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British Columbia Hydro and Power Authority

Application for a Certificate of Public Convenience and Necessity for the Mainwaring Substation Upgrade Project

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Decision
and Order C-4-22

August 16, 2022

Before:
A. K. Fung, QC, Panel Chair
E. B. Lockhart, Commissioner
A. Pape-Salmon, Commissioner

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Executive summary

On November 5, 2021, British Columbia Hydro and Power Authority (BC Hydro) filed an application with the British Columbia Utilities Commission (BCUC) seeking a Certificate of Public Convenience and Necessity (CPCN) for the Mainwaring substation upgrade project to replace two power transformers, a feeder section and associated equipment (the Project). BC Hydro identifies that the Project is required to maintain the reliability of the substation, and to address safety, environmental and compliance risks. The equipment proposed for replacement as part of the Project is reaching end of life. In addition, certain equipment in the substation contains Polychlorinated Biphenyls (PCBs) which exceed the amounts allowed under the federal PCB Regulations and must be removed by December 31, 2025 according to the Regulations.

The BCUC established a regulatory timetable for review of the application, which included public notification, filing of confirmation of compliance with public notification directives, two rounds of BCUC and Intervener information requests, submission of letters of comment and final and reply arguments. The following parties registered as interveners in the proceeding: British Columbia Old Age Pensioners' Organization et al.; Commercial Energy Consumers Association of British Columbia; and the Residential Consumer Intervener Association. One individual registered as an interested party and the BCUC did not receive any letters of comment.

The Panel finds that the evidence supports the need to address the reliability, environmental, and safety risk due to deteriorated equipment at the Mainwaring substation. The Panel makes this determination substantially based on the asset condition as analyzed through BC Hydro's Asset Health Index methodology, including the 2013 engineering assessments on the condition of the substation's two power transformers. In addition, the Project mitigates any compliance risks associated with failure to remove PCBs contained in the equipment at the substation by the stipulated deadline as required pursuant to the federal PCB Regulations.

With respect to other aspects of the Project, the Panel makes the following findings:

- BC Hydro's analysis of the Project alternatives is reasonable;
- The choice of 150 MVA power transformers for the replacement of the T1 and T3 power transformers is justified, rather than simply replacing them with 75 MVA power transformers;
- The cost estimates for the Project are reasonable;
- BC Hydro's consultation with Indigenous communities and other stakeholders has been adequate to date; and
- The Project is in alignment with relevant legislation in the *Utilities Commission Act* and the *Clean Energy Act*, including BC's energy objectives, along with BC Hydro's 2021 Integrated Resource Plan.

Overall, the Panel finds that the public convenience and necessity require the construction and operation of the Mainwaring substation upgrade Project.

Accordingly, the Panel grants a CPCN to BC Hydro for the Project.

Given the magnitude of the Project and the timeline for its implementation, the Panel also directs BC Hydro to provide ongoing reporting to the BCUC for the duration of the Project, as detailed in Appendix A of this Decision.

1.0 Introduction

On November 5, 2021, British Columbia Hydro and Power Authority (BC Hydro) filed an application with the British Columbia Utilities Commission (BCUC) pursuant to sections 45 and 46 of the *Utilities Commission Act* (UCA) seeking a Certificate of Public Convenience and Necessity (CPCN) for the Mainwaring substation upgrade project (Application).[1]

BC Hydro proposes to replace two power transformers, a feeder section and associated equipment at the Mainwaring distribution substation in South Vancouver (the Project). BC Hydro identifies that the Project is required to maintain the reliability of the Mainwaring distribution substation, and to address safety, environmental and compliance risks. The equipment proposed for replacement as part of the Project is reaching end of life. In addition, certain equipment in the substation contains Polychlorinated Biphenyls (PCBs) which exceed the amounts allowed under the federal PCB Regulations and must be removed by December 31, 2025 according to the Regulations.[2]

The Project is expected to be in-service by October 2026 and has an estimated cost of $114.4 million.[3]

In 2018, the BCUC directed BC Hydro to file a CPCN application for the Project, if it was pursued;[4] hence, this Application.

1.1 Legislative and Regulatory Framework

The Panel reviews this Application in the context of the following applicable legislative and regulatory framework.

1.1.1 *Utilities Commission Act*

Section 46(3.3) of the UCA provides that in deciding whether to issue a CPCN to BC Hydro, the BCUC, in addition to considering the interests of persons in British Columbia who receive or may receive service from BC Hydro, must consider:[5]

(a) British Columbia's energy objectives;

(b) the most recent of the following documents:

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

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

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

[1] Exhibit B-1, p. 1-1.
[2] Ibid.
[3] Ibid., p. 1-7.
[4] Decision and Order G-47-18 in the matter of BC Hydro's F2017 to F2019 Revenue Requirements Application, p. 39.
[5] UCA, section 46(3.3).

1.1.2 *Clean Energy Act*

Section 2 of the *Clean Energy Act* defines British Columbia's energy objectives.[6]

Section 19 of the *Clean Energy Act*, which applies to BC Hydro, addresses clean and renewable resources and provides:

> 19(1) to facilitate the achievement of British Columbia's energy objective set out in section 2 (c), a person to whom this subsection applies:
>
> (a) must pursue actions to meet the prescribed targets in relation to clean or renewable resources, and
>
> (b) must use the prescribed guidelines in planning for
>
> (i) the construction or extension of generation facilities, and
>
> (ii) energy purchases.

1.1.3 PCB Regulations

The PCB Regulations are federal Regulations issued under the *Canadian Environmental Protection Act, 1999*.[7] Sections 7 to 17 of the federal PCB Regulations obligate BC Hydro to remove, by December 31, 2025, all equipment containing PCBs with a concentration of 50 ppm or more.[8]

1.1.4 BCUC Guidelines

The following BCUC Guidelines are applicable to this Application:

- The CPCN Guidelines provide general guidance regarding the BCUC's expectation of the information that should be included in a CPCN application;[9] and
- The 2010 First Nations Information Filing Guidelines for Crown Utilities identify the information that must be filed by Crown utilities (of which BC Hydro is one), in support of their applications and filings.[10]

1.2 Regulatory Process

Pursuant to an order issued on November 26, 2021, as amended December 2, 2021, the BCUC established a regulatory timetable for the review of the Application, which included public notification, filing of confirmation of compliance with public notification directives, two rounds of BCUC and Intervener information requests (IRs), submission of letters of comment and further process to be determined.[11]

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[6] *Clean Energy Act*, section 2.
[7] S.C. 1999, c.33
[8] The PCB Regulations (SOR/2008-273) came into force on September 5, 2008, with amendments effective January 1, 2015. Permitted activities are provided in sections 7-17 and subject to specified conditions. Section 16(1)(b)(ii) provides that specified equipment (such as electrical transformers) containing PCBs in a concentration of 50 mg/kg or more may only be used until December 31, 2025. Retrieved from https://laws-lois.justice.gc.ca/eng/regulations/SOR-2008-273/index.html.
[9] Appendix A to Order G-20-15, BCUC 2015 Certificate of Public Convenience and Necessity Guidelines (CPCN Guidelines), p. 1. Available at https://docs.bcuc.com/documents/Guidelines/2015/DOC_25326_G-20-15_BCUC-2015-CPCN-Guidelines.pdf
[10] Appendix A to Order G-51-10, dated March 18, 2010, BCUC 2010 First Nations Information Filing Guidelines for Crown Utilities, p. 3. Available at https://docs.bcuc.com/documents/Guidelines/2010/DOC_25327_G-51-10_2010-First-Nations-Information-Filing-Guidelines.pdf
[11] Order G-347-21 dated November 26, 2021; Order G-353-21, dated December 2, 2021.

By order issued March 4, 2022, the BCUC amended the regulatory timetable to include final and reply arguments.[12]

Three parties registered as interveners in the proceeding:

- British Columbia Old Age Pensioners' Organization et al. (BCOAPO);
- Commercial Energy Consumers Association of British Columbia (the CEC); and
- The Residential Consumer Intervener Association (RCIA).

One individual, A. Faries, registered as an interested party and the BCUC did not receive any letters of comment.

1.3 Structure of Decision

The structure of this Decision largely follows that of the CPCN Application and the BCUC's CPCN Guidelines:

- Section 2 addresses the need for the Project;
- Section 3 addresses the alternatives to the Project;
- Section 4 addresses the Project description and risk management;
- Section 5 addresses the cost of the Project and rate impact;
- Section 6 addresses public and Indigenous consultation for the Project;
- Section 7 addresses the Project's consistency with BC's energy objectives, BC Hydro's long term resource plan and the *Clean Energy Act*;
- Section 8 addresses an issue that arose during the proceeding, namely, the lack of an area study for the South Vancouver/Burnaby supply area within which the Mainwaring substation is located;
- Section 9 sets out the overall CPCN determination; and
- Appendix A sets out the reporting requirements for the Project as directed by the Panel.

2.0 Project Need and Justification

BC Hydro states that the Project is needed to address the following risks:[13]

1. Reliability risks associated with the end-of-life T1 and T3 power transformers;
2. Reliability risks associated with the end-of-life 50/60 feeder section;
3. Environmental risks due to oil leaks and PCBs in the T1 and T3 power transformers and equipment in the 50/60 feeder section;
4. Safety risks in the 50/60 feeder section due to the deteriorated condition of equipment and insufficient electrical clearances; and
5. Reputational risks associated with not complying with the federal PCB Regulations.

[12] Order G-64-22 dated March 4, 2022.
[13] Exhibit B-1, pp. 2-13 – 2-14.

In the following subsections, we provide an overview of the Mainwaring substation, describe BC Hydro's Asset Health Index methodology, review the need to address the condition of the T1 and T3 power transformers and the 50/60 feeder section, including the need to comply with the federal PCB Regulations, and review the need for the continued operation of the substation.

2.1 Overview of the Mainwaring Substation

The Mainwaring substation is centrally located within the Metro Vancouver Burnaby sub-region, which comprises 16 substations. The Metro Vancouver Burnaby sub-region has the largest load in the BC Hydro system. Based on peak demand, Mainwaring substation is the seventh largest distribution substation in the BC Hydro system. BC Hydro states that in fiscal year 2020, Mainwaring substation supplied power to approximately 66,000 distribution customers, with a normalized peak load of 172 MVA.[14]

The Mainwaring substation was built in 1957 and has undergone several upgrades since then to maintain reliability and to increase substation capacity. At present, the substation has a total capacity of 211 MVA and has three power transformers (T1, T2 and T3), two feeder sections of 20 feeders each (feeder sections 50/60 and 70/80), and two switchyards that connect to three 230 kV transmission lines connecting to three other substations.[15] The Mainwaring substation layout is shown in Figure 1, below.

Figure 1: Mainwaring Substation Layout[16]

[14] Exhibit B-1, pp. 2-3 - 2-4.
[15] Ibid., p. 2-8.
[16] Ibid., p. 2-9, Figure 2-4.

2.2 BC Hydro's Asset Health Index Methodology

One of the factors BC Hydro considers in identifying and prioritizing investments in its system is an asset's Asset Health Rating, which is determined through BC Hydro's proprietary Asset Health Index methodology. To determine the Asset Health Rating of a given asset, BC Hydro uses the Asset Health Index methodology to assess and evaluate the health of transmission and distribution assets, including the transformers and feeder section equipment at the Mainwaring substation. BC Hydro states that an asset's Asset Health Rating is not determinative when BC Hydro makes investment decisions, but rather, is an indicator used as part of its overall assessment of investment need.[17]

This subsection provides a description of BC Hydro's Asset Health Index methodology. Subsections 2.3 and 2.4 provide the specific Asset Health Ratings for those assets that are proposed to be replaced as part of the Project.

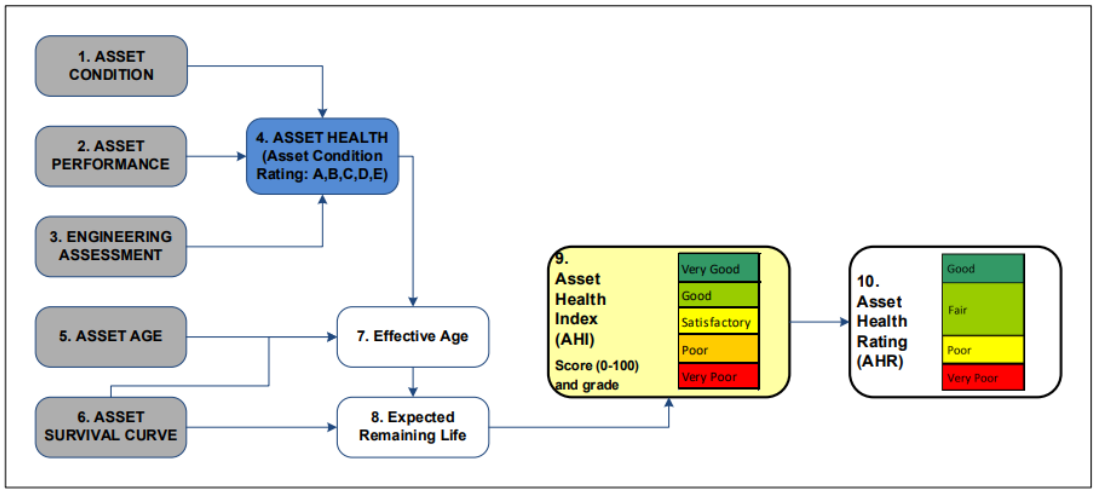
BC Hydro states that the information gleaned from its Asset Health Index methodology is used for the life-cycle management of its assets, including supporting the need for capital investments. BC Hydro considers that the Asset Health Index methodology provides a systematic, objective, repeatable, and transparent assessment of asset health based on operating, maintenance and asset management data.[18]

Although BC Hydro started collecting baseline data for asset health as early as 2004, it explains that the Asset Health Index methodology was formally adopted by BC Hydro in 2014.[19] BC Hydro considers that its approach to collecting and monitoring asset data is aligned with industry standards for asset management practices, including the 2015 International Infrastructure Management Manual (IIMM) standard. Based on the IIMM standard, the Office of the Auditor General's 2018 review of BC Hydro's asset management practices found that the BC Hydro had an advanced level of maturity for the "Collecting Asset Information" and "Monitoring Asset Performance and Condition" components of its asset management framework. BC Hydro states that while there are no specific industry standards for the development of asset health methodologies, BC Hydro considers itself an industry leader. [20]

Figure 2 below summarizes BC Hydro's Asset Health Index methodology:[21]

[17] BC Hydro Final Argument, p. 5.
[18] Exhibit B-1, p. 2-9.
[19] Exhibit B-3, BCUC IR 2.8.
[20] Ibid., BCUC IR 2.10
[21] In the Application (Exhibit A-1), BC Hydro provides Figure 2-5, however provided an expanded version of its methodology in response to RCIA IR 6.1, Attachment (Exhibit B-4).

Figure 2: BC Hydro's Transmission and Distribution Asset Health Index Methodology[22]



Further explanations for certain components of BC Hydro's Asset Health Index methodology are as follows:[23]

- Asset Health (#4, blue box), also known as Asset Condition Rating, reflects the current state of an asset based on field or engineering observations and is assigned a letter grade from A to E.
- Effective Age (#7) accounts for the impact of Asset Health on the physical age of an asset and depending on the value of Asset Health, Effective Age of an asset can be higher, lower or the same as the asset's real physical age.
- Expected Remaining Life (#8) is the amount of time an asset is expected to remain in service, based on its Effective Age and using Gaussian probability distribution for that asset class survival curve.
- Asset Health Index (#9, yellow box) is calculated as a numerical score from 0 to 100, which translates to an Asset Health Index grade of "Very Good," "Good," "Satisfactory," etc. The Asset Health Index score is the ratio between the asset's Expected Remaining Life and the Mean Life for that asset class.
- Asset Health Rating (#10) is a reporting method introduced as a common scale between Generation, Transmission and Distribution assets to allow for consistent asset health presentation. The Asset Health Rating is used to predict the asset's future performance and investment needs.[24]

Table 1 below summarizes the Asset Health Rating scale and corresponding possible investment needs:

[22] Exhibit B-4, RCIA IR 6.1, Attachment 1.
[23] Ibid.
[24] Exhibit B-1, p. 2-10.

Table 1: Asset Health Rating[25]

Asset Health Rating	Description	Possible Investment Needs
Good	As new condition, with no noticeable deterioration or defects	Normal maintenance
Fair	Normal deterioration of the asset with one or more minor defects; function is not affected	May require increased diagnostics and component replacement
Poor	Serious deterioration of the asset or serious defects	Overhaul or replacement may be required within four to ten years
Very Poor	Extensive serious deterioration of the asset or asset function is affected	Overhaul or replacement may be required within three years

2.3 Need to Address Deteriorated Condition of T1 and T3 Power Transformers

According to BC Hydro, a key driver of the Project need is the current age and condition of the T1 and T3 power transformers at the Mainwaring substation.[26]

BC Hydro states that the transformers are the most critical assets at the Mainwaring substation, and their failure can lead to supply interruptions to all customers supplied by the substation and can damage and/or trip customer electrical equipment.[27]

BC Hydro estimates the average expected service life of 230 kV transformers on its system to be 57 years, while noting that this may depend on multiple factors.[28] The T1 and T3 power transformers were manufactured in 1964 and 1957, respectively, and as such, BC Hydro considers that the T1 and T3 power transformers are approaching end of life.[29] The T2 power transformer was manufactured in 2006 and is therefore not in scope for this Project.[30]

In the Application, BC Hydro identifies that the T1 and T3 power transformers had an Asset Health Rating of "Poor," which means there is widespread and serious deterioration.[31] However, BC Hydro explained during the proceeding that this Asset Health Rating corresponded to the value in BC Hydro's Asset Health database that inadvertently did not include the most recent engineering assessments for the T1 and T3 power transformers from 2013. Despite not being included in BC Hydro's Asset Health database, BC Hydro states that the 2013 engineering assessments were considered when the Project was initiated and informed the Project justification as stated in the Application.[32] BC Hydro states that if the 2013 engineering assessments for these transformers

[25] Exhibit B-1, p. 2-10, Table 2-3; updated by Exhibit B-1-3, Errata 2 to the Application.
[26] Ibid., p. 2-4.
[27] Ibid., p. 2-14.
[28] Exhibit B-3 BCUC IR 3.3.
[29] Exhibit B-1, pp. 2-15 - 2-16; Age provided represents age at Application filing.
[30] Ibid., p. 2-16.
[31] Ibid., pp. 2-15 – 2-16.
[32] Exhibit B-6, BCUC IR 23.2.

were explicitly factored into the Asset Health Rating, then the actual Asset Health Rating for these two assets would be "Very Poor" rather than "Poor."[33]

This is reflected in the following table:

Table 2: T1 and T3 Asset Health Index Methodology Inputs[34]

Asset Health Index Methodology Inputs	If the 2013 Engineering Assessments are not factored into the Asset Heath Rating		If the 2013 Engineering Assessments are factored into the Asset Heath Rating	
	T1	**T3**	**T1**	**T3**
Asset Condition Rating	A	A	D	D
Effective Age (years)	51.3	51.3	56	63
Expected Remaining Life (years)	9.3	9.3	6	4
Asset Health Rating	Poor	Poor	Very Poor	Very Poor

In addition to having an Asset Health Rating of "Very Poor," as noted in Table 2 above, BC Hydro identifies certain problems associated with the T1 and T3 power transformers, which include the following:

- T1 power transformer:
    - The main transformer tank is leaking oil. BC Hydro maintains that this indicates that the seal is compromised such that moisture or contamination can enter the transformer, which will hasten its degradation. BC Hydro states that oil leaks are currently being mitigated by oil spill containment, regular maintenance and monitoring, and additional leak mitigation as required. Uncontained oil releases from leaking equipment could potentially impact soil, groundwater and habitat.[35] Further, BC Hydro states that the transformer contains PCBs, and if leaks are not addressed, it could lead to a prohibited and reportable release in accordance with federal PCB Regulations.[36]
    - Dissolved gas analysis indicates that the transformer has been undergoing arcing in the coil, which means that it has an elevated risk of failure if it is overloaded.[37]
    - The transformer's bushings must be removed by December 31, 2025 to comply with the PCB Regulations.[38]
- T3 power transformer:
    - The main transformer tank is leaking oil, with similar consequences, mitigations, and environmental risks as described for T1 above. BC Hydro states that previous leaks were repaired in 2019.[39]

[33] BC Hydro Reply Argument, p. 8; Exhibit B-7-1, RCIA IR 46.1.
[34] Exhibit B-1, pp. 2-15 – 2-16; Exhibit B-4, RCIA IR 6.2.2; Exhibit B-6, BCUC IR 23.2; Exhibit B-7, RCIA IR 58.3.1; Exhibit B-7, RCIA IR 58.4.1; Exhibit B-7-1, RCIA IR 46.5; BC Hydro Reply Argument, p. 10.
[35] Exhibit B-1, p. 2-15.
[36] Exhibit B-7, RCIA IR 46.1.
[37] Exhibit B-6, BCUC IR 23.3.
[38] Exhibit B-1, p. 2-15.
[39] Ibid., pp. 2-16 – 2-17.

- In the Application, BC Hydro identified that dissolved gas analysis indicated that T3 had been undergoing arcing in the coil; however, BC Hydro provided an update during the proceeding that this was in error and not one of T3's issues.[40]
- In the Application, BC Hydro also identified that T3's bushings must be removed by December 31, 2025 to comply with the PCB Regulations. However, it provided an update during the proceeding that additional testing revealed that the PCB concentrations in these bushings were below the prescribed threshold such that they are not being targeted for removal to comply with the federal PCB Regulations.[41]

BC Hydro plans its power transformer system with N-1 redundancy,[42] which requires that service to customers be restored if any single transformer fails.[43] BC Hydro states that if both power transformers fail at the same time, service to up to 40,000 customers will be interrupted and the duration of the customer interruption would be approximately three months. BC Hydro states that due to the age and condition of the T1 and T3 power transformers, there is a risk of failure and loss of equipment redundancy, resulting in an increased risk of loss of service.[44]

BC Hydro states that it appropriately took into consideration the long lead time of the Project and the fact that reliability is a lagging indicator of asset condition in assessing the need to address the risks posed by the T1 and T3 power transformers. As such, BC Hydro considers that addressing the risks posed by the T1 and T3 power transformers must be initiated in advance of the reliability risks materializing. BC Hydro identifies that the Project will take approximately eight years from Project initiation to transformer installation, with this Application being filed approximately in year three of that timeframe. BC Hydro states that if it were to wait until a transformer is in immediate need of replacement prior to taking action, system reliability would drastically decrease, work would not necessarily be sequenced to take advantage of construction efficiencies (thus potentially increasing costs), and ultimately, customers could be adversely impacted with a reduction in reliability and/or an increase in costs.[45]

In BC Hydro's view, the deterioration of the T1 and T3 power transformers creates a reliability risk that it must address within the Project timeframe.[46]

2.4 Need to Address Deteriorated Condition of 50/60 Feeder Section

According to BC Hydro, another driver for the Project is the need to address the condition of one of the two feeder sections in the Mainwaring substation.[47]

[40] Exhibit B-6, BCUC IR 23.3; Exhibit B-1-4, Errata 3 to the Application.
[41] BC Hydro indicated that the probability of T3's bushings containing PCBs with a concentration greater than 43 ppm decreased below the threshold, and therefore, they would not be targeted for removal by the December 31, 2025, in order to comply with the federal PCB Regulations. Exhibit B-6, BCUC IR 23.6.1.
[42] BC Hydro states that N is the number of components normally available. At Mainwaring substation, three power transformers are normally available, in this case N=3, and N-1 (=2) redundancy reflects that two transformers are essential to supply power. Exhibit B-1, p. 2-14, footnote 32.
[43] Exhibit B-1, p. 2-14.
[44] Ibid., p. 6-8.
[45] Exhibit B-7, BCOAPO IR 33.1.
[46] BC Hydro Final Argument, p. 10.
[47] Exhibit B-1, p. 2-18.

The feeder sections in the Mainwaring substation are operated at 12 kV and are required to distribute electricity from the substation to customers via a large number of distribution circuits. The feeder sections include circuit breakers, disconnect switches, current limiting reactors, and voltage regulators, as well as the bus structures connecting the components, and protection and control relays.[48] The Mainwaring substation relies on two feeder sections: the 50/60 and 70/80 feeder sections.[49] The 70/80 feeder section is not in scope for this Project.

The 50/60 feeder section was installed in two stages: in 1957 and 1995. BC Hydro identifies that the 14 northern-most feeders in the feeder section were installed as part of the initial installation in 1957 and are in worse condition. BC Hydro explains that the equipment in these older feeder positions generally has an Asset Health Rating of "Poor." The six southern-most feeders in the feeder section were added in 1995 and the equipment in these feeder positions is generally in "Good" condition.[50]

BC Hydro has assessed the 50/60 feeder section as presenting reliability, safety and environmental risks that it must address as part of the Project. BC Hydro states that of the 140 assets in the 50/60 feeder section, 103 are in "Poor" or "Very Poor" condition and need to be replaced or refurbished. Table 3 below provides a summary of the 50/60 feeder section condition:

Table 3: Summary of 50/60 Feeder Section Condition[51]

Equipment	Total Number of Units	Asset Health Rating: Poor		Asset Health Rating: Very Poor	
		Number of Units	Percentage of Units (%)	Number of Units	Percentage of Units (%)
Circuit Breakers	24	0	0	13	54
Disconnect Switches	77	61	79	0	0
Current Limiting Reactors	20	0	0	14	70
Voltage Regulators	19	11	58	4	21

BC Hydro identifies risks associated with the "Poor" and "Very Poor" equipment in the 50/60 feeder series, which include the following:[52]

- Decreased reliability of the distribution circuits in the event of equipment failures. Failure of a circuit breaker, disconnect switch, current limiting reactor or voltage regulator would result in the loss of one feeder position and could result in loss of service to about 1,800 customers on an average feeder circuit for two to six hours.
- Environmental risks due to oil spills. BC Hydro identifies that many of the equipment items are oil filled, and some contain PCBs. BC Hydro identifies that environmental consequence of a spill could be high and that uncontained oil spills could adversely impact soil, groundwater and habitat, and require remediation of impacted soils, groundwater and receiving bodies of water. BC Hydro states that in the event of an oil spill, the surrounding area would need to be checked for oil contamination and cleaned

[48] Exhibit B-1, p. 2-18.
[49] Ibid.
[50] Ibid., p. 2-18.
[51] Ibid., pp. 2-19 – 2-20. Table 2-5.
[52] Ibid., pp. 2-20 – 2-28.

up. For an oil spill in the southwest corner of the substation, BC Hydro states that the municipal storm sewer would also need to be checked for oil contamination.

- One of the circuit breakers contains PCBs over 50 ppm and is subject to the federal PCB Regulations deadline for PCB removal by December 31, 2025.
- Safety risks due to insufficient electrical clearances.
- Safety risks due to fire. BC Hydro states that due to insulation degradation in certain equipment, there is a risk of arcing, which could result in a fire.

BC Hydro explains that the feeder sections were designed to be compact in size and were built to the electrical clearance requirements at the time of construction in the 1950s. The existing structure supporting the 50/60 feeder section does not meet BC Hydro's current design standards for Limits of Approach, which are the closest distance a qualified or unqualified worker is permitted to approach exposed energized conductors or equipment. BC Hydro states that there are insufficient electrical clearances in the feeder sections that increase the risk of accidental exposure to energized electrical equipment or conductors and restrict access for maintenance and operations.[53]

Further, according to BC Hydro, the existing structure does not meet the seismic requirements of the National Building Code or BC Hydro's requirements for post-disaster buildings. As a result, BC Hydro considers that there is an elevated risk of damage to the 50/60 feeder section equipment during a seismic event where the structure could undergo movement resulting in equipment and interconnections being overly stretched, compressed and bent, or the structure could collapse resulting in dropped equipment. BC Hydro identifies that these failure scenarios are more likely due to the structure not meeting seismic requirements, and the higher likelihood of these failures would translate to more widespread damage to equipment that may result in a higher likelihood of an outage, more customers being affected by an outage and longer outage duration.[54]

2.5 Need for Continued Operation of the Mainwaring Substation

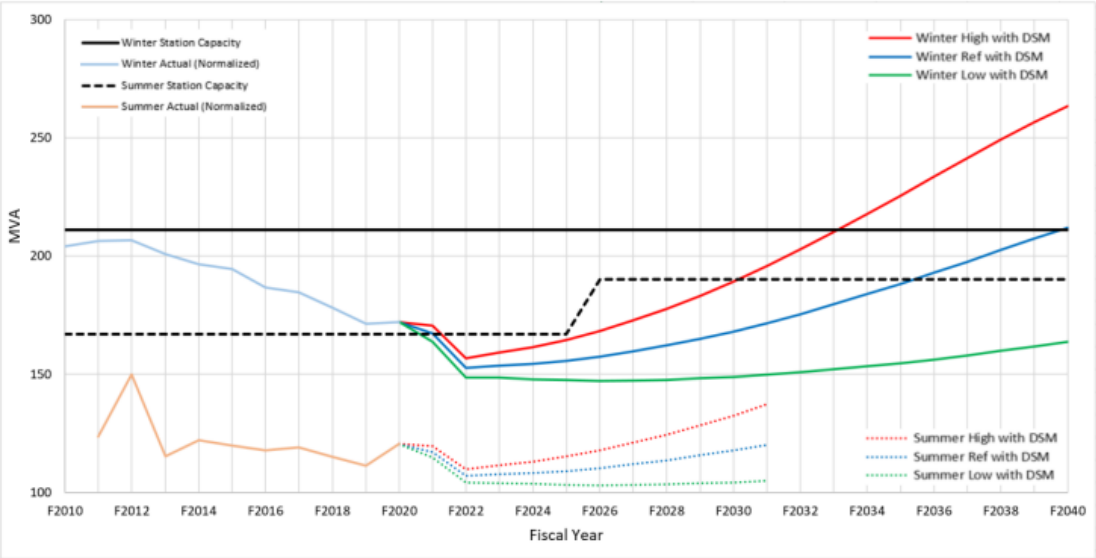
BC Hydro considers that the Mainwaring substation load forecast demonstrates the ongoing need for the substation to serve peak load in the supply area, which is forecast to increase in the long term.[55] Given this, BC Hydro considers ongoing investment to maintain the reliability of the Mainwaring substation, including the Project, is necessary and prudent.[56]

In addition to using the peak load forecast to demonstrate ongoing need for the Mainwaring substation, BC Hydro considers its peak load forecast in determining the size of the proposed replacement transformers, which is discussed further in subsection 3.2.1.

The peak demand forecasts for the Mainwaring substation are derived by BC Hydro by allocating the peak demand projections derived from the March 2020 load forecast for BC Hydro's integrated system. The peak demand forecasts for the Mainwaring substation under various scenarios are shown in Figure 3 below:[57]

[53] Exhibit B-1, pp. 2-28 – 2-29.
[54] Ibid.
[55] Ibid., p. 2-4.
[56] BC Hydro Final Argument, p. 5.
[57] Exhibit B-1, p. 2-4.

Figure 3: Mainwaring Substation Peak Demand Forecast (Fiscal 2021)[58]



BC Hydro states that capacity planning for the Mainwaring substation is based on the winter reference forecast after incremental DSM, which it considers represents the most likely peak demand scenario. Based on the winter reference forecast, represented by the thick blue line in Figure 3 above, the peak load of the Mainwaring substation is expected to grow by approximately 45 MVA over the next 20 years.[59]

BC Hydro explains, as shown in Figure 3 above, that peak load decreased in F2020 and is forecasted to further decrease in F2021 and F2022 because of load transfers to neighbouring substations to keep the Mainwaring substation below capacity and to accommodate load growth in the Mainwaring substation supply area. However, after F2022, BC Hydro explains that peak load is forecast to increase in the long term, mainly due to a few large developments in the sub-region.[60]

BC Hydro used its March 2020 load forecast in the Application, instead of its more recent December 2020 load forecast, because the work required to complete the alternative analysis was finalized before the December 2020 load forecast was available.[61] BC Hydro explains that its practice is to only update load forecast information in studies and applications when the load forecast materially impacts the study results. For this Application, BC Hydro does not consider the differences between the two load forecasts to materially change the results.[62] BC Hydro explains further that the December 2020 load forecast and March 2020 load forecast for the Vancouver-Burnaby sub-region are similar over the long term. However, if the December 2020 load forecast is used, this would result in approximately 4 percent higher peak demand by F2040 for the Mainwaring substation.[63]

[58] Exhibit B-1, p. 2-7, Figure 2-3.
[59] Ibid., p. 2-6.
[60] Ibid., pp. 2-7 – 2-8.
[61] Exhibit B-3, BCUC IR 2.6.
[62] Exhibit B-7, CEC IR 47.2.
[63] Exhibit B-3, BCUC IR 2.6.1.

Positions of the Parties

The CEC submits that BC Hydro has adequately demonstrated the need for a project to address the aging infrastructure and the federal PCB Regulations.[64]

Referencing BC Hydro's practice to only update load forecast information in studies that support applications when the load forecast materially impacts the study results, the CEC is of the view that BC Hydro's policy should be to update this Project to account for changes in information as they arise during a proceeding, which enables stakeholders to have confidence in the evidence being presented and allows the BCUC to make decisions based on the most up to date information. The CEC observes that the forecasted electric vehicle (EV) demand used in the December 2020 load forecast is approximately 13% lower by F2040 than the forecasted EV demand used in the March 2020 load forecast, which was used in the Application,[65] and submits this could be material. The CEC recommends that the BCUC direct BC Hydro to update load forecasts for major projects when new information arises and a proceeding is underway, if only to argue that the differences are not material.[66]

BC Hydro submits in reply that the Project is not driven by the forecast load at the Mainwaring substation and is instead driven by the need to address the reliability, safety, environmental and reputational risks of the Mainwaring substation caused by the condition of the T1 and T3 power transformers and the 50/60 feeder section and to comply with the federal PCB Regulations. BC Hydro comments that while the forecast load at the Mainwaring substation is relevant to the choice of the size of replacement transformer (i.e., 75 MVA versus the proposed 150 MVA), the difference between the March and December 2020 load forecasts is not material to this choice.[67]

The CEC considers that BC Hydro has demonstrated the nature of its Asset Health Index methodology as far as it goes and recommends that the BCUC direct BC Hydro to upgrade from a subjective description process to one based on quantitative probabilities and consequences of failures and of mitigation success.[68]

BC Hydro submits in reply that there is no foundation for such a direction and that the CEC has not demonstrated any deficiency in BC Hydro's Asset Health Index methodology or established that there are other asset health methods based on quantitative probabilities and consequences of failures that BC Hydro could adopt. BC Hydro considers that BC Hydro's Asset Health Index methodology has compared favourably to that of other utilities and meets BC Hydro's current business needs for a systematic, objective, repeatable, and transparent assessment of the health of its assets.[69]

BCOAPO is satisfied that BC Hydro has demonstrated that the condition of the T1 and T3 power transformers and the 50/60 feeder section at the Mainwaring substation is, at best, poor and the risks of their failure serious enough that timely action is in ratepayers' and the public interest.[70] Further compounding the need for timely action is the statutory deadline for removing PCBs, and the criticality of the station and the long-lead times associated with substation upgrades, which indicate that it is prudent for remedial action be initiated in advance

[64] CEC Final Argument, p. 14.
[65] Exhibit B-7, BCOAPO IR 27.1.1.
[66] CEC Final Argument, p. 5.
[67] BC Hydro Reply Argument, p. 29.
[68] CEC Final Argument5, p. 7.
[69] BC Hydro Reply Argument, p. 31
[70] BCOAPO Final Argument, p. 23.

of reliability issues actually materializing (e.g. major asset failures) if significant customer outages are to be avoided.[71] Additionally, BCOAPO notes that there are a significant number of issues associated with the 50/60 feeder section and significant risk if the assets in the 50/60 feeder section were to continue to be operated on an as-is basis.[72]

BCOAPO considers that BC Hydro's Asset Health Index methodology appears to place too much emphasis on age as opposed to asset condition but notes that the actual details are considered proprietary. In BCOAPO's view, asset condition assessments in the form of inspections, tests and engineering assessments provide a much better indication than age of an asset's condition and its potential need for investment. BCOAPO submits that in considering the need for future investment in the Mainwaring substation, both age and asset condition need to be separately considered when assessing reliability and that greater weight should be placed on the latter.[73]

BC Hydro submits in reply that when factoring in the 2013 engineering assessments, the Asset Health Rating of the T1 and T3 power transformers downgrades from "Poor" to "Very Poor." BC Hydro considers that this illustrates the impact of the Asset Condition Rating on the Asset Health Rating. BC Hydro also emphasizes that the results of the Asset Health Index methodology are only indicators as part of its overall assessment of the need to make investments on the system. Therefore, the results of the methodology are not determinative, and BC Hydro appropriately takes into account all available information when making its asset management and investment decisions.[74]

RCIA considers that based on the evidence submitted, the Project is not required at this time and can be prudently deferred for at least five years and possibly to 2031. RCIA submits that the Project can be deferred because the capacity to serve demand growth, asset conditions, reliability risks, safety risks, environmental risks, legislative risks, and reputational risks do not justify the Project at present. RCIA believes that at some future date the Project may be appropriate (i.e., when the asset conditions of power transformers T1 and T3, and the 50/60 feeder section warrant replacement) and that the Project can be prudently deferred with little additional risk, while providing material financial savings to ratepayers.[75]

In RCIA's view, for BC Hydro to demonstrate that the Project is needed and in the public interest, it must be justified based on one or more "Primary Drivers," which RCIA considers are factors and considerations that are sufficient to justify the present need for the Project investment, either individually or collectively. RCIA submits that the Project may be enhanced by one or more "Secondary Drivers," which RCIA considers are factors and considerations that may provide incremental benefits, but which do not individually or collectively justify the Project investment at this time.[76]

RCIA considers asset condition to qualify as a "Primary Driver" for justifying the Project. However, RCIA submits that the evidence indicates that replacement of the power transformers T1 and T3 can be deferred for 9.3 years, based on the Expected Remaining Life of the assets. Further, RCIA submits that the evidence indicates the replacement of the 50/60 feeder assets can be deferred for 5 to 10 years, based on the Expected Remaining Life

[71] BCOAPO Final Argument, p. 8.
[72] Ibid., p. 10.
[73] Ibid., p. 6.
[74] BC Hydro Reply Argument, p. 30.
[75] RCIA Final Argument, pp. 7, 31.
[76] Ibid., p. 7.

of the assets.[77] According to RCIA, all other Project drivers described in BC Hydro's evidence, such as capacity to serve demand growth and unacceptable reliability, environmental, legislative, safety and reputational risks are "Secondary Drivers." Even taken together, RCIA considers that the "Secondary Drivers" are insufficient collectively to comprise a "Primary Driver" that would justify the Project.[78]

In reply, BC Hydro submits that, "RCIA's approach is fundamentally flawed and fails to consider all the evidence" and that "RCIA's assertions of evidence should be given no weight."[79]

BC Hydro submits that RCIA cites no BCUC decision or other authority to support its theory of drivers and that RCIA's theory of drivers leads it into error by fostering a piecemeal approach that unduly focusses on the classification of drivers, rather than considering the substance of the issue and alternatives to address the identified needs. BC Hydro explains that it does not organize its Project drivers in this way and that investment decisions may have multiple drivers that all need to be considered. While RCIA appears to agree that a combination of drivers may justify a project, BC Hydro considers that RCIA makes no effort to consider such a possibility and essentially dismisses all risks and needs on the basis that they are not a "Primary Driver."

BC Hydro submits that this is not a helpful analytical tool and only serves to distract from a serious consideration of the factors driving the need for the Project and the alternatives to addressing the need.[80]

BC Hydro identifies that RCIA's interpretation of Expected Remaining Life from BC Hydro's Asset Health Index methodology is in error and that RCIA mistakenly relies on it to claim that the replacement of these assets can be deferred "without taking on unacceptable risks." BC Hydro explains that this does not reflect how its Asset Health Index methodology is designed to be used and presents an unrealistic level of precision and a misleading picture of the risk of deferral.[81] BC Hydro does not rely on the Expected Remaining Life as an indicator; rather, the Expected Remaining Life is an intermediate step in the methodology to arrive at the Asset Health Rating.[82]

BC Hydro submits that RCIA neither cited nor filed any evidence to substantiate its claim that it can use the Expected Remaining Life to forecast with certainty the life of the assets and the timing of the need for the Project. According to BC Hydro, RCIA's use of this component of BC Hydro's Asset Health Index methodology in this novel way is not supported by any evidence and must be rejected.[83]

BC Hydro observes that RCIA does not consider the length of time required to complete the Project as planned. BC Hydro's scheduled Project in-service date is October 2026, approximately five years from the time the Application was filed, and BC Hydro views that this is within the range of years that RCIA suggests the Project can be deferred. Therefore, BC Hydro considers that based on RCIA's own assessment, the Project is properly timed.[84] BC Hydro also notes that the Expected Remaining Life of the T1 and T3 power transformers is actually less than the 9.3 years, when the 2013 engineering assessments are factored in.[85] BC Hydro submits that

[77] Ibid., pp. 15, 17.
[78] RCIA Final Argument, p. 9.
[79] BC Hydro Reply Argument, pp. 3-4.
[80] Ibid., p. 3.
[81] Ibid., p. 7.
[82] Ibid., p. 8.
[83] Ibid.
[84] Ibid.
[85] Ibid.

therefore, even if the Expected Remaining Life were to be interpreted as the "actual" remaining life, which it is not, the Project should not be deferred.[86]
BC Hydro states that in the "do nothing" alternative, which it considers is effectively the same as a Project deferral, BC Hydro would still have to remove specified equipment to comply with the federal PCB Regulations. BC Hydro goes on to note that RCIA's argument ignores that conducting this work outside the Project will still require costs and will have implications for other equipment in the station. BC Hydro submits that it is these consequences that it has considered, along with other factors, when concluding that "doing nothing" is not feasible. BC Hydro observes that RCIA does not address these consequences or explain why "doing nothing" or deferring the Project is preferable to the proposed Project.[87]

Panel Determination

The Panel finds that the evidence supports the need to address the reliability, environmental and safety risks due to deteriorated equipment at the Mainwaring substation. In addition, the Project mitigates any compliance risks associated with the failure to remove PCBs from the equipment at the substation by the deadline stipulated in the federal PCB Regulations.

The Panel's determination that there is a need for the Project is substantially based on the results from the application of BC Hydro's Asset Health Index methodology to various Mainwaring substation assets. Most important among these is the deteriorated condition of the T1 and T3 power transformers, which are rated "Very Poor" when considered along with the 2013 engineering assessment. This Asset Health Rating indicates extensive serious deterioration of the asset, or that asset function is affected, with possible investment needed for overhaul or replacement within three years. In addition to these "Very Poor" Asset Health Ratings, BC Hydro has identified a number of issues related to both transformers, which, if not mitigated, could have safety and environmental consequences and potentially contravene the federal PCB Regulations.

BC Hydro has also identified serious deterioration of assets making up the 50/60 feeder section. Specifically, 54 percent of the circuit breakers, 70 percent of the current limiting reactors and 21 percent of the voltage regulators received an Asset Health Rating of "Very Poor" and 58 percent of the voltage regulators and 79 percent of the disconnect switches received an Asset Health Rating of "Poor."

BC Hydro has stated that the risks related to the deterioration of these assets could result in loss of service to approximately 1,800 customers for two to six hours for each feeder circuit that fails, and the loss of service for up to 40,000 customers if both power transformers fail at the same time.

The Panel accepts that there is considerable risk that can only be mitigated by Project completion. The Panel finds that BC Hydro has provided sufficient evidence to establish a need for the Project.

The Panel disagrees with RCIA's position that the Project is not required at this time and can be prudently deferred for at least five years and possibly through to 2031.

The Panel notes that RCIA's reliance on the 9.3 year Expected Remaining Life estimate for the T1 and T3 power transformers did not take into account the 2013 engineering assessments. Furthermore, the Expected

[86] Ibid.
[87] BC Hydro Reply Argument, pp. 25-26.

Remaining Life is not the basis of asset replacement decisions; rather, the Asset Health Index is used for transmission and distribution assets and the Asset Health Rating is used across the BC Hydro system. Finally, the Panel disagrees with RCIA's characterization of safety, reliability and legislative risks as being merely Secondary Drivers given the magnitude of consequences presented in the evidence, most notably the risk of customer outages.

In summary, the Panel finds deferral of the Project is not in the public interest. Deferral poses significant risks and associated consequences to ratepayers, the utility and the general public. Furthermore, the Panel observes that the BC Hydro CPCN Application includes an eight-year Project implementation timeframe, already underway with planned Project completion in 2027, which would be aligned with the earliest date of the RCIA proposed Project deferral of between five to ten years.

3.0 Description and Evaluation of Alternatives

BC Hydro identified seven alternatives to maintain the reliability of the Mainwaring substation, as well as address safety, environmental and reputational risks at the substation:[88]

1. Do nothing;
2. Refurbish the T1 and T3 power transformers;
3. Replace the T1 and T3 power transformers;
4. Refurbish the 50/60 Feeder Section;
5. Replace the 50/60 Feeder Section;
6. Replace part of the 50/60 Feeder Section and Refurbish the remainder; and
7. Replace the 50/60 Feeder Section with a New Substation.

3.1 Alternatives Considered Not Feasible

BC Hydro initially considered all of these alternatives. However, it rejected three of the alternatives as not feasible without detailed assessments.[89] The "Do Nothing," "Refurbish the T1 and T3 power transformers" and "Replace the 50/60 Feeder Section with a New Substation" alternatives were determined to be not feasible, as discussed in greater detail below.

Do Nothing

This alternative involves BC Hydro continuing to run the existing T1 and T3 power transformers and the equipment in the 50/60 feeder section to failure and replacing the individual assets as they fail.[90] BC Hydro states that this alternative would not address the risks associated with the declining reliability of the aging assets. Further, this alternative would not address the identified safety hazards, increasing oil leaks from the aging equipment, and widespread and longer outage(s) following a seismic event.

[88] Exhibit B-1, p. 3-3.
[89] Ibid.
[90] Ibid., p. 3-4.

BC Hydro states that while doing nothing would defer some investments, investment would still be required to comply with the federal PCB Regulations (i.e., replacing circuit breaker 12CB56 and the bushings of the T1 transformer by December 31, 2025). BC Hydro states that investments would also be required to replace any of the 15 voltage regulators, which have an Asset Health Rating of "Poor" or "Very Poor," when they fail. BC Hydro submits that the replaced voltage regulators could become stranded assets when the near-end-of-life transformers are eventually replaced with new, modern transformers that do not require voltage regulators.[91] During the proceeding, BC Hydro provided a cost estimate to replace the T1 transformer bushings in order to comply with the federal PCB Regulations as well as a cost estimate of potential stranded voltage regulator assets.[92]

As a result, BC Hydro screened out the "Do Nothing" alternative as not feasible because it would not address the identified risks or avoid significant future investments.

Refurbish the T1 and T3 Power Transformers

This alternative would extend the service life of the T1 and T3 power transformers and defer their replacement. The refurbish approach was screened out as not feasible, as some components of the transformers are not able to be refurbished. For example, refurbishment of critical components such as the windings would be difficult and unusual, requiring removing and transporting the transformers to a facility and requiring destruction of parts of the transformer.[93]

Similar to the "Do Nothing" alternative, this alternative would also require investments in voltage regulators, which could become stranded assets when the refurbished power transformers reach end-of-life and are replaced.[94]

For these reasons, BC Hydro states that this alternative is not feasible.

Replace the 50/60 Feeder Section with a New Substation

BC Hydro states that the construction of a new substation, which would be designed to split the electrical load with the existing Mainwaring substation, could meet the objectives of the Project. The scope of this alternative includes building a new substation with two new power transformers and new gas insulated feeder sections, installing new transmission cables for the new substation, decommissioning of the T1 power transformer and the existing 50/60 feeder series and the replacement of the T3 power transformer at the Mainwaring substation.[95]

BC Hydro determined that this alternative is not feasible, since costs would be significant, stakeholders would be greatly impacted, and it would not be completed in time to comply with the federal PCB Regulations.[96]

[91] Exhibit B-1, p. 3-4.
[92] Exhibit B-4, CEC IR 19.1; Exhibit B-7-1, response to RCIA IR 46.1.
[93] Exhibit B-1, p. 3-5.
[94] Ibid.
[95] Ibid., p. 3-6.
[96] Ibid.

3.2 Project Alternatives Description

BC Hydro identified one feasible alternative for the power transformers and three feasible alternatives for the 50/60 feeder sections for further evaluation using Association for the Advancement of Cost Engineering (AACE) International Level 5 cost estimates.

3.2.1 Power Transformer Alternative

Following the initial screening of identified alternatives, replacement of the T1 and T3 power transformers and associated equipment was determined to be the only feasible alternative to meet the Project objectives. BC Hydro states that replacement of the T1 and T3 power transformers will:

- Meet the long-term capacity needs of the substation;
- Enable future 25 kV operation, if required;
- Eliminate the need for voltage regulators; and
- Allow for the reconfiguration of the 12 kV switchyard.

The existing T1 and T3 power transformers are rated at 84 MVA. This transformer capacity is a non-standard capacity, which BC Hydro no longer purchases; the next smaller standard size is 75 MVA and the next larger standard size is 150 MVA. BC Hydro states that it generally only installs substation transformers of standard sizes rather than customized sizes.[97]

BC Hydro proposes to replace both power transformers with new power transformers rated at 150 MVA.[98] Based on the peak load at the Mainwaring substation under the winter reference forecast, should BC Hydro elect to replace the T1 and T3 power transformers with 75 MVA rated power transformers, they would not meet the required capacity of the substation by fiscal year 2038.[99] As the service life of these power transformers is approximately 57 years, replacement in 2038 would mean the 75 MVA power transformers would have only been in service for about one quarter of their asset life. BC Hydro states that the incremental cost of each 150 MVA power transformer, as compared to the 75 MVA power transformer, is approximately $1 million. The 150 MVA power transformers, which can accommodate new feeder sections in the future, will provide sufficient capacity for the Mainwaring substation beyond F2040.[100]

3.2.2 Feeder Section Alternatives

BC Hydro states that the Structured Decision Making (SDM) approach used to evaluate the feasible feeder section alternatives is typical of the process used to analyze alternatives for a project of this kind, and has been implemented on several other recent capital projects.[101] BC Hydro identified the following three feasible alternatives to addressing the condition of the 50/60 feeder section:

[97] Exhibit B-3, BCUC IR 1.4.2
[98] Exhibit B-1, p. 3-9.
[99] Ibid.
[100] Ibid.
[101] Exhibit B-3, BCUC IR 1.6.5.1

1. Refurbish the feeder section;
2. Replace the feeder section; and
3. Replace part of the feeder section and refurbish the remainder.

Descriptions of each alternative and the evaluation methodology BC Hydro used to select its preferred alternative are provided below.

Refurbish the Feeder Section (Refurbish Alternative)

This alternative focuses on replacing equipment with a "Poor" and "Very Poor" Asset Health Rating, which would enable BC Hydro to defer the replacement of the feeder section for approximately 25 years.[102] As part of this alternative, BC Hydro states it would not be feasible to replace the support structure. Therefore, the identified reliability and safety risks associated with the support structure would remain. [103]

Replace the Feeder Section (Replace Alternative)

Under this alternative, BC Hydro proposes to replace the existing 50/60 feeder section with three new gas insulated indoor feeder sections, housed within a new building sized for the addition of future feeder sections. The new building would be located on the south end of the substation property, on previously disturbed land outside the existing substation fence, as BC Hydro states there is insufficient space within the existing fence.[104]

Replace Part of the Feeder Section and Refurbish the Remainder (Replace/Refurbish Alternative)

This alternative involves replacement of the 14 oldest feeder positions with two new gas insulated indoor feeder sections and the refurbishment of the remaining six existing feeder positions. The two new gas insulated indoor feeder sections would be housed within a new building, located on the south end of the substation property – similar to the preceding alternative. BC Hydro states the refurbishment of the six existing feeder positions would defer their replacement for 25 years.[105]

3.3 Feeder Section Alternatives Evaluation

BC Hydro identified four objectives with which to compare and evaluate the 50/60 feeder section alternatives:

1. Improve Worker Safety;
2. Maximize Reliability;
3. Comply with Regulations; and
4. Minimize Cost and Cost Risk.

Table 4 below summarizes the results of the trade-off alternative analysis with respect to these objectives. BC Hydro determined that the Replace Alternative is the preferred alternative as it would:[106]

[102] Exhibit B-1, p. 3-10.
[103] Ibid.
[104] Ibid., p. 3-11.
[105] Ibid., p. 3-12.
[106] Ibid., p. 3-14.

- Improve worker safety by eliminating the likelihood of a worker breaching Limits of Approach during maintenance and by minimizing the duration of construction requiring Qualified Worker Limits of Approach;
- Maximize reliability by supporting the feeders with a structure that complies with current seismic standards; and
- Comply with the federal PCB Regulations.

Table 4: Consequence Table: Alternative Analysis Results[107]

Worse	Better	Similar	Point of Comparison		
Objectives & Sub-Objectives	**Criteria**	**Measure**	**Alternative 1** **Refurbish Feeder Section 50/60**	**Alternative 2** **Replace Feeder Section 50/60**	**Alternative 3** **Replace Part of Feeder Section 50/60, Refurbish Remainder**
Improve Worker Safety					
Minimize worker exposure to feeder section hazards during maintenance, requiring workers to maintain Limits of Approach	Likelihood of violating Limits of Approach	High/ Medium/ Low/ **Zero**	High	Zero	14 feeders: Zero 6 feeders: High
Minimize worker exposure to potential electrical contact during construction	Duration of construction work requiring Qualified Worker Limits of Approach	Working years (**lowest is best**)	1.7 years	0.2 years	0.9 years
Maximize Reliability					
Comply with seismic standards	Meets current seismic standards	**Yes**/ No	No	Yes	14 feeders: Yes 6 feeders: No
Comply with Regulations					
Meet 2025 Federal PCB removal deadline	Likelihood of removing PCBs >43 ppm by 2025 deadline	**High**/ Medium/ Low	Medium	High	High
Minimize Cost and Cost Risk					
Minimize Present Value of Cost	Present Value of Cost	$ million (**lowest is best**)	$30.4	$42.2	$39.4
Maximize Future Upgradeability	Ease of future expansion	**High**/ Medium/ Low/ Zero	Zero	High	Low
Minimize Construction Schedule Risk	Likelihood of delays due to outage constraints	High/ Medium/ **Low**	High	Medium	Medium

BC Hydro noted that although the Replace Alternative is the highest cost alternative, it offers other cost-benefits such as the simplest future expansion and the lowest likelihood of delays due to outage constraints. In light of these benefits, which would reduce future costs, BC Hydro concluded that the higher costs of the Replace Alternative are justified.[108]

[107] Exhibit B-1, p. 3-16, Table 3-3.
[108] Ibid., p. 3-15.

3.3.1 Justification for Trade-off Alternative Analysis

BC Hydro states that the outcome of the SDM process is to recommend the most cost-effective alternative and that it has not determined a present value cost differential at which the safety and reliability benefits of the Replace Alternative would no longer be justified.[109] BC Hydro further states that the trade-off alternative analysis it completed, which uses quantitative and qualitative measures as summarized in Table 4 above, is sufficient to identify the trade-off between the higher cost and additional benefits of the Replace Alternative.[110]

The SDM framework submitted by BC Hydro calls for quantitative scales and weightings when necessary to make decisions.[111] The SDM framework states that in the case that a project involves a large number of alternatives, with many conflicting objectives, and with no obviously best alternative, a more rigorous "swing weighting" analysis method is required. This quantitative weighting method is reserved for only the most complex decisions, and its use is considered rare.[112] BC Hydro considers that the trade-off analysis used is sufficient, and that a more rigorous approach was not required.[113]

3.3.2 Feeder Section Alternative Cost Estimating

The BCUC's CPCN Guidelines state that a CPCN application should contain a comparison of costs between the Project and its feasible alternatives and that the cost estimates used in the economic comparison should have, at a minimum, an AACE International Class 4 level of accuracy.[114]

In the Application, however, BC Hydro presents cost estimates for the feeder section alternatives prepared to an AACE International Class 5 level of accuracy.[115] BC Hydro states that its project development process supports identifying a leading alternative for the Project based on AACE International Class 5 cost estimates and other criteria, and that it only develops AACE International Class 4 estimates for multiple alternatives at the conceptual design stage if required to identify the leading alternative. It is BC Hydro's experience that a Class 5 cost estimate is sufficient to identify the leading alternative at the conceptual design stage in almost all cases.[116] Further, if during the subsequent feasibility design stage, the cost estimate of the leading alternative increases significantly following completion of the Class 4 estimate, BC Hydro can re-evaluate the alternatives. BC Hydro notes that the present value of the cost for the Replace Alternative increased by only 9 percent between the Class 5 and Class 4 cost estimate.[117]

BC Hydro expects that the combined cost of advancing all feasible feeder section alternative cost estimates to a Class 4 level would materially exceed the cost of the feasibility design stage for the Replace Alternative, which was approximately $1.1 million.[118] The duration of the feasibility design stage was 11 months, and within that time period, the time to complete the feasibility design estimate was approximately 8 months.[119] BC Hydro

[109] Exhibit B-3, BCUC IR 1.6.6.1.
[110] Exhibit B-4, CEC IR 1.28.6.1.
[111] Ibid.
[112] Ibid., Attachment 1.
[113] Ibid.
[114] BCUC's CPCN Guidelines, p. 4.
[115] Exhibit B-1, p. 1-16, Footnote 13.
[116] Exhibit B-3, BCUC IR 1.6.1.
[117] Ibid.
[118] Exhibit B-3, BCUC IR 1.6.2.
[119] Ibid.

states there is a high probability that the Project would experience delays and cost increases in the event that Class 4 estimates were required for all feasible alternatives.[120]

Positions of the Parties

The CEC submits that BC Hydro has adequately defined and assessed the alternatives and recommends that the BCUC accept the alternatives as being reasonably well founded.[121] With respect to BC Hydro's selection of 150 MVA power transformers, the CEC states that it does not find the incremental cost of the load risk to be significant and that larger capacity can enable load transfers and switching loads from other stations to potentially extend asset life elsewhere in the system.[122]

Referencing BC Hydro's Consequence Table, provided in Table 4 above, the CEC states that it would be preferable to evaluate the alternatives on a pre-established, independent scale, rather than establishing the Replace Alternative as the basis for a point of comparison. Overall, the CEC finds the added benefits of the Replace Alternative have not been adequately quantified and summarized to justify the cost-effectiveness of additional costs. However, the information on the record supporting the Project is the best available to the BCUC, though subjective to a significant degree and could be improved in the future.[123] The CEC recommends that the BCUC direct BC Hydro to improve its cost-effectiveness benefits analysis for project decisions and be prepared to provide upgraded information in the future. [124]

Overall, BCOAPO generally agrees with BC Hydro's alternative analysis, including its proposal to use 150 MVA power transformers, with one noted exception listed below.[125] BCOAPO also submits that the comparison of alternatives using Class 5 cost estimates is reasonable.[126]

BCOAPO submits that the objectives BC Hydro identified and used in its consequence table are appropriate with one exception. BCOAPO submits that under 'Maximize Reliability,' there should have been a second sub-objective addressing the future likelihood of customer outages and the length of customer outages due to equipment failure (as opposed to seismic events).[127]

BC Hydro submits in reply that it agrees that the risk and associated impact of customers' outages are important considerations and that it has ensured that this risk is properly reflected in its assessment of alternatives. However, as each of the feasible alternatives for the 50/60 feeder section addressed the identified risks of outages, the future likelihood and length of customer outages due to equipment failure was not a distinguishing feature upon which to compare the feasible alternatives.[128]

RCIA did not submit argument specific to BC Hydro's analysis of alternatives to the Project.

[120] Exhibit B-3, BCUC IR 1.6.2.
[121] CEC Final Argument, p. 18.
[122] Ibid., p. 19.
[123] Ibid., p. 17.
[124] Ibid.
[125] BCOAPO Final Argument, p. 10-20.
[126] Ibid., p. 20.
[127] Ibid.
[128] BC Hydro Reply Argument, p. 27.

Panel Determination

The Panel finds that BC Hydro's development and analysis of the alternatives is reasonable and that the evidence supports BC Hydro's submissions relating to their feasibility.

The Panel finds that BC Hydro's summary rejection of three alternatives ("Do Nothing," "Refurbish the T1 and T3 power transformers" and "Replace the 50/60 Feeder Section with a New Substation"), is reasonable. BC Hydro's experience in building, operating, maintaining and replacing substations and their components lends credibility to its analysis of these options and conclusions.

Within the remaining options, the Panel is satisfied with BC Hydro's use of AACE International Class 5 estimates for its feeder section alternative analysis in this instance, despite not aligning with the BCUC CPCN Guidelines. BC Hydro has appropriately weighed the benefits of greater budgeting precision (to Class 4) versus the cost and delay associated with advancing all feasible feeder section alternative cost estimates to a Class 4 level.

The Panel finds the choice of 150 MVA power transformers for the replacement of the T1 and T3 power transformers to be justified, rather than simply replacing them with 75 MVA transformers. The Panel is persuaded by BC Hydro's submission that if the existing transformers were replaced with 75 MVA transformers, they would not meet the required capacity of the substation by fiscal year 2038 based on the winter reference case forecast. While the load forecast and substation capacity were not primary considerations to establish the Project need, the Panel finds that the expanded capacity of the power transformers for a modest cost is warranted given the projected load growth. Having regard to all these factors, the Panel is satisfied that the incremental investment of $2 million to replace the 84 MVA T1 and T3 power transformers with 150 MVA power transformers is reasonable.

The Panel finds merit in the BCOAPO submission for BC Hydro to develop a second "Maximum Reliability" criterion on mitigating the future risk of customer outages due to equipment failure, as opposed to those caused by seismic events. The Panel encourages BC Hydro to include a second "Maximum Reliability" criterion on mitigating the risk of customer outages due to equipment failure in future SDM alternatives analyses associated with relevant CPCN and capital expenditure applications.

4.0 Project Description and Risk Management

4.1 Project Scope

The Project scope includes replacing the T1 and T3 power transformers with two new 150 MVA power transformers, removing the existing 50/60 feeder section (20 existing feeders) and replacing it with three new gas insulated indoor feeder sections with a total of 21 feeder positions and all associated equipment.[129] The station footprint and fence line at the Mainwaring substation will be expanded within BC Hydro's property to accommodate a new Gas Insulated Switchgear (GIS) feeder building, which includes space for one additional feeder section module in future.[130] All equipment in the Project will be energized to the current distribution

[129] Exhibit B-1, p. 4-1.
[130] Exhibit B-1, p. 4-2.

system voltage of 12 kV, but could be energized to 25 kV to accommodate future voltage conversion if necessary.[131]

The Project is expected to be in service by October 2026. BC Hydro states that it developed the Project schedule so that all required PCB-containing equipment would be removed from the site before the federal PCB Regulations compliance deadline of December 31, 2025.[132] BC Hydro provides the following summary of estimated dates for the Project's major milestones:

Table 5: Project Major Milestones[133]

Description of Major Milestone	Estimated Date
Stage 1 Contract Award - Transformers	July 2021
Application Filed with BCUC	November 2021
Requested BCUC Decision Date	August 2022
Stage 2 Contract Award - Transformers	October 2022
Gas Insulated Switchgear Feeder Building Contract Award	October 2022
Construction Services Mobilization	November 2022
Contractor Mobilization	January 2023
Asset In-Service Date - T4 Transformer	September 2024
PCB Equipment Removal Complete	January 2025
Asset In-Service Date - T5 Transformer	March 2025
Project In-Service Date	October 2026
Project Complete	October 2027

BC Hydro states that the Project will align with BC Hydro's Safety by Design principles. BC Hydro states that it systematically identifies hazards and failure modes that pose safety risks to workers and the public during the construction, operation, and maintenance of equipment. BC Hydro then assesses these hazards and failure modes through the design process to eliminate or reduce the associated safety risks. The objective is to produce safer designs to enable safer operability and maintainability.[134] BC Hydro also identifies that it will identify all Mandatory Reliability Standard requirements for the Project, and ensure the Project is compliant.[135]

The Project delivery methodology is design-bid-build, and various procurement approaches will be applied to deliver the key scope elements. BC Hydro states that public procurement processes will be initiated for the design and supply of the equipment and BC Hydro's blanket contract orders will be leveraged for the supply of equipment and services.

Indigenous procurement opportunities will be provided for site preparation and building construction, duct banks and maintenance holes installation and landscaping.[136] To align with BC Hydro's mandate to advance reconciliation with Indigenous Nations through implementation of the United Nations Declaration on the Rights of Indigenous Peoples and the Truth and Reconciliation Commission Calls to Action, BC Hydro has been seeking to advance relationships with First Nations through broader initiatives extending beyond project-based consultation. With this Project, BC Hydro aims to create economic benefits through BC Hydro's Indigenous

[131] Ibid., p. 4-5.
[132] Ibid., p. 4-26.
[133] Ibid., Table 4-4.
[134] Ibid., p. 4-11.
[135] Ibid., p. 4-9.
[136] Ibid., pp. 4-16 – 4-17.

contracting and procurement policy so that the Indigenous Nations most affected by the Project can share meaningfully in business opportunities arising from the Project.[137]

BC Hydro retained SNC-Lavalin Inc. (SNC-Lavalin) to provide design and engineering services for the Project. SNC-Lavalin also prepared an Environmental and Socio-Economic Effects Report (Appendix K to the Application), which determined a low overall socio-economic risk rating and a negligible overall environmental risk rating for the Project.[138]

Work not included in the Project includes replacement of end-of-life assets in the 70/80 series feeder section (five circuit breakers and seven disconnect switches), which is planned for F2024 under the 12/25 kV Circuit Breaker Replacement program. BC Hydro states that this aligns with its practice for circuit breaker replacements, as this type of replacement work is less complex and more routine, and it is therefore more efficiently and cost effectively delivered as part of a dedicated program that specializes in the replacement of these asset types.[139]

4.2 Risk Management

BC Hydro describes its Project risks and risk management in Chapter 6 of the Application. BC Hydro identifies three material risks[140] in the definition phase of the Project, three material risks for the implementation phase of the Project, and two material operational risks at the Mainwaring substation that will be retained following the implementation of the Project. Associated risk treatments have been identified to manage each of these material risks.[141] These risks and mitigation measures are summarized below:

Definition Phase:

1. Risk of this proceeding impacting the Project schedule: BC Hydro mitigates this risk by developing a comprehensive application; proposing a regulatory schedule that allows for a decision by August 2022; including a three-month contingency in the Project schedule; and preparing a contingency plan to remove PCB-containing equipment to meet the regulatory timeline if this risk materializes.[142]

2. Risk of one or both of existing power transformers T1 and T3 failing before they are replaced resulting in loss of service: BC Hydro mitigates this risk by advancing the original equipment manufacturer design of the transformers from the implementation phase to the definition phase to expedite detailed design and help to meet the Project schedule.[143] BC Hydro also mitigates this risk by maintaining N-1 supply redundancy. In the Application, BC Hydro had originally planned on installing one of the new transformers in a temporary location to provide equipment redundancy. However, it identified during the proceeding that it would instead rely on transfer capacity of the adjacent distribution system.[144] This change results in potential cost savings of up $1,388,080.[145]

[137] Exhibit B-1, pp. 5-15 – 5-15.
[138] Ibid., p. 4-29.
[139] Ibid., pp. 2-12 – 2-13.
[140] BC Hydro defines 'material' in this case to be any risk with a pre-treatment risk level in the Executive Risk zone, as identified in the Project Delivery Risk Matrix, which is provided in Appendix O to Exhibit B-1, p. 6-2, footnote 115.
[141] Exhibit B-1, p. 6-2.
[142] Ibid., p. 6-7.
[143] Ibid., p. 6-8.
[144] Exhibit B-3, IR 19.1.
[145] Exhibit B-4, RCIA IR 42.1.

3. Risk of sunk costs due to early procurement: BC Hydro mitigates this risk by staging the award of the long lead time equipment contracts as BC Hydro will commit to original equipment manufacturer design (stage 1) work (approximately $2 million) in the definition phase and including an exit clause in the stage 1 contract that the remaining supply and installation scope is subject to the BCUC's decision on this Application as well as BC Hydro Board approval.[146]

Implementation Phase:

1. Risk of equipment containing PCBs not being removed by the December 31, 2025 deadline due to Project schedule delays: BC Hydro mitigates this risk by completing critical implementation phase work in the definition phase, early procurement of long lead time equipment, prioritizing construction work for PCB removal, and preparing a contingency plan for removal of PCB-containing equipment to meet the regulatory timeline if the risk of schedule delays materializes.[147]

2. Risk of potential safety incidents due to workers working in an energized substation: BC Hydro mitigates this risk by maintaining the role of Prime Contractor, providing workers with the proper training and work methods, using mostly BC Hydro internal resources for high-risk work, reviewing contractor's safety management plans, appropriate work sequencing, use of physical barriers and use of safety watchers. [148]

3. Risk of Noise levels from the new transformers exceeding the City of Vancouver noise bylaw levels: BC Hydro mitigates this risk by specifying and ordering a low noise level (70/72 dBA) transformers, and making the provision for total tank sound enclosure of the transformers to further reduce the noise level by 15 to 20 dBA. [149] In the Application, BC Hydro had originally included the cost for the total tank sound enclosures in its estimate ($800k). During the proceeding, BC Hydro provided an update that based on updated noise measurements, it now considers the likelihood of requiring the sound enclosures lower and intends to remove these costs from the Project estimate and cover as contingency if required. [150]

Operational risks retained following the implementation of the Project:

1. The 70/80 series feeder section not meeting current safety or structural standards: BC Hydro has chosen to retain this operational risk and will replace the feeder section when it reaches end-of-life or can no longer reliably provide service. BC Hydro manages this risk by maintaining barriers, using special operating procedures, and protection schemes.[151]

[146] Exhibit B-1, p. 6-9.
[147] Ibid., p. 6-11.
[148] Ibid., p. 6-13.
[149] Ibid., p. 6-14.
[150] Exhibit B-4, RCIA 22.2.1.3.
[151] Exhibit B-1, p. 6-15.

2. Seismic withstand capability of the control building: The Project will not mitigate the risk associated with the seismic stability of the control building, however, removal of the 50/60 feeder section controls from the control building, as it proposed as part of the Project, reduces the risk of the outages of this feeder section following a seismic event.[152]

Positions of the Parties

The CEC submits that it has reviewed the evidence related to the particulars of the equipment and the Project design and finds it to be well-established and capable of meeting the needs of the Project.[153] The CEC also finds BC Hydro's approach to risk identification and mitigation to be comprehensive and well thought out.[154]

The CEC notes that there are several items identified as being in Poor or Very Poor condition that are not being replaced as part of the Project. The CEC submits that it does not find adequate quantitative analysis supporting the allocation of components to being in the Project versus not being in the Project and the appropriate thresholds for those decisions. The CEC considers that it could potentially be cost-effective for BC Hydro to consider upgrading other assets identified as being in "Poor" or "Very Poor" condition at the same time as this Project is underway, but no evaluation of this for cost-effectiveness has been provided on the record. The CEC recommends that the Project analysis of the cost effectiveness for replacement and refurbishment versus not being in the Project be upgraded in the future to show a quantitative analysis of the decisions being included in such projects.[155]

BC Hydro submits in reply that it has carefully considered the Project scope and has explained its approach to addressing retained asset risks in the substation. BC Hydro considers that the replacement of the assets referenced by the CEC that are not being replaced as part of the Project are more efficiently and cost-effectively delivered as part of a dedicated program that specializes in the replacement of these asset types.[156]

The CEC also notes that BC Hydro retained SNC-Lavalin to provide design and engineering services for the Project through an existing master services agreement awarded in 2012. The CEC recommends that the BCUC require BC Hydro to provide a compliance filing regarding's BC Hydro's retendering of the SNC-Lavalin master services agreement in 2022.[157]

BC Hydro submits in reply that the length of a potential future master services agreement is not within the scope of this proceeding. BC Hydro submits that its procurement practices are properly part of the utility's management function and that a compliance filing on the retendering of the service agreement would serve no purpose and therefore should not be directed.[158]

BCOAPO and RCIA did not provide submissions on the topic of Project description and risk management specifically.

[152] Exhibit B-1, p. 6-15.
[153] CEC Final Argument, p. 24.
[154] Ibid., p. 26.
[155] CEC Final Argument, p. 21.
[156] BC Hydro Reply Argument, p. 31.
[157] CEC Final Argument, p. 22-23.
[158] BC Hydro Reply Argument, pp. 32-33.

Panel Discussion

The Panel is satisfied that the Project schedule will support compliance with the deadline for PCB removal set out in the federal PCB Regulations.

The Panel considers BC Hydro's proposal for Indigenous procurement to be consistent with the provincial *Declaration on the Rights of Indigenous Peoples' Act*.
Regarding risk management, the Panel acknowledges BC Hydro's thorough consideration of implementation risk factors, evaluation, treatment with mitigation measures and overall accountability framework.

With respect to the CEC's recommendation for the BCUC to direct BC Hydro to provide a compliance filing regarding's BC Hydro's retendering of the SNC-Lavalin master services agreement in 2022,[159] the Panel agrees with BC Hydro that its procurement practices are properly part of the utility's management function and that a compliance filing on the retendering of the service agreement would serve no purpose. The Panel therefore declines to make such direction. However, the Panel observes that regular retendering of large contract awards by Crown corporations is a practice that is commonly adopted to ensure value for service through a competitive and transparent bid process.

5.0 Project Cost and Rate Impact

5.1 Capital Cost Estimate

The Project has a total cost estimate range of $91.5 million to $143.3 million, based on an expected cost of $114.4 million and a 25% project reserve.[160] It conforms to an AACE International Class 3 cost estimate requirements with an accuracy range of +25%-20%.[161] A summary of the total estimated project costs is provided in Table 6.

Table 6: Project Cost ($Million)[162]

Row No.	Description	Preliminary Cost Estimate ($ million)[64]
20	**BC Hydro Expected Amount**[67]	**114.4**
21	Project Reserve (Loaded)	28.9
22	**BC Hydro Authorized Amount**	**143.3**
23	**Project Cost Range (+25%/-20%)**[68]	**143.3 - 91.5**

The Project cost range includes actual costs to date and forecast direct construction costs, indirect construction costs, contingency and reserves, escalation, interest during construction, and capital overhead.[163]

[159] CEC Final Argument, p. 22-23.
[160] Exhibit B-1, p. 4-19.
[161] Ibid.
[162] Ibid., p. 4-21.
[163] Exhibit B-1, p.4-19, Row 23 in Table 6.

A project (P50) contingency is included to account for cost risks that are not specifically identified or captured in the direct or indirect construction costs.[164] These cost risks include the impact of COVID-19 on labour and construction, changes in the commodity prices, obtaining outages during construction and removal of oil-containing equipment. Escalation is applied to the total direct construction costs to reflect the economic inflation rates in the construction sector expected to occur over the course of the Project. These rates are based on economic trends, advice from independent economists, and data from Statistics Canada.[165] BC Hydro explains the interest rate forecast used to calculate interest during construction rates includes increases in interest rates over time. Additionally, BC Hydro considers that the existing preliminary estimate will cover the cost increase pressures from the current inflationary environments within the accuracy range of the cost estimate.[166]

Capital cost estimates for direct construction costs, indirect construction costs, contingency and reserves, escalation, interest during construction, and capital overhead were submitted confidentially through Appendix B-1-1 and Appendix B-1-1-1 to the Application, respectively.

The authorized cost of $143.3 million includes a Project reserve of $28.9 million.[167] The Project reserve accounts for the additional financial impact of known risks to the Project. The Project reserve for the Project is the difference between the P90 contingency and the P50 contingency. BC Hydro states access to the Project reserve requires approval from BC Hydro's Board of Directors.[168]

During the proceeding, BC Hydro identified two updates to its cost estimate:

- The cost of the total tank sound enclosure was originally included in the Project's expected cost.[169] However, in light of both the design progressions and BC Hydro's additional information on existing noise levels, the transformer sound enclosures are now categorized as a risk mitigation should noise levels exceed the by-law thresholds after installing the transformers.[170] BC Hydro explains this cost will now be covered under the Project contingency in the preliminary estimate.[171]
- BC Hydro states the outage staging plan is being refined and as a result the revised plan no longer includes the temporary installation of the T5 transformer, which will result in cost savings for the Project. The estimated incremental cost associated with the temporary installation and eventual relocation of the T5 power transformer is $1,388,080.[172]

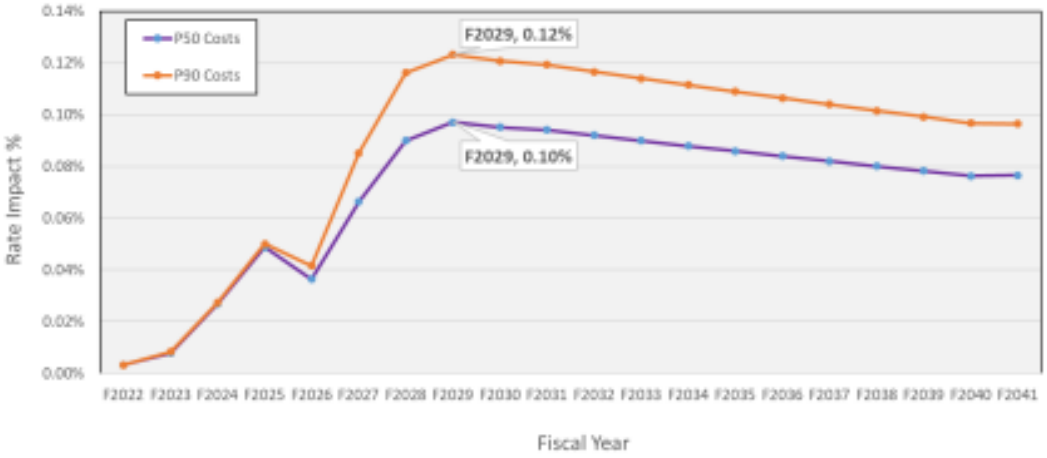
BC Hydro is updating the AACE International Class 3 estimate with the most recent information and cannot provide an updated Project cost range breakdown to reflect the updates noted above at this time. BC Hydro expects to complete the cost estimate update by July 2022 and states that it will submit an updated Project cost range breakdown table to BCUC as part of a semi-annual progress report. [173]

[164] P50 is defined as the final project cost that will not exceed the cost estimate 50% of the time. This is also defined as the Expected Cost estimate; Exhibit B-1, 4-22 – 4-23
[165] Exhibit B-1, p. 4-23 - 4-24; Exhibit B-3, IR 1.12.6.
[166] Exhibit B-7, CEC IR 63.2.
[167] Exhibit B-1, pp. 4-19, Row 21 and 22 of Table 6.
[168] P90 is defined as the cost estimate that will not be exceeded 90% of the time; Exhibit B-1, p. 4-24
[169] Exhibit B-4, RCIA IR 22.2.1.3.
[170] Ibid.
[171] Ibid.
[172] Ibid., RCIA IR 42.1.
[173] Exhibit B-6, IR 26.1.

5.2 Rate Impact

The Project will affect operating costs, amortization and finance charges in BC Hydro's revenue requirements.[174] BC Hydro provides the following estimated cumulative incremental rate impact analysis for the Project in Table 7, assuming the Project assets go into service as planned, based on an expected cost estimate of $114.4 million (P50 Costs) and an authorized cost estimate of $143.3 million (P90 Costs).[175]

Table 7: Cumulative Incremental Rate Impact Analysis



With both the expected cost estimate and authorized cost estimate, there is an initial increase in BC Hydro's revenue requirements in the early years as the assets are placed in service.[176] The cumulative incremental rate impact declines after F2029 because of lower finance charges as amortization recovered from ratepayers is used to pay down the debt over time.[177] Based on the expected cost estimate and authorized cost estimate, the highest cumulative incremental rate impact would be 0.10 percent and 0.12 percent, respectively, in 2029.[178]

Positions of the Parties

The CEC is satisfied that BC Hydro has adequately addressed the issue of rising inflation and interest rates.[179] The CEC submits that it finds the Project cost estimate to be acceptable and within the expected standard of a CPCN application. The CEC recommends that the BCUC accept the BC Hydro cost estimate as being reasonably well founded.[180]

BCOAPO submits that given the cost pressures from the COVID-19 pandemic, the current political climate and recent forecasts for inflation and interest rates the Project is experiencing, BC Hydro should be directed to include a detailed variance explanation of any material differences between the currently estimated Expected

[174] Exhibit B-1, p. 4-25.
[175] Ibid.
[176] Ibid.
[177] Ibid.
[178] Ibid.
[179] CEC Final Argument, p. 25.
[180] Ibid.

Cost and Authorized Cost and the updated value in its progress report to be provided by mid-2022.[181] BCOAPO submits that it has no issues with BC Hydro's rate impact analysis.[182]

BC Hydro expects that the updated cost estimate will continue to fall within the Project Cost Range of $91.5 million to $143.3 million.[183] BC Hydro submits in reply that it will adhere to reporting requirements directed by the BCUC and will provide a variance explanation in its progress report that presents the updated AACE International Class 3 estimate (Expected Cost and Authorized Cost) if directed.[184]
RCIA did not make any specific submissions relating to BC Hydro's cost estimate or rate impacts.

Panel Determination

The Panel finds the Project cost estimates to be reasonable. The capital cost estimate is consistent with an AACE International Class 3 cost estimate, which is in alignment with the BCUC's CPCN Guidelines.

The Panel acknowledges the change of cost status for two assets, which were originally proposed within the Project scope, namely, the transformer sound enclosures for noise reduction and the temporary installation of the T5 power transformer. The former has now been moved into the contingency budget and the latter has been removed from the Project scope, thus reducing the Project's total expected cost.

The Panel finds the approach for release of the Project Reserve to be reasonable, namely, the requirement for approval from the BC Hydro Board. We accept that this provides for appropriate due diligence and governance of investments above the expected cost of the Project including contingency.

6.0 Public Engagement and Indigenous Consultation

BC Hydro has undertaken consultation and engagement activities with Indigenous communities and the public with respect to the Project. In this section, the Panel reviews these activities, and makes its determination on whether consultation to date on the Project has been adequate.

With respect to consultation with Indigenous communities, the BCUC established its First Nations Information Filing Guidelines for Crown Utilities in 2010.[185] These Guidelines identify the information that must be filed by Crown utilities in support of applications including CPCN applications. BC Hydro, as a Crown Corporation, has a duty to consult when "the Crown has knowledge, real or constructive, of the potential existence of the Aboriginal right or title and contemplates conduct that might adversely affect it…"[186] In *Haida Nation v. British Columbia (Minister of Forests),* the Supreme Court of Canada introduced the concept of a spectrum of consultation, where the extent of the duty to consult is dependent on the strength of claim to Aboriginal title and rights, as well as the level of potential infringement.[187]

[181] BCOAPO Final Argument p. 22.
[182] Ibid.
[183] BC Hydro Reply Argument, p. 28.
[184] Ibid.
[185] https://docs.bcuc.com/documents/Guidelines/2010/DOC_25327_G-51-10_2010-First-Nations-Information-Filing-Guidelines.pdf
[186] *Haida Nation v. British Columbia (Minister of Forests)*, 2004 SCC 73 (Haida) at para. 35.
[187] Ibid., at paras. 43 to 44.

In the Application, BC Hydro states the Project falls within the consultative boundaries of 16 Indigenous communities or organizations.[188] BC Hydro has undertaken consultation with Indigenous communities with respect to the Project in its capacity as a Crown agent since 2015. BC Hydro submits it has worked collaboratively with Indigenous communities through all phases of the Project to date, including ensuring these groups have opportunities to provide feedback, which was incorporated into the development of the Project, where possible. To date, BC Hydro notes Indigenous communities have not identified any significant concerns with the Project. BC Hydro has determined that there will be minimal or no incremental adverse impact on Aboriginal rights or title arising from the Project, which is confined to the existing boundary of a restricted industrial site within a heavily developed urban area.[189] Looking ahead, BC Hydro will continue to consult with Indigenous communities through the regulatory process and construction phase, sharing the outcome of the BCUC regulatory process, and will provide procurement opportunities consistent with BC Hydro's Indigenous Contracting and Procurement Policy.[190]

With respect to public consultation, since 2016 BC Hydro has been engaging with stakeholders including Municipal and regional governments, residential and commercial property owners and occupants, a nearby school and health centre.[191] BC Hydro submits that the majority of feedback has been positive, that all stakeholder comments have been addressed, and no concerns remain outstanding. BC Hydro will continue to update stakeholders as the Project advances to ensure they remain adequately informed regarding both construction activities, such as traffic changes or construction outside normal hours, and key upcoming Project milestones.[192]

Positions of the Parties

The CEC finds BC Hydro's consultation and engagement to be acceptable.[193]

BCOAPO submits the evidence indicates that BC Hydro has undertaken an appropriate level of consultation on the Project.[194]

RCIA did not address consultation and engagement in its final argument.

Panel Determination

The Panel finds that BC Hydro's consultation with First Nation Governments and Indigenous communities to date has been adequate and is in alignment with the BCUC's 2010 First Nations Information Filing Guidelines for Crown Utilities.

The Panel finds BC Hydro's consultation with community stakeholders to be adequate, along with its commitment to ongoing communications during Project implementation.

[188] Exhibit B-1, p. 5-3
[189] BC Hydro Final Argument, p. 42.
[190] Ibid., p. 43.
[191] Exhibit B-1, p. 5-27
[192] BC Hydro Final Argument, p. 43.
[193] CEC Final Argument, p. 27.
[194] BCOAPO Final Argument, p. 23.

7.0 Alignment with Provincial Government Energy Objectives, the Long-Term Resource Plan and the *Clean Energy Act*

As previously noted, section 46(3.3) of the UCA provides that in deciding whether to issue a CPCN to BC Hydro, the BCUC, in addition to considering the interests of persons in British Columbia who receive or may receive service from BC Hydro, must consider BC's energy objectives, a long-term resource plan filed by BC Hydro under section 44.1 of the UCA, and the extent to which the Application is consistent with the requirements under section 19 of the *Clean Energy Act*.

BC Energy Objectives

BC Hydro identifies the following energy objectives that have relevance to the Project:[195]

Energy Objective	Commentary
(e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act*[14] continue to accrue to the authority's ratepayers;	The Project will upgrade Mainwaring substation so that BC Hydro can continue to reliably distribute electricity to ratepayers, therefore helping to ensure that BC Hydro's ratepayers continue to receive the benefit of heritage assets.
(k) to encourage economic development and the creation and retention of jobs;	The Project will result in contracting opportunities and positive economic benefits, as set out in Chapter 4, sections 4.3.1, 4.3.2, and 4.3.3

Long-Term Resource Plan

At time of filing the Application, BC Hydro's most recent IRP was the 2013 IRP, which was approved by Government on November 25, 2013.[196] Subsequent to filing the Application, BC Hydro filed its 2021 IRP with the BCUC on December 21, 2021.

BC Hydro identifies that the Project aligns with BC Hydro's 2021 IRP because:[197]

- It is required to maintain the reliability and capacity of the existing substation infrastructure so that generation from existing and committed resources, as set out in the 2021 IRP, can be transmitted to customers; and
- BC Hydro's 2021 IRP shows that BC Hydro's existing and committed resources are required to meet future resource needs, based on the energy and capacity reference forecasts.

Section 19 of the *Clean Energy Act*

Section 19 of the *Clean Energy Act*, which applies to BC Hydro, addresses clean and renewable resources.

BC Hydro states that at this time, there are no prescribed targets or guidelines under section 19 of the *Clean Energy Act*.[198] BC Hydro states, however, that the Project is consistent with and will aid BC Hydro in continuing

[195] Exhibit B-1, p. 1-23.
[196] Ibid.
[197] Exhibit B-3, IR 1.2.
[198] Exhibit B-1, p. 1-24.

to achieve British Columbia's energy objective set out in section 2(c) of the *Clean Energy Act,* which is "to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity."

Positions of the Parties

No intervener provided submissions on these issues.

Panel Determination

The Panel finds that the Project aligns with the relevant legislation including the *Utilities Commission Act*, along with section 19 of the *Clean Energy Act* and BC's energy objectives, notably energy objective (e) ensuring ratepayers benefit from heritage assets and (k) to encourage economic development and jobs.

In addition, the Panel notes that the Project is also indirectly aligned with other BC energy objectives outlined in section 2 of the *Clean Energy Act,* namely: "(g) to reduce greenhouse gas emissions" and "(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia." The Project will add 132 MVA of transformer capacity at the Mainwaring substation, partly enabling electrical load growth which may replace fossil fuel use in the area, subject to the constraints of the distribution system and customers' ability to fuel switch.

Finally, the Project aligns with BC Hydro's 2021 IRP, which is its most recently filed IRP.

8.0 Other Issues Arising

During the proceeding, BC Hydro identified that it has not completed an area study for the South Vancouver/Burnaby supply area within which the Mainwaring substation is located. BC Hydro's area studies are long-term (20-30 years) studies typically initiated in response to load growth in an area, which also consider BC Hydro's sustainment needs across the distribution and transmission system. These studies often consider load forecasts and asset needs across multiple locations and identify solutions requiring multiple projects that can span different time periods. BC Hydro confirms that a study for the South Vancouver/Burnaby area was initiated in 2014 and put on hold in 2016 when it became evident that additional capacity in the area would not be required for the foreseeable future.[199] BC Hydro expects to begin the next area study within the next five years, which would require approximately two years to complete.[200]

Positions of the Parties

RCIA submits that it is concerned that an area study was omitted before developing a costly project that will sweepingly reconfigure such a high criticality substation, one that is considered by BC Hydro to be the 13th most critical distribution substation in its entire system. Considering that substation assets have long service lives, RCIA is concerned by BC Hydro's omission of a Mainwaring area study prior to submitting a CPCN application for a Project alternative that involves a significant station reconfiguration as well as replacement of multiple major pieces of long-life equipment. In RCIA's review, proposing to develop this Project absent an area study is

[199] Exhibit B-3, BCUC IR 2.1.
[200] Exhibit B-4, BCOAPO IR 18.2.

concerning because it simultaneously increases the risk of both stranding (i.e., over-sizing) assets and under-sizing because the selected transformation assets are selected and sized based on incomplete assessments about area load growth and the future interplay between Mainwaring and its neighbouring substations, rather than a comprehensive and diligent area study.[201]

In reply, BC Hydro submits that this argument is a red herring as it is not claiming that the capacity at the Mainwaring substation is insufficient to serve area load. BC Hydro explains that it conducts area studies when there is a need for additional capacity and that BC Hydro will continue to monitor the load forecast for the area and will initiate an area study should additional capacity be required in the area due to load growth. Further, BC Hydro has filed its Asset Plan for the Mainwaring substation as Appendix D to the Application and submits that the Asset Plan demonstrates that it has considered the overall long-term needs of the substation and supports the substation configuration proposed as part of the Project.[202]

The CEC and BCOAPO did not make specific submissions with respect to the need, if any, for area studies.

Panel Determination

As noted above, BC Hydro submits that the associated area study was put on hold in 2016 when it became evident that additional capacity in the area of the Mainwaring substation would not be required for the foreseeable future. This suggests that the sole trigger for an area study is to assess the need for expanded capacity at a specific substation. The Panel disagrees. In fact, the larger power transformers (i.e., 150 MVA) in the selected Project alternative include a capacity expansion, albeit requiring additional investments in feeder sections to increase the overall substation capacity. The Panel finds that an area study would have strengthened the case for preferring the expanded capacity of the proposed larger power transformers at the Mainwaring substation.

The Panel agrees with RCIA that an area study would provide assessments about local area load growth and the future interplay between Mainwaring and its neighbouring substations in the vicinity. The Panel views that an area study can inform consideration of both increases and decreases in capacity of the Mainwaring substation in tandem with the need for potential investments at other substations as well as associated transmission and distribution infrastructure in the vicinity. In short, an area study could have supported development of additional alternatives to the Project beyond those considered by BC Hydro in this Application. This is particularly relevant in the context of BC Hydro's 2021 IRP which heavily emphasizes electrification and decarbonization of components of BC's energy demand.

While the Panel has determined that there is a need for the Project notwithstanding that BC Hydro did not complete an area study in support of the Project, for future substation CPCN and Capital Expenditure applications, the Panel recommends that BC Hydro either submit an area study or provide an explanation as to why such an area study is not needed. The Panel views that an area study can be a useful tool to inform the development of project alternatives beyond the substation footprint as well as proposed changes in capacity of individual substation components.

[201] RCIA Final Argument, p. 10.
[202] BC Hydro Reply Argument, p. 6.

9.0 Overall CPCN Determination

Positions of the Parties

BCOAPO recommends that the BCUC approve the Application. BCOAPO states that BC Hydro has provided a body of evidence sufficient to satisfy BCOAPO that the condition of the T1 and T3 power transformers and the 50/60 feeder section at the Mainwaring substation are, at best, poor and the risks of their failure serious enough that timely action is in ratepayers' and the public interest. In addition, BCOAPO submits that the evidence supports that the Project's proposed scope, planning and costs are all reasonable.[203]

The CEC recommends that the BCUC approve the CPCN for the Project.[204] The CEC finds the Project to be appropriately justified and planned and is in the public interest.[205]

RCIA does not agree that the Project, as proposed, is "necessary and prudent." RCIA submits that the evidence filed by BC Hydro does not meet the required burden of proof to justify the Project, and as such RCIA objects to approval of the CPCN at this time. RCIA submits that based on the evidence submitted, the Project is not required at this time, because none of the evidence on capacity to serve demand growth, asset condition, reliability risk, safety risk, environmental risk, legislative risk, and reputational risk, taken either alone or together, justify the need for the Project as proposed. In fact, the evidence indicates that the Project can be prudently deferred with little additional risk, while providing material financial savings to ratepayers.[206]

In reply, BC Hydro reiterates that the Project is in the public interest and urges the BCUC to grant a CPCN for the Project.[207]

Panel Determination

The Panel finds that the public convenience and necessity require the construction and operation of the Mainwaring substation upgrade Project.

Earlier in section 2.0 of this Decision, the Panel found that there is a need to address the reliability, environmental, safety and compliance risks associated with the deteriorated equipment at the Mainwaring substation, and in section 3.0 that the Project is the most appropriate alternative to meet this need. In sections 4.0 and 5.0, the Panel found that the Project implementation, risk management and capital costs are reasonable. In section 6.0, the Panel found that BC Hydro's consultation with Indigenous communities and other stakeholders has been adequate to date, and in section 7.0, the Panel determined that the Project is consistent with applicable provisions in the *Utilities Commission Act* and the *Clean Energy Act*, including BC's energy objectives, and aligns with BC Hydro's 2021 IRP. In section 8.0 the Panel made recommendations to BC Hydro regarding the completion of area studies for future substation CPCN and Capital Expenditure applications.

In light of these findings, **the Panel grants a CPCN to BC Hydro for the Project.**

[203] BCOAPO Final Argument, p. 23.
[204] CEC Final Argument, p. 1.
[205] Ibid., p. 27.
[206] RCIA Final Argument, p. 7.
[207] BC Hydro Reply Argument, p. 33.

Given the magnitude of the Project and the timeline for its implementation, the Panel also directs BC Hydro to provide ongoing reporting to the BCUC for the duration of the Project, as detailed in Appendix A of this Decision.

DATED at the City of Vancouver, in the Province of British Columbia, this 16th day of August 2022.

Original signed by:

A. K. Fung, QC
Panel Chair / Commissioner

Original signed by:

E. B. Lockhart
Commissioner

Original signed by:

A. Pape-Salmon
Commissioner

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ORDER NUMBER
C-4-22

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority
Application for a Certificate of Public Convenience and Necessity
for the Mainwaring Substation Upgrade Project

BEFORE:
A. K. Fung, QC, Panel Chair
E. B. Lockhart, Commissioner
A. Pape-Salmon, Commissioner

on August 16, 2022

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

WHEREAS:

A. On November 5, 2021, British Columbia Hydro and Power Authority (BC Hydro) filed an application with the British Columbia Utilities Commission (BCUC) pursuant to section 45 and 46 of the *Utilities Commission Act* seeking a Certificate of Public Convenience and Necessity (CPCN) for the Mainwaring substation upgrade project (Application);

B. In the Application, BC Hydro proposes to replace two power transformers, a feeder section and associated equipment at the Mainwaring distribution substation (Project) and states that the expected cost of the Project is $114.4 million;

C. By Orders G-347-21, G-353-21, and G-64-22 dated November 26, 2021, December 2, 2021 and March 4, 2022, respectively, the BCUC established and amended the regulatory timetable for the review of the Application, which included public notification, filing of confirmation of compliance with public notification directives, two rounds of BCUC and Intervener information requests, letters of comment submissions and final and reply arguments;

D. By January 7, 2022, British Columbia Old Age Pensioners' Organization et al., Commercial Energy Consumers Association of British Columbia and the Residential Consumer Intervener Association registered as interveners in the proceeding; and

E. The BCUC has considered the Application, evidence and submissions in this proceeding and finds that public convenience and necessity require that the Project proceed and the following determinations to be warranted.

NOW THEREFORE pursuant to sections 45 to 46 of the *Utilities Commission Act* and for the reasons set out in the Decision issued concurrently with this order, the BCUC orders as follows:

1. A CPCN is granted to BC Hydro for the Project.

2. BC Hydro is directed to file Project reports as outlined in Appendix A to the Decision.

3. BC Hydro is directed to comply with all the directives outlined in the Decision issued concurrently with this order.

DATED at the City of Vancouver, in the Province of British Columbia, this 16th day of August 2022.

BY ORDER

Original signed by:

A. K. Fung, QC
Commissioner

British Columbia Hydro and Power Authority
Application for a Certificate of Public Convenience and Necessity
for the Mainwaring Substation Upgrade Project

PROJECT REPORTING

The scope of Project reporting for the duration of the Project will comprise the following:

1. **Semi-annual Progress Reports**

   Each report is required to detail:

   - **Actual costs incurred to date compared to the Project cost breakdown table estimate provided in Table 4-2 of the Application, highlighting variances with an explanation of significant variances;**
   - **Updated forecast of costs, highlighting the reasons for significant changes in Project costs anticipated to be incurred; and**
   - **The status of Project risks provided in Chapter 6 of the Application, highlighting the status of identified risks, changes in and additions to risks, the options available to address the risks, the actions that BC Hydro is taking to deal with the risks and the likely impact on the Project's schedule and cost.**

   BC Hydro must file semi-annual progress reports within 30 days of the end of each semi-annual reporting period, with the first report covering the period ending June 30, 2022. Each report must provide the information set out in Appendix A to this Decision.

2. **Material Change Reports**

   A material change (Material Change) is a change in BC Hydro's plan for the Project that would reasonably be expected to have a significant impact on the schedule, cost or scope, such that:

   - **There is a schedule delay of greater than six months compared to the schedule provided in Table 4-4 of the Application;**
   - **The total Project cost exceeds 10 percent of the estimated Project cost provided in Table 4-2 of the Application; or**
   - **There is a change to the Project scope provided in Chapter 4 of the Application.**

   In the event of a Material Change, BC Hydro must file a Material Change report with the BCUC explaining the reasons for the Material Change, BC Hydro's consideration of the Project risk and the options available, and actions BC Hydro is taking to address the Material Change. BC Hydro must file the Material Change report as soon as practicable and in any event within 30 days of the date on which the Material Change occurs.

3. Final Report

A Final Report within three months of substantial completion of the Project. The report is to include:

- **The final cost of the Project, including a breakdown of the final costs; and**

A comparison of these costs to the estimates provided in Table 4-2 of the Application and an explanation of all material cost variances for any of the cost items provided in Table 4-2 of the Application that exceed 10 percent.

BC Hydro and Power Authority
Application for a Certificate of Public Convenience and Necessity
for the Mainwaring Substation Upgrade Project

GLOSSARY AND ACRONYMS

ACRONYM / GLOSSARY	DESCRIPTION
AACE	Association for the Advancement of Cost Engineering
Application	Application for a Certificate of Public Convenience and Necessity (CPCN) for the Mainwaring substation upgrade project
BC Hydro	British Columbia Hydro and Power Authority
BCOAPO	British Columbia Old Age Pensioners' Organization et al.
BCUC	The British Columbia Utilities Commission
CEC	Commercial Energy Consumers Association of British Columbia
CPCN	Certificate of Public Convenience and Necessity
EV	Electric Vehicle
GIS	Gas Insulated Switchgear
IIMM	International Infrastructure Management Manual
IRP	Integrated Resource Plan
MVA	Mega Volt-Amp
PCBs	Polychlorinated Biphenyls
Project	Replacement of two power transformers, a feeder section and associated equipment at the Mainwaring distribution substation in South Vancouver
RCIA	The Residential Consumer Intervener Association
SDM	Structured Decision Making
SNC-Lavalin	SNC-Lavalin Inc.
UCA	The *Utilities Commission Act*

BC Hydro and Power Authority
Application for a Certificate of Public Convenience and Necessity
for the Mainwaring Substation Upgrade Project

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated November 16, 2021 – Appointing the Panel for the review of the BC Hydro Application for a CPCN for the Mainwaring Substation Upgrade Project
A-2	Letter dated November 26, 2021 – BCUC Order G-347-21 establishing a regulatory timetable
A-3	Letter dated December 2, 2021 – BCUC Order G-353-21 amending the regulatory timetable
A-4	Letter dated January 13, 2022 – BCUC issuing Information Request No. 1 to BC Hydro
A-5	Letter dated March 4, 2022 – BCUC Order G-64-22 amending the regulatory timetable
A-6	Letter dated March 17, 2022 – BCUC issuing Information Request No. 2 to BC Hydro
APPLICANT DOCUMENTS	
B-1	**BC HYDRO AND POWER AUTHORITY (BC HYDRO)** – Application for a Certificate of Public Convenience and Necessity (CPCN) for the Mainwaring Substation Upgrade Project dated November 5, 2021
B-1-1	**CONFIDENTIAL** – BC Hydro Application for a CPCN for the Mainwaring Substation Upgrade Project dated November 5, 2021
B-1-1-1	**CONFIDENTIAL** – Letter dated February 17, 2022 – BC Hydro submitting Confidential Errata No. 1 to the Application
B-1-2	**PUBLIC** – Letter dated February 17, 2022 – BC Hydro submitting Errata No. 1 to the Application
B-1-3	Letter dated March 11, 2022 – BC Hydro submitting Errata No. 2 to the Application
B-1-4	Letter dated April 14, 2022 – BC Hydro submitting Errata No. 3 to the Application
B-2	Letter dated January 12, 2022 – BC Hydro submitting compliance with Orders G-347-21 and G-353-21 Directives
B-3	Letter dated February 17, 2022 – BC Hydro submitting responses to BCUC Information Request No. 1

B-4	Letter dated February 17, 2022 – BC Hydro submitting responses to Intervener Information Requests No. 1
B-4-1	**CONFIDENTIAL** - Letter dated February 17, 2022 – BC Hydro submitting confidential responses to Intervener Information Requests No. 1
B-5	**CONFIDENTIAL**- Letter dated February 17, 2022 – BC Hydro submitting responses to Confidential Intervener Information Requests No. 1
B-6	Letter dated April 14, 2022 – BC Hydro submitting responses to BCUC Information Request No. 2
B-7	Letter dated April 14, 2022 – BC Hydro submitting responses to Interveners Information Request No. 2
B-7-1	**CONFIDENTIAL** - Letter dated April 14, 2022 – BC Hydro submitting confidential responses to Interveners Information Request No. 2
B-8	**CONFIDENTIAL** - Letter dated April 14, 2022 – BC Hydro submitting responses to RCIA Confidential Information Request No. 2

INTERVENER DOCUMENTS

C1-1	**BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION, DISABILITY ALLIANCE BC, COUNCIL OF SENIOR CITIZENS' ORGANIZATIONS OF BC, AND THE TENANT RESOURCE AND ADVISORY CENTRE (BCOAPO)** – Letter dated January 7, 2022 – Request for Intervener Status by Leigha Worth and Kristin Barham
C1-2	Letter dated January 20, 2022 – BCOAPO submitting Information Request No. 1 to BC Hydro
C1-3	Letter dated March 17, 2022 – BCOAPO submitting Information Request No. 2 to BC Hydro
C2-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC)** Letter dated January 7, 2022 Request to Intervene by David Craig and Christopher Weafer
C2-2	Letter dated January 17, 2022 – CEC submitting Confidentiality Declaration and Undertakings for C. Weafer, P. Weafer, D. Craig and J. Rhodes
C2-3	**CONFIDENTIAL** - Letter dated January 20, 2022 – CEC submitting confidential Information Request No. 1 to BC Hydro
C2-3-1	**PUBLIC** - Letter dated January 20, 2022 – CEC submitting redacted Information Request No. 1 to BC Hydro
C2-4	Letter dated March 17, 2022 – CEC submitting Information Request No. 2 to BC Hydro
C3-1	**RESIDENTIAL CONSUMER INTERVENER ASSOCIATION (RCIA)** – Letter dated January 7, 2022 submitting request to intervene by Matthew Matusiak

C3-2	Letter dated January 20, 2022 – RCIA submitting Information Request No. 1 to BC Hydro
C3-3	Letter dated March 10, 2022 – RCIA submitting Confidential Declaration and Undertaking
C3-4	Letter dated March 17, 2022 – RCIA submitting Information Request No. 2 to BC Hydro
C3-5	**CONFIDENTIAL** - Letter dated March 17, 2022 – RCIA submitting Information Request No. 2 to BC Hydro

INTERESTED PARTY DOCUMENTS

D-1	**FARIES, A. (FARIES)** – Request for Interested Party status letter dated December 28, 2021