Yukon Utilities Board

Board Order 2025-13

Appendix A: Reasons for Decision

September 8, 2025

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1. DECISION SUMMARY

1. On December 20, 2024, ATCO Electric Yukon and Yukon Energy Corporation (jointly the Utilities) filed an Application with the Yukon Utilities Board (Board) requesting an order approving the changes set out in the proposed 2025 Terms and Conditions of Service, Maximum Investment Levels, and Schedule D Fees and Service Charge Summary.

2. The Board has determined that not all of the requested changes are reasonable and has consequently adjusted or denied specific proposed changes. Further, the Board has decided that additional changes are needed. Because the application has not been approved as filed, the Utilities shall submit a compliance filing with respect to their proposed 2025 Terms and Conditions of Service, Maximum Investment Levels, and Schedule D Fees and Service Charge Summary within 30 days of the issuance of this Board Order.

2. INTRODUCTION

3. On December 20, 2024, the Utilities filed an Application with the Board, pursuant to the *Public Utilities Act* (the Act) and *Order-in-Council* 1995/90, requesting an order approving changes set out in the proposed 2025 Terms and Conditions of Service (T&Cs) including Maximum Investment Levels (MILs) and Schedule D Fees and Service Charge Summary (Schedule D Fees Schedule).

4. As noted in Board Orders 2025-01, 2025-02, and 2025-03, the Board considered the submissions of the Utilities and interested parties and determined that the 2025 T&Cs application would be decided by way of a written hearing rather than oral hearing. On February 18, 2025, in Board Order 2025-03, the Board provided a final process schedule which included steps allowing for two rounds of information requests and responses, the submission of intervener evidence followed by a round of information requests and responses related to same, rebuttal evidence and simultaneous written final argument followed by simultaneous written reply argument. Although the process allowed for the submission of intervener evidence, none was filed; as a result, there was no rebuttal evidence submitted.

5. The Board received approval from the Minister of Justice for this proceeding on January 14, 2025.

6. In making its decision, the Board has considered all relevant materials comprising the record of this proceeding. Accordingly, references to specific parts of the record in this *Appendix A: Reasons for Decision* are intended to assist the reader in

understanding the Board's reasoning related to a particular matter and should not be taken as an indication that the Board did not consider all relevant portions of the record.

7. The Board considers the record of this proceeding closed as of June 24, 2025.

3. OVERVIEW OF THE APPLICATION

8. The 2025 T&Cs application was filed pursuant to a Board letter, dated March 31, 2023, directing AEY to examine the need for a review of the T&Cs, MILs, and Schedule D Fees Schedule at the time of its next GRA.

9. This was because the T&Cs, MILs, and the Schedule D Fees Schedule, under which the Utilities currently provide service, were last amended effective July 1, 2011, as approved in Board Order 2011-05.[1] Prior to the 2011 update, minor revisions were approved in Board Order 2005-12,[2] which focused on clarifying definitions. Accordingly, it has been over 10 years since the last update to the T&Cs, MILs, and the Schedule D Fees Schedule. The Board determined such a review is timely.

10. As noted at the time of AEY's 2023-2024 GRA application,[3] in response to the Board March 31, 2023 letter, AEY submitted that the T&Cs are also the T&Cs of YEC. Both AEY and YEC favoured addressing the changes to the T&Cs as a standalone, limited-scope filing to be submitted as one application rather than within the context of each of their respective GRAs.

11. Consequently, in the current application, the Utilities jointly prepared the changes to the T&Cs. The MILs and the Schedule D Fees Schedule have been prepared by AEY as AEY serves most of the distribution customers in the Yukon. However, these two documents are equally applicable to all YEC distribution service customers.

12. An overview of the proposed changes is provided in the sections that follow.

3.1. Terms and Conditions of Service

13. YEC and AEY provide electrical service to customers in the Yukon under a Common Electric Service Tariff which is comprised of Rate Schedules and T&Cs approved by

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1 Board Order 2011-05: Application by Yukon Electrical Company Limited and Yukon Energy Corporation for a 2009 Joint Phase II Rate Application, April 28, 2011.

2 Board Order 2005-12: Application by Yukon Energy Corporation for Approval of 2005 Revenue Requirements.

3 AEY 2023-2024 GRA Application, PDF pages 2-3.

the Board. Specifically, the Utilities must conduct their business activities in compliance with the approved Rate Schedules and T&Cs.

14. In this application, the Utilities proposed changes to the current approved T&Cs that are intended to "modernize" the T&Cs, and enhance clarity, transparency, and understanding of the provisions under which electricity is provided. These provisions include the rights and obligations of both the utility and customer and the need to reflect the Utilities' current practices and policies, legislation, and regulation — all of which may have evolved since the time the T&Cs were last approved in 2011.

15. The Utilities proposed that the implementation of the updated T&Cs document would take effect upon the date set by the Board, which date, they suggested, should be the same date upon which the Board renders a decision on this application.[4] [5]

16. The Utilities identified the proposed changes in the following sections and their reasons for suggesting those changes:

(i) Section 3.6 Customer Generation – this section was expanded to ensure safety, compliance, and clear communication between parties, and now makes reference to the requirement for all necessary permits, licenses, and authorizations before starting or changing service.[6]

(ii) Section 4.5 Changes in Service Connections – this section now reflects an intention to better manage service connections under a broader range of conditions and scenarios, and would address, as two examples, significant load increases such as those related to Electric Vehicles and Isolated Communities.[7]

(iii) Section 4.8 Extension of Service – this section was changed to provide a clear and fair framework for cost sharing among customers requiring service extensions. A cost-sharing limit of up to $20,000 over a maximum term of five years and a limit of three customers was set, which ensures that the administrative burden is manageable, and costs are equitably distributed.[8]

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4 AEY-YEC 2025 T&Cs Application, PDF page 61.

5 AEY-YEC 2025 T&Cs Application, Terms and Conditions of Service, Clean Version, PDF pages 11-49, and Blackline Version, PDF pages 50-91. These references also include schedules A, B, C and D.

6 AEY-YEC 2025 T&Cs Application, PDF pages 5 and 62.

7 AEY-YEC 2025 T&Cs Application, PDF pages 5 and 65.

8 AEY-YEC 2025 T&Cs Application, PDF pages 5 and 67.

(iv) Section 4.13 Multiple Dwellings – this section now includes provisions for common use areas such as hallways, lobbies, laundry rooms, elevators, and parkades, and the manner under which these services will be billed. For a Multiple Dwelling, these services will be billed under the general service price schedule (non-residential) where the services are delivered through a single point. Also in Section 4.13, the definition of a residential customer was reviewed to account for situations where a single home is used for commercial purposes.[9]

(v) Section 5.2 Right of Entry, Section 5.4 Interference with Company's Facilities, Section 5.5 Customer Brushing and Section 10.3 Customer Liability – in general, these sections were changed to enhance access to the Utilities' facilities in order to prioritize safety and ensure the integrity of the Utilities' infrastructure and that the applicable requirements of the Canadian Electrical Code are met.[10]

(vi) Section 6.1 Installation [of meters] – this section was modified to allow customers more flexibility and control over available metering options.[11]

(vii) Section 11.3 Company Termination Other Than for Safety – changes to this section were made to ensure that the utilities can effectively manage and protect their infrastructure and service quality. Clarification of certain technical requirements which address specific issues that may impact service quality were included in the update.[12]

3.2. Schedule D - Fees and Service Charge Summary

17. Similar to the approved MILs, the Utilities are required to obtain Board approval for any fees and service charges to be recovered from customers. These charges are for services the Utilities provide to customers beyond those being charged through the Rate Schedules.

18. The Utilities proposed updates to Schedule D: Fees and Service Charges Summary (Schedule D Fees Schedule) to, in their view, more accurately reflect today's costs for the services it is providing to customers under its Schedule D Fees Schedule.[13]

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9 AEY-YEC 2025 T&Cs Application, PDF pages 5 and 68.

10 AEY-YEC 2025 T&Cs Application, PDF pages 5-6, 70-71 and 81-82.

11 AEY-YEC 2025 T&Cs Application, PDF pages 6 and 72-73.

12 AEY-YEC 2025 T&Cs Application, PDF pages 6 and 83-84.

13 AEY-YEC 2025 T&Cs Application, Schedule D: Fees and Service Charge Summary, Clean Version PDF page 49, and Blackline Version, PDF pages 90-91.

19. The following are the more substantive increases in fees and new fees set out in the proposed Schedule D Fees Schedule:

(i) Connection and Reconnection Fees – currently approved fees for connection and reconnection are $50 and $60, respectively, with the proposed fee to be set to $87 for both;[14]

(ii) Customer Usage Information Requests – there is currently no approved fee, with the proposed fee to be set to $75;[15]

(iii) Supplementary Meter Reads – there is currently no approved fee, with the proposed fee to be set to $11 per meter read for a Standard Meter and $87 per meter read for Non-Standard Meter;[16]

(iv) Late Payment and Disconnection – currently approved fees for collection fee and late payment charge are $30 and $25, respectively, with the proposed fee to be set to $45 for both; and,[17]

(v) Meter Disputes – currently approved fees for testing meter accuracy of either a self-contained meter and instrument meter are $100 and $200, respectively, with the proposed fees to be set at $200 and $500, respectively.[18]

20. The Utilities requested that any Schedule D Fees Schedule approved by the Board in this application continue to be updated in a no-notice application each December, for the following year, by a percentage increase equal to that of the most recent prior year CPI for Whitehorse (referred to as an annual inflation factor).[19] [20] The Utilities made a similar request for any approved MILs. This is discussed further in Section 6 of this Decision.

3.3. Maximum Investment Levels

21. An MIL is the maximum dollar amount that the Utilities can invest in a given type of new customer service connection (also referred to as a new extension project) where that investment is then added to AEY's or YEC's rate base. In cases where the actual connection costs incurred exceed the approved MIL, those excess costs are

[14] AEY-YEC 2025 T&Cs Application, PDF pages 9 and 90.
[15] AEY-YEC 2025 T&Cs Application, PDF pages 9 and 90.
[16] AEY-YEC 2025 T&Cs Application, PDF pages 9 and 90.
[17] AEY-YEC 2025 T&Cs Application, PDF pages 9-10 and 90.
[18] AEY-YEC 2025 T&Cs Application, PDF pages 10 and 90-91.
[19] AEY-YEC 2025 T&Cs Application, PDF pages 4 and 10.
[20] Utilities' Final Argument, PDF page 3.

paid for directly by the connecting customer rather than being paid for by the utility and thus by all customers.

22. In this application, AEY proposed updates to four MIL categories of new customer service connections (and their inherent rate classes). AEY confirmed that the approach it advocated for on behalf of itself and YEC undertook the preparation of the MILs study. YEC provided feedback on the approach and results of the study prior to filing[21] because the updated MILs would also be applicable to YEC. Thus, the Utilities based the recommended MIL rate proposals on the outcome of its examination of certain approaches to estimating the current cost of providing the specific new customer service connection. The Utilities' MILs are provided in Schedule B: Maximum Company Investment.[22]

23. The four MILs for new customer service connection types examined in the application are as follows:

    (i) Residential single family ($MIL per site) – the proposed MIL for a new Residential Single Family connection type is to be set to $10,347 per site, which is an increase from the current approved MIL of $1,500 per site;[23]

    (ii) Residential Multiple Dwelling ($MIL per site) – the proposed MIL for a new Residential Multiple Dwelling connection type is to be set to $2,645 per site, which is an increase from the current approved MIL of $725 per site;[24]

    (iii) General Service ($MIL per kW) – the proposed MIL for a new General Service connection type is to be set to $1,801 per kW, which is an increase from the current approved MIL of $690 per kW,[25] and;

    (iv) Street Lighting ($MIL per light fixture) – the proposed MIL for a new Street Lighting connection type is to be set to $6,649 per light fixture, which is an increase from the current approved MIL of $1,240 per light fixture.[26]

24. In all cases, the Utilities proposed the updated MILs based on a methodology that examined historical cost data for each of the specific types of service connection.

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21 YUB-AEY/YEC-1-036(c), PDF page 70.

22 AEY-YEC 2025 T&Cs Application, Schedule B: Maximum Company Investment, Clean Version, PDF page 46, and Blackline Version, PDF page 87.

23 Approved MIL: Board Order 2020-10 13 Appendix A, PDF Page 55; Proposed MIL: AEY-YEC 2025 T&Cs Application, Table 8, PDF page 101.

24 Approved MIL: Board Order 2020-10 13 Appendix A, PDF Page 55; Proposed MIL: AEY-YEC 2025 T&Cs Application, Table 13, PDF page 104.

25 Approved MIL: Board Order 2020-10 13 Appendix A, PDF Page 55; Proposed MIL: AEY-YEC 2025 T&Cs Application, Table 18, PDF page 109.

26 Approved MIL: Board Order 2020-10 13 Appendix A, PDF Page 55; Proposed MIL: AEY-YEC 2025 T&Cs Application, Table 23, PDF page 113.

(For example, the data encompassing 10 years of actual historical costs of a Residential Single Family service connection.) The historical cost data for each of the four different service connection types was inflated for each applicable year by the Handy Whitman (HW) Index and resulted in an MIL recommendation equal to the median value of a single service connection of that type. The Handy Whitman Index of Public Utility Construction Costs is a recognized measure of construction costs for public utility projects in various regions of the United States.

25. The Utilities proposed that the implementation of the updated MILs (and the Schedule D Fees Schedule discussed in the section that follows) would commence upon receipt of the Board Order and were intended to be applicable for the year 2025 onward.[27]

26. The Utilities also proposed that the MIL rate approved in this application would continue to be updated in a no-notice application each December for the following year by the same percentage increase as the Consumer Price Index (CPI) for Whitehorse increased in the year immediately prior. The proposed update process would occur in years in which either no joint Phase II application or application seeking approval of new or updated T&Cs or MILs was in front of the Board.[28] [29]

3.4. Nomenclature of Information Requests and Responses

27. The Board set a final process schedule for this proceeding through Board Order 2025-03. As part of the process schedule, the Board included process steps for information requests (IRs). The Board sent IRs to the Utilities by the deadlines identified in this Board Order using the IR numbering and party ordering format designated by the Board. The IR responses from the Utilities used a different party ordering as well as a numbering format that also did not distinguish between first- and second-round IRs. Specifically, the Utilities changed the designated order where the party asking the IR is to be identified first and the party responding to the IR is to be identified next. The Board reminds the Utilities that they are not to change the IR responses from the designated Board party ordering format. For this decision, when referencing Board IRs, the Board will follow YUB-AEY/YEC-X-YYY ordering format, where X refers to the IR round and YYY refers to the IR number. This is the designated ordering format required to be used by all parties to a proceeding when asking and responding to IRs.

27 AEY-YEC 2025 T&Cs Application, PDF page 93.

28 AEY-YEC 2025 T&Cs Application, PDF page 8.

29 Utilities' Final Argument, PDF page 3.

4. TERMS AND CONDITIONS

28. The Board will only discuss and make findings on the changes in the T&Cs that the Board considers substantive. Other changes to the T&Cs that the Board does not discuss or make findings on are approved as submitted.

4.1. Stakeholder Consultations

29. The Utilities were questioned[30] on whether they undertook any stakeholder consultations regarding the review and update of the T&Cs, MILs, and Schedule D Fees Schedule documents. The Utilities responded that although there were no formal stakeholder consultations, their day-to-day interaction with customers (through phone, e-mail, and in-person) provided a base of knowledge by which they were able to address common areas of concern.

30. The Utilities also pointed to the fact that various parties were provided copies of the Notice of Application, and thereby advised of their eligibility to participate in the current proceeding should they wish to participate and provide comment.[31]

31. Specific to the MILs, the Utilities stated they did not consider stakeholder consultation was necessary given that the MILs Study examined project cost information using common principles ensuring a proper price signal, intergenerational equity, and the utility's right to earn a fair return. Similarly, the Schedule D Fees Schedule reflects current practices and the actual work involved when providing services to customers for those specific requests.[32] [33]

32. In argument, the Utilities submitted that the proposed changes to the T&Cs included broad consideration of customer interests from working with customers on a regular basis and consideration of government requirements and processes. The Utilities added that regular interactions with customers regarding new services and extension, the connection of generating customers, and day-to-day operations of the electrical system further evidenced customer input.[34]

33. Further the Utilities argued that:

> Given the extensive customer interactions which informed the proposed changes to the T&Cs, the Utilities submit that specific customer

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30 See for example, YUB-AEY/YEC-1-001, YUB-AEY/YEC-1-003(d), YUB-AEY/YEC-1-036(d), UCG-AEY/YEC-1-001, UCG-AEY/YEC-2-001, UCG-AEY/YEC-2-019, YUB-AEY/YEC-2-1and YUB-AEY/YEC-2-011.

31 YUB-AEY/YEC-1-001, 1-003 and 1-036, PDF pages 1-2, 5-6, 69-71; UCG-AEY/YEC-1-001, PDF page 1.

32 UCG-AEY/YEC-2-001, PDF pages 1-2.

33 Utilities' Final Argument, PDF page 4-5.

34 Utilities' Final Argument, PDF page 5.

consultation during the preparation of the Application was not necessary. Stakeholders were provided with ample notice of the Application and have had an opportunity to participate and provide feedback on the proposed changes in the course of this proceeding.[35]

4.1.1. Views of interveners

34. The UCG recommended that, in future T&Cs applications, the Utilities should undertake extensive consumer consultations which would help ensure that ratepayers have a clear understanding of proposed changes and their implications.

> Such consultations would allow for a balanced approach, considering both the utilities' financial requirements and the public's ability to cope with rising costs. This dialogue could include workshops, surveys, and public input through the utilities web page or Facebook to gather feedback and build consensus on contentious issues like MIL allocations and service charges.[36]

35. The UCG repeated several times the theme of utility engagement through consumer consultation and concern for affordability.[37]

36. Mr. Maissan indirectly discussed stakeholder consultations in his Reply Argument. In response to the Utilities' comments that the evidence was uncontroverted, Mr. Maissan said the following:

> True, no Intervenor filed evidence, however, this does not mean that the Utilities evidence in support of their Application is complete in every respect, is sufficient to support every one of their proposed changes, is fair to Customers, or is in the public interest.
>
> To the contrary I submit to the Board that there are a number of proposed changes in the Utilities' Application, as presented in my Final Argument, that are not supported by adequate evidence, or are unfair to Customers or prospective customers, or are not in the public interest.[38]

37. Mr. Maissan said that when customers interact with the Utilities, the customers focus on the matter of concern and are not required to answer a survey about other

[35] Utilities' Final Argument, PDF page 6.
[36] UCG Final Argument, PDF page 5.
[37] UCG Final Argument, PDF pages 2 and 5.
[38] Mr. Maissan Reply Argument, PDF page 2.

issues covered by the T&Cs. Therefore, customer interactions cannot substitute for customer consultation.[39]

38. In its Reply Argument, the UCG submitted that the Utilities need to address the broader implications of utility management through regular ratepayer consultations. The UCG contended that the customer interactions described by the Utilities was not evidence of consultations. In the UCG view it was inconsistent on the part of the Utilities to say that stakeholders were given ample notice and opportunity to provide feedback on the proposed changes to the T&Cs and then claim that intervener recommendations lack support from evidence and should not be given any weight by the Board.[40]

4.1.2. Utilities' Reply

39. In response to the UCG assertions, the Utilities emphasize that they are engaged in regular and ongoing informal customer consultation through the various customer interactions that take place in the course of providing utility service, as detailed on the record.[41]

40. The Utilities further argued that customer consultation would not have provided significant value to the preparation of the application given the nature of the revisions and the basis for determining updated costs within the Schedule D Fees Schedule and MILs.[42]

41. The Utilities took issue with what they described as extensive new evidence contained in argument. The Utilities referred to new evidence as information obtained from internet searches, anecdotes regarding experiences of friends and acquaintances or other utility customers, new bill formatting proposals, and references filed in other proceedings.[43]

42. In the Utilities view, all evidence should have been filed earlier in the process in accordance with the schedule established for this proceeding.

43. The Utilities stated the following:

> Unsubstantiated assertions by Mr. Maissan regarding the purported motivation of the Utilities in proposing certain changes to the T&Cs, questions that were not raised in the Information Request ("IR") process, and

[39] Mr. Maissan Reply Argument, PDF page 4.
[40] UCG Reply Argument, PDF page 2.
[41] Utilities' Final Argument, PDF pages 4-5.
[42] Utilities' Reply Argument, PDF pages 4-5.
[43] Utilities' Reply Argument, PDF pages 3-4

unsupported speculation and accusations by the UCG should be given no weight.[44]

44. The Utilities requested that for procedural fairness, no weight be afforded to such evidence.[45]

4.1.3. Board Findings

45. The Board finds the consultation process described by the Utilities is lacking. The Board agrees with Mr. Mason and UCG that interactions with customers on a matter of concern does not constitute consultation. The Board considers that the Utilities' use of recollections of day-to-day interactions with customers does not put forward the views of customers. There was nothing put on the record of this proceeding of any interaction with customers framed in terms of what would work better for the customer. In addition, a stakeholder consultation on the proposed T&Cs would have afforded the Utilities specific customer feedback on the changes proposed which may have informed the proposed changes. At the very least, the Utilities would have begun a dialogue with customers on the proposed changes and garnered different perspectives if the utilities had directly asked customers about changes to the T&Cs.

46. Therefore, on a go-forward basis, for any future proposed changes to the T&Cs, MILs, or Schedule D Fees Schedule, the Utilities are directed to conduct stakeholder engagement on the proposed changes and provide documentation on the stakeholder engagement undertaken, including the feedback received from the stakeholders for each proposed change.

47. On the issue raised by the Utilities regarding new evidence in Reply Argument filed by interveners, the Board will not consider information contained in these Arguments that is not supported by the evidence contained in the T&Cs application and the responses to IRs, nor information from other proceedings on issues that are out of scope of this proceeding, such as billing statements.

4.2. Effect on Revenue Requirement

48. In response to the UCG, the Utilities clarified their view that Board approval of the proposed changes to the T&Cs, MILs, and Schedule D Fees Schedule would neither necessitate nor allow for adjustments to either AEY's or YEC's approved 2023-2024 revenue requirement. The Utilities intended to "forecast the charges using the

44 Utilities' Reply Argument, PDF page 4.
45 Utilities' Reply Argument, PDF page 4.

approved rates and apply the amount to the revenue requirement for both the fees and charges and updated MILs in their next rate application."[46]

4.2.1. Views of interveners

49. Although the UCG understood that the Utilities proposed implementing the approved T&Cs, MIL, and Schedule D Fees Schedule effective from the date of a final Board Order, the UCG recommended that "any cost changes resulting from this process should only take effect in the subsequent GRA revenue requirements to avoid creating a financial windfall for the utilities in non-test years."[47]

50. The UCG argued that the requested changes stemming from the current application should not all be implemented simultaneously but delayed until the time a full GRA review is conducted. This recommendation was in addition to the UCG advocating that the Utilities be required to consult with ratepayers with respect to any affordability issues related to each of the fee changes.[48]

4.2.2. Utilities' Reply

51. The position of the Utilities is that any approved changes to the T&Cs, including MILs and Schedule D Fees Schedule, would occur on a prospective basis and would be effective from the date the Board issues a decision on this proceeding. They argued that the implementation of new fees, on their own, are not a financial windfall for the Utilities.[49]

52. The Utilities further elaborated that they are not requesting changes to their respective 2025 revenue requirement associated with the proposed Schedule D Fees Schedule and MILs. Instead, the revenue requirement impact of the Board-approved Schedule D Fees Schedule and MILs would be reflected in their next respective General Rate Applications filed after the approval of the changes to the T&Cs.[50]

4.2.3. Board Findings

53. The Board notes that, in response to YUB-AEY/YEC-1-16 (e), the Utilities stated that a two per cent CPI increase to Schedule D Fees Schedule would result in incremental revenue for AEY of $4,220 based on historical fee collections. Similarly,

[46] UCG-AEY/YEC-1-002, PDF page 2.
[47] UCG Final Argument, PDF page 1.
[48] UCG Final Argument, PDF page 1-2.
[49] Utilities' Reply Argument, PDF page 5.
[50] Utilities' Reply Argument, PDF page 6.

for YEC, the incremental revenue would be less than $500. However, the initial increases requested by the Utilities are significantly higher.

54. Impacts on revenue requirement due to changes in MILs during non-GRA test years have not been provided.

55. The Board understands that once the Schedule D Fees Schedule and MILs are approved, the Utilities will be permitted to collect the fees and invest in any new customer service connections through the MILs in each approved amount. While any additional Schedule D Fees Schedule fees collected are over and above current approved revenue requirement, any investment in new customer service connections related to the MILs will not be reflected in the Utilities rate base until the time of their next respective GRA. However, to partially address some of the concerns expressed by the UCG, the Board directs that for all future changes to the T&Cs, including changes to MILs and the Schedule D Fees Schedule, those changes must be included within and approved as part of a GRA. Furthermore, in any GRA proceeding, any party can make inquiries, submissions, or provide any evidence with respect T&Cs issues regardless whether the Utilities have incorporated any changes to the T&Cs in that application.

4.3. Bill Presentation

56. Mr. Yee brought forward issues pertaining to bill presentation including a two-column billing format raised by Mr. Yee during the course of the AEY-YEC Rate Rebasing proceeding.

4.3.1. Utilities' Reply

57. The Utilities stated that bill presentation is outside the scope of this proceeding. The Utilities referenced one of Mr. Yee’s IRs and added that bill simplification was considered in the rate rebasing proceeding.[51]

4.3.2. Board Findings

58. As noted above, the issue of bill presentation was brought forward by Mr. Yee in the AEY-YEC Rate Rebasing proceeding. At that time, the Board ruled that some of the comments from Mr. Yee are best addressed in a GRA. The Board maintains this view and rules that issues regarding bill presentation are outside the scope of this proceeding. However, at the time of AEY’s next GRA, the Board directs that bill presentation issues be put forward in the application.

[51] Utilities’ Reply Argument, PDF pages 6-7.

4.4. Section 2.1 Definitions

4.4.1. Electricity Purchase Agreement

59. The Utilities included several new definitions in Section 2.1. One definition is as follows:

> Electricity Purchase Agreement (EPA - is a contract established between the Company and independent power producers that sets out the terms for purchasing electricity by the Company. EPAs are considered out of the scope of these Terms and Conditions. The terms and conditions of EPAs are treated independently and are confined to the contractual relationship between the customer and the electricity generator under the applicable EPA. Microgeneration customers are separate from the EPAs and referenced under "Generating Customer."[52]

60. As this term is not used in the body of the T&Cs, when asked in an IR,[53] the Utilities stated they are not opposed to removing this term from the definitions and including a statement in the body of the T&Cs stating that the T&Cs don't apply to EPAs.

4.4.2. Board Findings

61. The Board directs that the term Electricity Purchase Agreement be removed from Section 2.1 of the T&Cs.

4.4.3. Generating Customer

62. Another new term included in Section 2.1 is Generating Customer:

> "Generating Customer" – Customer with generation equipment on premises, including microgeneration entities, interconnected with the Company's Facilities.

63. Mr. Maissan argued that generating customer should be redefined to exclude single family residential units that have micro-generation facilities installed.[54]

64. The Utilities replied that:

> Interruption of service under Section 9.2 of the T&Cs may take place for several reasons, including in order to maintain the safety and reliability of the Utilities' facilities and in situations of potential overloading, insufficient

[52] AEY-YEC 2025 Application, PDF page 58.
[53] YUB-AEY/YEC-1-17(a), PDF page 37.
[54] Mr. Maissan Final Argument, PDF page 2.

supply, or other circumstances that impair the Utilities' ability to provide safe and reliable service.[55] (footnote removed)

65. The Utilities added that Mr. Maissan’s submissions regarding potential service interruptions are new evidence and should be disregarded. The Utilities then submitted that it is important to be able to interrupt any generation in accordance with Section 9.2, and concluding that micro-generation customers should be included in the definition of generating customer to ensure that all responsibilities of all generating customers are captured in the T&Cs.[56]

4.4.4. Board Findings

66. The Board questions the need for a micro-generation customer to fall within the definition of a generation customer. The record of the proceeding has not established that, under the proposed definition, micro-generators are either net producers or net consumers of electrical energy. If micro-generators are net consumers of electrical energy, then the utilities have not established a case where a micro-generation customer should be a priority for issues surrounding interruption of service. Therefore, the Board directs the Utilities to develop a separate definition for micro-generation customer and either eliminate the need for a micro-generation customer to be a priority for service interruption or provide reasons why micro-generation customers should be a priority service interruption in the compliance filing to this decision. The issue of interruption of service for micro-generating customers will be further discussed in Section 9.2.

4.4.5. Seasonal Service

67. A third definition which received comments from interveners is Seasonal Service, defined as follows:

> “Seasonal Service” – service between October 15 to April 15, or between April 16 to October 14 when the overnight temperature is forecast to drop below zero (0) degree Celsius.[57]

68. Mr. Maissan recommended the term be restated as “Seasonal Disconnection of Service”[58]

69. The Utilities did not provide any comments on this.

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55 Utilities’ Reply Argument, PDF page 7.
56 Utilities’ Reply Argument, PDF page 8.
57 AEY-YEC 2025 Application, PDF page 60.
58 Mr. Maissan Final Argument, PDF page 2.

4.4.6. Board Findings

70. The Board finds Mr. Maissan's recommendation for this definition reasonable and therefore directs the Utilities to restate the term as recommended.

4.4.7. Electric Service Regulations

71. Electric Service Regulations (ESR) was defined as the following:

> "Electric Service Regulations" – the former title of this document outlining the terms and conditions governing Service, which title has been replaced by Terms and Conditions of Service. Where reference is made to Electric Service Regulations it shall be deemed to be a reference to these Terms and Conditions of Service and amended from time to time.

72. In response to YUB-AEY/YEC-1-18(a), the Utilities agreed to remove the definition from the T&Cs.

4.4.8. Board Findings

73. The Board directs the Utilities to remove the definition of "Electric Service Regulations" from the T&Cs.

4.4.9. Standard Meters

74. Standard Meters were defined as a meter that has the capability of remotely communicating with the Company's metering network, or any meter the Company deems appropriate in its sole discretion.

75. In Reply Argument, the Utilities stated that this definition ensures clarity between the standard and non-standard meters because customers will have such options when it comes to meters being installed or replaced. This change is also congruent with changes in Schedule D Fees Schedule reflecting supplementary manual meter reads.[59]

76. Parties did not provide any comments on the definition of a standard meter.

4.4.10. Board Findings

77. It is the Board's view that the definition of a standard meter requires further clarification. The applicability of fees regarding standard and non-standard meters will be discussed in a subsequent section of this decision. The Board approves the following definition for Standard Meters:

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[59] Utilities' Final Argument, PDF pages 10-11.

> Standard Meter means a meter that has the capability of remotely communicating with the Company's metering network, or any meter the Company deems appropriate in its sole discretion. However, the meter must meet Canadian Standards Association (CSA) guidelines and Measurement Canada standards. Non-standard meters must also meet CSA guidelines and Measurement Canada standards.

4.5. Section 3 General Provisions

4.5.1. Section 3.2(c)

78. For Section 3.2(c), the Utilities were asked if that subclause which states that:

> No agreement can provide for the waiver or alteration of any part of these Terms and Conditions unless such agreement is first filed with and approved by the Board.

could be removed.[60] The Utilities responded that deleting the subclause provision would not be problematic.[61]

4.5.2. Board Findings

79. The Board directs the Utilities to remove section 3.2(c) from the T&Cs.

4.5.3. Section 3.5

80. For Section 3.5, Mr. Maissan asked if the clause is intended to say the following:

> A Customer shall not extend or permit the extension of the Customer's facilities connected to the Company's Facilities beyond property owned or occupied by the Customer for any Point of Service.[62]

81. The Utilities responded that Mr. Maissan's proposed wording would add further clarity.[63]

4.5.4. Board Findings

82. The Utilities are directed to make the change to Section 3.5 as recommended by Mr. Maissan.

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[60] YUB-AEY/YEC-1-22(f), PDF page 44.
[61] YUB-AEY/YEC-1-22(f), PDF page 45.
[62] JM-AEY/YEC-2-007(b), PDF page 14.
[63] JM-AEY/YEC-2-007(b), PDF page 14.

4.5.5. Section 3.6(e)

83. In response to YUB-AEY/YEC-1-17(b), regarding Customer Generation, the Utilities proposed the following wording to be included as Section 3.6(e):

> The Company has the right to refuse the connection of Generating Customers due to safety concerns or potential impacts on the grid and service reliability, including the right to terminate service to or accept power generated by Generating Customers for reasons outlined in Sections 11.2 and 11.3.[64]

84. Parties did not comment on this proposed change.

4.5.6. Board Findings

85. The Board finds the wording proposed by the Utilities for Section 3.6(e) is overly broad. For this reason, the Board directs that this Section to be amended by deleting the words after “service reliability.” However, the Board will reconsider Section 3.6(e) as proposed by the Utilities if, in the compliance filing, the Utilities are able to explain why the deleted words are necessary. The Board approves the following wording for Section 3.6(e):

> The Company has the right to refuse the connection of Generating Customers due to safety concerns or potential impacts on the grid and service reliability.

4.5.7. Section 3.8

86. Section 3.8 Fees and Other Charges states:

> The Company will provide all standard services hereunder pursuant to the approved Electric Service Tariff. All additional and supplementary services provided by the Company to a Customer will be charged a separate rate or fee, such as those included, without limitation, in Schedule D herein. Payment for these services shall be in accordance with the provisions of these Terms and Conditions.[65]

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[64] YUB-AEY/YEC-1-17(a), PDF page 38.
[65] AEY-YEC 2025 Application, PDF page 63.

4.5.8. Views of interveners

87. The UCG argued that NSF (non-sufficient funds) charges should be displayed in bold-type on the preauthorized payment form and should specify the NSF charge amounts and also include the NSF language in Section 3.8 of the T&Cs.[66]

4.5.9. Utilities' Reply

88. The Utilities did not comment on this.

4.5.10. Board Findings

89. The Board agrees in principle, with the suggestion from the UCG on this item as it is reasonable and provides clarity to customers. The Board directs the Utilities to add wording to the effect that other services not defined in the T&Cs but supplied to specific customers will be recovered from those customers on a flow-through cost recovery basis, such as those costs, for example, related to NSF charges.

4.6. Section 4 Application for and Conditions of Service

4.6.1. Section 4.4 Application of Rate Schedules

90. Mr. Maissan asked and the Utilities agreed, that the last word in Section 4.4(b) should be customer[67] in the singular, such that it should read as:

> Whether or not a Customer has signed an application or contract for Service, these Terms and Conditions and the Rate Schedule applicable to the Service supplied by the Company shall apply. In addition to payments for Service, the Customer is required to pay the Company the amount of any tax or assessment levied by any tax authority on Service delivered to the Customer.[68]

4.6.2. Board Findings

91. The Board directs the Utilities make the change to Section 4.4(b) of the T&Cs as recommended by Mr. Maissan because the rest of the section refers to a singular "customer."

4.6.3. Section 4.5 Change in Service Connections

92. The Utilities proposed the following for Section 4.5:

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66 UCG Final Argument, PDF page 3.

67 JM-AEY/YEC-2-8, PDF page 15.

68 AEY-YEC 2025 Application, PDF pages 64-65 with correction to the word "Customer".

Change in Service Connections

(a) A Customer shall give to the Company reasonable prior written notice of any change in service requirements, including any significant change in load, as per section 8.1, to enable the Company to determine whether or not it can supply such revised service without changes to its Facilities.

(b) The Customer shall not change its requirement for a Service Connection without the Company's written permission. The Customer shall be responsible for all damage caused to the Company's facilities as the result of the Customer changing its requirements for a Service Connection without the Company's permission

(c) On Isolated Systems, Service for electric space heating (permanent or temporary for construction) and electric vehicle charging purposes may be supplied to Customers only with the prior written permission of the Company.[69]

93. The Utilities argued that the proposed changes to Section 4.5(a) of the T&Cs is for customers to provide the Utilities with reasonable prior written notice of changes in service requirements, including any significant change in load, so that the Utilities can determine whether or not they can supply the changed service without changes to their facilities.[70]

94. The position of the Utilities is this change encourages communication between customers and the Utilities during a period of transition including changes in consumption patterns due to government (federal and territorial) policies regarding decarbonization and EVs. The information is required by the Utilities to properly plan and implement system changes. In the Utilities' view this approach is intended to mitigate harm to customers.[71]

4.6.4. Views of interveners

95. Mr. Maissan argued that the Utilities did not provide details on what entails "reasonable prior written notice" or "significant change in load." Mr. Maissan questioned whether the Utilities want to dictate what customers may or may not acquire for electrical use in their homes. Mr. Maissan opined that, given usage per

[69] AEY-YEC 2025 Application, PDF page 65.
[70] Utilities' Final Argument, PDF page 6.
[71] Utilities' Final Argument, PDF page 6.

customer (UPC) information he provided comparing the years 1998-1999 to 2021-2022 showed limited growth on a per-customer basis, the requested changes by the Utilities for Section 4.5 and 8.1 were overkill. In support of his position, he provided examples of people taking winter vacation, of differences in UPCS of energy efficient homes relative to older homes, and of the impact of electric vehicle (EV) chargers. He added that no evidence was presented by the Utilities to show that they either collaborated with the Yukon government Motor Vehicles branch, Building Safety and Standards (electrical staff), or with customers, and thus Mr. Maissan questioned the Utilities ability to police or enforce Section 4.5.[72]

96. Stating that the Utilities' proposal is unreasonable and invasive, Mr. Maissan recommended the following:

> That Sections 4.5 and 8.1 of the proposed Terms and Conditions of Service be revised to:
>
> > a. Permit the Utilities to require advance notification and prior written permission for a conversion to electric heat from oil or propane heat to ensure that the Utilities' delivery system is capable of providing the required electrical power to the home, and that the Utilities are required to respond within 10 business days. Furthermore, if the Utilities determine that their system cannot supply the power requirement they must upgrade their system as soon as reasonably possible and notify the Customer when this has been completed.
> >
> > b. Permit the Utilities to require notification and prior written permission for any increase in load that requires the addition of a 50-amp or larger breaker or an upgrade to their breaker panel. This is to ensure that the Utilities' delivery system is capable of providing the required electrical power to the home. The Utilities must be required to respond within 10 business days. Furthermore, if the Utilities determine that their system cannot supply this power requirement they must upgrade their system as soon as reasonably possible and notify the Customer when this has been completed.
> >
> > c. In addition to the above, any change in Customer load that would require the Utilities to upgrade the service drop whether overhead or underground, to the Customer, and/or any of the Utilities'

72 Mr. Maissan Final Argument, PDF pages 3-7.

infrastructure, will be considered notification to the Utilities and will obligate the Utilities to respond as described in a. and b. above.[73]

97. In reply Mr. Maissan stated that the new T&Cs propose significant new requirements on customers for notification, but fails to provide any guidance as to what a material change in load is. He agreed that notification to the Utilities for conversions to electrical heating for homes is justifiable. However, in his view, the Utilities have not presented any evidence for electricity consumption for EVs. Mr. Maissan submitted that the Utilities should provide Yukon-based and averaged data on consumption of electrical energy by EVs from a credible third-party study before EV specific requirements are included in the T&Cs. Mr. Maissan also suggested an alternative — that the Utilities provide generic requirements for any increased electrical load based on very specific data such as breaker size to be added.[74]

98. Mr. Maissan did not accept the position of the Utilities that proposed changes to this section are not intended to restrict customers. Use of such words as “shall not” and “only with prior written permission” are considered draconian by Mr. Maissan, especially since the Utilities did not provide any bounds to those terms.[75]

99. Mr. Maissan concluded that:

> The lack of any clear guideline would be unfair and confusing to Customers and could create an enormous administrative burden on the Utilities should ratepayers follow the letter of what is proposed. The proposed changes to the T&C of Service with respect to load changes, other than conversions to electric heat, in the Application are not justified.[76]

4.6.5. Utilities’ Reply

100. In response to Mr. Maissan, the Utilities stated that Mr. Maissan’s argument contains a number of purported facts and unsubstantiated speculation regarding the Utilities' ability to enforce the proposed requirement and that these points were not raised in evidence and should be disregarded by the Board. The position of the Utilities is that this Section is forward looking for future loads and not intended to micro-manage customers. The intent is to collaborate with customers so that system planning can occur on a proactive basis.[77]

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[73] Mr. Maissan Final Argument, PDF page 7.
[74] Mr. Maissan Reply Argument, PDF pages 2-3.
[75] Mr. Maissan Reply Argument, PDF page 5.
[76] Mr. Maissan Reply Argument, PDF page 3.
[77] Utilities’ Reply Argument, PDF page 8.

4.6.6. Board Findings

101. In the Board's view, Section 4.5 needs clarification as to what is reasonable prior notice and on the types of changes in service requirements that are contemplated in the section, including what is a significant change in load. The Board finds that the issues raised by Mr. Maissan in relation to this this section have merit, but the Board does not accept the wording proposed by Mr. Maissan for Section 4.5 because it is too prescriptive. Therefore, the Board directs the Utilities, in the compliance filing to this decision, to provide wording that meets the objective of the Utilities but also sufficiently addresses the concerns raised by Mr. Maissan. This direction also applies to Section 8.1, which is discussed in a later section.

4.6.7. Section 4.8 Extension of Service – Cost Sharing

102. The Utilities proposed the following with respect to cost sharing:

> If a new Customer shares a portion or all of the costs of an existing extension, the existing Customers may be entitled to Cost Sharing of the Construction Contribution based on the amount of extension shared.
>
> Cost Sharing will be administered for a maximum of five (5) years commencing December 31 of the year of construction of the original extension. Cost share will not be administered for projects under $20,000 and is up to a limit of three shares.
>
> Cost sharing will not be eligible for non -metered, any public services such as street lights, heat tapes, and small technology services such as telecommunications power supplies.[78]

103. The Utilities stated that changes to cost sharing are intended to allow equitable distribution of costs while also ensuring that the administrative burden associated with cost sharing arrangements is manageable for the Utilities. The administrative burden is due to the need to track and maintain records for projects for the duration of the term. The increase in the minimum threshold before cost sharing is to reflect inflation and time since cost sharing was last reviewed.[79]

4.6.8. Views of interveners

104. Mr. Maissan noted that some long extensions of service are costly and often are paid through local improvement charges over a period of 10 years via the Yukon government's Rural Electrification Program (REP). In his view, allowing new

[78] AEY-YEC 2025 Application, PDF page 6

[79] Utilities' Final Argument, PDF page 11.

customers to connect after five years, with no cost sharing, while the original customer continues to pay for the remaining years under the REP is unreasonable.

105. Mr. Maissan rejected the Utilities' proposed wording for this Section and added that the Utilities' position of administrative burden was disingenuous as there have only been 53 cost sharing projects from 2011 to 2024.[80] Instead, Mr. Maissan recommended:

> Section 4.8(b) be revised to read as follows:
>
> Cost Sharing will be administered only for projects over $15,000 commencing December 31 of the year of construction of the original extension. Cost share for projects between $15,000 and $30,000 will be administered for a period of 5 years with a limit of 3 shares, and projects of $30,000 or more will be administered for 10 years. These cost thresholds are to be adjusted annually by the Whitehorse CPI in the same manner as is determined by the Board to be applied to Schedule D fees.[81]

106. The UCG rejected the cost sharing Section as proposed by the Utilities stating "that five years is too short and could be exploited by some customers, leaving others with the entire bill."[82]

107. In Reply Argument, Mr. Maissan stated in the last approved T&Cs (2011), a 10-year cost sharing period was allowed for more costly projects because of unfair advantage having been taken of existing customers. He also noted that there have only been 53 projects over 13 years at the 2011 cost thresholds implying a very small administrative burden. Mr. Maissan said "an appropriate balance between administrative costs as well as Customer fairness and the public interest would be to adjust the threshold costs under the same structure as in the 2011 T&C of Service."[83]

4.6.9. Utilities' Reply

108. It was noted by the Utilities that the probability of cost sharing occurring decreases later in the cost sharing period. The recommendation of Mr. Maissan would increase the administrative burden of the Utilities.[84]

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80 Mr. Maissan Final Argument, PDF pages 7- 8.
81 Mr. Maissan Final Argument, PDF page 8.
82 UCG Final Argument, PDF page 4.
83 Mr. Maissan Reply Argument, PDF page 3.
84 Utilities' Reply Argument, PDF page 10.

4.6.10. Board Findings

109. The Board does not accept the changes as submitted by the Utilities for the following reasons. Given the low number of incidents of cost sharing since 2011, the Board finds that the cost sharing agreements do not result in an administrative burden on the Utilities and do not warrant the provisions set out in the proposed section. As such, the Board finds that a threshold for large projects should be increased to $20,000 and that a reasonable cost sharing period for large projects should be 10 years and there should be no limit on the number of cost shares in that period.

110. The Board does not find that the low-end threshold of $15,000, as recommended by Mr. Maissan, creates a broad enough range for smaller projects. Therefore, the Board directs that cost shares for projects greater than $10,000 but less than $20,000 have a cost share period of five years and have a maximum number of three shares because for projects less than $20,000 the probability of cost sharing for projects of that size is limited.

4.6.11. Section 4.10 Conversion from Overhead to Underground Service

111. Section 4.10 states:

> When a customer requests that existing Company Facilities be converted from overhead to underground, the Customer may be charged for all costs incurred by the Company in connection with the conversion, including the following:
>
> (a) the actual cost of removing the existing Facilities, less the estimated value of the salvaged material, plus
>
> (b) the actual cost of installing the new underground Facilities, less any available Company Investment as specified in Schedule B - Maximum Company Investments.[85]

4.6.12. Views of interveners

112. Mr. Maissan found the distinction between new customer and existing customers between what is stated in the T&Cs and the explanation provided in IR responses[86] unclear and recommended the following:

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85 AEY-YEC 2025 Application, PDF page 68.

86 JM-AEY/YEC-1-11 and JM-AEY/YEC-2-5, PDF pages 19-20 and 10-11.

That the Utilities revise the wording of this section to make it unambiguous to both new customers (new buildings) and existing Customers with existing overhead service what costs, if any, the Utilities will bear in installing a requested underground service.[87]

4.6.13. Utilities' Reply

113. The Utilities did not provide any comments on Section 4.10.

4.6.14. Board Findings

114. The Board finds Mr. Maissan's recommendation on Section 4.10 to be reasonable as further clarity for customers is needed. The Utilities are directed to revise the wording to Section 4.10 to remove the ambiguity to both new customers and existing customers with existing overhead service and what costs, if any, the Utilities will bear in installing a requested underground service.[88]

4.6.15. Section 4.13 Multiple Dwellings

115. The proposed wording for Section 4.13 is:

> (a) Each individual unit within a Multiple Dwelling will be served as a separate Point of Service and billed individually on the applicable residential rate. The Company and a Customer may agree that one bill will be issued covering all individual units in a Multiple Dwelling and, in such case, the applicable general service (non- residential) rate will apply to the Service. Common use areas such as hallways, lobbies, and laundry rooms, elevators, and parkades will be billed under the applicable general service price schedule.
>
> (b) Where the Company and a Customer have agreed that service to a Multiple Dwelling shall be delivered through a single Point of Service, the applicable general service (non-residential) price schedule will apply to the service.[89]

116. The Utilities argued that the definition of a multiple dwelling should remain broad enough to include various multi-dwelling and point of service configurations. Too narrow of a definition requires clarification and introduces inefficiency and

[87] Mr. Maissan Final Argument, PDF page 9.
[88] Mr. Maissan Final Argument, PDF page 9.
[89] AEY-YEC 2025 Application, PDF page 68.

potential delay for customer connections. IR responses demonstrate the application of the definition, applicable configurations and the need for flexibility.[90]

117. Almost all residential multiple dwellings are served by individual meters and a common area meter with the common areas metered at a single point of service and at the General Service Rate. The Utilities cannot separate general service load to each of the metered customers where there is only one point of service for the common area. Further, the Utilities view the General Service Rate as the appropriate rate for common areas.[91]

4.6.16. *Views of interveners*

118. Mr. Maissan noted that, as written, this Section discourages the installation of electrically efficient central heating systems for multiple dwelling buildings. He added that this also inhibits the ability to limit peak load growth.

119. Mr. Maissan recommended:

> That the Board orders the Utilities to work with Multiple Dwelling building owners and managers to correct this adverse situation, and in the event that a mutually satisfactory solution is not found and communicated to the Board within 1 calendar year of the Board Order, that a revenue meter that measures the electricity input into such heating systems be installed and all the metered energy be allocated equally to each dwelling unit and paid for by unit owners / occupiers at Residential rates.[92]

120. In Reply Argument, it was Mr. Maissan's view that if the T&Cs are to be modernized then this issue must be addressed.[93]

4.6.17. *Utilities' Reply*

121. In response to Mr. Maissan's submissions, the Utilities said:

> ... [they] do not agree that the proposed changes to the T&Cs will discourage efficient heating systems, which is not supported by any evidence on the record, and submit that Mr. Maissan's recommendation is not necessary and

[90] Utilities' Final Argument, PDF page 8. Referenced IRs are YUB-AEY/YEC-1-019 (PDF page 41), YUB-AEY/YEC-1-037 (PDF pages 73-74), JM-AEY/YEC-1-003(a-d) (PDF page 8).

[91] Utilities' Final Argument, PDF pages 8-9

[92] Mr. Maissan Final Argument, PDF page 9.

[93] Mr. Maissan Reply Argument, PDF page 5.

would improperly impose a responsibility on Utilities to allocate general energy costs among Multiple Dwelling residents.[94]

122. They added that the proposed changes to the T&Cs do not prevent the installation of central heating systems.[95]

4.6.18. Board Findings

123. The Board does not agree with the proposed changes to Section 4.13 as submitted by the Utilities. The Board observes two issues with Section 4.13:

1) Whether each unit within a multiple Dwelling will be served as a separate point of service and billed individually on the applicable residential rate; and

2) Whether common use areas should be separately metered and be billed under the applicable general service price schedule.

124. Regarding the first point, in response to YUB-AEY/YEC-2-015, the Board notes that SaskPower does not permit single point of delivery for multiple occupancy buildings.[96] This is consistent with the definition of domestic service as defined by Newfoundland Power:

> For Service to a Domestic Unit or to buildings or facilities which are on the same Serviced Premises as a Domestic Unit and used by the same Customer exclusively for domestic or household purposes, whether such buildings or facilities are included on the same meter as the Domestic Unit or metered separately.[97]

125. The Board is of the view that each unit in multiple dwelling should be metered separately as it is a better identifier of costs for cost causation purposes, appropriately makes customers responsible for electrical energy consumption, and enables each customer to individually reap the rewards and benefits from DSM initiatives. The Board directs that Section 4.13 provide that each dwelling in a multiple dwelling be metered separately without exception.

126. Regarding the second point, in response to YUB-AEY/YEC-2-015, the Board notes the Hydro Quebec statement that "On condition that the electricity is exclusively used for habitation purposes, including the common areas…"[98] it charges a

94 Utilities' Reply Argument, PDF page 9.
95 Utilities' Reply Argument, PDF page 10.
96 YUB-AEY/YEC-2-015, PDF page 33.
97 YUB-AEY/YEC-2-015, PDF page 38.
98 YUB-AEY/YEC-2-015, PDF page 35.

residential rate. The Board prefers this definition as all aspects included in the multiple dwelling are used for residential purposes and would be fair to include in the residential rate. The Board's finds that such a definition is a more consistent application of what entails a residential rate. Such an application of the definition of a residential customer and residential rate will not impede residents of multiple dwelling buildings from seeking efficient energy solutions versus residential customers in single dwelling units.

127. Therefore, in the compliance filing to this decision, the Board directs the Utilities to redraft the wording of Section 4.13 to implement the findings and directions outlined above. In addition, the Utilities are to identify any obstacles to the implementation of these directions and identify how the Utilities will overcome those obstacles.

128. If Section 4.13 is approved in a decision on the compliance filing, it will apply on a go forward basis for metering. Existing metering configurations will be grandfathered. That is, residential rates will be applied to all individual units and common areas, but existing customer meters do not have to be re-configured to comply with this direction.

4.7. Section 6 Meters

129. In Section 6.1 the Utilities added sub-part (c) regarding changes to Standard Metering. No parties commented on this change.

130. In response to YUB-AEY/YEC-1-008(c), the Utilities stated that AMI meters are being implemented and that the Utilities are transitioning to that form of meter. The Utilities stated:

> During the transition to AMI meters, if the Utilities have not installed an AMI meter on a site and require manual meter reads, the customer will be charged the Non-Standard charge up until the time the AMI meter with remote access is installed.[99]

131. It is unclear whether, during the transition, those customers who have not been scheduled for implementation of AMI meters will be charged for manual meter reads.

[99] YUB-AEY/YEC-1-008, PDF page 15.

4.7.1. Views of interveners

132. The UCG noted that adding AMI information to the T&Cs is premature as the necessary infrastructure for remote or electronic meter reading is not yet in place.[100]

133. In relation to Section 6.3(a) Meter Tests and Adjustments, the UCG disagreed that customers should pay upfront for the Meter Accuracy Test Handling Fee.[101]

134. Mr. Yee recommended "[t]hat all new meters or replacement meters be AMI meters. They are less expensive than conventional meters and will not need to be replaced if/when the AMI project gets going. There is no reason to be installing non-AMI meters."[102]

4.7.2. Utilities' Reply

135. The Utilities submitted the addition of Standard Meters and related provisions into the T&Cs clarify what meters customers will be receiving and provide them with the option to opt out of AMI metering. In the Utilities view this is a proactive approach to improve customer awareness of AMI initiatives and facilitate customer choice with respect to their metering services.

136. During the transition to AMI metering, the Utilities will charge customers fees applicable for Non-Standard Meters until a Standard Meter (AMI) has been installed at the relevant site. The Utilities submit that this is a fair approach and that the approval of AMI-related language as part of the T&Cs in this application, rather than after AMI implementation is complete, will not result in harm to customers.[103]

4.7.3. Board Findings

137. The Board accepts the change and recognition of Standard Meters as the current and future direction for meters. However, The Board directs the Utilities to amend the wording to Section 6.1(c) to clarify that, for what is considered non-standard meters, meter reading charges for non-standard meters will not apply until the transition period to the new standard meters is complete. The transition period is from the time that a customer is offered the newly defined standard meter to be installed on a certain date until that customer rejects the installation of the standard meter on or before the expected installation date.

[100] UCG Final Argument, PDF page 3.

[101] UCG Final Argument, PDF pages 3-4.

[102] Mr. Yee Final Argument, PDF page 4.

[103] Utilities' Reply Argument, PDF pages 11-12.

138. The Board is of the view that all new meters or replacement meters should be AMI meters. However, that issue is outside the scope of this application and the Board will not issue such a direction. The Board is of the view that installation of new or replacement meters may attract a prudency review in future GRAs when the Utilities are asked to justify meter conversions of relatively new meters.

4.8. Section 7 Meter Reading and Billing

4.8.1. Section 7.1 Reading and Estimates

139. Section 7.1 reads:

> Unless otherwise specifically provided in a contract with a Customer, meters shall be read monthly or bi-monthly or at such other intervals as are practical in the circumstances. Customers' bills will be based on meter readings made by the Company or on estimates for those billing periods when the meter is not read. Whenever a bill is based on an estimate, an adjustment to reflect actual Energy consumption and Demand (if applicable) used will be made when the meter is next read.[104]

140. The Utilities did not propose any changes to this Section.

4.8.2. Views of interveners

141. The UCG stated that meters should not be estimated for more than one consecutive month to maintain bill stability and ensure accurate application of the interim electrical rebate program.[105]

142. Mr. Yee stated that in the past winter, in Faro, four-of-six meter readings (October, December, January and March) were estimates. Mr. Yee posited that "Just as there are consequences for customers failing to pay bills on time, there should also be consequences for the failure to read meters."[106]

143. Mr. Yee proposed a three per cent credit to each customer account on every estimated billing statement.[107]

4.8.3. Utilities' Reply

144. The Utilities replied that it is neither safe nor appropriate to impose specific meter reading requirements on the Utilities. Further, the Utilities added that with the

[104] AEY-YEC 2025 Application, PDF page 75.
[105] UCG Final Argument, PDF pages 2-3.
[106] Mr. Yee Final Argument, PDF page 4.
[107] Mr. Yee Final Argument, PDF page 4.

implementation of AMI, remote meter reading will enable meter reads when manual reads are not possible or safe.[108]

4.8.4. Board Findings

145. The Board notes that there are existing issues of missed cycles of meter reads and longer periods of meter estimations for billing purposes. However, the Board notes that there is no evidence on the record of this proceeding to support Mr. Yee's submissions about meter readings in Faro. Further, the Board rejects Mr. Yee's proposed penalty as it is arbitrary and without basis.

146. The Board has received complaints regarding customer bills and the frequency of meter reads and, therefore, directs the Utilities to propose a resolution to this problem in the compliance filing to this decision, including when a customer receives a large bill when the meter has not been read for more than two successive months, and that the customer will have the option to pay for variances greater than $400.00 between the estimated bill and actual bills over a three-month period without incurring late-payment fees or interest charges.

4.8.5. Section 7.2 Calculation of Bills

147. Section 7.2(c) reads:

> The Company may elect not to charge a Customer for the billing period if, during that period, Demand was five kilowatts or less, Service was provided for five days or less and Energy consumption was five kilowatt hours or less.[109]

148. YUB-AEY/YEC-1-33(b) the Utilities were asked if the wording for Section 7.2(c) should be:

> The Company may elect not to issue a bill to a customer for the billing period if, during that period, Demand was five kilowatts or less, Service was provided for five days or less and Energy consumption was five kilowatt hours or less.

149. The Utilities agreed to the wording change.[110]

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[108] Utilities' Reply Argument, PDF page 13.
[109] AEY-YEC 2025 Application, PDF page 75.
[110] YUB-AEY/YEC-1-33(b), PDF page 64.

4.8.6. Board Findings

150. The Utilities are directed to amend the T&Cs for Section 7.2(c) with the proposed wording noted above, but will add, for clarification, the following to Section 7.2(c)

> However, where the company has elected to not issue a bill to a customer, those charges will be reflected in the next bill to the customer.

4.8.7. Section 7.3 Payment

151. The Utilities included a new sub-section (d) which states:

> The bills are payable by way of EFTs, cash, debit bank payments, credit cards, money order or certified cheque as noted in the bills. The customer is responsible for the additional charges that may result due to payment methods other than those noted in the bills.[111]

152. YUB-AEY/YEC-1-034(a) asked if the Utilities accepted non-certified cheques as a form of payment. In response, the Utilities stated that they currently accept cheques.

4.8.8. Board Findings

153. The Board directs the Utilities to update Section 7.3(d) to include cheques.

4.8.9. Section 7.4 Late Payment Charge

154. Section 7.4 reads:

> The Company may add a Late Payment Charge as specified in Schedule D on any overdue amount not received by the due date specified in the issued bill. A Collection Fee as specified in Schedule D will be charged if a personal visit is required to collect an overdue amount.[112]

4.8.10. Views of interveners

155. The UCG argued:

> Regarding overdue charges, UCG suggests that it should be stated in the Terms & Conditions that the utility must first notify the customer with a distinctively coloured bill that their account is overdue. This will allow the customer time to address the issue or inform the utility of their situation and negotiate a resolution. Additionally, when a visit is required to collect an

[111] AEY-YEC 2025 Application, PDF page 76.
[112] AEY-YEC 2025 Application, PDF page 76.

> overdue account, additional charges will be applied as specified in YUB-014 (b) and billed with those amounts clearly shown. These steps and charges should also be outlined and safeguarded in the Terms & Conditions.[113] (footnote omitted)

4.8.11. Utilities' Reply

156. The Utilities did not provide any comments on this in either Final Argument or Reply Argument.

4.8.12. Board Findings

157. The Board accepts Section 7.4 Late Payment Charges as submitted by the Utilities. The wording is reasonable and clear. The Board declines to adopt the UCG suggestion as the suggestion is not necessary.

4.8.13. Section 7.6 Outstanding Charges

158. Section 7.6 states:

> The Company may add to the Customer's bill any outstanding charges due and owing to the Company (e.g., construction contribution, account receivable charges, former overdue accounts etc.).[114]

159. In response to YUB-AEY/YEC-2-17, the Utilities responded:

> As part of the Utilities' best efforts to work with customers, payment plans are viewed as a "tool-in-the-toolbox" in certain unique circumstances seen by customers. Each scenario should be developed and discussed on a case-by-case or customer-by-customer basis. It is the Utilities' view that payment plans are not prescriptive in the T&Cs as they should be viewed as unique in nature and not part of a normal course of business. Rather, the option to assist customers should continue as it has in the past to be an offering or a "tool-in-the-tool box", where the Utilities have the flexibility to work with the customer in these unique circumstances. The Utilities, however, are open to adjusting their current practice to ensure that information such as the agreement and penalties are clearer to the customers.[115]

[113] UCG Final Argument, PDF page 3. YUB-AEY/YEC-1-014(b), PDF page 31.
[114] AEY-YEC 2025 Application, PDF page 76.
[115] YUB-AEY/YEC-2-017, PDF page 43.

4.8.14. Views of interveners

160. The UCG argued:

- Customers should be notified with a distinctively colored bill that their account is overdue.

- When a site visit is necessary to collect an overdue account, the additional charges should be billed in accord with the response to YUB-AEY/YEC-1-14(b). Those charges and steps should be part of the T&Cs.[116]

4.8.15. Utilities' Reply

161. The Utilities replied that customers are currently provided with a full accounting of their account in monthly statements. Pending disconnection notices are mailed to customers noting overdue amounts and the Utilities work with customers on a case-by-case basis. The Utilities added that the T&Cs specify that a fee will be charged if a personal visit is required to collect an overdue account.[117]

4.8.16. Board Findings

162. In parallel with the UCG comments regarding late payment charges (Section 7.4), and the questions raised by the Board, the Board finds that the T&Cs should include terms regarding documentation of payment arrangements, consequences of non-payment, and copies of the written documentation to be provided to the customer. Such terms would make it clear to a customer what the payment arrangements the customer has agreed to, and, if the terms are not followed by the customer, what the consequences are, such as disconnection. The current lack of documentation of such arrangement has led to misunderstandings between a customer and a utility. It is reasonable to document such an agreement that has consequences for a customer if it is breached.

163. The Utilities are directed to include a clause, in the compliance filing to this application, which does the following: outlines that written documentation of payment arrangement terms with a customer is required; indicates in the written documentation the consequences of non-payment; and acknowledges that a copy of the written documentation is to be provided to the customer.

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[116] UCG Final Argument, PDF page 3.

[117] Utilities' Reply Argument, PDF pages 13-14.

4.9. Section 8 Service Changes

4.9.1. Section 8.1 Notice by Customer

164. The Utilities did not propose any changes to Section 8.1. It reads:

> A Customer shall give to the Company reasonable prior written notice of any change in Service requirements, including any material change in Connected Load, to enable the Company to determine whether or not it can supply such revised Service without changes to its Facilities. The Customer shall not change its Service requirements without the Company's written permission.[118]

4.9.2. Views of interveners

165. Mr. Maissan, in his argument, identified several issues with this section and Section 4.5 Changes in Service Connections. Issues included the meaning of "significant load increases" and "reasonable prior notice." In addition, Mr. Maissan noted that the Utilities stated "… the T&Cs require updating to enable customers and the Utilities to continue to Work together efficiently and effectively."[119]

166. To reiterate Mr. Maissan's concerns and recommendations as expressed with Section 4.5:

> Mr. Maissan argued the Utilities did not provide details on what entails "reasonable prior written notice" or "significant change in load." Mr. Maissan questioned whether the Utilities want to dictate what customers may or may not acquire for electrical use in their homes. It was opined by Mr. Maissan, that given usage per customer (UPC) information he provided comparing the years 1998-1999 to 2021-2022, showing limited growth on a per customer basis, that the requested changes by the Utilities fort Section 4.5 and 8.1 were overkill. He furthered his position by citing examples of people taking winter vacation, differences in UPCS of energy efficient homes relative to older homes and the impact of electric vehicle (EV) chargers. He added that no evidence was presented by the Utilities to show that they either collaborated with the Yukon government motor vehicles branch, building safety (electrical staff) or with customers and questioned the Utilities ability to police or enforce Section 4.5. [120]

118 AEY-YEC 2025 Application, PDF page 78.
119 UCG-AEY/YEC-1-4, PDF page 6.
120 Mr. Maissan Final Argument, PDF pages 3-7.

Stating that the Utilities' proposal is unreasonable and invasive, Mr. Maissan recommended the following:

That Sections 4.5 and 8.1 of the proposed Terms and Conditions of Service be revised to:

> a. Permit the Utilities to require advance notification and prior written permission for a conversion to electric heat from oil or propane heat to ensure that the Utilities' delivery system is capable of providing the required electrical power to the home, and that the Utilities are required to respond within 10 business days. Furthermore, if the Utilities determine that their system cannot supply the power requirement they must upgrade their system as soon as reasonably possible and notify the Customer when this has been completed.
>
> b. Permit the Utilities to require notification and prior written permission for any increase in load that requires the addition of a 50-amp or larger breaker or an upgrade to their breaker panel. This is to ensure that the Utilities' delivery system is capable of providing the required electrical power to the home. The Utilities must be required to respond within 10 business days. Furthermore, if the Utilities determine that their system cannot supply this power requirement they must upgrade their system as soon as reasonably possible and notify the Customer when this has been completed.
>
> c. In addition to the above, any change in Customer load that would require the Utilities to upgrade the service drop whether overhead or underground, to the Customer, and/or any of the Utilities' infrastructure, will be considered notification to the Utilities and will obligate the Utilities to respond as described in a. and b. above. [121]

167. Mr. Maissan did not accept the position of the Utilities that proposed changes to this section are not intended to restrict customers. Use of words such as "shall not" and "only with prior written permission" are considered draconian by Mr. Maissan, especially since the Utilities did not provide any bounds to those terms.[122]

4.9.3. Utilities' Reply

168. In reply, the Utilities stated:

[121] Mr. Maissan Final Argument, PDF page 7.
[122] Mr. Maissan Reply Argument, PDF page 5.

> The Utilities are proposing changes only to Section 4.5, in order to require customer communication with and permission from the Utilities in the event of changes in service requirements, including significant changes in load.[123]

169. The Utilities added:

> The Utilities also submit that it is not necessary, or appropriate, to require load data to demonstrate system impacts in support of this request, since the request is intended to prepare the Utilities and customers for future circumstances as loads that are not currently connected to the grid are added over time. The record is clear that the intent of the proposed changes to the T&Cs is not to micro-manage customers or to refuse service. The Utilities have confirmed that they intend to collaborate with customers and only seek to ensure that they are aware of upcoming significant changes so that system planning can occur on a proactive, rather than reactive, basis.[124] (footnote omitted)

4.9.4. Board Findings

170. In the Board's view, Section 8.1, like Section 4.5, needs clarification as to what is reasonable prior notice and the types of changes in service requirements that are contemplated in the section, including what is a significant change in load. The Board finds that the issues raised by Mr. Maissan in relation to this section have merit, but the Board does not accept the wording proposed by Mr. Maissan for this section because it is too prescriptive. Therefore, the Board directs the Utilities, in the compliance filing to this decision, to provide wording that meets the objective of the Utilities but also sufficiently addresses the concerns raised by Mr. Maissan. Further, the Utilities do not need approval from the Board or prescriptive sections in the T&Cs to communicate with customers as there is nothing in these T&Cs that prevent the Utilities or customers from talking to each other. It is the Board's view that the Utilities should record its efforts to communicate with customers as this would help identify common issues and provide valid documentation on what issues Utilities are reviewing or addressing. In addition, the Utilities have not provided any substantive evidence that EVs are currently an issue with respect to Service Changes. In the compliance filing to this decision, the Utilities are directed

[123] Utilities' Reply Argument, PDF page 8.

[124] Utilities' Reply Argument, PDF page 8.

to either delete references to EVs or provide evidence to support their claims regarding EVs.

4.9.5. Section 8.3 Changes to Company Facilities

171. No changes to this sub-section were proposed by the Utilities. It reads:

> If the Company must modify its Facilities to accommodate a Customer Load or Service change, the Customer shall pay for all costs in connection with such modification including the following costs:
>
> (a) the actual cost of removing the existing Facilities, less the estimated salvage value; less
>
> (b) any applicable adjustment required to the Company Investment as specified in Schedule B.

4.9.6. Views of interveners

172. Mr. Maissan discussed an example of an upgrade to a transformer that is used by more than one customer. Based on the responses to two IRs,[125] it was his position that this section required clarity and recommended:

> That the Board order the Utilities to add a part (c) to this section the wording of which would be something like this: (c) for clarity, upgrades to Company Facilities such as a shared transformer would be considered a system cost and a Company Investment.[126]

4.9.7. Utilities' Reply

173. Stating that the circumstances for reach upgrade to Company facilities are unique, the Utilities replied that the classification of the cost of an upgrade is best dealt with on a case-by-case basis. Adding that the hypothetical scenario presented by Mr. Maissan may not apply in all cases, the Utilities submitted that cost treatment for upgrades should not be specified in the T&Cs.[127]

4.9.8. Board Findings

174. Based on the submissions of the Utilities and the evidence on the record, the Board finds that the circumstances for upgrades to Company facilities are unique, and the classification of a cost upgrade is best dealt with on a case-by-case basis.

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[125] JM-AEY/YEC-1-17 and JM-AEY/YEC-2-10, PDF pages 29-31 (Round 1) and 16-17 (Round 2).

[126] Mr. Maissan Final Argument, PDF page 10.

[127] Utilities' Reply Argument, PDF page 11.

However, Mr. Maissan brought forward a valid concern whereby additional clarity would be beneficial for both customers and the Utilities. The Board directs, where facilities are shared with multiple customers, that the Utilities provide additional wording regarding the considerations necessary for the costs to be treated as system costs.

4.10. Section 9 Company Responsibility and Liability

4.10.1. Section 9.2 Interruption

175. The Utilities proposed changes to this Section, and the proposed section reads:

> Without liability of any kind to the Company, the Company shall have the right to disconnect or otherwise curtail, interrupt or reduce service to Customers:
>
> (a) whenever the Company reasonably determines that the Service must be interrupted, including to facilitate construction, installation, maintenance, repairs, replacement or inspection of any of the Company's Facilities, or to permit the connection or disconnection of other Customers;
>
> (b) to maintain the safety and reliability of the Company's Facilities; or
>
> (c) due to any other reason related to dangerous or hazardous circumstances including emergencies, forced outages, potential overloading of the Company's Facilities, insufficient supply or Force Majeure.
>
> The Company may first interrupt industrial customers, and customers with their own generation capacity.[128]

4.10.2. Views of interveners

176. Mr. Maissan stated that the last line to the section, in conjunction with the definition of Generating Customer, can imply that residential customers who have micro-generation may be first to be interrupted by the Utilities. Noting that, except in rare circumstances, these types of customers do not have energy storage systems, singling out and interrupting this customer is discriminatory.[129]

177. Mr. Maissan recommended:

[128] AEY-YEC 2025 Application, PDF page 79.

[129] Mr. Maissan Final Argument, PDF page 10.

> That the Board order the Utilities to revise the wording of the concluding sentence as follows: "The company may first interrupt Industrial Customers, and other Customers that have back-up generation to meet their needs."[130]

178. In reply, Mr. Maissan stated the following:

> The Utilities' desire to have the right to interrupt Micro-Generation customers, almost all of whom would not have back-up generation, along with Industrial Customers who must have their own back-up generation and other large Customers who have installed back-up generation, is totally unfair. The labour cost burden that the Utilities would place on themselves and the ratepayers is very much not in the public interest. Why the Utilities would propose such a ridiculous thing is beyond comprehension.[131]

4.10.3. Utilities' Reply

179. The Utilities replied that:

> Interruption of service under Section 9.2 of the T&Cs may take place for several reasons, including in order to maintain the safety and reliability of the Utilities' facilities and in situations of potential overloading, insufficient supply, or other circumstances that impair the Utilities' ability to provide safe and reliable service.[132] (footnote removed)

180. The Utilities added that Mr. Maissan's submissions regarding potential service interruptions are new evidence and should be disregarded. The Utilities then submitted that it is important to be able to interrupt any generation in accordance with Section 9.2, and concluded that micro-generation customers should be included in the definition of generating customer to ensure that all responsibilities of all generating customers are captured in the T&Cs.[133]

4.10.4. Board Findings

181. The Board is of the view that the wording for Section 9.2 (c) can be improved. For example, the Board accepts the position from Mr. Maissan that many micro-generators may be without electricity if they are treated as a priority interruption. The Board agrees that the Utilities have the right to interrupt service for safety and reliability reasons. However, it is unclear, based on the record for this proceeding, if the Utilities can interrupt receiving generation from the micro-generators but also,

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[130] Mr. Maissan Final Argument, PDF page 10.
[131] Mr. Maissan Reply Argument, PDF page 4.
[132] Utilities' Reply Argument, PDF page 7.
[133] Utilities' Reply Argument, PDF page 8.

when the micro-generators are not generating electricity, whether the Utilities provide electricity to those customers. If the premise of the last sentence is correct, then the Utilities are directed to change the wording for the last sentence of Section 9.2(c) to include the wording proposed by Mr. Maissan, but with the caveat that micro-generators, though interruptible, will not be a priority interruption during times when generation is not occurring (e.g. night time for solar generators). If the premise for that referenced sentence is incorrect, then, in the compliance filing to this decision, the Utilities are directed to explain why the premise is incorrect and propose wording that will meet the Utilities' needs yet not make micro-generators without a back-up power supply, a priority interruption.

4.11. Section 10 Customer Responsibility and Liability

4.11.1. Section 10.3 Customer Liability

182. The Utilities revised the part (b) of the Section to:

> The Customer will ensure that its Facilities comply with the applicable requirements of the Canadian Electrical Code and with any other technical guidelines that may be issued from time to time by the Company. Where a Customer uses its Service Connection in a manner that causes interference with the operation of the Company's Facilities or with any Customer's use of a Service Connection, such as abnormal voltage levels, frequency levels or harmonic and interharmonic levels, at the Company's request, and at the Customer's own expense, the Customer shall take whatever action is required to correct the interference or disturbance. Alternatively, the Company may elect to correct the interference or disturbance at the Customer's sole expense.[134]

4.11.2. Views of interveners

183. The UCG argued:

> UCG also calls for an internal study on the impact of harmonic and inharmonic distortions on power efficiency, as these noise waves affect power quality and delivery. This study should give some recommendations on how the utilities will modify their delivery of electricity to remedy these distortions. Research demonstrates that power companies use noise on the

[134] AEY-YEC 2025 Application, PDF page 81.

> sine waves to make all appliances use more power than they need to run.[135] (footnote removed)

4.11.3. Utilities' Reply

184. The Utilities replied that a study on the impact of harmonic and inharmonic distortions does not provide any benefit to how the Utilities deliver electricity to customers. As explained by the Utilities, an accepted approach for monitoring harmonic and interharmonic distortions is to check harmonic limits where there are significant changes in the system, such as when the addition of new equipment suspected of harmonic or interharmonic pollution.

185. In response to the UCG submission, the Utilities stated that power companies use of sine wave noise to make appliances use more power than necessary is new evidence, is unsubstantiated, and does not add to the harmonic/inharmonic discussion.[136]

4.11.4. Board Findings

186. The Board finds the wording proposed by the Utilities to be reasonable and accepts the changes as submitted for this Section. The UCG comments regarding noise on the sine waves are disregarded as the assertion is unsupported by evidence.

4.12. Schedule D: Fees and Service Charge Summary

187. Similar to the Board-approved MILs, the Utilities are required to obtain approval for any fees and service charges it may recover from customers. These charges are for services AEY or YEC provides to customers beyond those being charged through the common Rates Schedules.

188. The Utilities proposed updates to its Schedule D: Fees and Service Charges Summary (Schedule D Fees Schedule). which they asserted more accurately reflected costs for identified services.

189. As with its proposal respecting MILs, the Utilities similarly requested that the Schedule D Fees Schedule approved in this application would continue to be updated in a no-notice application each December for the following year by a percentage increase equal to that of the most recent prior year CPI for Whitehorse

[135] UCG Final Argument, PDF page 3.
[136] Utilities' Reply Argument, PDF page 12.

(referred to as an annual inflation factor).[137] [138] The Board's findings on the use of an annual inflation factor can be found in Section 6.

190. The Utilities relied on the expertise and experience of their management and office staff in developing the updated Schedule D Fees Schedule.

191. For some of the fees listed in Schedule D Fees Schedule, the Utilities submitted:

- For disconnection fees, the Utilities detailed the step taken for customer contact before travelling to the customer site.
- The fees for connection and disconnection have been updated to reflect actual work but expect those costs to reduce as more standard meters are installed.
- A new fee for customer information requests has been added that is based on cost causation principles, is intended to reduce administrative burden, and is to encourage use of the MyAccount system by customers.[139]

192. Not specifically included in the Schedule D Fees Schedule are additional or supplementary services. In the case of additional or supplementary services, customers are advised of the fees for those services in advance, and the fees are for cost recovery purposes. The Utilities submitted that services provided for at cost cannot be limited to those outlined in Schedule D Fees Schedule as that would lead to inefficiencies and may impact customer experience.[140]

4.12.1. Views of interveners

193. Mr. Maissan said that customer usage information was not previously charged for and all previous fee levels are proposed to increase by an amount higher than inflation. Noting the response to YUB-AEY/YEC-1-11(c), Mr. Maissan opined that it is unnecessary and inappropriate to lump simple usage requests with detailed technical information requests. Mr. Maissan postulated that the Utilities no longer desire to pass on efficiency gains with customers given that the proposed new fees exceed inflation.

194. The recommendations from Mr. Maissan were as follows:

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137 AEY-YEC 2025 T&Cs Application, PDF pages 4 and 10.

138 AEY-YEC Final Argument, PDF page 3.

139 Utilities' Final Argument, PDF pages 12-13.

140 Utilities' Final Argument, PDF pages 13-14.

- The request for a customer charge for simple historical power usage be denied.

- Complex customer information requests for technical information attract a fee of $75.

- Information pertaining to Sections 4.5 and 8.1 of the T&Cs are not to be considered as a customer information request but a utility system planning cost.

- The fees or service charges be reset according to the amounts in his recommendation.[141]

195. The UCG argued that certain cost charges be delayed until a full GRA review is conducted. The charges for connection and reconnection were acceptable to the UCG if they are explicitly detailed in the T&Cs, with each process step documented with time allocations.[142]

196. Regarding overdue charges, the steps and charges for collection should be outlined and safeguarded in the T&Cs.

197. Mr. Maissan in Reply Argument questioned whether the Utilities specifically asked customers about increases to fees and service charges set for Schedule D Fees Schedule.

4.12.2. Utilities' Reply

198. In reply, with respect to the meter testing fee, the Utilities said:

> if meter testing fees are not imposed up-front in such circumstances, there would be little incentive for customers to work with the Utilities in accordance with the meter dispute process, and that customers may request meter testing in situations where they feel that their bill does not reflect their energy consumption, without a strong basis to suspect that the meter is faulty.[143]

199. For historical usage information requests, the Utilities said that if the fee is approved as proposed, then the fee will only be incurred for complex customer

[141] Mr. Maissan Final Argument, PDF pages 12-13.
[142] UCG Final Argument, PDF pages 2-3.
[143] Utilities' Reply Argument, PDF page 14.

requests. There would be no charge for customers to access historical usage information from MyAccount.[144]

200. The Utilities disagreed with Mr. Maissan's recommendations for fees and service charges as no evidence has been provided to support such fees and charges. In response to Mr. Maissan's comments regarding the application of inflation to costs, the Utilities said there is no basis for such comments and that the way in which utilities find efficiencies and pass those savings on to customers is a GRA matter.[145]

201. In response to the UCG's submission that the fee for meter testing should not be billed up-front, the Utilities replied:

> In the Utilities' view, if meter testing fees are not imposed up-front in such circumstances, there would be little incentive for customers to work with the Utilities in accordance with the meter dispute process, and that customers may request meter testing in situations where they feel that their bill does not reflect their energy consumption, without a strong basis to suspect that the meter is faulty. The Utilities submit that an up-front fee should apply, as proposed in the Application, in order to avoid unnecessary use of the service and the unnecessary imposition of costs on other ratepayers.[146]

4.12.3. Board Findings

202. In this section, the Board makes its findings with respect to each Schedule D Fee or Service Charges as proposed by the Utilities. As noted earlier, The Board's findings on the use of an annual inflation factor can be found in Section 6.

203. The Board finds that most of the fees and service charges proposed by the Utilities in the Schedule D Fees Schedule exceed inflation when examined over the last 12 years. The Board has used the Utilities' response to YUB-AEY/YEC-2-5(a)[147] as the reference point for setting these fees and service charges. This is because the table provided in response to the IR illustrates that in all instances, each of the proposed Schedule D Fee or Service Charge, is in excess of the fee that is calculated by taking the currently approved Schedule D Fee or Service Charge inflated at Whitehorse CPI from 2012 to 2024.

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[144] Utilities' Reply Argument, PDF page 15.
[145] Utilities' Reply Argument, PDF page 16.
[146] Utilities' Reply Argument, PDF page 14.
[147] YUB-AEY/YEC-2-5(a), PDF page 11.

Table 1: Schedule D Fees and Service Charges Comparison

Table 1: Fees and Service Charges Comparison

Schedule D Fee Or Service Charge (a)	Currently Approved Fee Or Service Charge (b)	Currently Approved Fee Or Service Charge Inflated At Whitehorse CPI From 2012 To 2024 (c)	Proposed Fee Or Service Charge (d)
Connection Fee - Business Hours	50.00	65.65	87.00
Connection Fee - Outside Business Hours	50.00	65.65	87.00
Reconnection Fee - Business Hours	60.00	78.77	87.00
Reconnection Fee - Outside Business Hours	60.00	78.77	87.00
Collection Fee	30.00	39.39	45.00
Dishonoured Payment Fee	25.00	32.82	45.00
Meter Accuracy Test Handling Fee, Self Contained Meter	100.00	131.29	250.00
Meter Accuracy Test Handling Fee, Instrument Meter	200.00	262.58	500.00

Source: YUB-AEY/YEC-2-5(a) Table 1, PDF page 11.

204. The Board considers the Utilities' update for connection and reconnection fees to be high. First, with the implementation of AMI technology and the ability to connect and reconnect remotely, the Board directs that Schedule D Fees Schedule contain an amendment that will show the rate for supplementary reads for standard meter reads as the rate for connection and reconnection fees for those customers with functional standard meters. Secondly, with respect to non-standard meters, in reference to YUB-AEY/YEC-2-4(a), the connection and reconnection fees exceed inflation. The Board approves connection fees of $66.00 and approves reconnection fees of $79.00.

205. The Board denies the request for a fee or service charge for customer usage information requests. As the Utilities did not provide any information in terms of quantities of complex customer usage requests, the Board is of the view that such requests are already built into the rates of customers through the Utilities' last GRA. Furthermore, the Utilities can promote the usage of the MyAccount system to enable customers to obtain the information they require.

206. The Board approves the request of the Utilities for its supplementary meter reads but, as noted in Section 6 of this decision, the Utilities are directed to include a statement on Schedule D Fees Schedule that non-standard meter reading fees are not effective until the transition to standard meters is complete. Further, the Utilities are to inform the Board in writing within 30 days of the completion of the transition to standard meters.

207. The Board directs the Utilities to amend the term in Schedule D Fees Schedule for Late Payment and Disconnection. Under this term the Utilities are to implement wording that dishonoured payments fees are on a cost recovery basis and may include the charges the Utilities incur for the dishonoured payment, the payment amount owing, and the applicable fees in Schedule D Fees Schedule for dishonoured payment and collection. The proposed fees for collection and dishonoured payments exceed inflation and therefore are not approved. The Board approves a collection fee of $40.00 and a dishonored payment fee of $33.00.

208. Regarding meter disputes, the Board does not accept the revision to such fees as proposed by the Utilities. The increases proposed by the Utilities significantly exceed the inflation numbers demonstrated in response to YUB-AEY/YEC-2-5 (a). The Board approves a rate of $135 for meter accuracy test handling fee for a self-contained meter. The approved rate, for a meter accuracy test handling fee for an Instrument meter is $265.

209. In response to the UCG submission that customers should not pay meter test fees up front, the Utilities replied that without the upfront fee customers are less incented to work through the meter dispute process and that customers will request meter testing without a strong basis that a faulty meter exists. The Utilities also stated that the fee is required to avoid unnecessary costs on other ratepayers.

210. The Board finds that the Utilities did not provide any evidence that meter testing is a frequent event or a costly item to other ratepayers. It seems unusual to the Board that a customer must pay an up-front fee to determine whether the asset of the Utilities is working properly. The Board does agree that if the meter testing is at request of a customer, and a meter is found to be operating within its specifications, then the customer should pay the meter testing fee. However, the customer’s responsibility for the meter testing fee should arise after it is found that the meter has tested within its operational specifications. Therefore, the Board directs the Utilities to amend Section 6.3 such that the customer is responsible for the meter test fee if the meter testing is at the request of the customer and the meter is tested and found to be accurate. The fee from the customer is to be assessed after the meter test and will appear on the customer’s next billing following the meter test results. Further, the Utilities are to insert language in Section 6.3 that meter testing at the request of the customer can only occur after completing the meter dispute process.

211. The Utilities stated that Additional or Supplementary Services are not specifically included in the Schedule D Fees Schedule. In the case of additional or supplementary services, customers are advised of the fees for those services in advance and the fees are for cost recovery purposes. The Utilities submitted that

services provided for at cost cannot be limited to those outlined in the schedule as that would lead to inefficiencies and may impact customer experience.

212. The Utilities are directed to provide a statement on the Schedule D Fees Schedule that not all additional or supplementary services are listed in the Schedule. Customers will be advised of the fees for those additional or supplementary services in advance, and that the fees are for cost recovery purposes.

5. MAXIMUM INVESTMENT LEVELS

213. As noted earlier, a MIL is the maximum dollar amount that the Utilities can invest in a given type of new customer service connection (also referred to as a new extension project) where that investment is then added to AEY's or YEC's rate base. In cases where the actual connection costs incurred exceed the MIL, those excess costs are paid for directly by the connecting customer rather than being paid for by the utility.

5.1. The Utilities MILs study and analysis

214. A MIL is the limit of investment the utility contributes to new service connection (also referred to as an extension project),[148] such as a residential single family or multiple family dwelling connection, or general service connection or streetlight on the distribution grid. Service connection (or extension) costs that cost less than the approved MIL amounts are, in effect, fully contributed by the utility, while any portion of costs that are in excess of the approved MIL are contributed by the connecting customer.[149]

215. The Utilities stated that establishing an appropriate MIL takes into consideration factors such as economic efficiency and intergenerational equity, and ensures that the regulatory compact[150] is maintained. Doing so achieves outcomes that maintain equity between new and existing customers; allows utilities to earn a fair return; promotes orderly grid development and growth; and sends appropriate price signals for new developments. Alternatively, the absence of a balanced MIL can impact the strength of the Yukon economy by providing improper cost signals which may defer investment if set too low.[151]

[148] Also referred to as service connection projects.

[149] Utilities' Final Argument, PDF page 14.

[150] AEY-YEC 2025 T&Cs Application, PDF page 93, AEY describes the regulatory compact as the Utility's obligation to serve customers in return for a fair return on its investment.

[151] AEY-YEC 2025 T&Cs Application, PDF pages 93-94.

216. As noted by the Utilities, "MILs should be set to achieve a reasonable balance between the up-front costs borne by the individual customer and the costs paid by all customers in the applicable rate class through ongoing rates."[152]

5.2. MILs methodology

217. The Utilities, generally, relied on previously established methodologies in its approach to determining appropriate MILs for each of the four service type connections. Details of the Utilities approach can be found in the following Board-prepared table which summarizes each of the service type connections and the methodologies examined by the Utilities upon which its proposed MILs were based:

Table 2: Summary of MILs analysis

<table>
<tr><th>New service type connection (MIL rate classes):</th><th>Methodology for examination of costs to be applied on a per unit basis</th><th>For each connection type, the specific per unit MIL calculations followed a method of examination of the following data:</th><th>Proposed MIL based on method:</th></tr>
<tr><td>Residential Single Family</td><td>Cost-per-lot method, applied on a per site basis</td><td rowspan="4">(1) Median of 10 years of 2014-2023 actual costs inflated[153] by Handy Whitman (HW) Index to 2025[154]
(2) 2009 Study[155] inflated by HW Index to 2025
(3) Three (2021-2023) and five year (2019-2023) median costs[156] inflated by HW Index to 2025
(4) Desktop study of typical extension costs (2024 costs)[157]</td><td>(1)</td></tr>
<tr><td>Residential Multiple Dwelling</td><td>Cost-per-lot method, applied on a per site basis</td><td>(1)</td></tr>
<tr><td>General service</td><td>Cost per kW method, applied on a per kW basis</td><td>(1)</td></tr>
<tr><td>Street lighting</td><td>Cost-per-fixture method, applied on a per light basis</td><td>(1)</td></tr>
</table>

152 Utilities' Final Argument, PDF page 14.

153 AEY-YEC 2025 T&Cs Application, PDF page 95, "... this Study is based on available project actual cost data in the last 10 years, corresponding to the period 2014-2023."

154 AEY-YEC 2025 T&Cs Application, PDF page 96, footnote 4: "2024 and 2025 estimated, based on the 10-year average rate."

155 AEY-YEC 2025 T&Cs Application, PDF page 96: "AEY has inflated the values from its last MIL Study completed in 2009, outlined in Table 1, to 2025 dollars using Handy-Whitman as a reference point and comparison to the detailed cost per lot study."

156 AEY-YEC 2025 T&Cs Application, PDF page 100, Table 6, shows that the three- and five-year costs were inflated to 2025 dollars.

157 YUB-AEY/YEC-2-020(a), PDF page 51: "Due to the timing of the analysis being later in 2024, AEY conducted the Desktop Study using the latest 2024-unit costs, assuming these costs would remain

Source: AEY-YEC 2025 T&Cs Application, Study on Maximum Investment Levels (MILs), Approach and General Assumptions, PDF pages 94-97.

218. In determining both Residential Single Family and Residential Multiple Dwelling MILs, the Utilities utilized a cost per-lot methodology which allowed for an analysis that factored in changes in customer behaviours, standards, and lot designs.[158]

219. For the General Service MIL, the Utilities conducted an analysis on a per kW basis. This took into account the characteristics of the General Service Mil class and focused on reflecting infrastructure upgrades to handle peak demand, and ensuring that the MILs incorporate the higher demands on the system.

220. The Utilities developed a cost per-fixture analysis to derive MILs for street lighting sites, stating that this approach reflected the required infrastructure costs.

5.3. Inflationary Factors

221. The Utilities stated that the data relied on in the MIL Study used real project costs based on historical data (for each of the four extension-types), and did not use any specific percentage or investment proportion as a starting point for a given service connection type.[159] Specific to the Residential Multi Dwelling MIL, in the previous study supporting the currently approved MIL, that MIL was not a specific or dedicated calculation for Residential Multi Dwelling service connections, and was instead based on a ratio derived from the Residential Single Family MIL. In the Utilities view, this "dedicated" aspect of the MIL Study, and the dataset used in the analysis, captured a broad range of project variations, and provides stable, representative cost figures with which to work.[160]

222. As such, in all four MIL analysis, the Utilities looked at actual historical costs for each of the associated new service connection projects over the period 2014-2023. AEY then inflated the actual cost data for each of the service connection types to 2025 dollars using a HW Index for the years 2011-2023. The inflation rates used for 2024 and 2025 were estimated based on the 10-year average actual HW Index.[161]

223. The Utilities' MILs recommendations were based on using the median cost value (of the 10 years of actual project cost information inflated to 2025 dollars using the HW Index), whereas, historically, an average cost value was used. The Utilities stated

constant over the next few months. Thus, to be conservative, no additional inflation rate was applied. If inflation was applied, the results of the Desktop Study would be higher."

158 AEY-YEC 2025 T&Cs Application, PDF page 94.

159 Utilities' Final Argument, PDF pages 15-16.

160 Utilities' Final Argument, PDF page 15.

161 AEY-YEC 2025 T&Cs Application, PDF pages 94-96.

that, compared to the use of an average cost value, the median provides the middle value of the data set and is more central to the population distribution and, therefore, better represents the 10 years of data being assessed.[162]

224. Further, although AEY's MILs Study reflected actual historical project costs inflated by the HW Index, the Utilities proposed to inflate the final 2025 Board approved MILs, each year, by an inflation amount equal to a 12-month average of CPI for Whitehorse.[163] The proposal for an annual inflation factor, as it pertains to both MILs and the Schedule D Fees Schedule, is discussed further in Section 6 of this Board Order.

225. The Utilities provided a summary of the HW Index and CPI Whitehorse inflation rates for the period 2011-2025:

Table 3: Comparison of HW Index and CPI Whitehorse Inflation Rate

Year	**Handy-Whiteman**		**Whitehorse CPI**	
	Index	**% Change**	**Index**	**% Change**
2011	585.5	-	118.1	-
2012	608.8	4.0%	120.8	2.3%
2013	630.4	3.6%	122.8	1.7%
2014	649.5	3.0%	124.4	1.3%
2015	668.1	2.9%	124.1	-0.2%
2016	674.3	0.9%	125.4	1.0%
2017	696.3	3.3%	127.5	1.7%
2018	726.3	4.3%	130.6	2.4%
2019	756.0	4.1%	133.2	2.0%
2020	793.8	5.0%	134.5	1.0%
2021	832.3	4.9%	138.9	3.3%
2022	974.8	17.1%	148.3	6.8%
2023	1,215.0	24.6%	155.5	4.9%
2024	1,297.4	6.8%	158.6	2.0%
2025	1,385.4	6.8%	162.5	2.5%

[162] AEY-YEC 2025 T&Cs Application, PDF page 95.
[163] JM-AEY/YEC-1-020, PDF page 34.

Period Total 2013-2024		80.5%**		31.3%
Period Total 2013-2025		87.3%**		33.8%**

*Grey values were estimated by the 10-year average.
** % Change values for Handy Whitman index and CPI Whitehorse calculated by YUB.
Source: YUB-AEY/YEC-1-040(d), PDF pages 91-92, Table 1; YUB-AEY-YEC-2-005(a), PDF page 11, Table 2.

226. Given the significant difference between the HW Index and CPI Whitehorse inflation rates over the period examined, the Board questioned the inflationary inputs used by AEY in relation to each of the four methodologies and analysis it prepared. The Board requested an expanded analysis that took into account the alternative CPI Whitehorse inflation rates and further variations examining the use of median versus average cost data. The Board also requested the re-calculation of the HW Index inflation rate that removed the highest HW Index rates (2022 and 2023) as outliers related to COVID 19, and substituted those two years with the more moderate CPI Whitehorse rates.

Table 4: Summary of the effect on proposed MILs using alternative inflationary rates

	Table 8: Residential Single Family MIL	**Table 13: Residential Multi Dwelling MIL**	**Table 18: General Service MIL**	**Table 23: Street Lighting MIL**
	MIL (2025$/site)	**MIL (2025$/site)**	**MIL (2025$/kW)**	**MIL (2025$/light)**
Column (1)	**Column (2)**	**Column (3)**	**Column (4)**	**Column (5**
10-Year Median (Recommended)	10,337	2,645	1,801	6,649
10-Year Average using HWI	14,075 (Table 4)	4,023 (Table 9)	2,789 (Table 14)	6.933 (Table 19)
10-Year Median using HWI 2011-2025, replacing the years 2022 and 2023 with a % change of 6.8% and 4.9%, respectively	7,590	1,923	1,344	5,909
10-Year Average using HWI 2011 2025, replacing the years 2022 and 2023 with … 6.8% and 4.9% … (Note 1)	10,500	2,954	2,054	5,356

10-Year Median using CPI Whitehorse 2011-2025	7,088	1,694	1,192	5,711
10-Year Average using CPI Whitehorse 2011-2025	9,632	2,695	1,870	5,030
Inflating 2009 Study	10,347	5,175	3,298	6,559
2009 Study inflated using HWI 2011-2025, replacing the years 2022 and 2023 with … 6.8% and 4.9% …	7,524	3,763	2,399	4,770
2009 Study inflated using CPI Whitehorse 2011-2025	6,017	3,009	1,918	3,814
3-Year Median (2021-2023)	6,347	4,046	1,617	3,834
3-Year Average using HWI	11,347 (Table 6)	3,994 (Table 11)	2,595 (Table 16)	5,083 (Table 21)
3-Year Median using HWI, replacing the years 2022 and 2023 with … 6.8% and 4.9% …	6,019	3,228	1,244	3,636
3-Year Average using HWI, replacing the years 2022 and 2023 with … 6.8% and 4.9% …	9,389	3,176	1,999	4,434
3-Year Median using CPI Whitehorse 2021-2023	5,817	3,119	1,202	3,514
3-Year Average using CPI Whitehorse 2021-2023	9,074	3,069	1,932	4,286
5-Year Median (2019-2023)	9,943	4,046	2,039	6,649
5-Year Average using HWI	14,102 (Table 6)	4,271 (Table 11)	3,102 (Table 16)	6,925 (Table 21)
5-Year Median using HWI, replacing the years 2022 and 2023 with … 6.8% and 4.9% …	7,590	3,005	1,492	5,909
5-Year Average using HWI, replacing the years 2022 and 2023 with … 6.8% and 4.9% …	10,667	3,161	2,314	5,358

5-Year Median using CPI Whitehorse 2021-2023	7,335	2,860	1,388	5,711
5-Year Average using CPI Whitehorse 2021-2023	10,021	2,949	2,184	5,041
Desktop Study	11,014	2,754	4,533	4,571
Desktop Study – using CPI Whitehorse	11,014	2,754	4,533	4,571
Approved MIL: Board Order 2020-10-13 Appendix A, PDF Page 55	1,500	725	690	1,240

Source: YUB-AEY/YEC-2-022(a), PDF pages 60-62, Table 1.
Note 1: The MILs calculation for the scenario "10-Year Average using HWI 2011-2025, replacing the years 2022 and 2023 with a percent change of 6.8 percent and 4.9 percent, respectively" was not part of the request. AEY has included this calculation.

5.4. Comparison of Study Results to Other Jurisdictions

227. In response to intervener IRs, the Utilities provided a comparison of the equivalent MILs for Canadian jurisdictions outside Yukon. The results are shown in the table below.

Table 5: MILs of Northern and Southern Canadian Electric Utilities

	AEY/YEC Present MILs	AEY/YEC Proposed MILs	Naka-YK[1]	Naka-NWT[2]	NTPC	BC Hydro[3]	ATCO Electric Distribution	Fortis Alberta	Ontario and Quebec[4]
Year	2011	2025	2013	2016	2019	2025	2024	2024	2024
Residential Single Dwelling	$1,500 /site	$10,337 /site	$2,340 /site	$1,750 /site	$1,500 /site	$2,690 /site	$3,016 /site	$3,016/ site	Based on a basic service defined by the distributor.
Residential Multi Dwelling	$725 /site	$2,645 /site	$780 /site	$890 /site	$750 /unit	n/a	n/a	n/a	
General Service	$690 /kW	$1,801 /kW	$340 /kW	$340 /kW	$250 /kW	$501 /kW	$3,231 /kW	$6,461 fixed plus $1,028/ kW	

Street Lighting	$1,240 /light	$6,649 /light	Cost of installation	$1,430 /light	Cost of installation	$174 /Light	$2,865 /Light	$3,325/ light	

Source: JM-AEY/YEC-2-002(b), PDF page 4, Table 1, MILs of Northern and Southern Canadian Electric Utilities

[1] Northland Utilities (Yellowknife) Limited o/a Naka Power Utilities (Yellowknife) (Naka-YK).

[2] Northland Utilities (NWT) Limited o/a Naka Power Utilities (NWT) (Naka-NWT).

[3] BC Hydro adopts a present value methodology, equivalent to a Desktop Study plus economic modeling.

[4] As per Ontario's Distribution System Code (DSC) and Hydro Quebec's Conditions of Service, the cost recovery is based on a basic connection service defined by the distributor. Customers shall be subject to charges above and beyond the basic service.

5.5. Views of interveners

228. As noted earlier, the UCG was concerned about the lack of any consultative process undertaken by the Utilities in relation to either the MILs or Schedule D Fees Schedule. The UCG argued that doing so would have aided in the determination of price signals. The UCG recommended that the Board instruct the Utilities to track new MIL contracts while gathering ratepayer feedback on suitability and affordability.

229. The UCG pointed to increases to the customer's portion of the infrastructure costs for the updated MILs and Fees Schedule noting that it was significant. Specific to the MILS:

> ... increase[s] from $1,500 to $10,337—a 590 percent rise for single-family dwellings; from $725 to $2,645—a 265 percent rise for multiple dwellings; from $690 to $1,801—a 161 percent rise for general service; and from $1,240 to $6,649—a 440 percent rise for street lighting.[164]

230. The UCG also argued that implementing a phased approach to changes in both Schedule D Fees Schedule and MILs would help mitigate the shock of a sudden financial burden on customers as it would offer a more gradual transition while also enabling utilities to gather ratepayer feedback.[165]

231. Mr. Maissan took issue with an apparent lack of logic between the proposed MILs for a Residential Single Dwelling (MIL of $10,337 per dwelling) and Residential Multi Dwelling (MIL of $2,645 per dwelling). Mr. Maissan argued that the disparity between the relative per unit costs of the two MILs would only make sense if

[164] UCG Final Argument, PDF pages 2 and 4

[165] UCG Reply Argument, PDF page 3.

comparing one Residential Single Dwelling with a Residential Multiple Dwelling that consisted of a "larger number of apartments or condominium units."[166]

232. Mr. Maissan stated the reality was that various parties[167] within Yukon were attempting to limit or reduce housing cost growth through the encouragement of a "middle ground of duplexes to row housing, basement suites, and garden suites." However, this was not being reflected in the limited MILs being proposed by the Utilities. Mr. Maissan analyzed the MIL options as summarized by the Board in the following table:

Table 6: Board-prepared Summary of John Maissan MIL Analysis

Type of Dwelling	**Single Family Dwelling with Basement Suite**	**Single Family Dwelling constructed with or without Basement**	**Single Family Dwelling that adds Basement Suite later**	**Single Family Dwelling that adds a Garden Suite later**
MIL – Residential Single Family		$10,337	$10,337	$10,337
MIL – Residential Multi Dwelling	$5,290 ($2,645 X 2)		$2, 645	$10,337
Total MIL recovered	**$5,290**	**$10,337**	**$12,892**	**$20,674**

Source: Mr. Maissan Final Argument, PDF page 11, referring to JM-AEY-YEC-2-14, PDF pages 22-23.

233. In light of the above noted range of MILs, Mr. Maissan's view is that the two proposed MIL categories clearly do not address any attempt to reduce housing costs, nor does it provide the Utilities with prudent investment opportunities. As such, Mr. Maissan recommended that the Board direct the creation of a third category of MIL that would address a Residential Multi Dwelling with a "small number of units attracting a MIL of $10,337 or $2,645 per unit, whichever is greater."

234. Mr. Maissan further argued that consideration should be given to whether a garden suite that is not part of or attached to a Single-Family Dwelling, but on the same residential lot, attracts a MIL of $2,645 or $10,337. He stated that it may depend on whether the existing "service drop" could be shared and metered separately.

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166 Mr. Maissan Final Argument, PDF page 11.

167 Mr. Maissan Final Argument, PDF page 11; "The Yukon and Whitehorse reality is that in a desire to limit or reduce housing cost growth, various parties, including builders, building owners, the City of Whitehorse, as well as First Nations and Yukon governments, have been encouraging the middle ground of duplexes to row housing, basement suites, and garden suites."

5.6. Utilities' Reply

235. The Utilities did not respond to the UCG's concerns and recommendations with respect to tracking new MIL contracts while gathering ratepayer feedback on suitability and affordability, nor did it respond to the use of a phased-in approach to mitigate the increases related to MILs.

236. With respect to Mr. Maissan's recommendation for a "middle ground" residential MIL, the Utilities argued that further analysis was necessary to ensure fairness among all customers. However, if directed to do so, the Utilities would be willing to consider how Mr. Maissan's recommendation could be implemented in the next MIL review.[168]

5.7. Board Findings

237. The Board has examined the Utilities MILs study which was based on detailed actual (historical) cost-per-lot or fixture data (in the case of single and multi-dwelling residential service connections and light fixtures), or cost per kW data (in the cost of general service connections). For each of the four service connection types, the Utilities prepared analyses based on 10-year median of full cost, most recent 5-year median cost, most recent 3-year median cost as well as inflating 2009 study costs by HW Index and, lastly, a desktop study based on current costs. Although, historically, the Utilities' proposals relied on average costs (rather than median costs), the Board finds these methodologies and suite of analyses to be appropriate for the intended purpose.

238. However, the Board has concerns with the method by which the Utilities inflated the historical data used in the analyses in order to bring costs to current dollars. The use of the HW Index rather than CPI Whitehorse to inflate historical dollars in combination, with no tempering of the COVID era inflation to that experienced in Yukon, has resulted in substantially higher service connection costs in all instances. This is evident, as shown in Table 4 above, where, for example, for a Residential Single-Family MIL, the 10-year median service connection using the HW Index is estimated at $10,337 whereas the 10-year median service connection using CPI Whitehorse is estimated at $7,088. The Board finds this aspect of the Utilities MILs study results in unreasonable MILs being proposed.

239. Furthermore, Table 5 above shows that, with the exception of the General Service MIL, all MILs proposed by the Utilities exceed peer utility MILs by a significant margin. The Utilities did not offer an explanation of why this may be the case.

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[168] Utilities' Reply Argument, PDF page 16.

240. The Board is inclined to direct the implementation of MILs that takes into consideration both peer MIL values and a less aggressive approach to inflating actual historical costs to one that is more related to the Yukon service territory.

241. Accordingly, the Board finds that, for new service connections for Residential Single Family, Residential Multiple Dwelling, and Street Lighting, a MIL based on one-third of the 10-Year Average using CPI Whitehorse 2011-2025 is reasonable. As shown in Table 7 below, the resultant MILs are either consistent with the upper limit of peer utility MILs, as is the case with Residential Single Family and Residential Multiple Dwelling MILs, or at the mid-point of peer utility MILs, as is the case with Street Lighting.

242. With respect to new service connections for General Service, the Board finds that a MIL based on the 10-Year Average using CPI Whitehorse is reasonable given that it aligns near the midpoint of peer utility MILs for this category.

Table 7: Board-prepared Summary of Historic, Proposed and Peer Utility MILs

	Residential Single-Family MIL	Residential Multi Dwelling MIL	General Service MIL	Street Lighting MIL
	$ per connection or fixture and $ per kW and $ fixed (if applicable)			
Prior to 2010 approved (Note 1)	900 per connection	450 per connection	400 per kW	700 per fixture
Proposed in 2011-2015 – 5-year multi year (Note 1)	4,373-4,700	625-2,350	5,355-5,955 fixed + 275-305 per kW	930-2,975
Approved MIL: Board Order 2020-10-13 Appendix A, PDF Page 55	1,500	725	690 per kW	1,240
10-Year Median (AEY-Recommended) (Note 2)	10,337	2,645	1,801 per kW	6,649
10-Year Average using CPI Whitehorse 2011-2025 (Note 2)	9,632	2,695	1,870 per kW	5,030
Range for peer utilities (Note 3)	1,500-3,016	750-890	250-3,231 per kW OR 6,461 fixed plus + 1,028 per kW	174-3,325

1/3 of 10-Year Average using CPI (YUB calculated)	3,210	900	625 per kW	1,675

Source:
Note 1: YEC & YECL 2009 Phase II Rate Application, Table 8, Table 9, Table 10, Table 11, PDF pages 354-356
Note 2: YUB-AEY/YEC-2-022(a), PDF pages 60-62, Table 1.
Note 3: JM-AEY/YEC-2-002(b), PDF page 4, Table 1, MILs of Northern and Southern Canadian Electric Utilities

243. The Utilities are directed to implement MILs as follows:

(i) Residential Single-Family MIL $3,210 per connection

(ii) Residential Multi Dwelling MIL $900 per connection

(iii) General Service MIL (per kW) $1,870 per kW

(iv) Street Lighting MIL $1,675 per fixture.

244. The Board denies the UCG's proposal that the Utilities track new MIL contracts while gathering ratepayer feedback on suitability and affordability. Given that the Board, earlier in this decision, has directed consultations to occur at the time the T&Cs are next updated, the topic of suitability and affordability can be raised by stakeholders at that time.

245. With respect to Mr. Maissan's recommendation that the Utilities establish a MIL to accommodate an apparent growing number of multi-family type living arrangements, such as basement suites and garden suites, the Board finds Mr. Maissan's analysis supporting the creation of a middle-ground MIL to be a compelling and worthwhile exercise. As shown in Table 6 above, depending on when additional living quarters are added to an existing residence, the MILs appear to become asymmetrical and cost prohibitive.

246. However, the Board agrees with the Utilities that further analysis would be necessary in order for the middle-ground proposal to be fully vetted. Accordingly, at the time of the Utilities' next T&Cs application, the Board directs that an additional MIL and service connection type be investigated. The investigation would examine residential properties that allow for a smaller number of additional dwellings (such as a basement suite, garden suite, duplex, or row house) as opposed to additions that would typically be associated with a Residential Multi-Dwelling service connection.

6. Proposed Annual Inflation Factor for MILs and Schedule D Fees Schedule

247. As noted earlier, the Utilities proposed to inflate the final 2025 Board approved MILs and Schedule D Fees Schedule (in years in which either no joint Phase II application or application seeking approval of new or updated T&Cs or MILs is in front of the Board), by an inflation factor amount equal a 12-month average of CPI for Whitehorse.[169] This would "ensure that the annual MILs continue to be reflective of, or approximately reflective of, changes in cost pressures with respect to material and labour."[170] AEY stated it would use the CPI Whitehorse and not the HW Index for the annual inflation amount because the HW Index is typically one year behind.[171]

248. The Utilities argued that the annual inflation proposal, when combined with a no-notice application to the Board, would be efficient and would provide cost certainty for customers. The approach balanced the need to ensure that MILS and fees reflect inflation over time while also promoting regulatory efficiency and avoiding detailed annual reviews. Further, it was consistent with an approach used by utilities in Alberta where distribution utilities update MILs and fees in their annual rate filings based on inflation.[172]

6.1. Views of interveners

249. The UCG examined the Utilities request to add CPI for Whitehorse to reflect inflation to the MILs and Fees Schedule annually when a "rate case" is not in front of the Board[173] while noting that they have not proposed updates to the T&Cs since 2011. The UCG submitted that the utilities be denied the opportunity to apply yearly CPI inflation rates to their T&Cs charges during non-test years as it "would encourage them to use the regulatory process for any desired changes."[174]

250. Mr. Maissan also commented on the Utilities' annual inflation proposal, observing that the CPI for Whitehorse data only lags behind real time by about a month, but the HW Index lags about a year behind.

251. Mr. Maissan stated that the Utilities considered an alternative proposal of a two-step inflation calculation (one correcting the prior year's CPI adjustment for the now available HWI and the second step adjusting for the current year's Whitehorse CPI),

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169 JM-AEY/YEC-1-020, PDF page 34.

170 AEY-YEC 2025 T&Cs Application, PDF page 113.

171 JM-AEY/YEC-1-020, PDF page 34.

172 Utilities' Final Argument, PDF page 17.

173 UCG Reply Argument, PDF page 4.

174 UCG Final Argument, PDF page 4.

was inefficient and unnecessary. Mr. Maissan considered this position difficult to understand when considering the simplicity of the calculation and the significant disparity between the HWI and the Whitehorse CPI over the past decade.

252. Mr. Maissan argued that “the Utilities would be depriving themselves of a prudent investment opportunity as well as increasing the cost of new home construction, should that continue.”[175] Mr. Maissan recommended that the Board order the Utilities to do a two-line calculation once per year in December for adjustments to the approved MIL rates: one to adjust the prior year MIL inflation rate for the difference between the CPI and the HWI indices for that year; and the second to then adjust the MIL rate for the current year CPI change.[176] There is no justifiable reason why it would be inappropriate for the Utilities to do a two-line calculation once per year to keep the MIL rates better in line with the HW Index.[177]

6.2. Utilities’ Reply

253. While the Utilities agreed that CPI does not correlate perfectly to utility costs, its proposed annual inflation increase mechanism using CPI Whitehorse would better align the relevant amounts to inflationary factors ahead of the next full review.

254. Mr. Maissan’s recommendation to update the MILs by “an adjustment of the prior year MIL inflation rate for the difference between the CPI and the HWI indices for that year, as well as an adjustment of the MIL rate for the current year CPI change” should be disregarded by the Board as an unnecessary.[178]

6.3. Board Findings

255. The Board considers the request for an automatic CPI-based annual inflation adjustment to both MILs and Schedule D Fees Schedule to be unwarranted in the circumstances of these Utilities, and is denied.

256. First, in the Board’s view, annual inflation adjustments to existing costs or rates are more closely associated with Utilities regulated under some form of performance-based ratemaking (PBR) mechanism. Under this mechanism, a cost or rate, as the case may be, is typically adjusted annually by some inflation rate that also takes into account a reduction (to the inflation rate) for expected improvements in productivity. Further, the Utilities are regulated under a cost-of-service mechanism where is the review of the Utilities’ costs to provide service to its ratepayers is at the

175 Mr. Maissan Final Argument, PDF page 13.
176 Mr. Maissan Final Argument, PDF page 13.
177 Mr. Maissan Reply Argument, PDF pages 5-6.
178 Utilities’ Reply Argument, PDF page 6.

forefront, and includes the costs associated with determining MILs and Schedule D Fees Schedule. Neither of these aspects were raised by the Utilities in their proposal.

257. Second, there has been an 11-year lapse since the time of the Utilities' last review of MILs and Schedule D Fees Schedule. Accordingly, the Board finds there is no evidence of a sudden urgency to now adjust these charges on an annual basis. Further, an automatic annual adjustment provides a guaranteed increase for the Utilities which may not be warranted.

258. A third concern is the potential for a mismatch of the implementation of any updated MILs and Schedule D Fees Schedule and the associated impact on revenue requirement for each Utility. While the Utilities' proposal would keep the MILs and Schedule D Fees Schedule consistent between the Utilities for some period of time, there is a good likelihood that the Utilities will not submit their GRAs at the same time, and this creates the opportunity for a disconnect between the applicable MILs and Schedule D Fees Schedule, their implementation date, and the impact on each of the Utilities' revenue requirements.

259. Lastly, the Board finds that the better approach is adjusting the Schedule D Fees Schedule, and any other Service Charges, within the context of a GRA. Including such changes in a GRA reduces the risk of inflating charges that may no longer be applicable and supports customer participation in the rate setting process.

260. For the reasons provided above, the Board finds that the Utilities have not made a compelling case for moving from the status quo examination of MILs and Schedule D Fees Schedule.

261. Having made this finding, the Board denies the proposal of Mr. Maissan with respect to implementing a two-step update of the MILs and Schedule D Fees Schedule. The Board also views the concerns of the UCG with respect to the annual inflation update to be resolved, although for reasons different from those submitted by the UCG. This is because the UCG purported that a yearly application to adjust for CPI would encourage the Utilities to use the regulatory process for any desired changes.