that it accepted the conditions in Order C-4-13;

V. By Order G-51-13, dated April 8, 2013, and in response to requests from RDCK and CSTS, the Commission granted Interveners a one week extension to the filing date for their Final Submissions to April 25, 2013, and a corresponding one week extension to FortisBC to May 2 to file its Reply;

W. On April 19, 2013, CSTS advised the Commission of the release that day of the monograph of the International Agency for Research on Cancer (Report), requested a reopening of the record to admit the Report into evidence and an extension to the Regulatory Timetable by 10 days to allow parties the opportunity to review the Report and reference it in argument. On the same day, by Order G-62-13, the Commission denied RDCK's request to correct Exhibit C13-30-1;

X. By letter dated April 22, 2013, the Commission denied CSTS's request to extend the Regulatory Timetable, but established a process for written submissions on the reopening of the record to admit the Report;

Y. By Order G-80-13, dated May 15, 2013, the Commission reopened the evidentiary record, admitted the Report into evidence and allowed the filing of limited Supplemental Submissions on the Report. Interveners filed their Supplemental Submissions by May 23 and FortisBC filed its Reply on May 30, 2013; and

Z. The Commission Panel has considered the Application, the evidence and submissions presented on the Application and has determined that it is in the public interest that a CPCN be issued to FortisBC for the AMI Project.

NOW THEREFORE pursuant to sections 45, 46 and 56 of the *Utilities Commission Act* the Commission orders as follows:

1. A Certificate of Public Convenience and Necessity is granted to FortisBC for the AMI Project as described in the Application and as modified by directives in this Order and the Decision issued concurrently with it and subject to the condition that FortisBC must confirm in writing by August 1, 2013 that it will file an application for an opt-out provision by November 1, 2013 based on the following principles:

   (a) Customers may choose to opt-out of accepting a wireless transmitting meter.

   (b) Customers who choose to opt-out will be provided with an AMI meter that has the wireless transmit functions disabled. Transmit functions on these meters will remain disabled until the individual chooses to opt back in to the AMI program; in the event that the customer moves from the property, the opt-out choice will move with the customer.

   (c) The incremental cost of opting-out of the AMI program will be borne by the individuals choosing to opt-out.

2. A depreciation rate of 5 percent, to be applied to the AMI meters to be installed as part of the AMI Project, is approved until the completion of FortisBC's next depreciation study.

3. The request to recover the costs of FortisBC's 2007 AMI CPCN application as part of the costs of the AMI Project is denied. FortisBC is directed to apply for the recovery of those costs in its next Revenue Requirements application.

4. A capital budget of $50.898 million including approved development costs and contingency amounts is approved as a control budget.

5. FortisBC is directed to file with the Commission Quarterly Progress Reports on the AMI Project showing planned vs. actual schedule, planned vs. actual costs, and any variances or difficulties that the AMI Project may be encountering. The Quarterly Progress reports are to be filed within 30 days of the end of each reporting period.

6. FortisBC is directed to file with the Commission a Final Report on the AMI Project schedule and costs within six months of the end or substantial completion of the AMI Project that provides a complete breakdown of the final costs of the AMI Project, compares these costs to the cost estimate in the Application inclusive of the cost increase resulting from the Commission's approval of the CoK CPCN, and provides a detailed explanation and justification for all material cost variances.

7. FortisBC is directed to file with the Commission an Annual Cost/Benefit Tracking Report on the AMI Project benefits (reduced costs) and the new operating costs of the AMI program for each of the first 5 years following the end or substantial completion of the AMI Project. The Annual Cost/Benefit Tracking Report is to be filed with the Commission within 3 months of each calendar year end included in the 5 year period.

8. FortisBC is directed to determine the form and additional content of the Quarterly Progress Reports, Final Report and Annual Cost/Benefit Tracking Reports in consultation with Commission staff.

9. FortisBC is directed to comply with the directives in the Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 23rd day of July 2013.

BY ORDER

Original signed by:

L.F. Kelsey
Commissioner

SUMMARY OF RULINGS MADE BEFORE AND AFTER THE ORAL HEARING

1.0 Order G-135-12, September 26, 2012 (A-7) re establishing a Procedural Conference and an Amended Preliminary Regulatory Timetable;

2.0 Order G-137-12, September 28, 2012 re setting dates, locations and times for the Community Input Sessions; and amending the Regulatory Timetable;

3.0 Order G-177-12, November 23, 2102 (A-14) re Procedural Conference Issues including hybrid hearing, (financial, operations, fire safety and privacy issues for written hearing; health, security and environmental issues for oral hearing) video evidence and Updated Regulatory Timetable;

4.0 Order G-198-12, December 20, 2012 (A-19) re denial of requests of RDCK and NCGP to suspend proceeding;

5.0 Order G-11-13, January 18, 2013 (A-27) re denial of J. Flynn request to make an oral presentation at the Oral Hearing;

6.0 Order G-12-13, January 23, 2013 (A-29) re allowing access to confidential information on terms;

7.0 Letter, January 30, 2013 (A-31) re leave to CSTS for the late filing of the evidence of Dr. Jamieson;

8.0 Order G-17-13, February 1, 2013 (A-32) re Further Amended Regulatory Timetable, third round of IRs, no 2nd Procedural Conference;

9.0 Order G-21-13, February 7, 2013 (A-34) re denial of RDCK request for reconsideration and variance of part of Order G-177-12 relating to hybrid hearing;

10.0 Order G-24-13, February 13, 2013 (A-34) re additional IRs on financial impacts of addendum exhibits B1-2,B1-3 and B1-4 and inclusion of BCSEA Information Requests No. 1.1 and 1.2 in the FortisBC acquisition of the City of Kelowna electric utility assets proceeding;

11.0 Letter L-3-13, February 15, 2013 (A-37) re allowing videoconferencing of witnesses;

12.0 Letter L-5-13, February 20,2013 (A-39) re leave to RDCK to file certain IR responses by 4:00 p.m., March 1, 2013;

13.0 Order G-51-13, April 8, 2013 (A-41) re allowing RDCK and CSTS requests to amend the Regulatory Timetable and extend the dates for the filing of Intervener Submissions and Reply;

14.0 Order G-62-13, April 19, 2013 re denial of RDCK request to re-open the record to add a chart to Exhibit C13-30-1;

15.0 Letter, April 22, 2013 (A-42) re denial of CSTS request to extend the time for the filing of Interveners Final Submissions, but allowing submissions on whether the evidentiary record should be opened to admit the IARC Report into evidence; and

16.0 Order G-80-13, May 15, 2013 (A-43) re re-opening record to allow for the filing of the IARC Report and establishing a timetable for Supplemental Submissions.

Note: In addition to the above Rulings, that Commission also made a number of Rulings at the Oral Hearing.

AMALGAMATED REGULATORY TIMETABLE

ACTION	DATE (2012)
Registration of Interveners and Interested Parties	Friday, September 7
Comments on the regulatory process by which to review the Application, such as written, oral or both	Friday, September 7
Comments on the need to hold Community Input Sessions in the areas of Trail, Osoyoos, and Kelowna	Friday, September 14
Finalization of Registration of Interveners and Interested Parties	Friday, September 14
FortisBC reply on the need to hold Community Input Sessions in the areas of Trail, Osoyoos, and Kelowna	Wednesday, September 19
BCUC Information Request No. 1	Friday, September 14
Comments by Registered Interveners on the regulatory process by which to review the Application, such as written, oral or both	Friday, September 21
Commission Decision on the need to hold Community Input Sessions in the areas of Trail, Osoyoos, and Kelowna	Friday, September 21
Commission Decision on the regulatory process by which to review the Application, such as written, oral or both	Tuesday, September 25
Participants file their PACA Funding Budgets	Tuesday, October 2
FortisBC Response to BCUC Information Request No. 1	Friday, October 5
Intervener Information Request No. 1	Friday, October 26
Community Input Session in Trail	Tuesday, November 6
Community Input Session in Osoyoos	Wednesday, November 7
Community Input Session in Kelowna	Thursday, November 8
Procedural Conference, at the Best Western Plus Kelowna Hotel & Suites, South Ballroom, Kelowna	Thursday, November 8, commencing at 9:30 a.m.
FortisBC Response to Intervener Information Request No. 1	Friday, November 9
BCUC and Intervener Information Request No. 2	Friday, November 23
FortisBC Response to BCUC and Intervener Information Request No. 2	Friday, December 14

ACTION	DATE (2013)
Intervener Filed Evidence	Thursday, January 24
Information Requests on Intervener Filed Evidence	Thursday, February 7
Intervener Information Request No. 3	Friday, February 8
Intervener Confidential Information Request No. 1	Friday, February 8

ACTION	DATE (2013)
Intervener Responses to Information Requests on Intervener Filed Evidence	Thursday, February 21
FortisBC Responses to Intervener Information Request No. 3	Friday, February 22
FortisBC Responses to Intervener Confidential Information Request No.1	Friday, February 22
Oral Hearing in Kelowna	Monday, March 4 to Friday, March 15
FortisBC Responses to Intervener Information Request No. 3 (not related to Oral Hearing subject matter)	Thursday, March 21
FortisBC Response to Commission and BCPSO limited Information Request	Thursday, March 21
FortisBC Final Written Submission	Thursday, March 28
Intervener Final Written Submissions	Thursday, April 25
FortisBC Written Reply Submission	Thursday, May 2
Evidentiary Record reopened to admit International Agency for Research on Cancer monograph (IARC Report)	May 15, 2013
Intervener Supplemental Submissions on IARC Report	May 23, 2013
FortisBC Reply on IARC Report	May 30, 2013

LIST OF ACRONYMS

AACE International	Advancement of Cost Engineering American Association of Cost Engineers
AAEM	American Academy of Environmental Medicine
AGNIR	Advisory Group on Non-Ionising Radiation
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
Application	Advanced Metering Infrastructure Project
BC Hydro	British Columbia Hydro and Power Authority
BCMEU	BC Municipal Electrical Utilities
BCPSO	BC Pensioners and Seniors Organization
BCRUCA	BC Residential Utility Customers Association
BCSEA	BC Sustainable Energy Association and the Sierra Club of BC
BCSI	BC Southern Interior
CEA	*Clean Energy Act*, SBC 2010, c. 22
CEC	Commercial Energy Consumers Association of BC
Commission	British Columbia Utilities Commission
COSA	cost of service
CPCN	Certificate of Public Convenience and Necessity
CPI	Consumer Price Index
CSTS	Citizens for Safe Technology Society
EHS	Electromagnetic Hypersensitivity
ELF	extremely low frequency
EMP	electromagnetic pulse
FortisBC	FortisBC Inc.

GGRTA	Greenhouse Gas Reductions Targets Act
GHG	Greenhouse Gas
HAN	Home Area Network
HES	Head End System
IARC	International Agency for Research on Cancer
IARC Report	International Agency for Research on Cancer Report
IC	Industry Canada
ICG	Industrial Customers Group, Zellstoff Celgar Limited Partnership
ICNIRP	International Commission on Non-Ionizing Radiation Protection
IEEE	Institute of Electrical and Electronic Engineers
IHD	In-home Display
IRG	Irrigation Ratepayers Group
LAN	Local Area Network
LRMC	Long-run marginal cost
MDMS	Meter Data Management System
MHz	Megahertz
NCGP	Nelson Creston Green Party
NPV	Net Present Value
OMS	Outage Management System
PACA	Participant Assistance Cost Awards
PIPA	*Personal Information Protection Act*, SBC 2003, c. 63
PLC	Power Line Carrier
Proceeding	Commission public process to review AMI Application
RDCK	Area D, Regional District of Central Kootenay

RF	radio frequency
RFP	Request for Proposals
UCA	*Utilities Commission Act,* RSBC 1996, c. 473
US GAAP	US Generally Accepted Accounting Principles
VIGP Decision	Vancouver Island Generation Project Decision; Decision and Order G-55-03 dated September 8, 2003
VITR Decision	Vancouver Island Transmission Reinforcement Project Decision; Decision and Order C-4-06, dated July 7, 2006
WACC	weighted average cost of capital
WAN	Wide Area Network
WHO	World Health Organization
WKCC	West Kootenay Concerned Citizens

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

and

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

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated August 1, 2012 – Appointment of Commission Panel
A-2	Letter dated August 2, 2012 – Order G-105-12 Establishing a Preliminary Regulatory Timetable
A-3	Letter dated August 14, 2012 – Response to Requests to Amend the Preliminary Regulatory Timetable
A-4	Letter dated September 13, 2012 – Order G-124-12 Amending the Preliminary Regulatory Timetable
A-5	Letter dated September 14, 2012 – Commission Information Request No. 1
A-6	Letter dated September 21, 2012 – Confirming Community Input Sessions
A-7	Letter dated September 26, 2012 – Order G-135-12 Amending the Regulatory Timetable to include a Procedural Conference
A-8	Letter dated September 28, 2012 – Order G-137-12 Amending the Regulatory Timetable establishing the dates, times and locations for the Community Input Sessions
A-9	Letter dated October 4, 2012 – Community Input Sessions Participant Information
A-10	Letter dated October 11, 2012 – Procedural Conference proposed agenda and regulatory timetable
A-11	Letter dated October 15, 2012 – Order G-149-12 amending registration date for the Osoyoos Community Input Session

Exhibit No.	**Description**
A-12	Letter dated October 15, 2012 – Community Input Sessions Participant Information Revised
A-13	Letter dated November 9, 2012 – Order G-169-12 Timeframe for Further Submissions
A-14	Letter dated November 23, 2012 – Order G-177-12 Updated Regulatory Timetable and Reasons for Decision
A-15	Letter dated November 23, 2012 – Commission Information Request No. 2
A-16	Letter dated December 4, 2012 - Commission requests comments from Interveners regarding FBC Addendum (Exhibit B-1-2)
A-17	Letter dated December 13, 2012 – Request for Submissions on Mr. Flynn's request to make Evidence PowerPoint Presentation at the Oral Hearing (Exhibit C6-7)
A-18	Letter dated December 14, 2012 – Request for Comments on Mr. Shadrack's Reconsideration Application of G-177-12
A-19	Letter dated December 20, 2012 – Commission Order G-198-12 request for suspension of the Proceeding is denied and Reasons for Decision
A-20	Letter dated December 28, 2012 – Request for Comments from FortisBC Inc. and Itron regarding CSTS Objection to Confidential Exhibit B-14-1
A-21	Letter dated January 2, 2013 – Response to Nelson-Creston Comments regading FortisBC's Confidentiality Request
A-22	Letter dated January 3, 2013 – Response to Regional District Central Kootenay Comments regarding FortisBC's Confidentiality Request
A-23	Letter dated January 3, 2013 – Response to FortisBC Inc. request for extension
A-24	Letter dated January 7, 2013 – Response to RDCK providing clarification of Exhibit A-22
A-25	Letter dated January 10, 2013 – Procedural Information
A-26	Letter dated January 11, 2013 – Request for Comments regarding Third Round of Information Requests

Exhibit No.	Description
A-27	Letter dated January 18, 2012 – Commission Order G-11-13 and Reasons for Decision
A-28	Letter dated January 21, 2013 – Request for Submissions regarding Video Conference Testimony at Oral Hearing
A-29	Letter dated January 23, 2013 – Order G-12-13 and Reasons for Decision regarding Objection to Confidentiality Request by FortisBC
A-30	Letter dated January 25, 2013 – Guideance for filing video submissions
A-31	Letter dated January 30, 2013 – Leave granted to CSTS to file Late Evidence of Dr. Isaac Jamieson
A-32	Letter dated February 2, 2013 – Order G-17-13 Further Amended Regulatory Timetable Third Round of Information Requests
A-33	Letter dated February 5, 2013 – Request for Comments on CSTS video conferencing submission
A-34	Letter dated February 7, 2013 – Order G-21-13 Reconsideration and Variance of Order G-177-12 Reasons for Decision
A-35	Letter dated February 13, 2013 – Requesting comments on RDCK's Application for Leave to file late responses to Intervener Evidence Information Requests
A-36	Letter dated February 13, 2013 – Order G-24-13 regarding the submission of additional information requests to FortisBC on the Addendum exhibits and entering FortisBC's responses to BCSEA-SCBC IRs 1.1 and 1.2 from the proceeding reviewing the purchase of Kelowna's electric utility assets
A-37	Letter L-3-13 dated February 15, 2013 – Commission Panel determination on CSTS Expert Witness Video Conference request
A-38	Letter Dated February 20, 2013 – Commission Information Request No. 3
A-39	Letter Dated February 20, 2013 – Extension granted to RDCK to file late responses to information requests on RDCK evidence
A-40	Letter Dated February 28, 2013 – Commission Comments regarding FBC Responses to Information Request No. 3

Exhibit No.	Description
A-41	Letter Dated April 8, 2013 – Order G-51-13 amending the filing dates for Intervener Final Submissions and FortisBC Reply Submission
A-42	Letter dated April 22, 2013 – Request for Submissions on the CSTS application to reopen the evidentiary record to admit the International Agency for Research on Cancer (IARC) 462 page monograph relating to its designation of RF radiation as a possible cancer agent
A-43	Letter dated May 15, 2013 – Order G-80-13 with Reasons for Decision reopening the Evidentary Record to enter the IARC Report

COMMISSION STAFF DOCUMENTS

A2-1	Letter dated August 14, 2012 – Commission Staff filing The Increasing Problem of Electrical Consumption in Indoor Marihuana Grow Operations in British Columbia
A2-2	Letter dated August 14, 2012 - Commission Staff filing The Marihuana Indoor Production Calculator: A Tool for Estimating Domestic and Export Production Levels and Values
A2-3	Letter dated August 14, 2012 – Commission Staff filing Case Study of Smart Meter System Deployment
A2-4	Letter dated August 17, 2012 – Commission Staff filing online announcement FortisBC Selects Itron as Supplier of Advanced Metering Solution
A2-5	Letter dated August 20, 2012 – Commission Staff filing Victoria, Australia Department of Primary Industries web site, Smart Meters page
A2-6	Not Issued
A2-7	Letter dated September 14, 2012 – Commission Staff filing The Nature and Extent of Marihuana Growing Operations in Mission British Columbia: A 14 Year Review (1997-2010) by Plecas, D., Chaisson, K., Garis,. L, and Snow, A.
A2-8	Submitted at Oral Hearing March 11, 2012 - Commission Staff filing Document titled Radio Frequency (RF) Exposure Compliance of Radiocommunicatian Apparatus (All Frequency Bands)

Exhibit No.	Description
COMMISSION COUNSEL DOCUMENTS	
A3-1	Letter dated November 26, 2012 – Commission Council Response to RDCK Appeal
APPLICANT DOCUMENTS	
B-1	**FORTISBC INC. (FBC)** Letter Dated July 26, 2012 - Application for a Certificate of Public Convenience and Necessity for the Advanced Metering Infrastructure Project
B-1-1	Letter dated October 5, 2012 – Errata No. 1 to the July 26, 212 CPCN Application
B-1-2	Letter dated November 16, 2012 – FBC Submitting Addendum to the Application
B-1-3	Letter dated November 20, 2012 – FBC Submitting AMI Excel NPV Analysis - CoK Addendum
B-1-4	Letter dated January 22, 2013 – FBC Submitting Conditional Amendment
B-2	Letter Dated August 2, 2012 – FBC Submitting Confirmation of Application Notice
B-3	Letter dated August 17, 2012 – FBC Submitting AMI Excel NPV Analysis
B-4	Letter dated September 4, 2012 – FBC Submitting Letter from the National Research Council's Dominion Radio Astrophysical Observatory
B-5	Letter dated September 19, 2012 – FBC Submitting Comments on need for Community Input Sessions
B-6	Letter dated October 5, 2012 – Responses to Commission Information Request No. 1
B-6-1	**CONFIDENTIAL** - Letter dated October 5, 2012 – Confidential Responses to Commission Information Request No. 1
B-6-2	Letter dated October 12, 2012 – FBC Submitting BCUC IR1 Q44.1
B-6-3	**CONFIDENTIAL** Letter dated October 19, 2012 – FBC Submitting Confidential Excel Attachments
B-6-4	Letter dated October 19, 2012 – FBC Submitting Erratum 2 to Responses to BCUC IR1

Exhibit No.	Description
B-6-5	Letter dated Letter dated November 8, 2012 - FBC Submitting Revised Reponses to BCUC No. 1
B-7	Letter dated October 12, 2012 – FBC Submitting Request for Confidentiality regarding BCUC IR1
B-8	Letter dated October 12, 2012 – FBC Submitting Notice of Community Input Session Ad Publications
B-9	Letter dated October 19, 2012 – FBC Submitting Supplemental Privacy Information
B-10	Letter dated October 30, 2012 – FBC Submitting Comments regarding the Procedural Conference
B-11	Letter dated November 9, 2012 – FBC Submitting Responses to Intervener Information Requests No. 1
B-11-1	Letter dated November 21, 2012 – FBC Submitting Supplemental Response to BCPSO IR No. 1 Question 37.1
B-11-2	Submitted at Oral Hearing March 5, 2012 - DOCUMENT "FIGURE 2: UPDATED CHART", CONTAINING TWO BAR GRAPHS
B-12	Letter dated November 30, 2012 – FBC Submission to RDCK and Nelson-Creston and Interveners
B-13	Letter dated December 11, 2012 – FBC Response to Suspension of Proceedings
B-14	Letter dated December 14, 2012 – FBC Responses to BCUC IR No. 2
B-14-1	Letter dated December 14, 2012 – FBC Request for Confidentiality of certain responses to BCUC Information Requests No. 2
B-14-2	**CONFIDENTIAL** Letter dated December 14, 2012 – FBC Confidential Responses to BCUC Information Request No. 2
B-15	Letter dated December 14, 2012 – FBC Responses to Intervener Information Requests No. 2
B-15-1	Letter dated December 14, 2012 – FBC Responses to BC Hydro Information Request No. 2

Exhibit No.	**Description**
B-16	Letter dated December 14, 2012 – FBC Responses to Postnikoff Information Request No. 1
B-17	Letter dated January 3, 2013 - FBC Responses to Exhibits A-20 and A-21 request for extension
B-18	Letter dated January 4, 2013 – FBC comments on Jerry Flynn's request Exhibit C6-7
B-19	Letter dated January 4, 2013 – FBC Response to RDCK Reconsideration Request
B-20	Letter dated January 9, 2013 – FBC Submitting comments regarding Procedural Conference date
B-21	Letter dated January 11, 2013 – FBC Submitting Itron's comments regarding confidentiality (attachment subject to a request for confidentiality)
B-22	Letter dated January 16, 2013 – FBC Submitting comments regarding Exhibit A-26
B-23	Letter dated January 22, 2013 – FBC Submitting Additional Information
B-24	Letter dated January 22, 2013 – FBC Submitting Comments regarding third round of information requests
B-25	Letter dated February 7, 2013 - FBC Filing Comments on CSTS video conferencing submission
B-26	Letter dated February 7, 2013 - FBC Submitting IR No. 1 to CSTS on Intervener Evidence
B-27	Letter dated February 7, 2013 - FBC Submitting IR No. 1 to Jerry Flynn on Intervener Evidence
B-28	Letter dated February 7, 2013 - FBC Submitting IR No. 1 to KM on Intervener Evidence
B-29	Letter dated February 7, 2013 - FBC Submitting IR No. 1 to RDCK on Intervener Evidence
B-30	Letter dated February 7, 2013 - FBC Submitting IR No. 1 to WKCC on Intervener Evidence

Exhibit No.	Description
B-31	Letter dated February 15, 2013 – FBC Comment regarding RDCK Extension to Filing date for Intervener IR Responses to March 1, 2013
B-32	Letter dated February 20, 2013 - FBC Submitting Witness Panels Members
B-33	**CONFIDENTIAL** Letter dated February 22, 2013 - FBC Submitting Confidential Response to RDCK Confidential Materials regarding IR No. 1
B-34	Letter dated February 22, 2013 - FBC Submitting Responses to Intervener Information Request No. 3
B-35	Letter dated February 26, 2013 - FBC Submitting Response to CSTS Preliminary Matters
B-36	Letter dated February 27, 2013 - FBC Submitting Comments regarding Witnesses Cross Examination
B-37	Letter dated February 28, 2013 - FBC Submitting Councel's Opening Statement
B-38	Letter dated February 28, 2013 - FBC Submitting Opening Statement of Tom Loski
B-39	Submitted at Oral Hearing March 6, 2013 – FBC Undertaking No. 1
B-40	Submitted at Oral Hearing March 6, 2013 - FBC Undertaking No. 2
B-41	Submitted at Oral Hearing March 6, 2013 – FBC Undertaking No. 3
B-42	Submitted at Oral Hearing March 6, 2013 - FBC Undertaking No. 4
B-43	Submitted at Oral Hearing March 7, 2013 - FBC Undertaking No. 5
B-44	Submitted at Oral Hearing March 7, 2013 - FBC Undertaking No. 6
B-45	Submitted at Oral Hearing March 8, 2013 - FBC Undertaking No. 7
B-46	Submitted at Oral Hearing March 13 , 2013 – TRANSCRIPT OF THE EVIDENCE OF JAMES McNAMEE ON FEBRUARY 18, 2013 IN THE SUPERIOR COURT OF QUEBEC IN THE MATTER OF WHITE V. THE VILLE DE CHATEAUGUAY, ROGERS COMMUNICATION INC. AND BERNARD ROY
B-47	Submitted at Oral Hearing March 14 , 2013 - FBC Undertaking No. 8

Exhibit No.	Description
B-48	Submitted at Oral Hearing March 15 , 2013 - PRINTOUT FROM HEALTH CANADA ENTITLED"ENVIRONMENTAL AND WORKPLACE HEALTH"
B-49	Letter dated March 21 , 2013– FBC Submitting Revised Responses to Andy Shadrack IR No. 3 on PLC filing
B-50	Letter dated March 21 , 2013 – FBC Submitting Responses to BCUC IR No. 3
B-51	Letter dated March 21 , 2013 – FBC Submitting Responses to BCPSO IR No. 3
B-52	Letter dated March 26 , 2013– FBC Submitting Undertaking No. 9
B-53	Letter dated May 8, 2013 – FBC Opposing CSTS request to reopen evidentiary record to admit IARC report as evidence
B-54	Letter dated May 16, 2013 – FBC Response to Exhibit A-43

INTERVENER DOCUMENTS

C1-1	**RIDING OF BC SOUTHERN INTERIOR (BCSI)** Online Registration Dated August 14, 2012 – Request for Intervener Status by Alex Atamanenko and Comments regarding Community Input Sessions
C1-2	Letter dated November 22, 2012 – BCSI Submitting Comments on RDCK and Nelson-Creston suspension requests
C1-3	Letter dated December 7, 2012 – BCSI Submitting Supplemental Comments on suspension requests
C1-4	Letter dated December 20, 2012 – BCSI Submitting Comments on Jerry Flynn's request Exhibit C6-7
C1-5	Letter dated December 20, 2012 – BCSI Submitting Comments on Request for suspension of the Proceeding Exhibit A-18
C1-6	Letter dated January 28, 2013 - BCSI Submitting Confidentiality Undertaking by Alex Atamanenko
C1-7	Letter dated February 6, 2013 - BCSI Filing Comments on CSTS video conferencing submission
C1-8	Letter dated February 6, 2013 - BCSI Submitting Questions for Expert Witness Mr. Robert McLennan

Exhibit No.	**Description**
C1-9	Letter dated February 14, 2013 – Comments on RDCK late filing of responses to Intervener Evidence IRs
C1-10	Letter dated February 26, 2013 - BCSI Submitting Comments regarding FBC Incomplete IR No. 3 Responses
C1-11	Submitted at Oral Hearing March 5, 2012 - WRITTEN OPEN STATEMENT FROM MR. MILES
C1-12	Email dated April 22, 2013 – BCSI supporting CSTS request to reopen evidentiary record to admit IARC report as evidence
C2-1	**BRITISH COLUMBIA MUNICIPAL ELECTRICAL UTILITIES (BCMEU)** Letter dated September 6, 2012 Via Email - Request for Intervener Status by Christopher Weafer
C3-1	**BRITISH COLUMBIA PENSIONERS' AND SENIORS' ORGANIZATION (BCPSO ET AL)** Letter dated September 7, 2012 via Email – Request for Intervener Status by Tannis Braithwaite, Eugene Kung and Bill Harper
C3-2	Letter dated October 26, 2012 – BCPSO Submitting Information Request No. 1 to FBC
C3-3	Letter dated November 23, 2012 - BCPSO Submitting Comments on RDCK and Nelson-Creston suspension requests
C3-4	Letter dated November 23, 2012 - BCPSO Submitting Information Request No. 2 to FBC
C3-5	Letter dated January 17, 2013 - BCPSO Submitting Comments regarding Third Round of Information Requests
C3-6	Letter dated January 25, 2013 - BCPSO Submitting Confidentiality Undertaking by Tannis Braithwaite
C3-7	Letter dated January 25, 2013 - BCPSO Submitting Confidentiality Undertaking by Eugene Kung
C3-8	Letter dated February 14, 2013 - BCPSO Submitting Comments on RDCK extension request
C3-9	Letter dated February 20, 2013 - BCPSO Submitting Information Request No. 3 to FBC

Exhibit No.	Description
C3-10	Submitted at Oral Hearing March 4, 2012 - OPENING STATEMENT BY MR. KUNG
C4-1	**BRITISH COLUMBIA SUSTAINABLE ENERGY ASSOCIATION (BCSEA)** Letter dated August 23, 2012 – Request for Intervener Status by William J. Andrews and Comments regarding Community Input Sessions
C4-2	Letter dated September 21on the regulatory process
C4-3	Letter dated September 6, 2012 – BCSEA Submitting Comments regarding Community Input Sessions
C4-4	Letter dated October 26, 2012 - BCSEA Submitting Information Request No. 1 to FBC
C4-5	Letter dated October 30, 2012 - BCSEA Submitting comment on items to be addressed at the Procedural Conference
C4-6	Letter dated November 22, 2012 - BCSEA Submitting comment on RDCK and Nelson-Creston suspension requests
C4-7	Letter dated November 23, 2012 - BCSEA Submitting Information Request No. 2 to FBC
C4-8	Letter dated December 18, 2012 – BCSEA Submitting Comments on Jerry Flynn's request Exhibit C6-7
C4-9	Letter dated December 21, 2012 – BCSEA Submission on Reconsideration Application
C4-10	Letter dated December 21, 2012 – BCSEA Request for Third Round of Information Requests
C4-11	Letter dated January 17, 2013 - BCSEA Submitting Comments regarding Third Round of Information Requests
C4-12	Letter dated January 18, 2013 – BCSEA Submitting Comments regarding Third Round of Information Requests
C4-13	Letter dated January 24, 2013 – BCSEA Submitting Confidentiality Undertaking
C4-14	Letter dated February 7, 2013 - BCSEA Submitting IR No. 1 to RDCK

Exhibit No.	**Description**
C4-15	Letter dated February 7, 2013 - BCSEA Submitting IR No. 1 to CSTS
C4-16	Letter dated February 8, 2013 - BCSEA Comment regardingConfidential Information Request No. 1
C4-17	Letter dated February 8, 2013 - BCSEA Submitting IR No. 3
C4-18	Letter dated February 13, 2013 - BCSEA Submitting Comments on RDCK extension request
C4-19	Submitted at Oral Hearing March 4, 2012 - DOCUMENT ENTITLED "BCSEA-SCBC CROSS-EXAM AIDS…FORTISBC PANEL 1 SECURITY…"
C4-20	Submitted at Oral Hearing March 13 , 2012 – ORIGINAL REPORT, VOLUME 27, NUMBER 33, NOVEMBER 20, 2009, JOURNAL OF CLINICAL ONCOLOGY "MOBILE PHONE USE AND RISK OF TUMORS: A META-ANALYSIS"
C4-21	Submitted at Oral Hearing March 14 , 2012 – WIRELESS UTILITY METER SAFETY IMPACTS SURVEY, FINAL RESULTS SUMMARY, SEPTEMBER 13, 2011, ED HALTEMAN
C4-22	Submitted at Oral Hearing March 14 , 2012 – EXHIBIT D - SMART METER HEALTH EFFECTS, SURVEY AND REPORT
C4-23	Letter dated May 1, 2013 – BCSEA supporting CSTS request to reopen evidentiary record to admit IARC report as evidence
C4-24	Letter dated May 13, 2013 – BCSEA Filing Reply Submission to reopen evidentiary record
C5-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH)** Letter dated September 6, 2012 – Request for Intervener Status by Janet Fraser and Comments
C5-2	Letter dated September 21 2012 – BCH Submitting Comments on the regulatory process
C5-3	Letter dated November 23, 2012 - BCH Submitting Information Request No. 2 to FBC
C6-1	**FLYNN, JERRY (JF)** Letter dated July 31, 2012 via Email – Request for Intervener Status by Jerry Flynn and Comments

Exhibit No.	Description
C6-2	Letter dated September 21, 2012 – JF Submitting Comments on the regulatory process
C6-3	Letter dated November 6, 2012 – JF Submitting Comments
C6-4	Submitted at Community Input Session in Kelowna November 8, 2012- HARD COPY SUBMISSION OF Jerry Flynn
C6-5	Letter dated November 23, 2012 – JF Submitting Letter of Comment
C6-6	Letter dated December 6, 2012 – JF Submitting Comments regarding BCSI Supplemental Submission
C6-7	Emails regarding – JF Request to Present at Oral Hearing
C6-8	Letter dated December 15, 2012 – JF Submitting Comments regarding RDCK submission Exhibit C13-11
C6-9	Letter dated January 2, 2013 – JF Submitting Comments
C6-10	Letter dated January 23, 2013 – JF Submitting Comments and Presentation
C6-11	Letter dated February 5, 2013 - JF Filing Comments on CSTS video conferencing submission
C6-12	Letter dated February 6, 2013 - JF Submitting Response to Intervener IR No. 1
C6-13	Letter dated February 7, 2013 - JF Submitting Responses to FBC IR No. 1
C6-14	Letter dated February 13, 2013 - JF Submitting Comments on RDCK extension request
C6-15	Letter dated February 27, 2013 - JF Submitting Comments regarding Cross Examination
C6-16	Submitted at Oral Hearing March 5, 2012 - WRITTEN OPENING STATEMENT BY MR. FLYNN
C6-17	Email dated April 22, 2013 – JF supporting CSTS request to reopen evidentiary record to admit IARC report as evidence
C7-1	**GABANA, NORMAN (NG)** Letter dated September 5, 2012 via Email – Request for Intervener Status by Norman Gabana and Comments

Exhibit No.	Description
C7-2	Submitted at Community Input Session in Trail November 6, 2012 - HARD COPY SUBMISSION OF Norman Gabana
C8-1	**BC RESIDENTIAL UTILITY CUSTOMERS ASSOCIATION (BCRUCA)** Letter dated September 7, 2012 via Email – Request for Intervener Status by Guy Leroux and Comments
C8-2	Letter dated October 26, 2012 – BCRUCA Submitting Information Request No. 1 to FBC
C8-3	Letter dated November 23, 2012 - BCRUCA Submitting Information Request No. 2 to FBC
C8-4	Letter dated January 17, 2013 - BCRUCA Submitting Comments regarding Third Round of Information Requests
C9-1	**CITIZENS FOR SAFE TECHNOLOGY SOCIETY (CSTS)** Letter dated September 7, 2012 via Email – Request for Intervener Status by David Aaron
C9-2	Letter dated October 29, 2012 - CSTS Submitting Information Request No. 1 to FBC
C9-3	Letter dated October 30, 2012– CSTS submission for the Procedural Conference
C9-4	Letter dated November 23, 2012 -CSTS Submitting Information Request No. 2
C9-5	Letter dated December 21, 2012 – CSTS Request for Third Round of Information Requests
C9-6	Letter dated December 27, 2012 – CSTS Submitting Comments on Exhibit B-14-1
C9-7	Letter dated January 18, 2013 – CSTS Submitting Comments on FBC's January 16, 2013 submission Exhibit B-22
C9-8	Letter dated January 24, 2013 – CSTS Filing Evidence (contains attachments)
C9-9	Letter dated January 24, 2013 – CSTS Filing Witnesses List
C9-10	Letter dated January 25, 2013 – CSTS Request to file Late Evidence of Dr. Isaac Jamieson
C9-10-1	Letter dated January 25, 2013 – CSTS Submitting Evidence of Dr. Isaac Jamieson
C9-10-2	Letter dated January 28, 2013 – CSTS Submitting Supporting Evidence

Exhibit No.	Description
C9-11	Letter dated February 4, 2013 – CSTS Submitting Confidentiality Undertaking
C9-12	Letter dated February 21, 2013 – CSTS Submitting M. Sears Respsonses to BCSEA IR No. 1
C9-12-1	Letter dated February 21, 2013 – CSTS Submitting Respsonses to BCSEA IR No. 1 Questions 1.1 and 2.1
C9-12-2	Letter dated February 21, 2013 – CSTS Submitting T. Schoechle Respsonses to BCSEA IR No. 1
C9-12-3	Letter dated February 21, 2013 – CSTS Submitting D. Carpenter Respsonses to BCSEA IR No. 1
C9-12-4	Letter dated February 21, 2013 – CSTS Submitting I. Jamieson Respsonses to BCSEA IR No. 1
C9-12-5	Letter dated February 21, 2013 – CSTS Submitting D. Maish Respsonses to BCSEA IR No. 1
C9-12-6	Letter dated February 21, 2013 – CSTS Submitting M. Blank Respsonses to BCSEA IR No. 1
C9-13	Letter dated February 21, 2013 – CSTS Submitting T. Schoechle Respsonses to FBC IR No. 1
C9-13-1	Letter dated February 21, 2013 – CSTS Submitting D. Carpenter Respsonses to FBC IR No. 1
C9-13-2	Letter dated February 21, 2013 – CSTS Submitting I. Jamieson Respsonses to FBC IR No. 1
C9-13-3	Letter dated February 21, 2013 – CSTS Submitting D. Maish Respsonses to FBC IR No. 1
C9-13-4	Letter dated February 21, 2013 – CSTS Submitting G. Kumar Respsonses to FBC IR No. 1
C9-13-5	Letter dated February 23, 2013 – CSTS Late Filing M. Blank Respsonses to FBC IR No. 1
C9-14	Letter dated February 21, 2013 – CSTS Submitting T. Schoechle Respsonses to CEC IR No. 1

Exhibit No.	Description
C9-14-1	Letter dated February 21, 2013 – CSTS Submitting D. Carpenter Respsonses to CEC IR No. 1
C9-14-2	Letter dated February 21, 2013 – CSTS Submitting I. Jamieson Respsonses to CEC IR No. 1
C9-14-3	Letter dated February 21, 2013 – CSTS Submitting D. Maish Respsonses to CEC IR No. 1
C9-14-4	Letter dated February 21, 2013 – CSTS Submitting M. Blank Respsonses to CEC IR No. 1
C9-15	Letter dated February 25, 2013 – CSTS Submitting Preliminary Matters for Hearing
C9-16	Letter dated February 27, 2013 – CSTS Submitting Request Leave for Witnesses to Appear by Video Conference
C9-17	Submitted at Oral Hearing March 6, 2012 - PRESS DOCUMENT HEADED "A REVIEW OF THE POTENTIAL HEALTH RISKS OF RADIOFREQUENCY FIELDS FROM WIRELESS TELECOMMUNICATION DEVICES", DATED MARCH 1999
C9-18	Submitted at Oral Hearing March 6, 2012 - PRESS RELEASE WITH HEADER "THE SWERDLOW REPORTS: DOWNPLAYING THE MOBILE PHONE CANCER RISK/EMFACTS CONSULTANCY"
C9-19	Submitted at Oral Hearing March 6, 2012 - ACS "CERTIFICATE EXHIBIT - FCC ID: SK9AMI7…RF EXPOSURE"
C9-20	Letter dated March 22, 2012 – CSTS Submitting Undertakings of Dr. Jamieson
C9-21	Letter dated March 22, 2012 – CSTS Submitting Undertakings of Dr. Sears and Carpenter
C9-22	Letter dated April 19, 2013 – CSTS request to reopen evidentiary record to admit the International Agency for Reasearch on Cancer – Monographs on Non-Ionizing Ration, Part 2: Radiofrequency Electromagnetic Fields, Volume 102
C9-23	Letter dated May 1, 2013 – CSTS Response to BCSEA Comments on Request to reopen evidentiary record
C9-24	Email dated May 13, 2013 - CSTS advising they will not be filing a Reply Submission on the admission of the IARC monograph into evidence

Exhibit No.	Description
C9-25	International Agency for Research on Cancer – Monographs on Non-Ionizing Ration, Part 2: Radiofrequency Electromagnetic Fields, Volume 102
C10-1	**INDUSTRIAL CUSTOMERS GROUP (ICG)** Letter dated September 10, 2012 via Email – Request for Intervener Status by Robert Hobbs and Brian Merwin
C10-2	Letter dated September 14, 2012 – ICG Submitting Information Request No. 1 to FBC
C11-1	**MILES, KEITH (KM)** Letter dated September 7, 2012 via Email **AND** Online Registration dated August 29, 2012 – Request for Intervener Status by Keith Miles
C11-2	Letter dated September 24, 2012 – KM Submitting Comments on the regulatory process
C11-3	Letter dated October 26, 2012 – KM Submitting Information Request No. 1 to FBC
C11-4	Letter dated November 23, 2012 – KM Submitting Comments regarding the Suspension of Proceedings
C11-5	Letter dated November 23, 2012 - KM Submitting Information Request No. 2
C11-6	Letter dated January 22, 2013 – KM Submitting Evidence
C11-7	Letter dated January 24, 2013 – KM Submitting Evidence
C11-8	Letter dated February 7, 2013 - KM Filing Comments on CSTS video conferencing submission
C11-9	Letter dated February 8, 2013 – KM Submitting Information Request No. 3
C11-10	Letter dated February 21, 2013 – KM Submitting Respsonses to FBC IR No. 1
C11-11	Letter dated February 21, 2013 – KM Submitting Respsonses to RDCK IR No. 1
C11-12	Letter dated February 25, 2013 - KM Submitting Comments regarding FBC Incomplete IR No. 3 Responses
C11-13	Submitted at Oral Hearing March 5, 2012 - WRITTEN OPEN STATEMENT FROM MR. MILES
C12-1	**IRRIGATION RATEPAYERS GROUP (IRG)** Letter dated September 10, 2012 via Email – Request for Intervener Status by Fred Weisberg

Exhibit No.	**Description**
C13-1	**ELECTORAL AREA D REGIONAL DISTRICT CENTRAL KOOTENAY (RDCK)** Letter dated July 28, 2012 via Email – Request for Intervener Status by Andy Shadrack, Comments and resume of expert witness Robert McLennan
C13-2	Letter dated September 21, 2012 – RDCK Submitting Comments on the regulatory process
C13-3	Letter dated October 26, 2012 - RDCK Submitting Information Request No. 1 to FBC
C13-4	Letter dated October 30, 2012– RDCK Comments regarding Proceedings
C13-5	Letter dated November 7, 2012 - RDCK Submitting Notice of Expert Witness and Testimony
C13-6	Letter dated November 16, 2012 - RDCK Submitting Comments regarding a Wired Option
C13-7	Letter dated November 23, 2012 - RDCK Submitting Information Request No. 2
C13-8	Letter dated November 23, 2012 - RDCK Submitting Appeal to Proceeding Order Exhibit A-14
C13-9	Letter dated December 7, 2012 - RDCK Submission regarding Suspension Applications
C13-10	Letter dated December 10, 2012 - RDCK Further Submission regarding Suspension Applications
C13-11	Letter dated December 15, 2012 – RDCK Submitting Comments on Jerry Flynn's request Exhibit C6-7
C13-12	Letter dated December 21, 2012 – RDCK Submitting Request for a Third Round of Intervener Questions
C13-13	Letter dated December 31, 2012 – RDCK Submitting Comments regarding FBC request for Confidentiality
C13-14	Letter dated January 7, 2013 – RDCK requesting clarification Exhibit A-22
C13-15	Letter dated January 11, 2013 – RDCK Reply to submissions on RDCK Application to the Commission for reconsideration of Order G-177-12

Exhibit No.	**Description**
C13-16	Letter dated January 18, 2013 – RDCK Submitting Comments on Third Round of Information Requests
C13-17	Letter dated January 21, 2013 – RDCK Notice of Filing Further Evidence
C13-17-1	Letter dated January 21, 2013 – RDCK Submitting Evidence
C13-18	Letter dated January 23, 2013 – RDCK Filing Further Evidence
C13-19	Letter dated January 24, 2013 – RDCK Submitting Smart Meter Presentation
C13-20	Letter dated January 27, 2013 - RDCK Submitting Confidentiality Undertaking by Andy Shadrack
C13-21	Letter dated February 5, 2013 - RDCK Filing Comments on CSTS video conferencing submission
C13-22	Letter dated February 5, 2013 - RDCK Submitting Intervener IR No. 1 to Jerry Flynn
C13-23	Letter dated February 7, 2013 - RDCK Submitting Intervener IR No. 1 to Keith Miles
C13-24	Letter dated February 7, 2013 - RDCK Submitting Intervener IR No. 1 to Curtis Bennett
C13-25	**CONFIDENTIAL** Letter dated February 8, 2013 – RDCK Submitting Information Request for CONFIDENTIAL Materials regarding IR No. 1
C13-26	Letter dated February 8, 2013 – RDCK Submitting Information Request No. 3
C13-27	Email dated February 12, 2013 – RDCK Application for Leave to file Late Responses to Intervener Evidence Information Requests
C13-28	Email dated February 18, 2013 – RDCK Submitting Partial Response to FBC Information Request No. 1
C13-29	Email dated February 15, 2013 – RDCK Submitting Response to BCSEA-SCBC Information Request No. 1 Question 1.6
C13-30	Letter dated February 21, 2013 – RDCK Submitting Respsonses to BCSEA IR No. 1
C13-30-1	Letter dated February 21, 2013 – RDCK Submitting Addendum to BCSEA IR No. 1

Exhibit No.	Description
C13-31	Letter dated February 25, 2013 – RDCK Submitting Comments regarding Extension Request
C13-32	Letter dated February 25, 2013 – RDCK Submitting Request to Panel to review IR No. 3 scope
C13-33	Letter dated February 26, 2013 – RDCK Submitting Comments regarding Partial response to BCSEA IR No. 1
C13-34	Letter dated February 27, 2013 – RDCK Filing Responses to the Remaining IR No. 1 to FortisBC
C13-35	Submitted at Oral Hearing March 5, 2012 - WRITTEN OPENING STATEMENT BY MR. SHADRACK
C13-36	Email dated April 22, 2013 - RDCK supporting CSTS request to reopen evidentiary record to admit IARC report as evidence
C13-37	Email dated May 13,2013 - RDCK Reply Submission on CSTS request to reopen evidentiary record
C14-1	**HAYES, SHONNA (SH)** Letter dated September 5, 2012 via Email – Request for Intervener Status by Shonna Hayes and Comments
C14-2	Letter dated October 10, 2012 – SH Submitting Representative Appointment Notice
C14-3	Submitted at Community Input Session in Trail November 6, 2012 - HARD COPY SUBMISSION OF Shonna Hayes
C15-1	**TATANGELO, JOE (JT)** Letter dated September 4, 2012 via Email – Request for Intervener Status by Joe Tatangelo
C15-2	Letter dated October 24, 2012 – JT Submitting Information Request No. 1 to FBC
C16-1	**SLACK, BURYL (BS)** Letter dated August 17, 2012 – Request for Intervener Status by Buryl Slack and Comments
C16-2	Submitted at Oral Hearing March 6, 2012 - COPY OF HANDWRITTEN LETTER DATED MARCH 1, 2013
C17-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC)** Letter dated August 20, 2012 – Request for Intervener Status by Christopher Weafer

Exhibit No.	Description
C17-2	Letter dated September 7, 2012 – CEC Submitting Comments on Community Input Sessions
C17-3	Letter dated September 20, 2012 – CEC Submitting Clarification regarding Community Input Sessions
C17-4	Letter dated September 21, 2012 – CEC Submitting Clarification regarding J Flynn Comments
C17-5	Letter dated October 26, 2012 – CEC Submitting Information Request No. 1 to FBC
C17-6	Letter dated October 30, 2012– CEC submission for the Procedural Conference
C17-7	Letter dated November 23, 2012 – CEC Submitting Comments on RDCK and Nelson-Creston suspension requests
C17-8	Letter dated November 23, 2012 - CEC Submitting Information Request No. 2 to FBC
C17-8-1	Letter dated November 28, 2012 - CEC Submitting IR No. 2 Appendix H Replacement
C17-9	Letter dated December 20, 2012 – CEC Submitting Comments on Jerry Flynn's request Exhibit C6-7
C17-10	Letter dated December 21, 2012 – CEC Submitting Comments on Mr. Shadrack's Reconsideration Application
C17-11	Letter dated January 17, 2013 - CEC Submitting Comments regarding Third Round of Information Requests
C17-12	Letter dated January 24, 2013 – CEC Submitting Confidentiality Undertaking
C17-13	Letter dated February 7, 2013 - CEC Filing Comments on CSTS video conferencing submission
C17-14	Letter dated February 7, 2013 - CEC Submitting IR No. 1 to CSTS Intervener Evidence Carpenter
C17-15	Letter dated February 7, 2013 - CEC Submitting IR No. 1 to CSTS Intervener Evidence Maisch

Exhibit No.	Description
C17-16	Letter dated February 7, 2013 - CEC Submitting IR No. 1 to CSTS Intervener Evidence Kumar
C17-17	Letter dated February 7, 2013 - CEC Submitting IR No. 1 to CSTS Intervener Evidence Jamieson
C17-18	Letter dated February 7, 2013 - CEC Submitting IR No. 1 to CSTS Intervener Evidence Maret
C17-19	Letter dated February 7, 2013 - CEC Submitting IR No. 1 to CSTS Intervener Evidence Blank
C17-20	Letter dated February 7, 2013 - CEC Submitting IR No. 1 to CSTS Intervener Evidence Sears
C17-21	Letter dated February 7, 2013 - CEC Submitting IR No. 1 to CSTS Intervener Evidence Schoechle
C17-22	Letter dated February 14, 2013 - CEC Submitting Comments on RDCK extension request
C17-23	Submitted at Oral Hearing March 5, 2012 - DOCUMENT HEADED "CEC CROSS EXAMINATION OF FORTISBC INC. -WITNESS AID"
C17-24	Submitted at Oral Hearing March 12, 2012 - STAFF REPORT OF PUBLIC UTILITY COMMISSION OF TEXAS DATED DECEMBER 17, 2012
C17-24-1	Submitted at Oral Hearing March 14, 2012 - PAGE 6 FROM STAFF REPORT OF PUBLIC UTILITY COMMISSION OF TEXAS DATED DECEMBER 17, 2012
C18-1	**NELSON-CRESTON GREEN PARTY CONSTITUENCY ASSOCIATION (NCGP)** Letters dated August 22, 2012 and September 7, 2012 and Online Registration – Request for Intervener Status by Michael Jessen
C18-2	Letter dated October 26, 2012 – NCGP Submitting Information Request No. 1 to FBC
C18-3	Letter dated October 30, 2012 – NCGP Submitting Comments regarding attending the Procedural Conference and comments regarding the procedural conference, the regulatory timetable, and the Oral Hearing process
C18-4	Submitted at Community Input Session in Trail November 6, 2012 - HARD COPY SUBMISSION OF Michael Jessen

Exhibit No.	Description
C18-5	Letter dated November 16, 2012 – NCGP Submission Regarding Suspension of Proceedings
C18-6	Letter dated November 23, 2012 - NCGP Submitting Information Request No. 2
C18-7	Letter dated December 7, 2012 – NCGP Reply Submission regarding Suspension Request
C18-8	Letter dated December 21, 2012 – NCGP Submitting Comments on Mr. Shadrack's Reconsideration Application
C18-9	Letter dated December 31, 2012 – NCGP Submitting Comments on Objection to Confidential Exhibit B-14-1
C18-10	Letter dated January 17, 2013 - NCGP Submitting Comments regarding Third Round of Information Requests
C18-11	Letter dated February 6, 2013 - NCGP Filing Comments on CSTS video conferencing submission
C18-12	Email dated April 22, 2013 - NCGP supporting CSTS request to reopen evidentiary record to admit IARC report as evidence
C19-1	**WEST KOOTENAY CONCERNED CITIZENS (WKCC)** Letter dated September 25, 2012 and letters regarding Intervention – Request for Intervener Status by Cliff Paluck and Curtis Bennett
C19-2	Letter dated October 26, 2012– WKCC Submitting Information Request No. 1 dated October 26, 2012
C19-3	Letter dated October 31, 2012– WKCC submission for the Procedural Conference
C19-4	Submitted at Community Input Session in Trail November 6, 2012 - HARD COPY SUBMISSION OF WKCC
C19-5	Letter dated November 13, 2012 – WKCC submission regarding Request for Oral Hearing
C19-6	Letter dated November 23, 2012 – WKCC Submitting Comments regarding the Suspension of Proceedings
C19-7	Letter dated November 23, 2012 – WKCC Submitting Information Request No. 2
C19-7-1	Letter dated November 30, 2012 – WKCC Submitting IR No. 2 Q32 Attachment

Exhibit No.	Description
C19-8	Letter dated January 24, 2013 – WKCC Submitting Evidence
C19-9	Letter dated February 7, 2013 - WKCC Filing Comments on CSTS video conferencing submission
C19-10	Letter dated February 7, 2013 - WKCC Submitting Further Comments on CSTS video conferencing submission
C19-11	Letter dated February 8, 2013 – WKCC Submitting Information Request No. 3
C19-12	Letter dated February 15, 2013 – WKCC Submitting Petition
C19-13	Letter dated February 21, 2013 – WKCC Submitting Respsonses to FBC IR No. 1
C19-14	Letter dated February 21, 2013 – WKCC Submitting Respsonses to RDCK IR No. 1
C19-15	Letter dated February 25, 2013 – WKCC Submitting Request to Panel to review IR No. 3 scope
C19-16	Letter dated February 28, 2013 – WKCC Submitting comments regarding Cross Examination of Witnesses and FortisBC responses to IR No. 3 questions
C19-17	Submitted at Oral Hearing March 5, 2012 - WRITTEN OPENING STATEMENT BY MR. BENNETT
C19-18	Submitted at Oral Hearing March 15, 2012 - LETTER DATED MARCH 15, 2013 FROM THERMOGRAFIX CONSULTING CORPORATION WITH REDACTIONS
C19-19	Email dated April 22, 2013 – WKCC supporting CSTS request to reopen evidentiary record to admit IARC report as evidence
C19-20	Letter dated May 2,2013 – WKCC Submission on CSTS request to reopen evidentiary record to admit IARC report as evidence

INTERESTED PARTY DOCUMENTS

D-1	**POSTNIKOFF, CHRISTINA (CP)** Letter Dated August 16, 2012 – Request for Interested Party Status by Christina Postnikoff
D-1-1	Letter Dated October 5, 2012 – CP Submitting Letter of Comment
D-1-2	Letter dated October 30, 2012 - CP Submitting Comment

Exhibit No.	Description
D-1-3	Letter dated November 2, 2012 - CP Submitting Comments
D-1-4	PENDING Submitted at Community Input Session in Trail November 6, 2012 - HARD COPY SUBMISSION OF Christina Postnikoff
D-1-5	Letter dated November 19, 2012 - CP Submitting Letter of Comment
D-1-6	Letter dated November 10, 2012 - CP Submitting Petition Safety Code 6
D-1-7	Letter dated October 26, 2012 - CP Submitting a Request for Information
D-1-8	Letter dated November 23, 2012 - CP Submitting Letter of Comment Regarding Suspension Requests
D-1-9	Letter dated December 4, 2012 - CP Submitting Letter of Comment
D-1-10	Letter dated December 5, 2012 - CP Submitting Letter of Comment
D-1-11	Letter dated December 13, 2012 - CP Submitting Letter of Comment
D-1-12	Letter dated December 27, 2012 - CP Submitting Letter of Comment
D-1-13	Letter dated December 17, 2012 - CP Submitting Letter of Comment Regarding Jerry Flynn's request Exhibit C6-7
D-1-14	Letter dated January 10, 2013 - CP Submitting Letter of Comment
D-1-15	Letter dated January 22, 2013 – CP Submitting Comments Regarding Third Round of Information Requests
D-1-16	Letter dated January 24, 2013 – CP Submitting Letter of Comment
D-1-17	Letter dated February 5, 2013 – CP Submitting Letter of Comment
D-1-18	Letter dated February 27, 2013 – CP Submitting Letter of Comment
D-1-19	Letter dated February 27, 2013 – CP Submitting Letter of Comment Regarding Third Round of Information Requests
D-1-20	Submitted at Oral Hearing March 6, 2012 - CP Submitting Letter of Comment
D-1-21	Submitted at Oral Hearing March 7, 2012 - CP Submitting Letter of Comment

Exhibit No.	Description
D-1-22	Letter received March 8, 2012 - CP Submitting Petition contact details on petition redacted on web submission only
D-1-23	Letter received March 13, 2012 - CP Submitting Letter of Comment
D-1-24	Letter received March 15, 2012 - CP Submitting Letter of Comment
D-1-25	Letter received March 15, 2012 - CP Submitting Letter of Comment
D-2	**AULD, HELGA (HA)** Letter Dated August 30, 2012 – Request for Interested Party Status by Helga Auld
D-2-1	PENDING Submitted at Community Input Session in Trail November 6, 2012 - - HARD COPY SUBMISSION OF Helga Auld
D-3	**COMO, MARIO AND EILEEN (MEC)** Letter Dated August 22, 2012 – Request for Interested Party Status by Mario Como and Eileen Como
D3-1	PENDING Submitted at Community Input Session in Trail November 6, 2012 - HARD COPY SUBMISSION OF Eileen and Mario Como
D-4	**DOUCET, STEVE (SD)** Letter Dated September 7, 2012 – Request for Interested Party Status by Steve Doucet
D-5	**LOUISE, LINDA (LL)** Letter Dated September 7, 2012 – Request for Interested Party Status by Linda Louise
D-6	**MAGNER, GERHARD (GM)** Letter Dated September 6, 2012 – Request for Interested Party Status by Gerhard Magner
D-6-1	Letter dated October 26, 2012 - GM Submitting Comment
D-7	**NICHOLAS, JUDY (JN)** Letter Dated September 5, 2012 – Request for Interested Party Status by Judy Nicholas
D-7-1	Letter Dated February 5, 2013 – JN Submitting Letter of Comment
D-7-2	Letter received March 13, 2012 - JN Submitting Letter of Comment
D-8	**PALUCK, CLIFF** Letter Dated September 16, 2012 – Request for Interested Party Status by Cliff Paluck
D8-1	PENDING Submitted at Community Input Session in Trail November 6, 2012 - - HARD COPY OF SUBMISSION OF Cliff Paluck

Exhibit No.	Description
D-9	**RAYMOND, MARGARET (MR)** Letter Dated August 23, 2012 – Request for Interested Party Status by Margaret Raymond
D-10	**SIMONET, SARAH (SS)** Letter Dated August 24, 2012 – Request for Interested Party Status by Sarah Simonet
D-11	**THE VALLEY VOICE (VV)** Letter Dated September 12, 2012 – Request for Interested Party Status by Jan McMurray
D-12	**PONGRATZ-DOYLE, JEANETTE** Letter Dated September 17, 2012 – Request for Interested Party Status by Jeanette Pongratz-Doyle
D-13	**TOWN OF OLIVER (TO)** – Web Registration Dated February 18, 2013 – Request for Interested Party Status by Cathy Cowen

LETTERS OF COMMENT

E-1	Stein, C – Letter of Comment received August 1, 2012
E-2	Sadler, S and Hetman, T – Letter of Comment dated August 14, 2012
E-3	Moffet, J – Letter of Comment dated October 24, 2012
E-4	Louise, L - Submitted at Community Input Session in Trail November 6, 2012 - HARD COPY SUBMISSION OF LINDA LOUISE
E-5	Helfer , M - Submitted at Community Input Session in Trail November 6, 2012 - HARD COPY SUBMISSION OF MARY-LIN HELFER WITH ATTACHED PETITIONS contact details on petition redacted on web submission only
E-6	Boutet, S - Submitted at Community Input Session in Trail November 6, 2012 - HARD COPY SUBMISSION OF SAMANTHA BOUTET
E-7	Russell, K - Submitted at Community Input Session in Trail November 6, 2012 - HARD COPY SUBMISSION OF KIM RUSSELL
E-8	Fields, D - Submitted at Community Input Session in Trail November 6, 2012 - HARD COPY SUBMISSION OF DAPHNE FIELDS
E-9	Gallatin, A - Submitted at Community Input Session in Trail November 6, 2012 - HARD COPY SUBMISSION OF ANNETTE GALLATIN

Exhibit No.	Description
E-10	Bowles, P - Submitted at Community Input Session in Trail November 6, 2012- HARD COPY SUBMISSION OF PAUL BOWLES
E-11	Gay, M - Submitted at Community Input Session in Trail November 6, 2012- HARD COPY SUBMISSION OF MARY GAY
E-12	Catalano, R - Submitted at Community Input Session in Trail November 6, 2012- HARD COPY SUBMISSION OF ROGER CATALANO
E-13	Westbury, G - Submitted at Community Input Session in Trail November 6, 2012- HARD COPY SUBMISSION OF GARY WESTBURY
E-14	Baker, L and Conner, R - Submitted at Community Input Session in Trail November 6, 2012- HARD COPY SUBMISSION OF RALPH CONNER AND LILLIAN BAKER
E-15	Marshall, F - Submitted at Community Input Session in Trail November 6, 2012- HARD COPY SUBMISSION OF FRED N.J. MARSHALL
E-16	Tyl, Ivo - Submitted at Community Input Session in Osoyoos November 7, 2012- HARD COPY SUBMISSION OF IVO TYL
E-17	Voakes, R-M - Submitted at Community Input Session in Osoyoos November 7, 2012 - HARD COPY SUBMISSION OF ROSE-MARIE VOAKES
E-18	Town of Osoyoos - Submitted at Community Input Session in Osoyoos November 7, 2012- HARD COPY SUBMISSION OF MICHAEL RYAN, TOWN OF OSOYOOS
E-19	MCQuarrie, V - Submitted at Community Input Session in Osoyoos November 7, 2012- HARD COPY SUBMISSION OF VIRGINIA MCQUARRIE, WITH ATTACHED PETITIONS contact details on petition redacted on web submission only
E-20	Turek, V - Submitted at Community Input Session in Osoyoos November 7, 2012- HARD COPY SUBMISSION OF VERA TUREK
E-21	McCavour, P - Submitted at Community Input Session in Osoyoos November 7, 2012- HARD COPY SUBMISSION OF PAUL McCAVOUR
E-22	Winfrey, F - Submitted at Community Input Session in Osoyoos November 7, 2012- HARD COPY SUBMISSION OF FLORENCE WINFREY
E-23	Nicholas, J - Submitted at Community Input Session in Osoyoos November 7, 2012- HARD COPY SUBMISSION OF JUDY NICHOLAS

Exhibit No.	Description
E-24	Sutherland, A - Submitted at Community Input Session in Osoyoos November 7, 2012- HARD COPY SUBMISSION OF AGNES SUTHERLAND
E-25	PENDING Zita, S - Submitted at Community Input Session in Osoyoos November 7, 2012- HARD COPY SUBMISSION OF SUSAN ZITA
E-26	King, Skip Submitted at Community Input Session in Osoyoos November 7, 2012- HARD COPY SUBMISSION OF SKIP KING
E-27	Delagran, G - Submitted at Community Input Session in Osoyoos November 7, 2012- HARD COPY SUBMISSION OF GEORGINA DELAGRAN
E-28	Enns, M - Submitted at Community Input Session in Kelowna November 8, 2012 - HARD COPY SUBMISSION OF MS. MARTY ENNS
E-29	Kergan, C - Submitted at Community Input Session in Kelowna November 8, 2012- HARD COPY SUBMISSION OF CAROL KERGAN
E-30	Bleiler, G - Submitted at Community Input Session in Kelowna November 8, 2012- HARD COPY SUBMISSION OF GERALD BLEILER
E-31	Allan, B - Submitted at Community Input Session in Kelowna November 8, 2012- HARD COPY SUBMISSION OF BEVERLY ALLEN
E-31-2	Submitted at Oral Hearing March 11, 2012 – Letter of Comment and Petitions contact details on petition redacted on web submission only
E-31-3	Submitted at Oral Hearing March 15, 2012 – LETTER DATED MARCH 14, 2013 FROM B. ALLEN
E-31-4	Letter received March 6, 2013 – B.Allen Submitting Comments
E-32	Popp, S - Submitted at Community Input Session in Kelowna November 8, 2012- COPY OF PHOTOGRAPHS OF METERS WITH ATTACHED SKETCH from STEFAN POPP
E-33	Miles, R - Submitted at Community Input Session in Kelowna November 8, 2012- HARD COPY SUBMISSION OF ROBERT MILES
E-34	Pitman, E - Submitted at Community Input Session in Kelowna November 8, 2012- HARD COPY SUBMISSION OF EDITH PITMAN

Exhibit No.	Description
E-35	Roth, D - Submitted at Community Input Session in Kelowna November 8, 2012- HARD COPY SUBMISSION OF DONNA ROTH
E-36	Kapchinsky, R - Submitted at Community Input Session in Kelowna November 8, 2012- HARD COPY SUBMISSION OF RORY KAPCHINSKY
E-37	Moore, J – Letter of Comment dated August 15, 2012
E-38	Dueck, D and T– Letter of Comment dated August 30, 2012
E-39	Schoof, R and H – Letter of Comment dated August 31, 2012
E-40	Loftus, B – Letter of Comment dated September 1, 2012
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E-42	Young, L – Letter of Comment dated November 16, 2012
E-43	Beck, R – Letter of Comment dated September 3, 2012
E-44	Dansereau, A – Letter of Comment dated September 4, 2012
E-45	Bibby, N – Letter of Comment dated September 6, 2012
E-46	Jones, P and C – Letter of Comment dated September 5, 2012
E-47	Snider, L – Letter of Comment dated September 5, 2012
E-48	Charman, M – Letter of Comment dated September 7, 2012
E-49	Poulin, M and Trotter, P – Letter of Comment dated September 7, 2012
E-50	McNeil, T and G – Letter of Comment dated September 11, 2012
E-51	Nickisch, L – Letter of Comment dated September 11, 2012
E-52	Roberts, S – Letter of Comment dated October 25, 2012
E-53	Iannella, E – Letter of Comment dated October 30, 2012
E-54	Residents of Oliver – Letter of Comment dated October 31, 2012
E-55	Iannella, T – Letter of Comment dated October 30, 2012
E-56	Ostrikoff, S – Letter of Comment dated November 5, 2012

Exhibit No.	Description
E-57	Mufford – Letter of Comment dated November 8, 2012
E-58	Dahl, E – Letter of Comment dated November 12, 2012
E-59	Hook, A – Letter of Comment dated November 19, 2012
E-60	Duerichen, D – Letter of Comment dated November 22, 2012
E-61	Protheroe, T – Letter of Comment dated November 24, 2012
E-62	Morrish, H – Letter of Comment dated November 29, 2012
E-63	Mann, D – Letter of Comment dated December 1, 2012
E-64	Sharp, C – Letter of Comment dated November 9, 2012
E-65	Janko, D – Letter of Comment dated September 29, 2012
E-66	Form Letters of Comment (73 names)
E-67	McSwan, K – Letter of Comment dated October 3, 2012
E-68	Doucet, Sandra – Letter of Comment dated October 2, 2012
E-69	Currie-Johnson, P – Letter of Comment dated November 8, 2012
E-70	Verona, J and Jaynson, T – Letter of Comment dated November 9, 2012
E-71	Pallett, A – Letter of Comment dated November 9, 2012
E-72	Di Luorio, K – Letter of Comment dated November 18, 2012
E-73	Jensen, E and R – Letter of Comment dated December 5, 2012
E-74	Morrish, H – Letter of Comment dated December 10, 2012
E-75	Chapman, L – Letter of Comment dated December 3, 2012
E-76	Form Letters of Comment (29 names)
E-77	Form Letters of Comment (35 names)
E-78	Lepp, Frances E., Letter of Comment and Petitions November to December 2012 contact details on petition redacted on web submission only
E-79	Benoit, L and Chabot, A – Form Letter and Comment dated November 6, 2012

Exhibit No.	Description
E-80	Prince, A – Form Letter and Comment dated December 1, 2012
E-81	Munns, P – Form Letter and Comment dated dated November 28, 2012
E-82	Williams, D - Comment and Form Letter dated November 5, 2012
E-83	Form Letters of Comment (8 names)
E-84	Nicholas, J - Petitions October 2012 to January 2013 contact details on petition redacted on web submission only
E-85	Roth, D – Letter of Comment December 10, 2012
E-86	East, B – Letter of Comment November 12, 2012
E-87	MacLeod, R – Letter of Comment August 31, 2012
E-88	Council for the Village of Montrose – Letter of Comment August 23, 2012
E-89	Krohman, M and Kratky, L – Letter of Comment August 22, 2012
E-90	Clapp, P – Letter of Comment November 25, 2012
E-91	Regional District of Kootenay Boundary Board of Directors – Letter of Comment December 5, 2012
E-92	Janzen, A – Letter of Comment January 9, 2013
E-93	Janzen, M and P – Letter of Comment January 8, 2013
E-94	Johnson, E – Letter of Comment received November 27, 2012
E-95	Kaslo and Area Chamber of Commerce – Letter of Comment received December 5, 2012
E-96	Council of the Village of Kaslo– Letter of Comment received December 6, 2012
E-97	O'Reilly, D – Letter of Comment January 10, 2013
E-98	Rooney, S – Letter of Comment December 16, 2012
E-99	Turner, J - Letter of Comment, Photographs from meeting, newspaper article and meeting notice, petition and form letters received January 23, 2013 contact details on petition redacted on web submission only

Exhibit No.	Description
E-100	Karow, Hans - Letter of Comment and Petitions received January 28, 2013 contact details on petition redacted on web submission only
E-101	Beaulac, C and E – Letter of Comment January 23, 2013
E-102	DeNarda, L – Letter of Comment January 12, 2013
E-103	El Campanario B and B – Letter of Comment January 12, 2013
E-104	Gates, R – Letter of Comment September 7, 2012
E-105	Hatings, P – Letter of Comment January 14, 2013
E-106	McKay, D – Letter of Comment September 8, 2012
E-107	McKay, J and A – Letter of Comment received January 18, 2013
E-108	Rioux, T – Letter of Comment September 1, 2012
E-109	Robertson_J – Letter of Comment August 16, 2012
E-110	Sinclaire, C – Letter of Comment January 14, 2013
E-111	Bach, H and C – Letter of Comment January 14, 2013
E-112	Copeland, B and R – Letter of Comment January 14, 2013
E-113	Eikanger, D and F – Letter of Comment January 10, 2013
E-114	Fields, D - Petitions received January 28, 2013 contact details on petition redacted on web submission only
E-115	Roberts, S – Letter of Comment January 20, 2013
E-116	Form Letters of Comment (26 names) January 2013
E-117	Abott, R – Letter of Comment February 1, 2013
E-118	Taylor, F – Letter of Comment February 1, 2013
E-119	Zita, S – Letter of Comment September 7, 2012
E-120	Oliver Senior Center Society – Letter of Comment September 18, 2012
E-121	Howse, C – Letter of Comment July 29, 2012

Exhibit No.	Description
E-122	Gravelle, S – Letter of Comment August 17, 2012
E-123	Fields, D. – Petition
E-124	Nutter, H. and J. – Letter of Comment February 8, 2013
E-125	Tresek, J. – Letter of Comment November 9, 2012
E-126	Willness, D. – Letter of Comment February 5, 2013
E-127	Hampson, P. & L. – Letter of Comment dated February 15, 2013
E-128	Hopkins, D. & J. – Letter of Comment dated February 15, 2013
E-129	Hollihn, M. – Letter of Comment dated February 17, 2013
E-130	Lawrence, L. & C. – Letter of Comment dated February 25, 2013
E-131	Slosmanis, B. – Letter of Comment dated February 17, 2013
E-132	Jeffs, R., Long, A., Hammond H and S., Elder, B and R.G. – Form Letters of Comment received February 18, 2013
E-133	Reibin, K., – Letter of Comment dated February 21, 2013
E-134	Kaszuba, S and E., - Form Letter of Comment dated February 17, 2013
E-135	Stoushnow, V., – Form Letter of Comment dated February 17, 2013
E-136	Mackay, J., – Form Letter of Comment dated February 25, 2013
E-137	Schantz, U., – Form Letter of Comment and Petition dated February 22, 2013
E-138	Fields, D Petitions received February 27, 2013 contact details on petition redacted on web submission only
E-139	Form Letters of Comment (10 names) received January 28, 2013
E-140	Form Letters of Comment (70 names) received February 25, 2013
E-141	Rooney, S - Petitions and Letter dated February 22, 2013 contact details on petition redacted on web submission only
E-142	Lang, A - Petitions and Letter dated February 21, 2013 contact details on petition redacted on web submission only

Exhibit No.	Description
E-143	Form Letters of Comment (5 names) received February 25, 2013
E-144	Johansson, O - Letter of Comment dated March 3, 2013
E-145	Adams, G and G - Letter of Comment dated March 4, 2013
E-146	Anderson, L - Form Letter of Comment dated March 1, 2013
E-147	Conway, G - Letter of Comment dated March 8, 2013
E-148	Curran, L - Letter of Comment dated March 4, 2013
E-149	Currie, G – Form Letter of Comment dated March 4, 2013
E-150	Davidson, C - Letter of Comment dated March 4, 2013
E-151	Davis, K – Form Letter of Comment dated March 2, 2013
E-152	Idle, M - Letter of Comment dated March 6, 2013
E-153	Jonkheid, J and JJ Steenberg- Letter of Comment dated February 28, 2013
E-154	Kenny, R - Letter of Comment dated March 4, 2013
E-155	Klassen, K - Form Letter of Comment dated March 3, 2013
E-156	Lang, A - Letter of Comment dated March 7, 2013
E-157	Martin, M - Form Letter of Comment dated March 2, 2013
E-158	Nellestijn, G and A - Form Letter of Comment dated February 28, 2013
E-159	Ray, T - Form Letter of Comment dated February 28, 2013
E-160	Regional District Okanagan Similkameen Letter of Comment dated February 25, 2013
E-161	Richer, F - Letter of Comment dated March 2, 2013
E-162	Slocan Park Care Society - Letter of Comment dated March 6, 2013
	Exhibit numbers E-163 through E-165 were not issued
E-166	Catalano, R - Petitions received March 4, 2013 contact details on petition redacted on web submission only

Exhibit No.	Description
E-167	Sagewood Mobile Home Park – Petitions and Letter received March 5, 2013 contact details on petition redacted on web submission only
E-168	Petitions received February 28, 2013 - contact details on petition redacted on web submission only
E-169	Lerch, Bob - Letter of Comment dated February 22, 2013
E-169-1	Lerch, Bob - Letter of Comment dated February 27, 2013
E-170	White, C - Form - Letter of Comment dated March 6, 2013
E-171	Vanzhov, F - Letter of Comment dated February 28, 2013
E-172	Tatum, P- Letter of Comment dated February 28, 2013
E-173	Taylor, R - Letter of Comment dated March 4, 2013
E-174	Health Action Network Society - Letter of Comment dated March 14, 2013

TAB 15

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FortisBC Energy Inc.

2017 Long Term Gas Resource Plan

Decision
and Order G-39-19

February 25, 2019

Before:
K. A. Keilty, Commissioner/Panel Chair
A. K. Fung, QC, Commissioner
R. D. Revel, Commissioner

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natural gas demand and reliability requirements taking into consideration the cost to FEI's customers over the 20-year planning horizon (2017-2036).[5]

1.2 Application and Order Sought

On December 14, 2017, FEI filed its 2017 LTGRP for review by the BCUC. FEI states the 2017 LTGRP is consistent with the applicable sections of the UCA and the BCUC's Resource Planning Guidelines, and complies with directives from the BCUC arising from the acceptance of FEI's 2014 LTRP in Order G-189-14 (2014 LTRP Decision).[6]

FEI states the 2017 LTGRP:

- analyzes the external regulatory, policy and planning environment within which FEI operates;
- compares annual and peak energy demand forecasts against current resource capabilities, and evaluates the potential for demand reduction with Demand Side Management (DSM) initiatives;
- evaluates gas supply and system infrastructure options for meeting forecast customer needs under different scenarios; and
- includes an action plan that identifies the activities that FEI intends to take during the first four years of the 20-year planning horizon.

FEI submits this 2017 LTGRP will enable it to achieve the objective of providing cost-effective, secure and reliable energy for its customers.[7]

FEI requests acceptance of the 2017 LTGRP under Section 44.1(6) of the UCA and is not seeking approval of any particular elements of the plan. FEI states that any requests for approval of specific resource needs identified within this plan will be further evaluated and brought forward through a separate application to the BCUC if warranted in the future. FEI argues the LTGRP is not a substitute for the analysis done to support specific resource acquisitions or projects in the future, but rather it helps to inform the acquisition process.[8]

1.3 Legislative Framework

Section 44.1 of the UCA establishes the BCUC's framework for review and acceptance of FEI's 2017 LTGRP. Section 44.1(2) provides that FEI must file a long-term resource plan that includes all of the following:

(a) An estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan;

(b) A plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures;

(c) An estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures;

(d) A description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand referred to in paragraph (c);

[5] Exhibit B-1, p. 1.
[6] Ibid.
[7] Ibid.
[8] Ibid.

(e) Information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to in paragraph (c);

(f) An explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures; and

(g) Any other information required by the BCUC[9].

With respect to any other information required by the BCUC, the Panel agrees with FEI's submission[10] and finds relevant "other information" to include the information that the 2014 LTRP Decision directed FEI to include in the next LTRP. An additional element of "other information" includes consideration of BCUC's Resource Planning Guidelines which provide guidance regarding information to be included in a resource plan.[11]

Since the BCUC established a process to review FEI's 2017 LTGRP[12], sections 44.1(6) and (7) of the UCA require that after reviewing the plan, the BCUC must accept the plan, if the BCUC determines that carrying out the plan would be in the public interest, or reject the plan (in whole or in part). In determining whether the 2017 LTGRP is in the public interest, the BCUC must consider whether the following considerations under section 44.1(8) of the UCA support acceptance:

(a) The applicable of British Columbia's (BC) energy objectives;

(c) Whether the plan shows that FEI intends to pursue adequate, cost-effective demand-side measures; and

(d) The interests of persons in BC who receives or may receive service from FEI.

In the Terasen Utilities 2010 LTRP Decision, the BCUC determined that section 6 and 19 of the *Clean Energy Act* (CEA) only apply to electric utilities and therefore, section 44.1(8)(b) is not relevant to FEI's section 44.1 applications.[13] The Panel concurs with the determination of the 2010 LTRP Decision in this regard.

1.4 2014 LTRP Decision

On December 3, 2014, the BCUC issued the 2104 LTRP Decision accepting the 2014 LTRP. The 2014 LTRP Decision provided a number of directives related to information to be included in the next LTRP which the BCUC directed FEI to file on or before June 30, 2017.[14] A list of these directives is included in Appendix A in this decision.

1.5 Regulatory Process

On February 7, 2018, the BCUC established a written public hearing process for the review of FEI's 2017 LTGRP.[15] The regulatory timetable established outlined that further process would be determined following two rounds of information requests (IRs) and included a deadline for Intervener notice on filing intervener evidence. The B.C. Sustainable Energy Association and Sierra Club BC (BCSEA) provided notice that it intended to file expert evidence in this proceeding regarding FEI's long-term demand-side management plan. BCSEA's filing of Intervener Evidence was followed by IRs on Intervener Evidence. FEI filed Rebuttal Evidence followed by IRs on Rebuttal Evidence, prior to the final arguments phase of the proceeding.

[9] Exhibit B-1, p. 92.
[10] FEI Final Argument, para. 8.
[11] BCUC Resource Planning Guidelines, pp. 1-2.
[12] Section 44.1 (5) states the commission may establish a process to review a long-term resource plan. By Order G-33-18, dated February 7, 2018, the BCUC established a written public hearing process for the review of FEI's 2017 LTGRP.
[13] Terasen Utilities 2010 LTRP Decision, p. 16.
[14] 2014 LTRP Decision, p. 46.
[15] Order G-33-18.

TAB 16

British Columbia Utilities Commission

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Pacific Northern Gas (N.E.) Ltd.

Application for a Certificate of Public Convenience and Necessity to Implement Automated Meter Reading Infrastructure

---

Decision
and Order C-3-20

November 9, 2020

Before:
W. M. Everett, Q.C., Panel Chair
C. Brewer, Commissioner
R. I. Mason, Commissioner

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Executive summary

Pacific Northern Gas (N.E.) Ltd. (PNG(NE)) is a public utility operating natural gas distribution infrastructure serving over 21,000 residential, commercial and industrial customers in Northeastern British Columbia. On March 25, 2020, PNG(NE) filed an Application with the British Columbia Utilities Commission (BCUC) seeking a Certificate of Public Convenience and Necessity (CPCN) pursuant to sections 45 and 46 of the *Utilities Commission Act* (UCA) for the implementation of Automated Meter Reading (AMR) Infrastructure (Project).

On April 9, 2020, the BCUC established a written process to review PNG(NE)'s Application. The British Columbia Old Age Pensioners' Organization *et al.* (BCOAPO) registered as an intervener and participated in the proceeding. One letter of comment was also submitted. The regulatory review process included two rounds of BCUC and intervener written information requests followed by written final and reply arguments.

PNG(NE) proposes to update and replace the current manual read meter infrastructure for the residential and commercial customers in its service territory with automated remote-read AMR infrastructure. Currently, PNG(NE) uses meter reading employees to manually read customers' meters each billing cycle. PNG(NE) submits that there are several benefits to replacing the current manual meter reading with an automated system, including operational efficiency, worker safety and cost savings. PNG-West had successfully conducted an AMR pilot project in its service territory in 2018.

PNG(NE) evaluated both Advanced Metering Infrastructure (AMI) and two AMR project technologies from two different vendors. PNG(NE) proposes to implement the Itron 500G Encoder Receiver Transmitter (ERT) module technology as part of its preferred AMR infrastructure solution including vehicle-mounted radio transceivers to collect data and a Field Deployment Manager (FDM) interface at the PNG(NE) central server. The Panel finds that PNG(NE) has established the need for the Project to upgrade its meters to AMR infrastructure and that PNG(NE)'s choice of AMR technology and the selection of Itron Canada Inc. as the supplier to be reasonable.

The implementation of the Project has a positive net present value (NPV) of approximately $2.1 million over a 20-year term, equating to a rate impact of an $8 annual savings for the average residential ratepayer. Key project risks include inclement weather during project implementation and the sensitivity of the NPV analysis to the number of meter-reading employees and vehicles eliminated post-implementation. The Panel finds that PNG(NE) has estimated the Project on a basis consistent with the CPCN Guidelines, and further finds that overall, both capital costs and changes in operating costs are reasonable.

PNG(NE) provides for customers to opt-out of the AMR technology both before and after project implementation. Customers opting-out after the project is implemented will be charged an opt-out fee and all customers opting-out will be charged ongoing manual meter reading fees. The Panel finds that PNG(NE)'s opt-out provision for customers who do not want AMR installed is reasonable.

The Panel considered safety, cost savings, the *Clean Energy Act* and Regulations in determining that the public convenience and necessity require that the Project proceed. Pursuant to section 45 of the UCA, the Panel grants a CPCN to PNG(NE) for the Project.

1.0 Introduction

1.1 Background

On March 25, 2020, Pacific Northern Gas (N.E.) Ltd. (PNG(NE)) filed an Application with the British Columbia Utilities Commission (BCUC) seeking a Certificate of Public Convenience and Necessity (CPCN) pursuant to sections 45 and 46 of the *Utilities Commission Act* (UCA) for the implementation of Automated Meter Reading (AMR) Infrastructure (Project) (Application).[1]

1.2 The Applicant

PNG(NE) owns and operates a natural gas distribution system and provides natural gas service to over 21,000 residential, commercial and industrial customers in the British Columbia municipalities of Fort St. John, Dawson Creek and Tumbler Ridge, as well as in the rural areas of Doe River, Pouce Coupe, Rolla, Tomslake, Taylor and Pink Mountain.[2]

PNG(NE) is a subsidiary of Pacific Northern Gas Ltd. (PNG) which is, in turn, a wholly-owned subsidiary of AltaGas Canada Inc. (ACI). On October 21, 2019, ACI announced that it had concluded a definitive agreement with the Public Sector Pension Investment Board (PSPIB) and the Alberta Teachers' Retirement Fund Board (ATRFB) to acquire all the issued and outstanding common shares of ACI in an all cash transaction. On March 24, 2020, the BCUC approved the purchase by Order Number G-59-20.

1.3 Approvals Sought

In its Application, PNG(NE) applies for a CPCN to authorize the Project, to update and replace the current manual read meter infrastructure in its service territory with automated remote-read AMR infrastructure. The AMR infrastructure would be installed for PNG(NE)'s residential and commercial customers in its service territory.[3]

The estimated cost of the Project is $4.2 million.[4]

PNG(NE) requests an expedited review of its CPCN application to facilitate installation of the AMR infrastructure by the end of 2020.[5]

1.4 Regulatory Process

By Order G-86-20, dated April 9, 2020, the BCUC established a regulatory timetable for reviewing the Application which consisted of public notice, intervener registration and one round of information requests (IRs).

By Orders G-126-20, dated May 28, 2020, and G-169-20 dated June 24, 2020, the BCUC amended the regulatory timetable to include a second round of IRs, followed by final and reply arguments.

British Columbia Old Age Pensioners' Organization *et. al.* (BCOAPO) is the only registered intervener in this proceeding. A letter of comment was submitted by K. Bains (Letter of Comment).

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[1] Exhibit B-1, p. 6.
[2] Exhibit B-1, p. 6.
[3] Exhibit B-1, p. 6.
[4] Exhibit B-1, p. 6.
[5] Exhibit B-1, cover letter, p. 2.

1.5 Legal and Regulatory Framework

Section 45(1) of the UCA provides that:

> [E]xcept as otherwise provided, after September 11, 1980, a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the BCUC a certificate that public convenience and necessity.

Section 45(2) of the UCA provides that a public utility that is operating a public utility plant or system on September 11, 1980 is deemed to have received a certificate of public convenience and necessity, authorizing it to operate the plant or system, and, subject to subsection (5), to construct and operate extensions to the plant or system.

Section 46(3) provides that the BCUC may issue or refuse to issue a CPCN or may issue a CPCN for the construction or operation of a part of the proposed facility, line, plant, system or extension, and may attach terms and conditions to the CPCN. Sections 46 (3.1) and (3.2) provide that for public utilities, other than British Columbia Hydro and Power Authority (BC Hydro), the BCUC must consider:

> a) the applicable of British Columbia's energy objectives,[6]
>
> b) the most recent long-term resource plan filed by the public utility under section 44.1, if any, and
>
> c) the extent to which the application for the certificate is consistent with the applicable requirements under sections 6 and 19 of the Clean Energy Act [CEA].[7]

Section 46(8) provides that a public utility to which a CPCN has been issued is authorised, subject to the UCA, to construct, maintain and operate the plant, system or extension authorised in the CPCN.

The BCUC's CPCN Guidelines[8] provide general guidance regarding the information that should be included in a CPCN application and the flexibility for an application to reflect the specific circumstances of the applicant, the size and nature of the project and the issues raised by the application.[9]

2.0 Project Need, Alternatives and Justification

2.1 Project Need

PNG(NE)'s current manual meter reading infrastructure has been in place and substantively unchanged since PNG(NE) commenced operations. Over 99% of PNG(NE) meters in the Fort St. John, Dawson Creek, and Tumbler Ridge service areas are manually read by a meter reader. Residential meters are read on a bi-monthly basis and commercial meters are read monthly. Meter reading is performed over a series of 8 cycles, with each cycle taking approximately 3 days.[10] Additionally, manual meter reads are required when a customer completes a move-in or move-out or makes a special request for a meter read. Meter reads are also required to correct errors or verify previous reads. [11] PNG(NE)'s current meter reading workforce consists of two area managers and five full-time equivalent (FTE) meter readers.[12]

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[6] BC's energy objectives are defined in section 2 of the *Clean Energy Act*.
[7] Sections 6 and 19 of the CEA do not apply to PNG(NE).
[8] BCUC Order G-20-15, 2015 Certificate of Public Convenience and Necessity Application Guidelines https://www.bcuc.com/Documents/Guidelines/2015/DOC_25326_G-20-15_BCUC-2015-CPCN-Guidelines.pdf.
[9] BCUC CPCN Guidelines, p. 1.
[10] Exhibit B-1, p. 10.
[11] Exhibit B-1, p. 10.
[12] Exhibit B-1, p. 10.

PNG(NE) submits that it is committed to making improvements that positively impact the safety, efficiency and reliability of its natural gas service. While PNG(NE)'s existing manual meter reading infrastructure has been reliable and has produced adequate results for customers, PNG(NE)'s primary objectives for giving consideration to the automation of the meter reading function include achieving operational efficiencies and improving customer safety and satisfaction[13].

An automated meter pilot program (Pilot Program) was undertaken in PNG-West's service territory in the community of Thornhill in 2019 (PNG-West AMR Pilot Program). The PNG-West AMR Pilot Program successfully implemented AMR infrastructure for 1,700 customers over a 12-week period. The PNG-West AMR Pilot Program provided increased meter reading efficiency and accuracy, cost savings and reduced safety risks related to meter reading.[14]

2.2 Description of Project Alternatives

2.2.1 Alternative Meter Reading Technology

In its evaluation of the Project, PNG(NE) considered the following alternative meter reading technologies to replace the existing manual meter reading technology:[15]

1) Automated Meter Reading (AMR); and

2) Advanced Metering Infrastructure (AMI).

Both AMR and AMI technologies read gas meters by electronic devices installed on each meter (Encoder Receiver Transmitter, or ERTs) that collect readings from the meter and transmit them via radio signals to data collection units (DCUs). [16]

AMR is a one-way communication system that provides basic gas consumption readings at regular utility-scheduled intervals.[17] In respect of the AMR technology, meter readers are required to drive routes in vehicles equipped with a DCU in order to collect readings by radio signals. Once all readings have been gathered, the data collected by the DCU is downloaded to a server at the utility and used for customer billing purposes.[18]

AMI technology is a collection of endpoint, software, and communications network systems that enables two-way communication (ability to transmit and receive information) between a customer's meter and the utility. With AMI systems, DCUs are permanently located strategically across the service area and relay the collected data to the utility using radio signals.[19]

A key distinction between AMI and AMR is the ability to enhance system safety. PNG(NE) explains:

> An AMI endpoint [meter] may also have the ability to record a variety of other physical data (i.e. pressure, flowrate, temperature, corrosion data and methane detection) and the ability to

[13] Exhibit B-1, p. 4.
[14] Exhibit B-1, p. 25.
[15] Exhibit B-1, p. 12.
[16] Exhibit B-1, p. 14.
[17] Exhibit B-3, BCUC IR 4.3.
[18] Exhibit B-1, pp. 12-13.
[19] Exhibit B-1, pp. 13-14.

> virtually and remotely shut off the gas supply, offering the potential for further operational efficiencies for system safety and integrity.[20]

However, PNG(NE) notes that the configuration of its gas distribution system is such that there is reduced potential for benefits to be realized from remote shut-off capability. PNG(NE) states:

> PNG(NE)'s systems are relatively small with taps from upstream gas suppliers and, as such, line pack is not significant. Further, PNG(NE)'s systems do not serve large urban centres where the supply/demand balance can be managed through load shedding in the event of an upstream upset.[21]

A second key distinction between AMI and AMR is how often meter data can be collected and made available to customers. AMI-enabled meter's data can be made available the day following the reading or in some cases, with proper integration, every four to six hours.[22] Such data offers the ability to provide customers with greater details on their consumption and the potential to allow for flexible billing dates.[23] However, in its evaluation of alternatives, PNG(NE) did not determine customer interest in these potential benefits. PNG(NE) explains:

> PNG(NE) has not engaged customers regarding interest in access to real time consumption data. PNG(NE) further notes that none of the customers in the PNG-West Thornhill AMR Pilot, nor any participants in the public consultations expressed interest in terms of this type of data access. PNG(NE) submits that as real or near real time data is not as valuable for gas customers as it may be for electric customers, PNG(NE) did not consider customer interest in real time data in its assessment.[24]

2.2.1.1 Evaluation of Meter Reading Technology Alternatives

PNG(NE) evaluated a full-scale deployment of the AMR and AMI alternatives (i.e., for all active and inventoried meters), considering the capital cost of metering, collection and support systems to allow for automated meter reading, the cost of installation, and the cost of project management.[25]

Capital cost estimates for AMR deployment were in the range of $4 million to $5 million.[26] The net present value (NPV) of the proposed AMR technology over a 20-year test period was calculated to be $2.1 million to the benefit of ratepayers.[27]

PNG(NE)'s analysis of a fully-functioning AMI system indicated initial capital costs of $23.1 million[28] and results in a negative NPV of $32.7 million over a 20-year test period.[29] Removing the capital cost of the network infrastructure from the $23.1 million, the NPV is negative $10.9 million over a 20-year test period before provision for any joint use agreement payments that may be required for using a third-party's network. As well, the NPV is negative $6.2 million over a 20-year test period when removing both the capital cost of the network infrastructure and the capital and operating costs for an AMI system, and before provision for any joint use agreement payments.[30]

[20] Exhibit B-1, p. 15.
[21] Exhibit B-1, p. 15.
[22] Exhibit B-3, BCUC IR 6.6.
[23] Exhibit B-1, p. 15.
[24] Exhibit B-3, BCUC IR 6.6.1.
[25] Exhibit B-1, pp. 15-16.
[26] Exhibit B-1, p. 16.
[27] PNG(NE) Final Argument, p. 7.
[28] Final Argument pp. 8-9.
[29] PNG(NE) Final Argument, p. 8.
[30] PNG(NE) Final Argument, p. 8.

PNG(NE) concludes that an AMR solution is more cost effective than an AMI solution for automated meter reading.[31]

PNG(NE) submits that AMI is not viable in any way at this time. It states:

> PNG(NE)'s evaluation of AMI indicated significantly greater capital and operating costs, primarily for fixed communication network requirements and for system integration and for added human resources to operate and support a comprehensive AMI system. In addition to these significant additional costs and negative NPV, there were no significant incremental benefits to PNG(NE) or its customers beyond those identified for the proposed AMR Project; specifically the reduction in the number of meter reading staff and the reduction in the number of vehicles required for the meter reading function.[32]

Given the unfavourable financial indications for the AMI technology in comparison to a positive NPV of $2.1 million for the proposed AMR Project, PNG(NE) submits that there is no basis to support undertaking an AMI project at this time.[33]

In its assessment of alternatives, PNG(NE) did not quantify cost benefits from operational efficiencies related to AMI beyond automated meter reading.[34] PNG(NE) explains:

> Given the sheer magnitude of additional costs that would be borne by ratepayers under the AMI alternative, it determined that the cost benefits associated with operational efficiencies would be minor relative to the total costs and did not further attempt to quantify such efficiencies.[35]

2.2.2 AMR Vendor Alternatives

The products of Itron and Sensus, two industry leaders in the field of manufacturing meter reading technologies, were considered for PNG(NE)'s AMR alternatives. PNG(NE) regarded the technologies of the two manufacturers to be equivalent in terms of general functionality.[36]

PNG(NE) solicited bids from Itron Canada Inc. and KTI Ltd.[37]. In Canada, Itron Canada Inc. supports the Itron product line, while KTI Ltd. supports the Sensus product line.[38]

PNG(NE) describes Itron Canada Inc. as a global company offering innovative and secure utility service solutions. PNG and PNG(NE) have had a successful working relationship with Itron Canada Inc. for over 10 years using Itron meter reading hardware and software. As such, interfaces are presently in place between the Itron meters and PNG(NE)'s billing system.[39]

KTI Ltd. is a Canadian company specializing in the distribution of high quality and energy efficient products for gas, water, and electric utilities, including the Sensus product line.[40]

PNG(NE) submitted the summary of costs and rate impacts from both vendors for their AMR solution:[41]

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[31] Exhibit B-1, p. 16.
[32] PNG(NE) Final Argument, pp. 7-8.
[33] PNG(NE) Final Argument, pp. 8–9.
[34] Exhibit B-3, BCUC IR 6.5.1.
[35] Exhibit B-3, BCUC IR 6.5.2.
[36] Exhibit B-3, BCUC IR 5.1.
[37] Exhibit B-9, Cover Letter p. 4.
[38] Exhibit B-1, p. 15.
[39] Exhibit B-1, pp. 15-16.
[40] Exhibit B-1, pp. 15-16.
[41] Table prepared by Panel. Exhibit B-1, Table 2-5, p. 17; Exhibit B-3, BCUC IR 19.1; Exhibit B-9, BCUC Confidential IR 3.3.

Table 1 – Summary of Project Costs – Comparison of Itron Canada Inc. and KTI Ltd.

20 Year Evaluation Period - All Service Area	Itron Canada Inc. (Itron)	KTI Ltd. (Sensus)
Cost Impacts		
Capital Cost	$ 4,198,000	$ 5,203,108
Average Annual Incremental Costs	$ 393,000	$ 489,000
Average Annual Cost Savings	$ (673,000)	$ (661,000)
Average Annual Net Impact on Costs	$ (280,000)	$ (172,000)
Average Rate Impacts		
Incremental cost of service (per GJ)	$ (0.08)	$ (0.05)
Residential usage/year (GJ)	100.6	100.6
Impact to annual residential bill	$ (7.67)	$ (4.72)
Net Present Value of Customer Benefits	$ 2,119,493	$ 1,042,920

PNG(NE) used Itron AMR products for the PNG-West AMR Pilot Program. Based on the lower capital and incremental costs, greater anticipated financial benefits for customers, and prior established working relationships, PNG(NE) proposes proceeding with implementation of Itron AMR infrastructure from Itron Canada Inc..[42]

PNG(NE)'s chosen AMR technology is the Itron 500G Encoder Receiver Transmitter (ERT) module. PNG(NE) had originally selected the Itron 100G ERT module, which has since been discontinued by the manufacturer, but Itron Canada Inc. offered to provide PNG(NE) the more sophisticated Itron 500G ERT at the original cost quoted for the discontinued model.[43] In addition to being a fully functional AMR system, the Itron 500G module also supports extension of the system to AMI in the future, if PNG(NE) seeks to invest in upgrading its network at a later time.[44]

PNG(NE) states that the ERT selected for the AMR Project (Itron 500G ERT) has the capability to move from a mobile to a fixed network radio reading system at some point in the future, which will allow it to retain some optionality to further assess the potential of AMI. PNG(NE) explains:

> Itron's 500G ERT technology does provide an avenue for a future networked solution with BC Hydro, and could be considered if and when it meets both utilities [BC Hydro and PNG(NE)] economical goals. While no such plan presently exists, if such a project were to be contemplated, PNG(NE) would develop an appropriate business case, undertake stakeholder consultation and seek BCUC approval.[45]

PNG(NE) has selected Itron Canada Inc. as the preferred vendor to support the AMR Project with the implementation of Itron AMR technology. Itron Canada Inc. has provided PNG(NE) with a quotation for materials and services whereby it will undertake the installation and implementation of a fully functioning AMR system for all residential and small commercial customers in PNG(NE) service area.[46]

2.3 Project Justification

PNG(NE) submits a key benefit of AMR infrastructure is the reduction in costs to ratepayers, primarily due to the elimination of 5 meter-reading staff positions and corresponding reduction in vehicle usage. The Project has a positive NPV of approximately $2.1 million over the 20-year analysis period. Once fully implemented, on a net

[42] Exhibit B-1, p. 17.
[43] Exhibit B-7, response to BCUC IR 23.1.
[44] Exhibit B-7, response to BCUC IR 22.2.
[45] Exhibit B-7, BCUC IR 22.2.
[46] Exhibit B-1, p. 26.

basis, the AMR Project will provide significant operating cost savings, averaging $673,000 per year, and residential ratepayers will realize annual cost savings of approximately $8 over the 20-year life of the project.[47] Financial benefits are discussed further in Section 5 below.

Further, PNG(NE) submits the following are several non-financial (qualitative) benefits of AMR infrastructure:[48]

- AMR will protect the workforce from potential injuries from traversing ground in inclement weather and accessing customer premises.
- AMR will provide timely and accurate meter reads leading to improved accuracy in customer billing.
- Customer satisfaction is expected to increase.
- PNG(NE) submits environmental impacts will be positive from reduced vehicle emissions.
- Revenue protection will improve because actual consumption data can be analyzed for anomalies that may be indicative of gas theft. Further, AMR infrastructure has tamper technology to record meter movement.

PNG(NE) submits it is committed to making improvements that positively impact the safety, efficiency and reliability of its natural gas service. While PNG(NE)'s existing manual meter reading process has been reliable and has produced adequate results for customers, PNG(NE) has determined that the implementation of AMR technology is a prudent decision when the potential financial and operational benefits are considered.[49]

Position of Parties

BCOAPO is supportive of PNG(NE)'s desire to streamline its meter reading activities. BCOAPO states: "PNG's evidence on AMR is persuasive on this point: we accept the utility's submission that PNG's plan would increase the accuracy of its meter reads and reduce the need to use utility resources to manually adjust billing or bill based on estimates. In addition, PNG's evidence also presented qualitative benefits of timely meter readings: evidence our clients accept and support."[50]

BCOAPO submits that there is no evidence on the record that AMI is the better option and that residential ratepayers have no desire "to add unnecessarily to their energy costs absent clear and compelling evidence of either the necessity or net benefit to the and the utility…. As such, BCOAPO's position is that PNG(NE) has provided adequate evidence of its inquiries into project alternatives to satisfy residential ratepayers that we have sufficient information upon which to contrast their application with 'the roads not taken.'"[51]

In its Reply Argument, PNG(NE) acknowledges BCOAPO's support for the Project and its chosen alternative and states: "BCOAPO has expressed satisfaction that the evidence placed on record supports PNG(NE)'s proposal to proceed with the AMR Project rather than with the alternatives identified for both vendors and configurations. PNG(NE) reiterates that the proposed AMR Project utilizing mobile reads is a prudent, cost-effective solution that is supported by the opportunity to realize tangible financial and operational benefits."[52]

Panel Determination

The Panel finds that PNG(NE) has established the need for the Project to upgrade its meters to AMR infrastructure. The Panel is satisfied with the need for operational efficiencies, savings on operating costs and notes that worker safety will be improved. BCOAPO, the sole intervener, is supportive of the Project.

[47] Exhibit B-1, pp. 17-18.
[48] Exhibit B-1, pp. 11-12.
[49] PNG(NE) Final Argument, p. 3.
[50] BCOAPO Final Argument, p. 6.
[51] BCOAPO Final Argument, p. 4.
[52] PNG(NE) Reply Argument, p. 2.

The Panel finds PNG(NE)'s choice of AMR technology and the selection of Itron Canada Inc. to be reasonable.

The AMR technology proposed by PNG(NE) automates the capture of customer usage data at the meter, but still requires the data to be collected by a vehicle driving past the meter on a regular basis. The alternative AMI technology would further automate this process by delivering the billing data to PNG(NE) electronically via a telecommunications network. AMI technology captures more detailed usage data than AMR and may also be capable of performing other functions such as remote shut-off of gas by the utility. The Panel considered two issues in this regard: would there be sufficient benefits to justify implementing an AMI solution now; alternatively, if PNG(NE) were to implement an AMI solution in future, would the current proposed investment in AMR technology become redundant, leaving ratepayers paying for stranded assets.

The Panel is satisfied that there is presently no economic justification for implementing AMI. PNG(NE)'s analysis shows that no level of AMI technology implementation would have positive economic benefits at this time. A full AMI implementation would be a negative NPV of $32.7 million over 20 years. A partial implementation of AMI, excluding the telecommunications network, would reduce the risk of the assets becoming redundant, but would still have a negative NPV of at least $10.9 million over 20 years.

The Panel is also satisfied that there are insufficient non-economic benefits to justify the additional cost of the AMI solution compared to AMR. PNG(NE)'s system does not require remote shut-off or load balancing for residential customers, and there is no evidence that residential customers would benefit from more detailed or real-time usage data.

If PNG(NE) upgrades from the proposed AMR technology to an AMI solution at some point in future, it is possible some AMR assets will be made redundant. However, the degree of redundancy is reduced by PNG(NE)'s use of the more advanced Itron 500G ERT unit which has the capability to use a telecommunication network. Further, PNG(NE) will be expected to justify the move to AMI on its own merits, including consideration of the effect of any write-off of redundant assets. For these reasons, the Panel is satisfied that the risk of redundancy in choosing to implement AMR technology now is low, and that in the circumstances AMR is an appropriate choice of technology for PNG(NE).

The Panel accepts PNE(NE)'s selection of Itron Canada Inc. to implement its AMR solution. The cost of the solution involving Itron Canada Inc. is less than that using KTI Ltd., and Itron Canada Inc. has experience with PNG(NE)'s chosen Itron product. Further, Itron Canada Inc. has worked with PNG(NE) for over 10 years, and supported PNG(NE)'s AMR pilot scheme. In the Panel's view this working relationship and joint experience on the pilot mitigates some of the implementation risk associated with project.

3.0 Project Implementation

PNG(NE) proposes implementation of an AMR technology for residential and commercial customers in its service area as an alternative to current manual meter reading. Industrial customers are not within the scope of the Project as many already have advanced metering systems in place.[53]

PNG(NE)'s Manager, Operations Northeast, will have primary responsibility for overseeing the execution of the Project plan. Additional internal resources identified to support Project execution include PNG(NE) Leadership, Information Technology, Customer Billing, Customer Services and Customer Care personnel.[54]

[53] Exhibit B-1, p. 26.
[54] Exhibit B-1, p. 27.

PNG(NE) states it first informed the International Brotherhood of Electrical Workers (IBEW) Local 213 in early 2019 of its plans to examine the possibility of an AMR deployment. It adds that it will work with the IBEW to follow the collective agreement and execute a detailed plan as necessary project approvals are obtained. PNG(NE) states it has been in discussion with affected staff, and that it views ongoing communications as critical in reducing any unnecessary impact to the individuals directly affected.[55]

3.1 Project Schedule and Milestones

Implementation of the AMR Project is planned for 2020, with activation anticipated late in the fourth quarter of the year. The AMR Project is comprised of the following major components:[56]

1) Installation of the Field Deployment Manager (FDM) interface, server and work-flow configuration and testing;

2) Field installation of ERTs on existing meters; and

3) Route acceptance process testing.

The following table provides a schedule of key Project milestones, including the execution of these key components.[57]

Table 2 – Key Project Milestones

Milestone	Date (2020)
Procure Materials	August
Baseline Deployment Plan	August – September
Project Control Manual Reviewed and Approved	August – September
FDM/ERT Interfaces Complete and Tested	September – October
FDM Servers Configured and Tested	October – November
FDM System and Workflow Tested	October – November
Receipt of ERTs	October
Field Installation of ERTs	October – November
Route Acceptance Process Tested	November – December
Deployment (Up and Running)	December

3.2 Project Risks

PNG(NE) states it has been able to implement lessons learned from the PNG-West AMR Pilot Program into the planning for the PNG(NE) AMR Infrastructure Project which should reduce the risk of Project delays and cost over-runs.[58]

PNG(NE) provided a summary of project risks and mitigation strategies in its Application. PNG(NE) submits that any complex project carries potential risks and PNG(NE) will continue to focus resources on more likely and higher cost risks to ensure that mitigation efforts strike a reasonable balance between cost and risk.[59]

PNG(NE) states the structure of the contract with Itron Canada Inc. provides cost certainty on major project elements.[60] PNG(NE) adds:[61]

[55] Exhibit B-1, p. 28.
[56] Exhibit B-1, pp. 12-13.
[57] Exhibit B-1, p. 28.
[58] Exhibit B-1, p. 25; Appendix D.
[59] Exhibit B-1, p. 22.
[60] Exhibit B-1, p. 23.
[61] Exhibit B-1, p. 31.

> The Vendor A [Itron Canada Inc.] cost estimate is considered to be definitive as it is understood that Vendor A [Itron Canada Inc.] has a clear and thorough understanding of PNG(NE)'s requirements and applied this knowledge when preparing its quotation. Further, Vendor A [Itron Canada Inc.] is considered to be proficient in the implementation of AMR projects such as that proposed by PNG(NE), and hence knowledgeable of the anticipated costs to be incurred.

Field installation of the AMR infrastructure will start when site conditions are favorable. ERT installation route sequencing will be included as part of project planning. Route sequencing will be reviewed and accepted by PNG(NE) prior to installation.[62]

PNG(NE) ranked its Project risks and discusses its mitigation strategies for its two highest project risks: elimination of staff positions and installation during inclement weather.[63] The former will be addressed in section 5.2 below; the latter in this section on project implementation.

With respect to inclement weather, PNG(NE) states that weather may impact the field installation of the AMR technology if the Project encounters unfavorable weather conditions.[64] PNG(NE) confirms it has not made any provision in the AMR Project cost estimate for any additional resources required to support installation of AMR technology in the event of unfavorable weather conditions. However, it has included a 15% contingency .[65] PNG(NE) explains:

> As weather conditions at time of implementation are unknown and cannot be predicted with any certainty, costs above current estimates are extremely difficult to predict with precision. Upon successful award of the AMR Project, a full implementation plan will be developed with schedules and costs being considered. Based on weather conditions during this time, resources may be added to adapt to the weather or there may be modifications to the implementation schedule. PNG(NE) reiterates that potential incremental costs are expected to be within the 15% contingency.[66]

Position of the Intervener

BCOAPO made no submissions on the Project implementation, schedule or milestones.

Panel Discussion

The Panel considers PNG(NE)'s implementation planning for the AMR Project to be reasonable.

PNG(NE)'s project plan addresses responsibilities and staffing, schedule, risks, and communications with affected staff. The Panel views the level of detail in the plan to be satisfactory, and the assignment of primary responsibility to the manager of operations to be appropriate.

The focus on more likely and higher cost risks is also appropriate. PNG(NE) states its contract with Itron Canada Inc. "provides cost certainty on major project elements", and that the cost for Itron Canada Inc. is considered to be "definitive" based on Itron Canada Inc.'s knowledge of PNG(NE)'s requirements, its experience with PNG(NE), the Itron technology, and the pilot project. The project budget also includes a contingency of 15 percent to address the risk of capital cost overruns, such as additional effort required to implement the AMR technology in the event of unfavorable weather conditions. For these reasons, the Panel is satisfied that PNG(NE) has adequately mitigated its most likely and impactful project implementation risk.

[62] Exhibit B-1, pp. 22-23.
[63] Exhibit B-1, p. 23.
[64] Exhibit B-3, BCUC IR 14.1.
[65] Exhibit B-3, BCUC IR 14.2.
[66] Exhibit B-7, BCUC IR 24.1 Series.

4.0 Opt-Out Provisions

PNG(NE) submits that the chosen technology has minimized the radio frequency emissions and complies with Industry Canada safety standards.[67] PNG(NE) has also included provision to allow customers to opt-out of the proposed AMR technology.[68] Customers with existing manual-read meters who elect to opt-out will not have AMR technology installed, because the AMR technology module cannot be programmed with the radio off.[69] PNG(NE) notes that if a customer opts-out prior to Project deployment, there will be no opt-out fee levied.[70] Once installed, PNG(NE) proposes a one-time fee of $60 to opt-out of or opt back into the AMR infrastructure.[71]

PNG(NE) also proposes ongoing fees of $30 per reading for customers who elect to opt-out of AMR technology. This is to cover the cost of manually reading their meters. PNG(NE) further submits this proposed fee is consistent with the Customer Requested Meter Reading Fee under the Standard Fees and Charges Schedule of PNG's Consolidated Gas Sale General Terms and Conditions.[72]

PNG(NE) notes it has had zero customer requests to opt-out during the PNG-West AMR Pilot Program and anticipates any customer requests to opt-out of the proposed AMR infrastructure in its service territory to be low. In the 2013 FortisBC Inc. proceeding for a radio-off option for AMI infrastructure, an anticipated opt-out of 0.5% of customers was established as appropriate.[73] PNG(NE) further submits that if a similar opt-out percentage was applied to PNG(NE)'s service territory, a total of 93 customers would be anticipated to opt-out of AMR. This represents only a small financial impact to PNG(NE) and would not materially impact the cost savings of the AMR Project, since these customers would be charged a fee to have their meters read manually.[74]

Positions of the Parties

A Letter of Comment was received from Ms. K. Baines raising concerns about the potential adverse effect of radio frequency emissions arising from the installation of AMR.[75]

BCOAPO states:

> Our client groups have been involved in proceedings where other utilities have sought CPCN's for similar projects and as such, they think it unlikely that Ms. Kira Baines is alone in her concerns regarding the addition of AMR-related radio frequency capability to PNG(NE)'s meters. However, because this issue is so divisive and the science so contradictory our clients do not take a position on applications of this type either supporting or rejecting a project based on radio frequency related concerns.[76]

Panel Discussion

The Panel finds that PNG(NE)'s opt-out provision for customers who do not want AMR installed, is reasonable. Requirements for project reporting regarding opt-out adoption rates is detailed in Section 10.0 below.

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67 Exhibit B-1, pp. 28-29.
68 Exhibit B-1, p. 30.
69 Exhibit B-3, response to BCUC IR 15.4.
70 Exhibit B-3, response to BCUC IR 15.2.
71 Exhibit B-1, p. 30.
72 Exhibit B-1, p. 30.
73 Order G-220-13, Reasons to Decision in the FortisBC Inc. Application for a Radio-Off Advanced Metering Infrastructure Meter Option, p. 21.
74 Exhibit B-1, p. 30.
75 Exhibit E-1, Letter of Comment.
76 Exhibit E-1, Letter of Comment.

The Panel reminds PNG(NE) to file an application with the BCUC in respect of any amended tariff pages if PNG(NE) intends to implement the opt-out fee and the associated meter read fee.

5.0 Project Cost and Rate Impact

5.1 Project Cost Estimate

PNG(NE) submits that the total estimated capital cost of the proposed AMR Project is approximately $4.2 million as shown in Table 3 below. The total capital cost estimate is based upon a Class 2 level of accuracy as per the Association of Cost Engineering Guidelines 17R-97 and 18R-97 (Cost Estimating Classification System – revision November 2011) based on PNG(NE)'s assessment.[77]

Table 3 – Capital Cost Components of AMR Project[78]

Component	Cost ($)
Materials – ERT Modules	1,561,000
Materials – Mobile Collection System	72,000
Installation – ERT Retrofit	1,203,000
Project Management / Quality Assurance	302,000
	3,138,000
PST (7%)	220,000
	3,358,000
Overhead (10%)	336,000
	3,694,000
Contingency (15%)	504,000
Total Capital Cost	4,198,000

In developing its capital cost estimate, PNG(NE) obtained a quotation from its proposed product vendor, Itron Canada Inc., for materials, installation and project management/quality assurance components of the AMR Project using Itron AMR technology. The quotation was submitted confidentially to the BCUC through Appendix E to the Application.

While PNG(NE) submits that the Itron Canada Inc. cost estimate is definitive because it is proficient in implementing AMR projects and it has "a clear and thorough understanding" of PNG(NE)'s requirements, PNG(NE) states that it included a 10 percent provision for overhead costs in the total capital cost estimate. PNG(NE) submits that the overhead provision is typically included in PNG(NE)'s forecasting for capital projects and is for any internal resources that may be incidental to the base components of the project. In PNG(NE)'s opinion, there is a high likelihood that the 10 percent overhead cost will be realized.[79] In addition, PNG(NE) added a 15 percent contingency in the total capital cost estimate with respect to Itron Canada Inc.'s quotation to address the risk of capital cost overruns, submitting that the quotation is subject to certain conditions.[80] These conditions include the assumption that the project duration will not exceed nine months and the Implementation Manager will make one on-site trip every other month during the project.[81] At this point in time, PNG(NE) submits that it cannot ascertain the likelihood of whether some or all of the contingency will be realized.[82] Overall, PNG(NE) submits "it [is] prudent, conservative and appropriate" to include overhead and

[77] PNG(NE) Final Argument, pp. 5-6.
[78] Exhibit B-1, p. 31.
[79] Exhibit B-1, pp. 26, 31; PNG(NE) Final Argument, p. 6; Exhibit B-8, BCOAPO IR 3.2.
[80] Exhibit B-1, pp. 26, 31; PNG(NE) Final Argument, p. 6; Exhibit B-8, BCOAPO IR 3.2.
[81] Exhibit B-8, BCOAPO IR 3.1.
[82] Exhibit B-8, BCOAPO IR 3.2.

contingency provisions in its NPV analysis so as not to overstate the net benefits to customers of the AMR Project.[83] The net benefits to customers of the AMR Project are discussed in Subsection 5.2 below.

Positions of the Parties

BCOAPO is concerned that the capital cost estimate is overly conservative as it relates to the inclusion of a 10 percent overhead cost estimate and a 15 percent contingency on a vendor cost estimate which is otherwise characterized as definitive. However, based on the information available, BCOAPO leaves it to the BCUC's discretion to determine whether PNG(NE) has struck the appropriate balance between costs and risk.[84]

PNG(NE) replies to BCOAPO stating that the overhead and contingency provisions which have been applied are common to its forecasting for all PNG(NE)'s capital projects. PNG(NE) reiterates that it does not expect project costs to materially exceed the quotation but that the provisions remain "prudent, conservative and appropriate" in light of project cost risks associated with delayed implementation. Finally, PNG(NE) submits that there is minimal risk to customers as, irrespective of the noted provisions for overhead and contingency, only the actual costs incurred will be recovered from customers.[85]

Panel Determination

The Panel finds that PNG(NE) has estimated the Project on a basis consistent with the CPCN Guidelines, and further finds that overall, both capital costs and changes in operating costs are reasonable.

The Panel reminds PNG(NE) that the recoverability of the Project's final costs, including whether any budgeted overhead or contingency amounts were properly spent, is subject to prudency review.

5.2 Rate Impact

PNG(NE) submits that the proposed AMR Project will result in a net benefit to customers of approximately $2.1 million[86] based on a NPV analysis prepared over a 20-year evaluation period.[87] This equates to cost savings for the average PNG(NE) residential customer of approximately $8 annually.[88]

The financial benefits as determined by PNG(NE) are primarily in the form of net operating and maintenance cost savings averaging $673,000 per year, beginning in 2021. PNG(NE) states that operating cost reductions are from avoided labour and vehicle operating costs associated with the elimination of five full-time equivalent (FTE) meter reading positions and the elimination of five vehicles currently dedicated to meter reading, following AMR Project implementation. These savings are offset by some incremental maintenance costs for the new mobile collection system and the recovery of incremental capital costs in rates[89]. PNG(NE) submits that the NPV analysis is prepared over a 20-year evaluation period assuming that the AMR infrastructure assets are depreciated over their estimated useful life, which is 20 years to be consistent with its depreciation rate for meters.[90] A discount rate of 7.66 percent is used based on PNG(NE)'s pre-tax weighted average cost of capital.[91] For clarity, qualitative benefits of the AMR Project discussed in Subsection 2 are not included in the NPV analysis. Additionally, there are no incremental revenues from the AMR Project.[92]

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[83] PNG(NE) Final Argument, p. 6.
[84] BCOAPO Final Argument, p. 3.
[85] PNG(NE) Reply Argument, pp. 1-2.
[86] $2,119,493.
[87] PNG(NE) Final Argument, pp. 3, 7.
[88] PNG(NE) Final Argument, p. 3.
[89] Cost of service effects include impacts to depreciation, taxes, capital cost allowance, interest and return on equity.
[90] Exhibit B-1, p. 19.
[91] Exhibit B-1, p. 20.
[92] Exhibit B-8, BCOAPO IR 1.1.

After AMR Project implementation, PNG(NE) submits that an existing non-meter reading FTE (with an existing truck) will assume the responsibility of meter reading. Considering that PNG(NE) does not expect any additional salary expenses to be assumed by this FTE, PNG(NE) states that the NPV analysis does not include any incremental annual labour costs. However, additional fuel and maintenance costs which are equivalent to 40 percent of the vehicle fuel and maintenance costs associated with existing meter reading trucks are included.[93] The figure of 40 percent is an estimate of the time that the planned FTE will spend on meter reading activities after AMR Project implementation, as explained by PNG(NE).[94]

PNG(NE) submits, should the need arise for one additional FTE and a truck, it will result in an approximate reduction of $1.3M in the NPV of customer savings.[95]

Sensitivity Analysis

PNG(NE) examined several scenarios to evaluate the sensitivity of the net benefits to customers to a change in one or more financial assumptions, while holding all other assumptions constant. The scenarios examined and the impacts on the NPV analysis included the following:

Table 4 – Sensitivity Analysis

	Scenario	Impact on NPV analysis	PNG(NE) assessment[96]
1	Change the number of eliminated meter reading positions and vehicles by 1 FTE and 1 truck (i.e. need 1 additional FTE and 1 truck post implementation)	Reduces NPV by approximately $1.3 million[97]	"Moderate" likelihood
2	Change the timing of headcount reductions after the project is fully implemented from 3-months to 9-months (i.e. 6-month delay)	Reduces NPV by approximately $200,000[98]	"Moderate" likelihood
3	Reduce the Canadian to US dollar foreign exchange rate by $0.05	Reduces NPV by approximately $7,000[99]	"Low-Moderate" likelihood
4	Remove average 0.5% annual failure rate of equipment	Reduces NPV by approximately $100,000[100]	"Moderate" likelihood
5	Increase future vehicle fuel and maintenance costs by 10 percent	Reduces NPV by $11,648[101]	Not assessed
6	Decrease future vehicle fuel and maintenance costs by 10 percent	Increases NPV by $11,647[102]	Not assessed

PNG(NE) submits that it will focus resources in areas that rank higher in likelihood and cost impact to ensure that its mitigation efforts provide a reasonable balance between cost and risk.

93 Exhibit B-3, BCUC IR 17.2, 17.3.
94 Exhibit B-7, BCUC IR 26.3.
95 Exhibit B-1, p. 22.
96 Exhibit B-1, p. 23.
97 Exhibit B-1, p. 22, Exhibit 2-8.
98 Exhibit B-1, p. 22. Exhibit 2-8.
99 Exhibit B-1, p. 22. Exhibit 2-8.
100 Exhibit B-1, p. 22, Exhibit 2-8.
101 Exhibit B-7, BCUC IR 26.4.
102 Exhibit B-7, BCUC IR 26.4.

Position of the Parties

BCOAPO submits, "there is clear evidence that AMR will yield efficiency and accuracy benefits as well as a reasonably likely net consumer benefit of $2.178 [million] [*sic*] over the course of twenty years."[103]

Panel Discussion

PNG(NE) submits that the Project's rate impact will be positive for ratepayers over the 20-year term of the submitted NPV analysis. However, the Panel notes that the positive NPV, and associated rate impact, is most sensitive to the number of eliminated meter reading positions and eliminated vehicles. Accordingly, Project reporting detailing the actual eliminated meter reading positions and required vehicles and the associated realized financial benefits will be required. The details of Project reporting are contained in Section 10.0 below.

6.0 Consultation

PNG(NE) states during February 2020, PNG(NE) held community information sessions in each of the communities of Fort St. John, Dawson Creek and Tumbler Ridge. PNG(NE) advertised the sessions in print media circulating in these communities, including the Alaska Highway News and the Dawson Creek Mirror, and also via social media on PNG(NE)'s Twitter and Facebook interfaces.[104] In addition, in late-February 2020, PNG(NE) met with representatives from the City of Fort St. John, the City of Dawson Creek and the Peace River Regional District and provided an overview of the planned AMR Project, including a walk through of the presentation made at the Community Information Sessions.[105] PNG(NE) explains that issues raised by the public at the public information and municipal leader sessions were addressed directly at that time with project details and technology facts.[106]

With regards to First Nations consultation, PNG(NE) states that the scope of the AMR Project is limited to the installation of ERT devices on existing metering infrastructure at customer premises and does not involve any greenfield construction on any First Nations land or traditional territory. On this basis, PNG(NE) submits that no Indigenous or treaty rights are potentially affected, adversely or otherwise, as a result of the proposed project and therefore limits the duty to consult with First Nations on this Application.[107]

PNG(NE) planned to further engage with stakeholders and customer as the AMR Project progresses. PNG(NE) provides the following external consultation and communication plan milestones:

[103] BCOAPO Final Argument, p. 7; The Panel notes BCOAPO referenced a net customer benefit of $2.178 million in its final argument; however, this amount was subsequently updated by PNG(NE) to $2.119 million as stated on page 7 of PNG(NE)'s final argument.
[104] Exhibit B-1, p. 33.
[105] Exhibit B-1, p. 34.
[106] Exhibit B-3, BCUC IR 20.2.
[107] Exhibit B-1, p. 34.

Table 1: External Consultation and Communication Plan Milestones[108]

Item	Activity	Complete By
1	Community information sessions	February 2020
2	Informational meeting with local governmental agencies (City of Fort St. John, City of Dawson Creek, Peace River Regional District, District of Tumbler Ridge)	February 2020
3	Further communication with government agencies	July 2020
4	Advertisements on PNG website, social media and in local newspaper and radio, direct communication to affected customers via letters and emails	August 2020
5	Stakeholder communication on project updates	August 2020
6	Direct written communication to residential and commercial customers on field installation schedule	September 2020
7	Stakeholder communication on project completion	December 2020

PNG(NE) explains that the occurrence of the COVID-19 pandemic has required PNG(NE) to limit face-to-face interaction with the public. However, PNG(NE) is proceeding with the coordination of virtual meetings with local district representatives and municipalities to further communicate information regarding the AMR Project.[109] PNG(NE) is currently organizing web conference meetings with local municipal leaders and council members to distribute information and provide an opportunity for feedback. Further, direct communications with customers will occur upon the successful approval of the proposed Project to ensure there is widespread awareness of PNG(NE)'s planned activities. This direct communication is anticipated to include direct mailings and the provision of social media informational updates.[110]

Position of the Parties

No intervener raised issues with PNG(NE)'s consultation.

Panel discussion

The Panel is satisfied with PNG(NE)'s consultation to date, as well as its planned consultation activities.

7.0 British Columbia Government Energy Objectives

Energy Objectives

PNG(NE) submits its investment in the AMR Project is such that it does not provide direct support for the advancement of the provincial government's energy objectives as set out in Part 1 of the Clean Energy Act that primarily pertains to the matters of generation, cost and conservation of electricity.

However, PNG (NE) further submits the AMR Project generally supports the intent of British Columbia's GHG reduction objectives as driven by provisions of the following legislation:

Climate Change Accountability Act;
BC Climate Action Charter;
Carbon Tax Act; and
Utilities Commission Act.

[108] Exhibit B-1, p. 32.
[109] Exhibit B-3, BCUC IR 21.1.
[110] Exhibit B-3, BCUC IR 21.1.1.

PNG(NE) further submits the AMR Project will eliminate the use of five vehicles associated with meter reading and will therefore contribute to a significant reduction in GHG emissions related to meter reading activities.[111]

Clean Energy Act

As stated earlier, section 46(3.1) of the UCA requires the BCUC to consider "the applicable of British Columbia's energy objectives" and the extent to which the Application is consistent with the requirements of the Clean Energy Act.[112]

Section 17(6) of the *Clean Energy Act* (CEA) provides as follows:

> If a public utility, other than the authority [BC Hydro], 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.

Section 17(1) defines a smart meter as "a meter that meets the prescribed requirements, and includes related components, equipment and metering and communication infrastructure that meet the prescribed requirements."

Section 2 of the Smart Meters and Smart Grid Regulation (Smart Meter Regulation) defines the prescribed requirements as follows:[113]

> For the purposes of the definition of "smart meter" in section 17 (1) of the Act, the prescribed requirements for a meter are that it is capable of doing all of the following:
>
> (a) measuring electricity supplied to an eligible premises;
>
> (b) transmitting and receiving information in digital form;
>
> (c) allowing the authority remotely to disconnect and reconnect the supply of electricity to an eligible premises, unless
>
> i. the point of metering for the eligible premises
>
> (a) is greater than 240 volts,
> (b) is greater than 200 amperes, or
> (c) is three phase, or
>
> ii. the eligible premises
>
> (a) has a bottom-connected meter,
> (b) has an output or input pulse meter, or
> (c) has a meter that measures maximum electricity demand in watts;
> (d) recording measurements of electricity, and recording the date and time of the recording, at least as frequently as in 60-minute intervals;
> (e) being configured by the authority at a location either remote from or close to the meter;
> (f) measuring and recording measurements of electricity generated at the premises and supplied to the electric distribution system;

[111] Exhibit B-1, p. 35.
[112] UCA, sections 46(3.1)(a) & (c).
[113] https://www.bclaws.ca/civix/document/id/complete/statreg/368_2010.

(g) transmitting information to and receiving information from an in-home feedback device, unless the point of metering for the eligible premises meets any of the criteria set out in paragraph (c) (i) or the eligible premises meets any of the criteria set out in paragraph (c) (ii).

Panel Discussion

The prescribed requirements under the Smart Meter Regulation for a smart meter do not apply to gas metering. However, section 17(6) of the CEA requires the BCUC when considering an application by a public utility to consider the BC government's goal of having "other advanced meters" in use with respect to customers <u>other than those of the authority</u> [BC Hydro]. As such, while the proposed automated meters are not within the definition of smart meter in the Smart Meter Regulation, the Panel is of the view that the legislation is broad enough to include the proposed AMR meters as "advanced meters" within the meaning of section 17(6) of the CEA. [Underlining Added]

The Panel notes that BCOAPO did not comment on this aspect of the Application.

The Panel also considers the AMR Project will contribute to a reduction of GHG emissions by the reduction in the use of vehicles associated with meter reading activities.

For the foregoing reasons, the Panel considers the AMR Project and its proposed meters are aligned with the applicable energy objectives in the CEA.

8.0 PNG(NE) Long Term Resource Plan

PNG(NE)'s most recent long-term resource plan was filed with the BCUC in October 2019 as the 'PNG and PNG(NE) 2019 Consolidated Resource Plan.' The 2019 Consolidated Resource Plan does not include the AMR Project. However, PNG(NE) submits that the Project aligns with several resource plan objectives: safe, reliable service, least cost service, economic viability of utility, stable rates, environmental and socioeconomic impacts.[114]

Panel Discussion

The AMR Project will make the existing process of meter reading more efficient by automation. BCOAPO did not provide comment on the alignment of the Project with PNG(NE)'s long-term resource plan. The Panel considers that the Project is aligned with PNG(NE)'s most recently filed long-term resource plan as it will contribute to a lower the cost of service, more stable rates and reduced environmental impact.

9.0 CPCN Determination

PNG(NE) states it has demonstrated that AMR is a cost-effective meter reading solution that will enable more efficient and effective meter reads, while providing quantifiable financial benefits and a number of qualitative operational benefits. PNG(NE) submits that the proposed AMR Project is in the public interest and that the approval sought in the Application should be granted.[115]

Position of the Parties

BCOAPO is supportive of the project. BCOAPO states:

[114] Exhibit B-1, pp. 23-24.
[115] PNG(NE) Reply Argument p. 4.

> We can advise that PNG(NE) has satisfied our clients that the cost risk of this project is low and that its chosen vendor (Vendor A [Itron Canada Inc.]) appears to have provided a solid, well-informed estimate. Our clients also note there is clear evidence that AMR will yield efficiency and accuracy benefits as well as a reasonably likely net consumer benefit of $2.178M over the course of twenty years. As such, our clients support PNG(NE)'s application, subject to the comments offered above and any consideration the Commission might make of Ms. Baines' or other individuals' radio frequency concerns.[116]

Panel Determination

The Panel has found that there is a need to improve the meter reading in PNG(NE)'s service territory, that Itron Canada Inc.'s proposed Itron 500G ERT technology is the appropriate alternative, and that the capital cost of the Project is reasonable.

The Panel finds that the public convenience and necessity require that the Project proceed. The Panel, therefore, grants a CPCN to PNG(NE) for the Project to replace the current manual meter reading process for residential and commercial customers with AMR infrastructure.

10.0 Reporting

PNG(NE) submits that it had not planned formal tracking and reporting on the realization of expected financial and qualitative AMR Project benefits. However, should the BCUC request reporting on quantifiable metrics, PNG(NE) is amenable to annual reporting that would focus on the resources dedicated to meter reading (i.e. staffing and vehicles) before and after AMR Project implementation.[117]

Panel Determination

The Panel directs PNG(NE) to submit the following Project reporting:

1. Project Final Report to be filed 90 days after substantial completion of the Project, to include:
    a. Final costs using the same cost category breakdown as the Project estimate and an explanation of all material cost variances of greater than 5% to the estimate provided in this CPCN; and
    b. Any material schedule delays or issues encountered during implementation of the Project.
2. AMR Operational Report to be filed 18 months after substantial completion of the Project, to include:
    a. Operational information related to implementation of the AMR Project including:
        i. Number of meter reading FTE positions before and after substantial completion of the AMR Project;
        ii. Number of vehicles (wholly or in part) dedicated to meter reading before and after substantial completion of the AMR Project; and
        iii. Actual cost savings realised compared to anticipated cost savings as a result of:
            - reduced meter reading FTE positions,
            - reduced meter reading vehicle use, and
            - any other cost savings achieved.
    b. An analysis of the number of customers who have opted out of AMR technology including:

[116] BCOAPO Final Argument, p. 7.
[117] Exhibit B-3, BCUC IR 11 series.

i. Number of customers who opted out of AMR technology pre-implementation; and
ii. Number of customers who opted out of AMR technology post-implementation.

DATED at the City of Vancouver, in the Province of British Columbia, this 9th day of November 2020.

Original Signed By:

W. M. Everett, Q.C.
Panel Chair / Commissioner

Original Signed By:

C. Brewer
Commissioner

Original Signed By:

R. I. Mason
Commissioner

British Columbia Utilities Commission

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ORDER NUMBER
C-3-20

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

Pacific Northern Gas (N.E.) Ltd.
Application for a Certificate of Public Convenience and Necessity
To Implement Automated Meter Reading Infrastructure

BEFORE:
W. M. Everett, QC, Panel Chair
C. Brewer, Commissioner
R. I. Mason, Commissioner

on September 24, 2020

ORDER

WHEREAS:

A. On March 25, 2020, Pacific Northern Gas (N.E.) Ltd. (PNG(NE)) filed an application (Application) to the British Columbia Utilities Commission (BCUC), pursuant to sections 45 and 46 of the *Utilities Commission Act* (UCA), for approval of net capital expenditures of approximately $4.2 million to implement Automated Meter Reading (AMR) Infrastructure in its service areas (the AMR Project);

B. On April 9, 2020, by Order G-86-20, the BCUC established a regulatory timetable for the initial review of the Application, which provided for, among other things, provision of public notice, a round of BCUC Information Requests (IR), PNG(NE) responses to IRs, and intervener registration.

C. On May 26, 2020, PNG(NE) filed a letter, Exhibit B-5, to the BCUC stating PNG(NE) was not compliant with Directive 2 of Order G-86-20, to provide a copy of the Application to local municipalities and to interveners in the two most recent PNG(NE) proceedings.

D. On May 28, 2020, by Order G-126-20, the BCUC amended the regulatory timetable to extend intervener registration and solicit submissions on further process.

E. British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and Tenants Resource and Advisory Centre (collectively, BCOAPO *et al.*) registered as an intervener in the proceeding.

F. On June 24, 2020, by Order G-169-20, the BCUC amended the regulatory timetable, which provided for a subsequent round of IRs, final and reply arguments.

G. In its Application dated March 25, 2020, supporting documents dated April 3, 2020, and responses to BCUC IRs dated May 21 and July 21, 2020, PNG(NE) filed non-confidential, redacted versions of these documents requesting that certain portions of the Application, supporting documents and responses to BCUC IRs be kept confidential due to their commercially sensitive nature. The BCUC reserves its determination on the confidentiality of these documents until the reasons for its decision are issued.

H. The BCUC has considered the Application and all submissions and determines the following order is warranted.

NOW THEREFORE, for reasons to follow, the BCUC orders as follows:

1. A Certificate of Public Convenience and Necessity (CPCN) is granted to PNG(NE) for the AMR Project pursuant to sections 45 and 46 of the UCA.

2. PNG(NE) is directed to comply with all directives and reporting requirements as outlined in the reasons for decision to follow.

DATED at the City of Vancouver, in the Province of British Columbia, this 24th day of September 2020.

BY ORDER

Original Signed By:

W. M. Everett, QC
Commissioner

APPENDIX A

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

Pacific Northern Gas (N.E.) Ltd.
Application for a Certificate of Public Convenience and Necessity to
Implement Automated Meter Reading Infrastructure

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated March 26, 2020 - Appointing the Panel for the review of Pacific Northern Gas (N.E.) Ltd. Application for a Certificate of Public Convenience and Necessity to Implement Automated Meter Reading Infrastructure
A-2	Letter dated April 9, 2020 – BCUC Order G-86-20 establishing a regulatory timetable and public notice
A-3	Letter dated April 30, 2020 – BCUC Information Request No. 1 to PNGNE
A-4	**CONFIDENTIAL** – Letter dated April 30, 2020 – BCUC Confidential Information Request No. 1
A-5	Letter dated May 28, 2020 – BCUC Order G-126-20 further establishing the Regulatory Timetable
A-6	Letter dated June 24, 2020 – BCUC Order G-169-20 amending the Regulatory Timetable
A-7	Letter dated July 3, 3030 – BCUC Information Request No. 2
A-8	**CONFIDENTIAL** – Letter dated July 3, 2020 – BCUC Confidential Information Request No. 2
A-9	Letter dated October 8, 2020 – BCUC requesting information on confidentiality
A-10	Letter dated November 2, 2020 – BCUC Order G-278-20 granting confidentiality

APPLICANT DOCUMENTS

B-1	**PACIFIC NORTHERN GAS (N.E.) LTD. (PNGNE)** - Application for a Certificate of Public Convenience and Necessity to Implement Automated Meter Reading (AMR) Infrastructure dated March 25, 2020
B-1-1	**CONFIDENTIAL** - Letter dated March 25, 2020 – PNGNE Submitting Application for a CPCN to Implement AMR Infrastructure confidential Appendix E
B-2	Letter dated April 1, 2020 – PNGNE Submitting excel Appendices B and C
B-2-1	**CONFIDENTIAL -** Letter dated April 3, 2020 – PNGNE Submitting confidential excel Appendices B and C
B-3	Letter dated May 21, 2020 – PNGNE Responses to BCUC Information Request No. 1
B-4	**CONFIDENTIAL -** Letter dated May 21, 2020 – PNGNE Responses to Confidential BCUC Information Request No. 1
B-5	Letter dated May 26, 2020 – PNGNE Request Amended Timetable regarding G-86-20 Compliance Fault
B-6	Letter dated June 16, 2020 – PNGNE Submitting comment on Further Process
B-7	Letter dated July 21, 2020 – PNGNE Submitting Responses to BCUC Information Request No. 2
B-7-1	**CONFIDENTIAL -** Letter dated July 21, 2020 – PNGNE Submitting Responses to BCUC Confidential Information Request No. 2
B-7-2	**CONFIDENTIAL -** Letter dated July 21, 2020 – PNGNE Submitting Redacted Responses to BCUC Confidential Information Request No. 2
B-8	Letter dated July 21, 2020 – PNGNE Submitting Responses to BCOAPO Information Request No. 2
B-9	Letter dated October 13, 2020 – PNGNE Submitting Considerations of Requests for Confidentiality

INTERVENER DOCUMENTS

C1-1	**BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION, DISABILITY ALLIANCE BC, COUNCIL OF SENIOR CITIZENS' ORGANIZATIONS OF BC, AND THE TENANT RESOURCE AND ADVISORY CENTRE (BCOAPO) –** Letter dated May 22, 2020 – Request for Intervener Status by Leigha Worth and Irina Mis
C1-2	Letter dated June 18, 2020 – BCOAPO Submitting comment on Further Process
C1-3	Letter dated July 7, 2020 – BCOAPO Submitting Information Request No. 1 to PNGNE

INTERESTED PARTY DOCUMENTS

D-1	**FORTISBC ENERGY INC. (FEI)** - Submission dated April 6, 2020 Request for Interested Party Status

LETTERS OF COMMENT

E-1	Bains, K. - Letter of Comment dated June 6, 2020

TAB 17

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

TERASEN UTILITIES
(TERASEN GAS INC., TERASEN GAS (WHISTLER) INC.
AND TERASEN GAS (VANCOUVER ISLAND) INC.)

2010 LONG TERM RESOURCE PLAN

DECISION

February 1, 2011

Before:

D.A. Cote, Panel Chair/Commissioner
A.W.K. Anderson, Commissioner
L.A. O'Hara, Commissioner

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the current forecast does not include the full impact of Terasen EEC programs for 2012 and beyond. (Terasen Reply, p. 4)

The Commission Panel accepts the view of Terasen Utilities with respect to the lack of sector specific allocations for GHG targets and that its demand forecasts have not included the impact of additional EEC program funding. However, we are disappointed that Terasen did not broaden its scenario options and, more importantly, provide more detailed information in preparing its alternative future scenarios. The purpose of resource planning is, in part, to create a better understanding of how the actions which are being taken in the present and over the medium term will impact the long term future. To limit the number of scenarios and details related to each reduces the usefulness of the 2010 LTRP as a tool designed to further understanding. Therefore, the Panel, while finding that the 2010 LTRP is consistent with British Columbia's energy objectives notes that the opportunity to create further understanding and perhaps debate over a key component of the plan has not been explored.

2.3.2 Requirements Under Sections 6 and 19 of the Clean Energy Act

Sections 6 and 19 of the *CEA* apply to electric utilities only and accordingly are not relevant to this Application.

2.3.3 Adequate, Cost-Effective Demand-Side Measures

Section 44.1(8) (c) requires the Commission to consider whether the LTRP demonstrates an intention to pursue adequate, cost-effective demand-side measures. The Demand-Side Measures Regulation, B.C. Reg. 326/2008 provides direction as to what is required and is listed in its entirety in Appendix D.

Terasen states that EEC programs are an integral part of its drive to meet the province's current and future energy needs and ensure the efficient use of natural gas. In April, 2009 the Commission approved funding for Terasen Utilities of $41.5 million for EEC activities through the end of 2010.