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ORDER NUMBER
G-321-24

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

and

British Columbia Utilities Commission
Generic Cost of Capital Stage 2

BEFORE:
A. K. Fung, KC, Panel Chair
K. A. Keilty, Commissioner
T. A. Loski, Commissioner

on November 29, 2024

ORDER

WHEREAS:

A. By Order G-66-21 dated March 8, 2021, pursuant to section 82 of the *Utilities Commission Act*, the British Columbia Utilities Commission (BCUC) established a Generic Cost of Capital (GCOC) proceeding to be completed in two stages. Stage 1 of the GCOC proceeding sets the deemed equity component and allowed return on equity (ROE) of FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC). Stage 2 of the GCOC proceeding determines which utility will act as the benchmark (Benchmark Utility) and sets the deemed equity component and allowed ROE for all utilities that use the Benchmark Utility in British Columbia to set their capital structure and equity return;

B. By Orders G-236-23 and G-237-23 dated September 5, 2023, the BCUC concluded Stage 1 of the GCOC proceeding and commenced Stage 2 of the GCOC proceeding. The BCUC set, among other things, the deemed equity component and allowed ROE at 45.0 percent and 9.65 percent, respectively, for FEI and 41.0 percent and 9.65 percent, respectively, for FBC. The BCUC also established interim rates, effective January 1, 2024, on a refundable or recoverable basis, for all other utilities, except FBC, that currently use the Benchmark Utility to set their capital structure and equity return pending the BCUC's final decision on Stage 2 of the GCOC proceeding;

C. By Order G-6-24 dated January 11, 2024, the BCUC finalized the scope for Stage 2 of the GCOC proceeding and set FEI as the Benchmark Utility;

D. By Orders G-6-24, G-150-24, G-172-24, G-209-24, and G-213-24, respectively, the BCUC set and amended the regulatory timetable for Stage 2 of the GCOC proceeding which included utilities' filing of evidence, one round of information requests, letters of comment, final arguments, and reply arguments. Eight utilities and six interveners participated in Stage 2 of the GCOC proceeding; and

E. The BCUC has reviewed the submissions, evidence, and arguments filed in Stage 2 of the GCOC proceeding and makes the following determinations.

NOW THEREFORE for the reasons outlined in the decision accompanying this order and pursuant to sections 58 to 61 of the *Utilities Commission Act*, the BCUC orders as follows:

1. Effective January 1, 2024, the equity premium over the Benchmark Utility (i.e. deemed equity component) and ROE premium over the Benchmark Utility (i.e. allowed ROE) for the following Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. (collectively, PNG) divisions are:

Utility	Equity Premium over the Benchmark Utility (i.e. Deemed Equity Component)	ROE Premium over the Benchmark Utility (i.e. Allowed ROE)
PNG-West	7.0 percentage points (52.0 percent)	75 basis points (10.40 percent)
PNG(NE) Tumbler Ridge	7.0 percentage points (52.0 percent)	75 basis points (10.40 percent)
PNG(NE) Fort St. John / Dawson Creek	1.0 percentage points (46.0 percent)	75 basis points (10.40 percent)

2. Effective January 1, 2024, the equity premium over the Benchmark Utility (i.e. deemed equity component) and ROE premium over the Benchmark Utility (i.e. allowed ROE) for the following thermal energy system (TES) utilities and the default TES as discussed in Section 3.3.4 of the decision accompanying this order (TES Default) are:

Utility	Equity Premium over the Benchmark Utility (i.e. Deemed Equity Component)	ROE Premium over the Benchmark Utility (i.e. Allowed ROE)
Corix Burnaby Mountain DE Limited Partnership	4.0 percentage points (49.0 percent)	75 basis points (10.40 percent)
Corix UBCDE Limited Partnership	4.0 percentage points (49.0 percent)	75 basis points (10.40 percent)
Corix Dockside Green DE Limited Partnership	4.0 percentage points (49.0 percent)	75 basis points (10.40 percent)
Creative Energy Vancouver Platforms Inc. (Creative Energy) Core Steam System	6.0 percentage points (51.0 percent)	75 basis points (10.40 percent)
Creative Energy South Downtown Heating TES	4.0 percentage points (49.0 percent)	75 basis points (10.40 percent)
Creative Energy South Downtown District Cooling System	4.0 percentage points (49.0 percent)	75 basis points (10.40 percent)
Creative Energy Mount Pleasant Limited Partnership	4.0 percentage points (49.0 percent)	75 basis points (10.40 percent)
River District Energy	4.0 percentage points (49.0 percent)	75 basis points (10.40 percent)
TES Default	4.0 percentage points (49.0 percent)	75 basis points (10.40 percent)

3. Effective January 1, 2024, the equity premium over the Benchmark Utility (i.e. deemed equity component) and ROE premium over the Benchmark Utility (i.e. allowed ROE) for the following electric utilities are:

Utility	Equity Premium over the Benchmark Utility (i.e. Deemed Equity Component)	ROE Premium over the Benchmark Utility (i.e. Allowed ROE)
Boralex Ocean Falls Limited Partnership	5.0 percentage points (50.0 percent)	75 basis points (10.40 percent)
Nelson Hydro	5.0 percentage points (50.0 percent)	75 basis points (10.40 percent)
Kyuquot Power Ltd.	5.0 percentage points (50.0 percent)	75 basis points (10.40 percent)

4. For PNG, the directive to include an updated business risk assessment in all future revenue requirements applications in accordance with page 114 of the decision accompanying Order G-47-14 is rescinded.

5. For Kyuquot Power Ltd., Directive 1 of Order G-121-24 is varied by directing Kyuquot Power Ltd. to apply to the BCUC for a revised deemed interest on notional debt or permanent rates by January 31, 2025.

6. Unless otherwise ordered by the BCUC, Exhibits B9-14-1 and B9-14-2 will be held confidential due to restrictions on distribution of the two private ratings reports issued in confidence by Morningstar DBRS to PNG.

7. Utilities impacted by Stage 2 of the GCOC proceeding must comply with all other directives and determinations that apply to them as outlined in the decision accompanying this order.

8. Stage 3 of the GCOC proceeding is to commence on a date with regulatory process to be determined by the BCUC.

DATED at the City of Vancouver, in the Province of British Columbia, this 29th day of November 2024.

BY ORDER

Electronically signed by Anna Fung

A. K. Fung, KC
Commissioner

DECISION

Table of Contents

Page no.

APPENDICES

Executive Summary

The British Columbia Utilities Commission (BCUC) is responsible for ensuring that shareholders of its regulated utilities are afforded a reasonable opportunity to earn a fair return on their invested capital. The BCUC has traditionally done this through periodic generic cost of capital (GCOC) reviews.

Utilities' cost of capital is made up of two components: (1) the capital structure, which is the sum of deemed equity and debt, and (2) the return on each component of the capital structure, which take the form of the allowed return on equity (ROE) and the interest rate on debt.

Consistent with past practice, the BCUC initiated a GCOC proceeding in January 2021. This GCOC proceeding has two stages to date:

- Stage 1 determined the allowed return for FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) since both utilities are the largest investor-owned natural gas and electric utilities, respectively, in British Columbia. Stage 1 concluded in September 2023 and the BCUC found that FEI's business risk has increased significantly since it was last assessed in 2016, while FBC's business risk remains similar to its last assessment in 2014. For FEI, the BCUC set a deemed equity component of 45.0 percent and an allowed ROE of 9.65 percent. For FBC, the BCUC set a deemed equity component of 41.0 percent and an allowed ROE of 9.65 percent.
- Stage 2 was initiated at the conclusion of Stage 1 and began by establishing FEI as the benchmark utility (Benchmark Utility) against which other utilities that currently use the Benchmark Utility set their own cost of capital. These utilities include Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. (collectively, PNG), Corix (CA) DE Services Limited Partnership (Corix), Creative Energy Vancouver Platforms Inc. (Creative Energy), River District Energy, Boralex Ocean Falls Limited Partnership (Boralex), Nelson Hydro, and Kyuquot Power Ltd (collectively the Stage 2 utilities).

This Stage 2 decision sets the equity premium (or discount) against the Benchmark Utility, which results in each Stage 2 utility's deemed equity component, and the ROE premium (or discount) against the Benchmark Utility, which results in each Stage 2 utility's allowed ROE. This decision also examines whether a methodology to set a deemed interest rate for debt is warranted.

Key Principles for Establishing Fair Return

Two key regulatory principles inform the determination of a fair return for utilities. The first is the Fair Return Standard and the second is the Standalone Principle.

The Fair Return Standard requires a fair and reasonable return on capital to meet the following three elements:

1. The comparable investment requirement – the return on capital should be comparable to the return available from the application of the invested capital to other enterprises of like risk;
2. The financial integrity requirement – the return on capital should enable the financial integrity of the regulated enterprise to be maintained; and

3. The capital attraction requirement – the return on capital should permit incremental capital to be attracted to the enterprise on reasonable terms and conditions.

All three requirements must be met, and none ranks higher in priority to the others. The BCUC applied the Fair Return Standard in Stage 1, and the Panel continues to apply it in Stage 2.

In applying the Fair Return Standard, the BCUC must assess each utility based on the Standalone Principle, which provides that the utility should be regulated as if it were a standalone entity, raising capital on the merits of its own business and financial characteristics, regardless of affiliations within the holding company structure. The BCUC applied the Standalone Principle in Stage 1 in the determination of the cost of capital for the FortisBC utilities and the Panel continues to apply it, along with the Fair Return Standard, with respect to its determination of the cost of capital for all Stage 2 utilities.

Approach and Allowed ROE for Stage 2 Utilities

The Panel takes the same approach in determining the deemed equity component and allowed ROE in Stage 2 as it applied in Stage 1. Namely, the deemed equity component reflects the change in each utility's business risks relative to the Benchmark Utility and since the time of each utility's most recent cost of capital review. The business risk analysis is done for each Stage 2 utility based on the evidence provided in Stage 2.

The allowed ROE, on the other hand, does not reflect business risks but rather is a function of the equal weighting of three financial models with market driven inputs that are transparent and easily replicated, with minimal subjective adjustments. Of the three financial models assessed for the allowed ROE, the Panel finds that only the capital asset pricing model would warrant an adjustment for the smaller size of Stage 2 utilities compared to the Benchmark Utility, FEI. Based on the size premium evidence presented in the proceeding, the Panel determines that the ROE premium for all Stage 2 utilities is 75 basis points to reflect their smaller size relative to the Benchmark Utility.

Deemed Equity Component and Allowed ROE Determinations for Stage 2 Utilities

The Panel determines the following deemed equity component and allowed ROE for Stage 2 utilities to be fair and reasonable. Implementation and adjustments will be made to rates effective January 1, 2024.

Gas Utilities

PNG applied for its three divisions: PNG-West, PNG(NE) Fort St. John / Dawson Creek, and PNG(NE) Tumbler Ridge. The Panel found that all three PNG divisions' overall business risks when compared against the Benchmark Utility have not materially changed since the last cost of capital proceeding in 2014. The Panel sets the following allowed return for the three PNG divisions:

Utility	Equity Premium over the Benchmark Utility (i.e. Deemed Equity Component)	ROE Premium over the Benchmark Utility (i.e. Allowed ROE)
PNG-West	7.0 percentage points (52.0 percent)	75 basis points (10.40 percent)
PNG(NE) Tumbler Ridge	7.0 percentage points (52.0 percent)	75 basis points (10.40 percent)
PNG(NE) Fort St. John / Dawson Creek	1.0 percentage points (46.0 percent)	75 basis points (10.40 percent)

Thermal Energy System (TES) Utilities

Corix applied for three TES projects: Corix Burnaby Mountain DE Limited Partnership, otherwise known as Burnaby Mountain District Energy Utility, Corix UBCDE Limited Partnership, and Corix Dockside Green DE Limited Partnership. The Panel considers that the Corix TES projects exhibit an overall higher risk profile relative to the Benchmark Utility due to challenges in build-out, including risks associated with recovery of revenue deficiencies under their levelized rate structure, and a limited customer base. However, the Panel assesses that this higher risk profile has not changed significantly since each of the Corix TES projects' respective most recent cost of capital reviews. The Panel finds that with Corix Dockside Green DE Limited Partnership now operating for over fifteen years, its build-out challenges have stabilized and its technology risks have diminished, and it now has a comparable risk profile to that of the other two Corix TES projects. Accordingly, the Panel concludes that all three Corix TES projects should be treated similarly regarding equity and ROE premiums, as no unique risks justify differentiated allowed returns among them.

Creative Energy applied for four TES projects that it separated into two groups. The first group is the small district energy systems (Small DES) group that includes South Downtown Heating Thermal Energy System, South Downtown District Cooling System, and Creative Energy Mount Pleasant Limited Partnership. The Panel does not consider there have been changes sufficient to substantiate an increase in the overall risk profile for the Small DES projects compared to the Benchmark Utility. The second group is the Creative Energy Core Steam System. The Panel finds that the business risks associated with the Core Steam System are higher relative to the Benchmark Utility and have increased since the last assessment in 2014.

For River District Energy, the Panel finds that its overall business risk continues to be higher than the Benchmark Utility, but the risk differential has not materially changed since its last cost of capital proceeding in 2014.

Lastly, consistent with the last generic cost of capital proceeding in 2014, the Panel determines that establishing a TES Default is warranted in Stage 2. The Panel views that establishing a TES Default will continue to reduce regulatory burden on small utilities and therefore promotes regulatory efficiency. The TES Default will be reflective of the typical TES based on a combination of the risk factors commonly faced by TES utilities (i.e. greenfield characteristics, non-traditional rate structures, small size, complex systems, competition from conventional energy sources, competition from other TES providers, high upfront capital costs, and high counterparty risk). The Panel finds that the TES Default should not be automatically applied, and that each future TES should have the opportunity to justify its proposed equity premium (i.e. deemed equity component) and ROE premium (i.e. allowed ROE), which could be the TES Default, or higher or lower than the TES Default based on its business risks and circumstances at the time of its regulatory filing.

The Panel sets the following allowed return for the TES utilities including the TES Default:

Utility	Equity Premium over the Benchmark Utility (i.e. Deemed Equity Component)	ROE Premium over the Benchmark Utility (i.e. Allowed ROE)
Corix Burnaby Mountain DE Limited Partnership	4.0 percentage points (49.0 percent)	75 basis points (10.40 percent)
Corix UBCDE Limited Partnership	4.0 percentage points (49.0 percent)	75 basis points (10.40 percent)
Corix Dockside Green DE Limited Partnership	4.0 percentage points (49.0 percent)	75 basis points (10.40 percent)
Creative Energy Core Steam System	6.0 percentage points (51.0 percent)	75 basis points (10.40 percent)
Creative Energy South Downtown Heating Thermal Energy System	4.0 percentage points (49.0 percent)	75 basis points (10.40 percent)
Creative Energy South Downtown District Cooling System	4.0 percentage points (49.0 percent)	75 basis points (10.40 percent)
Creative Energy Mount Pleasant Limited Partnership	4.0 percentage points (49.0 percent)	75 basis points (10.40 percent)
River District Energy	4.0 percentage points (49.0 percent)	75 basis points (10.40 percent)
TES Default	4.0 percentage points (49.0 percent)	75 basis points (10.40 percent)

Electric Utilities

For Boralex, the Panel finds that its overall business risk remains higher than the Benchmark Utility, but that the gap has now narrowed since its last cost of capital review in 2020.

For Nelson Hydro, the Panel finds that Nelson Hydro's overall business risk has not changed since its last cost of capital proceeding in 2022 and, when compared to the Benchmark Utility, there is a similar narrowing of the gap as there is for Boralex.

For Kyuquot Power Ltd., the Panel finds that its business risks can be reasonably assessed as similar to the other two Stage 2 electric utilities operating in remote service areas (i.e. Boralex and Nelson Hydro).

The Panel sets the following allowed return for the electric utilities:

Utility	Equity Premium over the Benchmark Utility (i.e. Deemed Equity Component)	ROE Premium over the Benchmark Utility (i.e. Allowed ROE)
Boralex	5.0 percentage points (50.0 percent)	75 basis points (10.40 percent)
Nelson Hydro	5.0 percentage points (50.0 percent)	75 basis points (10.40 percent)
Kyuquot Power Ltd.	5.0 percentage points (50.0 percent)	75 basis points (10.40 percent)

Deemed Interest Rate

The Panel finds that establishing a deemed interest rate continues to be warranted when a utility does not have third-party debt, when there is no observable debt, or where the utility does not incur actual financing costs.

The Panel determines that the deemed interest rate methodology should be based on the sum of:

1. Government of Canada 10-year bond yields based on the average of the last trailing 12 months;
2. The corporate credit spreads on the Government of Canada 10-year bonds for BBB and BBB(low) rated utilities based on the average of the last trailing 12 months;
3. Non-investment grade lending premium of 92 basis points; and
4. A deemed issuance fee of 50 basis points.

The deemed interest rate methodology established above is effective January 1, 2024, for those utilities that use a deemed interest rate in setting their cost of debt.

Notwithstanding the establishment of the above deemed interest rate methodology, the Panel finds that utilities should be free to apply for approval of different deemed interest rate methodologies based on their specific circumstances and evidence. These alternate methodologies could result in a deemed interest rate that is higher or lower than the resulting deemed interest rate based on the methodology established in this proceeding, but the review of such an alternate methodology would be subject to assessment by a future BCUC panel.

Stage 3

The scope after completion of Stage 2 (i.e. Stage 3) will consist only of regulatory account financing costs and will commence on a date with regulatory process to be determined by the BCUC.

1.0 Introduction

1.1 Background to Stage 1 and Stage 2 of the Generic Cost of Capital Proceeding

Pursuant to section 59(5)(b) of the *Utilities Commission Act* (UCA), the British Columbia Utilities Commission (BCUC) is responsible for ensuring that shareholders of its regulated utilities are afforded a reasonable opportunity to earn a fair return on their invested capital. The BCUC has traditionally done this through periodic generic cost of capital (GCOC) reviews.[1]

Consistent with that practice, the BCUC issued in January 2021, a Notice of Initiating a GCOC Proceeding pursuant to section 82 of the UCA.[2] As was the case with past GCOC proceedings, the BCUC determined that a two-stage proceeding to establish public utilities' cost of capital was appropriate for the current GCOC proceeding.[3]

The BCUC found that it was appropriate and efficient to first determine the cost of capital for FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC), (collectively FortisBC), since both utilities are the largest investor-owned natural gas and electric utilities, respectively, in British Columbia (BC).[4] This was the main focus of Stage 1 of the GCOC proceeding.

Table 1 below summarizes the cost of capital, comprising the deemed equity component and the allowed return on equity (ROE), for the two FortisBC utilities, as determined by the BCUC in Stage 1, along with the resultant weighted ROE, which is calculated as the deemed equity component multiplied by the allowed ROE. For ease of comparison, Table 1 also sets out the utilities' previously approved cost of capital prior to Stage 1 of the GCOC proceeding.

Table 1: Previously Approved and Currently Approved Cost of Capital for FEI and FBC

	Previously Approved[5]			Currently Approved[6]		
	Deemed Equity Component	Allowed ROE	Weighted ROE	Deemed Equity Component	Allowed ROE	Weighted ROE
FEI	38.5	8.75	3.37	45.0	9.65	4.34
FBC	40.0	9.15	3.66	41.0	9.65	3.96

[1] BCUC GCOC proceeding (Stage 1), Decision and Order G-236-23 dated September 5, 2023 (GCOC Stage 1 Decision), p. 1.
[2] GCOC Stage 1 Decision, p. 1.
[3] Order G-156-21 with Reasons for Decision dated May 21, 2021, Appendix A, p. 7; Order G-281-21 with Reasons for Decision dated September 24, 2021, p. 6.
[4] Order G-156-21 with Reasons for Decision dated May 21, 2021, Appendix A, p. 7; Order G-281-21 with Reasons for Decision dated September 24, 2021, p. 6.
[5] FEI Application for its Common Equity Component and Return on Equity for 2016, Decision and Order G-129-16 dated August 10, 2016 (2016 FEI COC Decision), Directives 1 and 2; GCOC Stage 1 Decision, pp. 3; BCUC 2013 GCOC proceeding (Stage 2), Decision and Order G-47-14 dated March 25, 2014 (2014 GCOC Stage 2 Decision), p. 86.
[6] GCOC Stage 1 Decision, Table 41, pp. 136, 137.

The decision for Stage 1 of this GCOC proceeding (GCOC Stage 1 Decision) also established interim rates, effective January 1, 2024, on a refundable or recoverable basis, for all other utilities except FBC, that use a benchmark utility to set their deemed equity component and allowed ROE pending the BCUC's final decision on Stage 2 of the GCOC proceeding.[7] Hereafter, Stage 1 refers to the first stage of the GCOC proceeding and Stage 2 refers to the second stage of the same proceeding.

Following the issuance of the GCOC Stage 1 Decision in September 2023, the BCUC commenced Stage 2. The scope of Stage 2 as determined by the BCUC is three-fold. First, the Panel has to determine which utility should serve as the benchmark utility (Benchmark Utility) for those BC utilities that use the Benchmark Utility to set their cost of capital. A list of the affected public utilities (collectively the Stage 2 utilities) that participated in Stage 2 is set out in Section 1.2 below. Secondly, having made such determination, the Panel must then establish the equity premium (or discount) and resulting deemed equity component and ROE premium (or discount) and resulting allowed ROE for Stage 2 utilities. The Panel clarifies that the deemed equity component for Stage 2 utilities would be the sum of the Benchmark Utility's 45.0 percent deemed equity component established in Stage 1 plus each Stage 2 utility's equity premium (or discount) to be set in this Stage 2. The same logic is applied to the allowed ROE as being the sum of the Benchmark Utility's 9.65 percent allowed ROE established in Stage 1 plus each Stage 2 utility's ROE premium (or discount) to be set in this Stage 2. Lastly, the Panel must determine whether the establishment of a deemed interest rate for Stage 2 utilities is warranted, and whether an automatic adjustment mechanism is also warranted and if so, their quantum and the circumstances in which they should apply.[8]

In light of this scope, the BCUC sought submissions on which utility should serve as the Benchmark Utility at the outset of Stage 2. In January 2024, after reviewing the submissions received, the BCUC set FEI as the Benchmark Utility for the purposes of Stage 2 because it is the largest investor-owned public utility in BC, it carries third-party debt and has independent credit ratings, and it provides a consistent and familiar Benchmark Utility given its history as the Benchmark Utility in previous GCOC proceedings.[9]

1.2 Regulatory Process

In accordance with the established regulatory timetable, the BCUC has undertaken a public review process for Stage 2, including the following:[10]

- Submissions on Benchmark Utility and scope of Stage 2
- Reply submissions on Benchmark Utility and scope of Stage 2
- Utilities' filing of evidence
- One round of information requests (IRs) on utilities' evidence
- Letters of comment[11]
- Utilities' final arguments, interveners' final arguments, and utilities' reply arguments

The following Stage 2 utilities participated in this proceeding:

[7] GCOC Stage 1 Decision, p. 142.
[8] Order G-6-24 with Reasons for Decision dated January 11, 2024, Appendix B.
[9] Order G-6-24 with Reasons for Decision dated January 11, 2024, Appendix C, p. 8.
[10] Orders G-6-24, G-150-24, G-172-24, G-209-24 and G-213-24.
[11] No letters of comment were filed in Stage 2.

- Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. (collectively, PNG)
- Corix Multi-Utility Services Inc., now known as Corix (CA) DE Services Limited Partnership (Corix)
- Creative Energy Vancouver Platforms Inc. (Creative Energy)
- River District Energy (RDE)
- FortisBC Alternative Energy Service Inc. (FAES)[12]
- Boralex Ocean Falls Limited Partnership (Boralex)
- Nelson Hydro
- Kyuquot Power Ltd. (KPL)[13]

The following interveners participated in Stage 2:

- Residential Consumer Intervener Association (RCIA)
- Commercial Energy Consumer Association of British Columbia (the CEC)
- British Columbia Old Age Pensioners' Organization et al. (BCOAPO)
- Simon Fraser University (SFU)

The following parties registered to intervene in Stage 2 but did not actively participate:

- Association of Major Power Customers of BC (AMPC)
- British Columbia Hydro and Power Authority (BC Hydro)

2.0 Key Principles and Decision Framework

2.1 Legislative Requirement

Pursuant to section 59 of the UCA, the BCUC is responsible for establishing rates that are not unjust, unreasonable, unduly discriminatory or unduly preferential. In discharging its duty under section 59 of the UCA, the BCUC must ensure that shareholders of regulated utilities are afforded a reasonable opportunity to earn a fair return on their invested capital (Fair Return Standard), otherwise commonly referred to as cost of capital.[14]

2.2 Guidance from Stage 1

Since much of our approach to the review of the issues raised in Stage 2 relies on and is consistent with our findings and approach adopted in Stage 1, we consider it instructive to summarize some of the key regulatory principles and findings from Stage 1.

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[12] While FAES participated in Stage 2, it does not currently have any rate-regulated thermal energy system (TES) projects that are directly impacted by the deemed equity component and allowed ROE determinations of Stage 2. FAES's submissions in Stage 2 are discussed primarily in Section 3.3.4 regarding the TES Default and Section 4.0 regarding the deemed interest rate.
[13] KPL did not file evidence or arguments in Stage 2, but did provide responses to BCUC IR No. 1.
[14] GCOC Stage 1 Decision, p. 7.

Two key regulatory principles inform the determination of an appropriate cost of capital. The first is the Fair Return Standard and the second is the standalone principle (Standalone Principle). Each is described in turn below.

Fair Return Standard

When determining the utilities' cost of capital, the BCUC is guided by certain fundamental regulatory principles, including the Fair Return Standard, pursuant to which the BCUC must set rates that will provide the utilities' shareholders a reasonable opportunity to earn a fair return on their invested capital.[15] The Supreme Court of Canada established the following principles regarding the concept of "fair return" for a regulated company in *Northwestern Utilities Limited v. City of Edmonton*:[16]

> The duty of the [National Energy] Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise, (which will be net to the company,) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise. (per Lamont J.)

The Fair Return Standard is fundamental to cost of capital proceedings. A fair and reasonable return on capital, as articulated in the National Energy Board's Decision,[17] must meet the following three elements:

a) The comparable investment requirement – the return on capital should be comparable to the return available from the application of the invested capital to other enterprises of like risk;

b) The financial integrity requirement – the return on capital should enable the financial integrity of the regulated enterprise to be maintained; and

c) The capital attraction requirement – the return on capital should permit incremental capital to be attracted to the enterprise on reasonable terms and conditions.

All three requirements must be met, and none ranks higher in priority to the others.[18] The BCUC applied the Fair Return Standard in Stage 1, and the Panel continues to apply it in Stage 2.

Standalone Principle

In applying the Fair Return Standard, the BCUC must assess the utility based on the Standalone Principle, which provides that the utility should be regulated as if it were a standalone entity, raising capital on the merits of its own business and financial characteristics, regardless of affiliations within the holding company structure.[19] The BCUC applied the Standalone Principle in Stage 1 in the determination of the cost of capital for the FortisBC

[15] GCOC Stage 1 Decision, p. 5.
[16] Supreme Court of Canada, Northwestern Utilities Ltd. v. Edmonton (City), [1929] S.C.R. 186.
[17] National Energy Board, Reasons for Decision RH-2-2204, TransCanada PipeLines Limited, p. 17. The National Energy Board was the predecessor to the current Canada Energy Regulator.
[18] GCOC Stage 1 Decision, p. 6.
[19] GCOC Stage 1 Decision, p. 6.

utilities and the Panel continues to apply it, along with the Fair Return Standard, with respect to its determination of the cost of capital for all the Stage 2 utilities.

In addition to the above two regulatory principles, the BCUC recognized in Stage 1 that while past BCUC decisions in GCOC proceedings are informative and provide historical context, they are not determinative.[20] The Panel agrees with that caution and considers that it must evaluate the evidence presented in the current proceeding[21] to set the cost of capital for the Stage 2 utilities.

The Panel acknowledges that the BCUC's approach in Stage 1 differs from previous GCOC proceedings in certain respects but is satisfied that the methodology adopted in Stage 1 is sound, provides a reasonable basis to assess cost of capital for Stage 2 utilities, and results in desired consistency in approach between Stage 1 and Stage 2. The Panel also acknowledges the importance of exercising informed judgment, supported by quantitative and qualitative evidence during Stage 1 and Stage 2 of this proceeding, in determining the appropriate cost of capital for each of the Stage 2 utilities. The Panel notes that this assessment is grounded in art as much as science, rather than the mechanical application of a mathematical formula.

Additionally, the Panel notes that this Stage 2 decision is essentially a continuation of the GCOC Stage 1 Decision since the determination of the cost of capital for the Stage 2 utilities will be based on the Benchmark Utility. As such, this decision will at times refer to and be grounded upon specific findings from Stage 1 which are relevant to our determination of the Stage 2 utilities' cost of capital, including the following:

- In determining the cost of capital for a utility, there are four key elements that the BCUC must consider:
    1. The returns of a proxy group of peer utilities.
    2. The business risks facing the utility in question, including how those risks may have changed since the last time the BCUC approved a cost of capital for that utility.
    3. Its credit rating, if any.
    4. The results of various financial models that are designed to assess how the market prices risk and considers earnings in the evaluation of cost of capital.[22]

- No one of the above elements is, in itself, determinative. Rather, the BCUC considers all of these elements together, applying an appropriate weight to each of them as it determines a utility's allowed cost of capital.[23]

- With respect to the selection of a proxy group of peer utilities for the FortisBC utilities, the BCUC determined that the use of a North American proxy group was appropriate in light of the increasing integration of the US and Canadian capital markets and the limited number of comparable Canadian utilities.[24]

[20] GCOC Stage 1 Decision, p. 6.
[21] By Order G-237-23 dated September 5, 2023, the BCUC determined that the Stage 1 record will form part of the Stage 2 record.
[22] GCOC Stage 1 Decision, p. 7.
[23] GCOC Stage 1 Decision, p. 8.
[24] GCOC Stage 1 Decision, pp. 15–17.

- In establishing the allowed ROE for each of FortisBC utilities in Stage 1, the BCUC placed equal weight on the outputs of three financial models (the capital pricing asset model (CAPM), the multi-stage discounted cash flow model, and the risk premium model), in recognition that all financial models are simplifications of reality, using simplifying assumptions and as such, each model is prone to varying degrees of criticism.[25]

- To the greatest extent possible, changes in a utility's business risks should be reflected in its deemed equity component, and any adjustments to its allowed ROE should be limited to objective market inputs that impact the financial models.[26]

- Financial leverage and financial flexibility should be considered within the deemed equity component, but not as a direct input that would warrant a higher or lower cost of capital. The BCUC must strive to strike the right balance between equity and debt so as not to adversely affect the credit ratings or financing opportunities of utilities in BC. So long as the cost of capital meets the Fair Return Standard, there should be no detrimental impact to a utility's credit rating or financial risk.[27]

- The increased deemed equity component as determined by the BCUC for the Benchmark Utility in Stage 1 and shown in Table 1 above, reflects the increase in the Benchmark Utility's business risks since its last cost of capital review in 2016. The BCUC noted in Stage 1 that the main driver for the increase in the Benchmark Utility's business risks is the energy transition risk that has arisen for FEI as a natural gas utility since 2016. In contrast, that risk is not pertinent to FBC as an electric utility.[28]

- Nothing in the UCA prescribes a statutory timeframe for reviewing a utility's cost of capital. The BCUC has the power to initiate a cost of capital review at any time within its discretion, as it did in this instance. Similarly, a utility can apply to the BCUC for review of its cost of capital at any time.[29]

For clarity, the Panel adopts the above approach, findings, and principles as the basis for its determination of the cost of the capital for the Stage 2 utilities in the remainder of this decision.

2.3 Structure of the Decision

The remainder of this decision is structured as follows:

- Section 3.0 discusses the deemed equity component and allowed ROE for Stage 2 utilities based on their energy types (gas, thermal energy, and electricity);
- Section 4.0 reviews the deemed interest rate proposals put forward by Stage 2 utilities; and
- Section 5.0 discusses other matters including implementation considerations of this decision on Stage 2 utilities, further process after the completion of Stage 2, and confidentiality of certain exhibits within Stage 2.

[25] GCOC Stage 1 Decision, pp. 135–136.
[26] GCOC Stage 1 Decision, p. 133.
[27] GCOC Stage 1 Decision, pp. 132–133.
[28] GCOC Stage 1 Decision, pp. 49–50, 62–63.
[29] GCOC Stage 1 Decision, p. 149.

3.0 Deemed Equity Component and Allowed ROE for Stage 2 Utilities

Having determined that FEI should continue to serve as the Benchmark Utility in Stage 2, the Panel's next task is to determine the equity premium (or discount) over the Benchmark Utility resulting in the deemed equity component and the ROE premium (or discount) over the Benchmark Utility resulting in the allowed ROE for Stage 2 utilities.[30]

In considering whether there should be a premium or a discount for Stage 2 utilities compared to the Benchmark Utility, we note that with the exception of FAES's submissions on the default equity component and default ROE premium for rate-regulated thermal energy systems (TES Default) as discussed in Section 3.3.4, no Stage 2 utility has proposed an equity discount or an ROE discount. The Panel discusses the merits of each of the utilities' respective proposals, including the applicability of an equity premium (or discount) or ROE premium (or discount), in the remainder of this decision.

3.1 Approach to Stage 2

The Panel first outlines below, its approach to setting the equity premium and ROE premium in Stage 2 and then applies this approach to each of the Stage 2 utilities grouped by utilities of the same energy type (i.e. gas, thermal energy systems, and electric).

3.1.1 Factors Affecting Equity Premium and Allowed ROE

In Stage 1, FortisBC's expert, Mr. Coyne noted that the deemed equity component and allowed ROE are "inextricably linked" and that regulators must consider both values together to determine whether the Fair Return Standard has been met.[31] The BCUC agreed with the latter proposition in the GCOC Stage 1 Decision.[32] Given this inter-relationship, the BCUC determined to reflect changes in business risks as adjustments to the deemed equity component, while recognizing that these changes in business risks also impact the allowed ROE.[33] The BCUC noted that this approach provides for both consistency with past decisions and room for the exercise of informed judgment.[34]

The GCOC Stage 1 Decision used changes in business risk as the main driver of the deemed equity component and market inputs in financial models as the main driver of the allowed ROE.[35] In assessing changes in business risk for FortisBC in Stage 1, the BCUC used a risk matrix which included the following factors:[36]

- Business profile – including type and size of utility,[37] service area, and customer profile;
- Economic conditions – including overall economic conditions;
- Political – including climate action goals and expectations, and energy policies and legislation;

[30] Order G-6-24 with Reasons for Decision dated January 11, 2024, Appendix B.
[31] GCOC Stage 1 Decision, p. 127.
[32] GCOC Stage 1 Decision, p. 133.
[33] GCOC Stage 1 Decision, p. 133.
[34] GCOC Stage 1 Decision, p. 133.
[35] GCOC Stage 1 Decision, pp. 132–137.
[36] GCOC Stage 1 Decision, Table 9, p. 31.
[37] Size of the utility will be discussed separately in this decision.

- Indigenous Rights and Engagement – including legislative and policy developments, Aboriginal rights and title, and social licence/work interruption;
- Energy price – including commodity price, commodity price volatility, price competitiveness and carbon tax;
- Demand/market – including perception of energy, new technology and energy forms, net customer additions, changes in building type and capture rates, changes in end-use market share, and changes in use per customer;
- Energy supply – including availability of energy supply, access to supply, and renewable gas supply;
- Operating – including aging infrastructure and time dependant threats, third-party damages, attitudes towards fossil fuel industry, municipal operating challenges, cybersecurity, and unexpected events; and
- Regulatory – regulatory uncertainty and lag, and administrative penalties.

Stage 2 utilities generally provided a summary of changes in their business and financial risks given the nature of their operations as compared to the Benchmark Utility now, as opposed to those operations that existed at the time of each utility's most recent cost of capital determination. With the exception of FAES, all Stage 2 utilities put forward justifications for their proposed equity premium and ROE premium, either wholly or in part, using the argument of higher business risks than the Benchmark Utility.[38]

Positions of Parties

The CEC was the only intervener to make submissions on the overall approach to Stage 2. The CEC states that each utility made its own unique case in Stage 2 which resulted in a record of many different approaches and requests. The CEC recommends that the BCUC should have as an objective for Stage 2, a more consistent standard for all utilities in BC with gradually fewer exceptions made only for substantially necessary reasons, and a consistent structure for making such decisions.[39]

Panel Determination

The Panel finds that business risk should only affect the deemed equity component in Stage 2 and that the equity premium can wholly reflect the difference in each Stage 2 utility's business risks relative to those of the Benchmark Utility. The Panel views that an approach whereby the equity premium is driven solely by changes in business risks is consistent with the approach taken in Stage 1, is reasonable considering the evidence provided in Stage 2, and meets the requirements of the Fair Return Standard.

The Panel upholds the BCUC finding from Stage 1, that financial risk is not in and of itself a driver of the deemed equity component. Rather, the Panel will aim to ensure that the cost of capital set for each Stage 2 utility meet the Fair Return Standard such that the utility's financial risk should not be detrimentally impacted by this decision.

[38] Exhibit B9-9, PNG Evidence, p. 32; Exhibit B6-9, Corix Evidence, p. 6; Exhibit B7-8, Creative Energy Evidence, p. 16; Exhibit B8-5, RDE Evidence, p. 17; Exhibit C3-2, Boralex Evidence, p. 14; Exhibit B4-6, Nelson Hydro Evidence, p. 4-21.
[39] The CEC Final Argument, p. 8.

The Panel adopts the same risk matrix as was used in Stage 1 for its analysis of a utility's business risks, except for the size of the utility included within the business profile risk. For the reasons stated in the following section, size will be reflected in the ROE premium as opposed to the equity premium in Stage 2. Additionally, the Panel notes that Stage 2 utilities modified the risk matrix in their evidence for various reasons including the use of expert evidence, consistency with historical filings, or adaption of risks to their unique businesses and circumstances. Therefore, this decision will not examine each individual risk for each of the Stage 2 utilities in detail in the way the GCOC Stage 1 Decision did for FortisBC. Rather, in Sections 3.2 through 3.4, the Panel will focus on the overall business risk assessment for each utility as driven or supported by the specific risk factors that are germane to the Panel's equity premium determination for that utility. The Panel will also assess changes in the Stage 2 utilities' business risks relative to the changes in the Benchmark Utility's business risks.

3.1.2 ROE Premium

Given the Panel's intention to reflect changes in business risk in a utility's equity premium, this section outlines the Panel's approach to establishing an ROE premium whereby it is consequently <u>not</u> driven by changes in business risks but rather by market inputs to the financial models used in Stage 1.

In the GCOC Stage 1 Decision, the BCUC gave equal weight to three distinct financial models to determine the ROE, which are the CAPM, the multi-stage discounted cash flow model, and the risk premium model. Using this methodology, the Panel determined an allowed ROE of 9.65 percent for both FEI and FBC.[40] When setting the allowed ROE in Stage 1, the BCUC took the approach of making determinations that have a sound basis in financial theory, that are transparent and easily replicated, with minimal subjective adjustments (i.e. those made without any underlying basis in financial theory or empirical support).[41] Of the three ROE models used in Stage 1, the evidence in Stage 2, as discussed below, shows that only the CAPM would have had a different output had the Stage 2 utilities been included in the analysis of the three models.[42] In the Panel's view, this difference in CAPM output for Stage 1 and Stage 2 could be reflected by recognizing a "size premium" within the CAPM.

In addition to this size adjustment, PNG's expert, The Brattle Group (Brattle) contends that the credit spread between BBB and A rated Canadian utility bonds has widened since 2014, indicating that debt investors (and likely equity investors) now require a greater premium to invest in smaller Canadian utilities, such as PNG, than for large A-rated utilities like the Benchmark Utility. Based on this credit spread, Brattle adjusted its ROE recommendation by 65 basis points (bps) for PNG's western division (PNG-West) and Pacific Northern Gas (N.E.) Ltd. [PNG(NE)] Tumbler Ridge and 70 bps for PNG(NE) Fort St. John / Dawson Creek.[43]

Prior to Stage 1, in both the 2013 GCOC Stage 1 Decision[44] and the 2014 GCOC Stage 2 Decision[45], the BCUC declined to include a size premium, noting that although the academic literature and empirical studies supported the importance of size in explaining returns, it found insufficient evidence on how to implement such

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[40] GCOC Stage 1 Decision, Table 40, p. 136.
[41] GCOC Stage 1 Decision pp. 135–136.
[42] Exhibit B6-9-1, Brattle Evidence for Corix, p. 65; Exhibit B9-9, Brattle Evidence for PNG, pp. 71–72.
[43] Exhibit B9-9, Brattle Evidence for PNG, pp. 65–67, PNG Evidence, pp. 31–32. PNG-West is PNG's western division.
[44] BCUC 2013 GCOC proceeding (Stage 1), Decision and Order G-75-13 dated May 10, 2013 (2013 GCOC Stage 1 Decision).
[45] BCUC 2013 GCOC proceeding (Stage 2), Decision and Order G-47-14 dated March 25, 2014 (2014 GCOC Stage 2 Decision).

an adjustment in either stage of the 2013 BCUC GCOC proceeding's record.[46] Instead, in the decisions on both stages, the BCUC opted to reflect size in a utility's business and financial risks.

In Stage 1, the BCUC's independent expert, Dr. Lesser explained the size premium as stemming from an observation that smaller firms (for which size is measured by market capitalization) tend to have higher returns than predicted by the CAPM. Dr. Lesser explained that most analysts rely on the size-based stock portfolios created by the Center for Research in Security Prices (CRSP) at the University of Chicago's Graduate School of Business. Dr. Lesser further explained that CRSP includes 10 separate groups of stocks ranked from 1 (largest) to 10 (smallest) by market capitalization and publishes size premium values each year by Kroll[47] as part of its "Cost of Capital Navigator."[48]

Table 2 below shows the CRSP size premium as filed in Dr. Lesser's August 2021 report in Stage 1.

Table 2: CRSP Size Premium, 2021[49]

Decile	Market Capitalization Range (Millions of US$)		Size Premium
	Low	High	
1	$29,025.80	$1,966,078.88	-0.22%
2	$13,178.74	$28,808.07	0.49%
3	$6,743.36	$13,177.83	0.71%
4	$3,861.86	$6,710.68	0.75%
5	$2,445.69	$3,836.54	1.09%
6	$1,591.87	$2,444.75	1.37%
7	$911.586	$1,591.77	1.54%
8	$451.955	$911.103	1.46%
9	$190.019	$451.8	2.29%
10	$2.194	$189.831	5.01%

Dr. Lesser explained that the size premium can be added to the CAPM results to estimate the allowed ROE.[50] In contrast, while Mr. Coyne believes a size premium is appropriate, he did not add one to the CAPM results for FBC in Stage 1.[51]

In Stage 2, both PNG and Corix retained Brattle to provide expert evidence on their behalf. Brattle states that the size premium as observed in capital markets is consistent with equity investors requiring a higher rate of return from smaller companies compared to larger ones.[52] Size premiums are widely used in cost of capital calculations by valuation practitioners such as Kroll and have been accepted by regulators such as the Federal Energy Regulatory Commission.[53] Unlike the CRSP data from the US, there are no high-quality size premium

[46] 2013 GCOC Stage 1 Decision, p. 101; 2014 GCOC Stage 2 Decision, pp. 28, 33.
[47] Kroll was formerly Duff & Phelps.
[48] Exhibit A2-3, Lesser Report, p. 55.
[49] Exhibit A2-3, Lesser Report, Table 1, p. 56. Dr. Lesser's report was filed in August 2021, and while the table is labelled as submitted in 2021, it contains CRSP size premium data for the most recent year ended 2020.
[50] Exhibit A2-3, Lesser Report, p. 56.
[51] GCOC Stage 1 Decision, pp. 85, 132, 135; Exhibit B1-8-1, Appendix C, Concentric Report, p. 5, footnote 3.
[52] Exhibit B9-9, Brattle Evidence for PNG, p. 72.
[53] Exhibit B9-9, Brattle Evidence for PNG, p. 72; Exhibit B6-9-1, Brattle Evidence for Corix, pp. 66–66.

studies that are regularly updated for the Canadian stock market.[54] However, Brattle points out that in Stage 1, the BCUC recognized there is a high degree of integration between Canadian and US capital markets.[55] Therefore, Brattle refers to the same CRSP small size premium data as published by Kroll that Dr. Lesser referred to in Stage 1. Brattle further explains that the CRSP small size premiums are calculated as the actual annual average returns less the CAPM-predicted returns for each of the decile portfolios.[56]

Table 3 below shows the CRSP size premium and decile break points from 2019 to 2023 as included by Brattle in both PNG's and Corix's evidence.

Table 3: CRSP Size Premium and Decile Break Points (in USD millions)[57]

CRSP	2019		2020		2021		2022		2023	
Decile	Minimum Threshold	Size Premium	Minimum Threshold	Size Premium	Minimum Threshold	Size Premium	Minimum Threshold	Size Premium	Minimum Threshold	Size Premium
1	$31,090	-0.28%	$29,026	-0.22%	$36,161	-0.22%	$31,549	-0.26%	$36,943	-0.06%
2	$13,143	0.50%	$13,179	0.49%	$16,759	0.43%	$12,373	0.45%	$14,911	0.46%
3	$6,619	0.73%	$6,743	0.71%	$8,216	0.55%	$5,919	0.57%	$7,494	0.61%
4	$4,313	0.79%	$3,862	0.75%	$5,020	0.54%	$3,770	0.58%	$4,622	0.64%
5	$2,689	1.10%	$2,446	1.09%	$3,281	0.89%	$2,365	0.93%	$3,011	0.95%
6	$1,670	1.34%	$1,592	1.37%	$2,170	1.18%	$1,390	1.16%	$1,864	1.21%
7	$994	1.47%	$912	1.54%	$1,306	1.34%	$789	1.37%	$1,050	1.39%
8	$516	1.59%	$452	1.46%	$629	1.21%	$377	1.18%	$556	1.14%
9	$230	2.22%	$190	2.29%	$290	2.10%	$218	2.15%	$213	1.99%
10	$2	4.99%	$2	5.01%	$11	4.80%	$2	4.83%	$2	4.70%

Table 4 below shows Brattle's application of the CRSP size premiums from Table 3 to PNG and FEI as the Benchmark Utility. Brattle calculates the size premium differential for PNG as compared to the Benchmark Utility as the difference between the size premium of PNG as a 7th to 9th decile utility and that of FEI as a 2nd decile utility.

[54] Exhibit B9-9, Brattle Evidence for PNG, p. 73; Exhibit B6-9-1, Brattle Evidence for Corix, p. 67.
[55] Exhibit B9-9, Brattle Evidence for PNG, p. 73; GCOC Stage 1 Decision, pp. 15–16.
[56] Exhibit B9-9, Brattle Evidence for PNG, p. 72.
[57] Exhibit B9-9, Brattle Evidence for PNG, Figure 22, p. 73; Exhibit B6-9-1, Brattle Evidence for Corix, Figure 21, p. 67.

Table 4: Indicative Size Premium for PNG[58]

End of Calendar Year/Half Year	2018	H1 2019	H2 2019	2020	2021	2022	2023
Market Capitalization							
(in USD millions)							
ACI/TriSummit (Equity Issuer for PNG) [1]	$357	$549	$772	$772	$772	$772	$1,243
Fortis Inc. (Equity Issuer for FEI)	$14,289	$17,083	$19,179	$19,049	$22,806	$19,228	$20,162
CRSP Decile							
ACI/TriSummit (Equity Issuer for PNG) [1]	9	8	8	8	8	8	7
Fortis Inc. (Equity Issuer for FEI)	2	2	2	2	2	2	2
CRSP Size Premium							
ACI/TriSummit (Equity Issuer for PNG) [1]	2.46%	1.59%	1.59%	1.46%	1.21%	1.18%	1.39%
Fortis Inc. (Equity Issuer for FEI)	0.52%	0.50%	0.50%	0.49%	0.43%	0.45%	0.46%
Size Premium Differentials							
(in bps)							
ACI/TriSummit over Fortis Inc.	194	109	109	97	78	73	94

Source/Note: CRSP Decile Study 2018 to 2023, Kroll Cost of Capital Navigator; Capital IQ.
[1]: ACI's year-end 2019 market cap is used as a proxy for TriSummit's from 2020 to 2023. On March 1, 2023, TSU acquired Alaska Utilities Business at $800 million, of which $471 million was equity. To account for this, $471 million was added to ACI/TSU Market Cap in 2023.

Brattle places little weight on the 2018 indicative size premium given transactions occurring in PNG's parent company at that time. Brattle notes that another parent company transaction accounts for PNG's change in decile from 2022 to 2023. Given the amounts shown in Table 4 above, Brattle proposes a size premium for PNG of between 73 bps and 109 bps based on the data from 2019 to 2023.[59]

Similarly, Table 5 below shows Brattle's application of the CRSP size premiums from Table 3 to Corix and FEI as the Benchmark Utility. Brattle calculates the size premium differential for Corix as compared to the Benchmark Utility to be the difference between the size premium of Corix as a 9th decile utility less the size premium of FEI as a 2nd decile utility.

[58] Exhibit B9-9, Brattle Evidence for PNG, Figure 23, p. 74.
[59] Exhibit B9-9, Brattle Evidence for PNG, pp. 74–75.

Table 5: Indicative Size Premium for Corix[60]

End of Calendar Year/Half Year	2018	2019	2020	2021	2022	2023
Market Capitalization						
(in USD millions)						
Fortis Inc. (Equity Issuer for FEI)	$14,289	$19,179	$19,049	$22,806	$19,228	$20,162
9th Decile Maximum	$728	$516	$452	$628	$374	$555
CRSP Decile						
Corix (Assuming 9th Decile)	9	9	9	9	9	9
Fortis Inc. (Equity Issuer for FEI)	2	2	2	2	2	2
CRSP Size Premium						
Corix (Assuming 9th Decile)	2.46%	2.22%	2.29%	2.10%	2.15%	1.99%
Fortis Inc. (Equity Issuer for FEI)	0.52%	0.50%	0.49%	0.43%	0.45%	0.46%
Size Premium Differentials						
(in bps)						
Corix (9th) over Fortis Inc.	194	172	179	167	169	153

Given the amounts laid out in Table 5 above, Brattle proposes a size premium for Corix of approximately 150 bps based on the most recent data.[61]

In Stage 2, utilities proposed ROE premiums between 50 bps and 135 bps. However, as previously noted, all Stage 2 utilities with the exception of FAES justified their proposed equity premium and ROE premium, either wholly or in part, using the argument of higher business risks than the Benchmark Utility.[62] Given their engagement of Brattle, PNG's and Corix's proposed ROE premiums do include both a size premium component and a business risk component.[63] FAES submits that a size premium within the allowed ROE in the range of 50 bps to 75 bps would be consistent with the BCUC's previous decisions and would recognize the sound theoretical basis for a size premium and the influence of utility size on business risk.[64]

Positions of Parties

The CEC acknowledges that the small size of the utilities may warrant an increase in the deemed equity component as suggested by the CRSP size premium tables.[65] However, BCOAPO takes issue with Brattle's proposed credit spread adder to PNG's proposed allowed ROE.[66]

SFU submits that Corix Burnaby Mountain District Energy Utility's allowed ROE should only increase to the extent that the Benchmark Utility's allowed ROE was increased due to market effects, and not for any increase that may be associated with the increase in business risks.[67]

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[60] Exhibit B6-9-1, Brattle Evidence for Corix, Figure 22, p. 68.
[61] Exhibit B6-9-1, Brattle Evidence for Corix, p. 68.
[62] Exhibit B9-9, PNG Evidence, pp. 32–33; Exhibit B6-9, Corix Evidence, p. 6; Exhibit B7-8, Creative Energy Evidence, p. 16; Exhibit B8-5, RDE Evidence, p. 17; Exhibit C3-2, Boralex Evidence, p. 14; Exhibit B4-6, Nelson Hydro Evidence, p. 4-21.
[63] Exhibit B9-9, PNG Evidence, pp. 31–33; Exhibit B6-8, Corix Evidence, pp. 6–7.
[64] FAES Final Argument, p. 23.
[65] The CEC Final Argument, p. 33.
[66] BCOAPO Final Argument, pp. 24–25.
[67] SFU Final Argument, p. 22.

With the exception of FAES as noted above, other Stage 2 utilities and interveners did not comment on the small size premium within the allowed ROE explicitly in their submissions, but did factor in size in their business risk analysis and corresponding proposed equity premium and allowed ROE. Interveners proposed ROE premiums for Stage 2 utilities which ranged from 25 bps to 135 bps due to arguments that generally, but not exclusively, centred around increases in business risk.[68]

Panel Determination

Following from the Panel's findings on the equity premium approach above, the Panel finds that business risk is not a primary driver of the ROE premium. Rather, consistent with BCUC's approach in Stage 1, the Panel finds that the ROE premium in Stage 2 should be based on sound financial theory and empirical evidence that would have resulted in a different allowed ROE from the 9.65 percent determined for the Benchmark Utility in Stage 1. Based on the evidence provided in both Stage 1 and Stage 2, the Panel views that the only proposed adjustment that would meet this consideration for the ROE premium in Stage 2 would be the inclusion of a size premium within the CAPM.

We agree with the BCUC's findings in the 2013 GCOC Stage 1 Decision and the 2014 GCOC Stage 2 Decision. We find that the academic literature and empirical studies supporting the importance of size in determining differences in returns are persuasive.[69] Similarly, we are persuaded by the evidence provided by Dr. Lesser in Stage 1 and Brattle in Stage 2 which leads us to conclude that a size premium for the Stage 2 utilities, all of which are considerably smaller than the Benchmark Utility and FBC, is appropriate and is reasonably estimable. We note that while Mr. Coyne did not advocate for a size premium for FBC in Stage 1, all three experts (Dr. Lesser, Mr. Coyne and Brattle[70]) acknowledge that any size premiums and differences in returns would be attributed to the CAPM only.

As for Brattle's novel recommendation to add a credit spread adjustment to PNG's allowed ROE, we find no sound rationale to make such an adjustment since Brattle has not provided any evidence of a mechanism to do this within the three accepted financial models that form the basis of our ROE premium determination. Therefore, we reject Brattle's recommendation to add a credit spread adjustment to PNG's ROE, which would be an addition to the size premium.

The Panel notes that Brattle only performed the indicative size premium analysis for PNG and Corix in Stage 2, but views that this analysis can and should be applied to all Stage 2 utilities. The Panel takes this approach because all Stage 2 utilities can be reasonably classified as "small" compared to FEI, the Benchmark Utility. However, the Panel does not view that differentiating further increments of size differences amongst the various Stage 2 utilities would add value. Rather, such attempts at differentiation could portray false precision when ultimately the determination of the appropriate size premium for a particular utility is based on informed judgement. The Panel further expects that any resulting changes in size premium based on such differentiation would be so minor as not to be material. **Accordingly, the Panel finds that a size premium is warranted within the CAPM output for Stage 2 utilities' allowed ROE and that such size premium should be the same for all Stage 2 utilities.**

[68] The CEC Final Argument, p. 5; BCOAPO Final Argument, pp. 27, 35, 41, 50, 53, 57–59, 69; RCIA Final Argument, p. 65.
[69] 2013 GCOC Stage 1 Decision, p. 101; 2014 GCOC Stage 2 Decision, pp. 28, 33.
[70] Exhibit B9-9, Brattle Evidence for PNG, p. 71; Exhibit B6-9-1, Brattle Evidence for Corix, p. 65.

Having so determined, the Panel now assesses the appropriate amount of the size premium. While Dr. Lesser in Stage 1 and Brattle in Stage 2 rely on published data by CRSP, we recognize that the assessment of the appropriate amount for a size premium involves a high degree of informed judgement. We make this observation for two reasons.

First, the experts' analyses are based on US market data because there is limited Canadian market data available. However, in Stage 1, the BCUC accepted the use of a North American combined proxy group, as it considered the use of a US-only or Canada-only proxy group to be inferior.[71] Thus, we accept the US-based evidence presented in Stage 2 with respect to the size premium but caution that there is some uncertainty associated with that evidence due to the lack of comparable Canadian market data. Nonetheless, we consider that use of that evidence is warranted in this instance. As the BCUC noted in accepting the use of a North American combined proxy group to assess the cost of capital for the FortisBC utilities in Stage 1, from an investor perspective, US and Canadian capital markets are becoming increasingly integrated such that the use of comparable data between the two has become a more common practice amongst North American regulators.[72]

Second, we note that there is a wide range of size premium values recommended by the parties and Brattle's analysis and these values are subject to interpretation. The range of size premium values presented in evidence is 73 bps (from Table 3 for PNG's 2022 indicative size premium) to 194 bps (from Table 4 for Corix's 2018 indicative size premium).[73] Looking at all deciles, the range of size premium values widens to -28 bps (from Table 2 for 2019) to 501 bps (from Tables 1 and 2 for 2020).[74] Brattle's proposed size premium ranges from 73 bps to 150 bps for both PNG and Corix combined.[75] Other utility and intervener submissions on the ROE premium range from 25 bps to 135 bps.[76] It is unclear to the Panel, however, whether parties have proportionately taken into account in their recommendations the fact that CAPM is the only one of three financial models considered in Stage 1 in which market inputs would have included size with resulting impacts on the model outputs. Thus, the Panel finds that the ROE premium adjustment for size should not be bound by the ranges presented above. Rather, the Panel considers the "size premium" to be a component of a specific financial model (i.e. CAPM) and the "ROE premium" to be any adjustments ultimately being factored into the allowed ROE which was determined by placing equal weight on three distinct financial models, of which only the CAPM results would have been affected by size.

The Panel determines that the ROE premium for all Stage 2 utilities will be 75 bps to reflect size relative to the Benchmark Utility. As discussed above, the determination of the size premium amount is subject to a high degree of uncertainty and a wide range of possibilities, which requires the Panel to exercise discretion and informed judgement. The Panel arrived at the 75 bps ROE premium by considering that the BCUC relied on three different financial models in Stage 1. Thus, the magnitude of the size premium should be adjusted downward to reflect that the CAPM is only one of three financial models used to determine a utility's allowed ROE, and its

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[71] GCOC Stage 1 Decision, p. 16.
[72] GCOC Stage 1 Decision, pp. 15–17.
[73] Exhibit B9-9, Brattle Evidence for PNG, Figure 23, p. 74; Exhibit B6-9-1, Brattle Evidence for Corix, Figure 22, p. 68.
[74] Exhibit A2-3, Lesser Report, Table 1, p. 56; Exhibit B9-9, Brattle Evidence for PNG, Figure 22, p. 73; Exhibit B6-9-1, Brattle Evidence for Corix, Figure 21, p. 67
[75] Exhibit B9-9, Brattle Evidence for PNG, pp. 74–75; Exhibit B6-9-1, Brattle Evidence for Corix, p. 68.
[76] Exhibit B9-9, PNG Evidence, pp. 32–33; Exhibit B6-8, Corix Evidence, p. 6; Exhibit B7-8, Creative Energy Evidence, p. 16; Exhibit B8-5, RDE Evidence, p. 17; Exhibit C3-2, Boralex Evidence, p. 14; Exhibit B4-6, Nelson Hydro Evidence, p. 4-21; The CEC Final Argument, p. 5; BCOAPO Final Argument, pp. 27, 35, 41, 50, 53, 57–59, 69; RCIA Final Argument, p. 65.

results are weighted accordingly. Additionally, the Panel finds that the 75 bps ROE premium remains consistent with the ROE premiums for most Stage 2 utilities which the BCUC has approved in the past.

As an alternative to 75 bps, the Panel has also considered an ROE premium of 50 bps. However, the Panel views that a lower ROE premium for size would have put too much upward pressure on the deemed equity component to compensate certain utilities for a lower overall ROE premium than what the BCUC has historically approved for them.

The Panel acknowledges that the BCUC did not adjust for size in respect of its determination of the allowed ROE for FBC in Stage 1, but notes that FortisBC's own expert, Mr. Coyne, did not advocate for nor did FBC propose such an adjustment in Stage 1. Instead, they accepted that as long as the utility's overall allowed return is sufficient to satisfy the Fair Return Standard, such explicit adjustment may not be required.[77]

The Panel clarifies that in light of its approach (to reflect size in the ROE premium only), the equity premiums to be set in for the Stage 2 utilities in Sections 3.2 through 3.4 of this decision, which will be determined by changes in their business risks, will <u>not</u> compensate Stage 2 utilities for changes in business risks attributable to size relative to the Benchmark Utility.

While our discussion thus far has focused on the impact of a size premium on the allowed ROE, we also acknowledge that the utilities' overall equity return is equally important. As already noted, the overall equity return, or the weighted ROE, is the product of the deemed equity component multiplied by the allowed ROE. In our examination of each Stage 2 utility's business risks below, we will consider the weighted ROE differential relative to the Benchmark Utility as a commonsensical check of the reasonableness of the allowed ROE we ultimately approve for each of the Stage 2 utilities. By doing so, we aim to ensure that the combination of the deemed equity component and the allowed ROE for the Stage 2 utilities will fairly compensate the investors' opportunity cost, maintain the financial integrity of the utilities, and enable each utility to continue to attract new capital upon reasonable terms. In other words, such determination of a utility's cost of capital should be sufficient to meet the Fair Return Standard.

3.2 Gas Utilities

PNG is the only natural gas provider participating in Stage 2 and filed submissions on behalf of the three utilities it owns and operates: (i) its western division, or PNG-West, (ii) PNG(NE) Fort St. John / Dawson Creek, and (iii) PNG(NE) Tumbler Ridge.[78]

The first PNG utility, PNG-West, is the natural gas transmission and distribution system located in the west-central part of northern BC from Summit Lake to the northwest coast. The second and third PNG utilities are owned and operated by PNG(NE). PNG(NE) Fort St. John / Dawson Creek pertains to the distribution system in the Fort St. John and Dawson Creek service areas, while PNG(NE) Tumbler Ridge pertains to the transmission and distribution systems and gas processing plant in the Tumbler Ridge service area.[79]

[77] GCOC Stage 1 Decision, pp. 127, 134–135; Exhibit B1-8-1, Appendix C, Concentric Report, p. 147; Stage 1, FortisBC Final Argument, pp. 177–178.
[78] Exhibit B9-9, PNG Evidence, p. 2.
[79] Exhibit B9-9, PNG Evidence, p. 2, Brattle Evidence for PNG, pp. 15–16, 22.

PNG-West has approximately 20,800 customers, PNG(NE) Fort St. John / Dawson Creek has approximately 20,500 customers, and PNG(NE) Tumbler Ridge has approximately 1,200 customers as of 2023. On a consolidated basis, PNG's customer base is predominantly residential which makes up approximately 87.1 percent of all PNG customers. The commercial sector is the second largest sector and accounts for approximately 12.5 percent of all customers, and the remaining 0.4 percent is composed of industrial and transportation customers.[80] PNG-West and PNG(NE) Fort St. John / Dawson Creek are PNG's largest divisions providing 4,777 terajoules and 4,068 terajoules of gas to customers in 2023, respectively. The PNG(NE) Tumbler Ridge division is significantly smaller, providing 828 terajoules of gas to customers in 2023.[81]

The BCUC initially determined the existing cost of capital for each of the three PNG divisions in the 2014 GCOC Stage 2 Decision by setting PNG-West and PNG(NE) Tumbler Ridge's deemed equity component at 46.5 percent (8.00 percentage points (pps) above the Benchmark Utility) and an allowed ROE of 9.50 percent (75 bps above the Benchmark Utility). At the same time, the BCUC established for PNG(NE) Fort St. John / Dawson Creek, a deemed equity component of 41.0 percent (2.50 pps above the Benchmark Utility) and an allowed ROE of 9.25 percent (50 bps above the Benchmark Utility).[82]

Table 6 below summarizes PNG's previously approved cost of capital as stated above, as well as the currently proposed cost of capital in this Stage 2 proceeding which are discussed by division in the sections that follow.

[80] Exhibit B9-9, Brattle evidence for PNG, p. 16.
[81] Exhibit B9-9, Brattle evidence for PNG, p. 17.
[82] 2014 GCOC Stage 2 Decision, p. 113.

Table 6: Previously Approved and Currently Proposed Cost of Capital for PNG

	Previously Approved[83]			Currently Proposed[84]		
	Equity Premium (i.e. Deemed Equity Component)	ROE Premium (i.e. Allowed ROE)	Weighted ROE	Equity Premium (i.e. Deemed Equity Component)	ROE Premium (i.e. Allowed ROE)	Weighted ROE
PNG-West	8.0 pps (46.5%)	75 bps (9.50%)	4.42%	5.0 pps (50.0%)	135 bps (11.00%)	5.50%
PNG(NE) Tumbler Ridge	8.0 pps (46.5%)	75 bps (9.50%)	4.42%	5.0 pps (50.0%)	135 bps (11.00%)	5.50%
PNG(NE) Fort St. John / Dawson Creek	2.5 pps (41.0%)	50 bps (9.25%)	3.79%	2.5 pps (47.5%)	80 bps (10.45%)	4.96%

The BCUC made these deemed equity component and ROE premium determinations in 2014 based on the business risks faced by the three PNG divisions at that time and to reflect the difference in short-term and long-term risks between the divisions as well as in comparison to the Benchmark Utility. At that time, the BCUC placed significant weight on PNG-West's issues with customer growth, market demand and throughput, while factors related to size and difficulties with supply were key determinants for the PNG(NE) Tumbler Ridge division. The BCUC found that PNG(NE) Fort St. John / Dawson Creek is less susceptible to some of the business risks and is closest to the Benchmark Utility in terms of levels of business risk. In determining the ROE premiums, the BCUC considered the PNG divisions' debt ratings as affected by credit metrics and factors related to size and their impact on short-term risk.[85]

PNG's proposals for each division are discussed in turn below.

3.2.1 PNG-West

As shown in Table 6 above, PNG's proposal would reduce the equity premium from the currently approved 8.0 pps to 5.0 pps, while increasing the ROE premium from 75 bps to 135 bps to reflect that PNG-West's risks are relatively higher than the Benchmark Utility and since the 2014 GCOC Stage 2 Decision. PNG explains that Brattle's approach allows for a more gradual increase in the deemed equity component than would otherwise arise if the 2014 equity premium of 8.0 percent were maintained.[86]

Brattle considered five elements of business risk in its expert evidence for PNG: (i) competitive risk, (ii) demand/market risk, (iii) supply risk, (iv) operating risk (including Indigenous rights and engagement risk), and (v) regulatory risk (including political risk). Brattle states that it incorporated each of the risk factors used in Stage 1 within these five risk elements.[87] Brattle postulates that PNG's business risks should be assessed holistically based on the overlapping and interacting impacts of all the relevant risk factors and states that

[83] 2014 GCOC Stage 2 Decision, p. 113.
[84] Exhibit B9-9, PNG Evidence, p. 33.
[85] 2014 GCOC Stage 2 Decision, pp. 20–21, 113–114.
[86] Exhibit B9-12, BCOAPO IR 23.2; PNG Final Argument, p. 27.
[87] Exhibit B9-9, Brattle Evidence for PNG, pp. 7–8.

ultimately, "what investors care about is the holistic impact of all business risk factors on the expected variability in the utility's future cash flows." [88] Brattle states that many of the risks identified in past GCOC proceedings continue to exist and that there are new risks that have emerged since 2014. Accordingly, Brattle opines that the deemed equity component for each PNG division should be at least as high as the ones set in 2014, if not higher, to compensate for the heightened business risks that PNG faces relative to the Benchmark Utility.[89] In developing its recommended deemed equity components for PNG, Brattle also considered PNG's size and "high risk service territory"; PNG's parent company, TriSummit Utilities Inc., which maintains a 48.7 percent equity component; and the average allowed equity component for US natural gas utilities, which was 54.45 percent in 2023.[90]

PNG submits its political risk, which includes energy transition risk, is higher for all PNG divisions than the Benchmark Utility and has increased since 2014.[91] PNG states that energy transition risk has grown since Stage 1, with Brattle concluding that political risk is greater for PNG's shareholders than FEI.[92] Since the GCOC Stage 1 Decision, the Government of Canada announced a cap on oil and gas sector emissions, with the goal of reaching net zero by 2050.[93] In line with Brattle's view, PNG states that an element of business risk could manifest across multiple business risk categories and therefore, business risks should be assessed holistically. For example, political risk in the form of decarbonization policies may cause a utility to procure new forms of low-carbon energy (i.e. supply risk), but the higher costs of the low-carbon energy may cause customers to use less energy or switch to cheaper alternative low-carbon energy sources (i.e. competitive risk.[94]

PNG states, like FEI, that its Indigenous rights and engagement risk has increased since 2014 and remains higher than the Benchmark Utility for PNG-West due to the construction and maintenance requirements in its service area.[95] PNG explains that the PNG-West system, which requires system betterment work to address aging infrastructure, spans almost the entire province of BC, from east to west, and crosses the traditional territories of 17 First Nations with unceded land claims.[96] Brattle noted that the costs associated with Indigenous rights and engagement have a larger impact on a smaller utility like PNG relative to FEI due to its limited customer base.[97]

PNG states that the price competitiveness of natural gas as compared to electricity is impacted by increasing commodity costs which flow-through to rate increases.[98] Decarbonization policies may also impact PNG to a greater extent than the Benchmark Utility, as PNG may need to increase its basic charges and variable delivery charges to recover rapidly escalating expenses while facing stagnant or declining throughput.[99] PNG notes that its rates for PNG-West and PNG(NE) Tumbler Ridge are already higher than those of FEI and thus, the price competitiveness of PNG's gas service in those areas as compared to electricity is already at a higher risk than the

[88] Exhibit 9-12, BCOAPO IR 6.2.
[89] Exhibit B9-9, PNG Evidence, p. 30.
[90] Exhibit B9-9, Brattle Evidence for PNG, p. 63.
[91] Exhibit B9-9, PNG Evidence, p. 29.
[92] Exhibit B9-9, PNG Evidence, pp. 27–28.
[93] Exhibit B9-9, Brattle Evidence for PNG, p. 49.
[94] Exhibit B9-12, BCOAPO IR 6.2.
[95] Exhibit B9-9, PNG Evidence, p. 26, Exhibit 9-14, RCIA IR 24.6.
[96] Exhibit B9-9, PNG Evidence, p. 26.
[97] Exhibit B9-9, Brattle Evidence for PNG, p. 43.
[98] Exhibit B9-9, PNG Evidence, p. 19.
[99] Exhibit B9-9, PNG Evidence, pp. 19–20.

Benchmark Utility.[100] Additionally, PNG submits that volatile natural gas prices have a greater impact for PNG because its customers use higher amounts of gas due to their northern climate.[101] The requirement for gas utilities to increase reliance on renewable natural gas will also increase the commodity cost for ratepayers, which will reduce the energy cost differential between natural gas and electricity and erode a primary advantage that gas has historically had over electricity, which in turn may affect investors' expectations. Thus, PNG submits that its competitive risk has likely grown both since 2014 and relative to the Benchmark Utility.[102]

With respect to demand/market risk, PNG states that its customer base is mainly made up of residential customers. Brattle notes that over the past five years, all three PNG divisions have seen an overall decline in residential consumption with PNG-West experiencing a 2.3 percent decline in 2023 from 2019 levels, as compared to FEI's 7.27 percent increase in residential customer demand over the same period.[103] In PNG's view, the demand risk is more pronounced in the PNG-West service area due to the underutilization of the PNG-West system and the incremental impacts of the volatile forestry sector industrial customer group, which make cost recovery from existing customers more challenging.[104] PNG expects its demand risk will continue to increase as the market share for natural gas continues to decline due to federal and provincial decarbonization policies.[105] In conclusion, PNG submits that its demand/market risk is greater than that of the Benchmark Utility and has increased since 2014.[106]

PNG-West states that it currently only has one access point for all of its gas supply through the Enbridge Westcoast T-South pipeline at Summit Lake. PNG-West then takes that gas and transports it across 964 kilometers of transmission pipeline to supply all of its customers through aging and under-utilized infrastructure.[107] PNG notes that these circumstances are generally the same as in the past, but that volatile natural gas prices along with the political push for gas utilities to move towards using higher priced renewable natural gas also create new supply risks for PNG.[108] FEI and PNG will be competing for a limited supply of renewable natural gas and PNG states that the potential cost effects are greater for PNG, exacerbating aspects of PNG's demand risk and competitive risk.[109] PNG submits that supply risks manifest differently for PNG than the Benchmark Utility, as PNG has a lack of supply redundancy whereas FEI can access redundant supply for a greater proportion of its system.[110] Therefore, PNG considers its supply risk to be higher than that of the Benchmark Utility and higher than in 2014.[111]

Brattle identifies the key operating risks for PNG that differentiate it from the Benchmark Utility as being the need for PNG to make more significant investments in its aging system to maintain regulatory compliance as well as to ensure ongoing safe and reliable service. Brattle states that performing this work is more logistically challenging than for the Benchmark Utility, as PNG's assets are more remotely located. Particularly, PNG-West's

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[100] Exhibit B9-9, PNG Evidence, p. 21.
[101] Exhibit B9-9, PNG Evidence, p. 21.
[102] Exhibit B9-9, PNG Evidence, pp. 22–23.
[103] Exhibit B9-9, PNG Evidence, p. 13, Brattle Evidence for PNG, p. 29.
[104] Exhibit B9-9, PNG Evidence, p. 13.
[105] Exhibit B9-9, PNG Evidence, pp. 13–14, 16, PNG Final Argument, p. 13.
[106] Exhibit B9-9, PNG Evidence, p. 14.
[107] Exhibit B9-9, PNG Evidence, p. 11.
[108] Exhibit B9-9, PNG Evidence, p. 10.
[109] Exhibit B9-9, PNG Evidence, pp. 12–13.
[110] Exhibit B9-9, PNG Evidence, p. 10.
[111] Exhibit B9-9, PNG Evidence, p. 12, Exhibit B9-10, BCUC IR 5.1 and 5.1.1.

assets are in mountainous areas subject to the highest geohazard risks in North America. PNG states that the costs associated with these increased operating challenges, together with a stagnant or declining customer base, impact PNG's ratepayers in a greater way than the Benchmark Utility because PNG has fewer remaining customers to recover costs from, as demonstrated by the 11.5 percent rate increases approved for PNG-West for each of 2023 and 2024. Further, PNG was required to carry a significant deductible of $5 million, which is up from $2 million in 2022, on its insurance program in relation to pipeline breaks, being reflective of the operating risk in the region it serves.[112] PNG concludes that its operating risk is higher than the Benchmark Utility and has increased since 2014.[113]

PNG states that regulatory risk has increased due to the uncertainty for PNG to recover unanticipated margin variances for its large commercial and small industrial customer classes through regulatory deferral accounts. The allocation of risk to PNG's shareholder for margin variances arising in respect of a volatile industrial customer group is a manifestation of elevated risk that PNG may not consistently be able to earn its allowed return.[114] Brattle also concludes that all PNG divisions currently have higher regulatory risks than the Benchmark Utility due to the usage-dependent rate design currently approved for PNG, which recovers fixed costs mainly through PNG's variable rates that are reliant on consumption as opposed to being recovered via its fixed basic charges.[115] PNG notes that even if it were to seek recovery of all fixed costs through its fixed charges, there is no certainty that such a shift in rate design could be reasonably supported from a bill impact perspective to the various customer groups or that it would be approved by the BCUC. As a result, PNG submits that the potential for a rate design change in the future is not impactful to the regulatory risk that PNG's investors face today.[116] Therefore, PNG concludes that the regulatory risk for all three divisions is higher than the Benchmark Utility and has increased since 2014.[117]

3.2.2 PNG(NE) Tumbler Ridge

As shown in Table 6 above and similar to PNG-West, PNG's proposal would reduce the equity premium from the currently approved 8.0 pps to 5.0 pps, while increasing the ROE premium from 75 bps to 135 bps to reflect that PNG(NE) Tumbler Ridge's risks are relatively higher than the Benchmark Utility and since the 2014 GCOC Stage 2 Decision. PNG explains that Brattle's approach allows for a more gradual increase in the deemed equity component than would otherwise arise if the 2014 equity premium of 8.0 pps were maintained.[118]

Brattle concludes that all PNG(NE) Tumbler Ridge's business risks are higher than they were in 2014 and that PNG(NE) Tumbler Ridge has higher business risks in all elements, with the exception of the Indigenous rights and engagement risk element, relative to the Benchmark Utility.[119]

Brattle concludes that PNG(NE) Tumbler Ridge faces similar Indigenous rights and engagement risk as the Benchmark Utility and that this risk has increased since 2014.[120] PNG explains that many of the Indigenous rights

[112] Exhibit B9-9, PNG Evidence, pp. 24–25.
[113] Exhibit B9-9, PNG Evidence, p. 25, Exhibit B9-10, BCUC IR 5.1 and 5.1.1.
[114] Exhibit B9-9, PNG Evidence, p. 27, Exhibit B9-10, BCUC IR 4.2 and 4.3.
[115] Exhibit B9-9, PNG Evidence, pp. 26–27.
[116] Exhibit B9-10, BCUC IR 4.4.
[117] Exhibit B9-9, PNG Evidence, p. 29, Exhibit B9-10, BCUC IR 5.1 and 5.1.1.
[118] Exhibit B9-12, BCOAPO IR 23.2; PNG Final Argument, p. 27.
[119] Exhibit B9-9, Brattle Evidence for PNG, Figure 13, p. 52, PNG Evidence, p. 29, Exhibit B9-10, BCUC IR 5.1 and 5.1.1.
[120] Exhibit B9-14, RCIA IR 24.5, Exhibit B9-10, BCUC IR 5.1 and 5.1.1.

and engagement risks facing PNG-West due to construction, as discussed in Section 3.2.1 above, and PNG(NE) Fort St. John / Dawson Creek due to permitting uncertainty, as discussed in Section 3.2.3 below, do not affect PNG(NE) Tumbler Ridge.[121]

As discussed earlier, PNG(NE) Tumbler Ridge's rates are already higher than those of FEI and thus, the price competitiveness of PNG(NE) Tumbler Ridge's gas service as compared to electricity is already at a higher risk than the Benchmark Utility.[122] Accordingly, PNG agrees with Brattle's assessment that PNG(NE) Tumbler Ridge's competitive risk is higher than it was in 2014.[123]

Due to its even smaller size relative to PNG(NE) Fort St. John / Dawson Creek, PNG states that PNG(NE) Tumbler Ridge faces the most volatility in terms of customer count and consumption.[124] PNG(NE) Tumbler Ridge continues to rely on one single industrial transportation customer (i.e. Canadian Natural Resources Ltd. (CNRL)) for more than 80 percent of its throughput volume and for approximately 25 percent of its margin since 2000. PNG notes that changes in CNRL's demand levels have volatile effects on PNG(NE) Tumbler Ridge's total throughput levels and CNRL's demand has been particularly volatile in recent years due to production curtailments caused by operational challenges.[125] In 2014, PNG(NE) Tumbler Ridge lost a significant portion of demand from its only large commercial customer which further reduced throughput.[126] With a very small customer group, PNG notes that capital costs impact this division significantly, and the PNG(NE) Tumbler Ridge system requires significant capital expenditures to continue to operate in a safe and reliable manner.[127] In conclusion, PNG submits that the demand/market risk for PNG(NE) Tumbler Ridge is greater than the Benchmark Utility and higher than in 2014.[128]

PNG states that the Tumbler Ridge service area is serviced solely through gas supply from CNRL wells which must be processed by the PNG(NE) Tumbler Ridge gas processing plant before usage by its customers. Continued depletion of the wells and/or greater usage of the gas processed for CNRL's own usage effectively limit the gas supply available to PNG(NE) Tumbler Ridge's other customers. Further, PNG states that no alternative, economically accessible pipeline quality gas sources are available for Tumbler Ridge. The PNG(NE) Tumbler Ridge gas processing plant will require significant capital investment to enable it to process the increasingly sour gas supply coming from CNRL, and to allow it to safely and reliably operate in the near-term while it considers longer-term gas supply options.[129] Therefore, PNG considers PNG(NE) Tumbler Ridge's supply risk to be higher than that of the Benchmark Utility and higher than in 2014.[130]

With respect to operating risk, PNG states that the increased focus by regulators has resulted in increased annual system betterment spending in all PNG(NE) divisions related to both facility and distribution system integrity repairs to aged assets that have largely gone unimproved or unreplaced due to the lack of customer

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121 Exhibit B9-14, RCIA IR 24.5.
122 Exhibit B9-9, PNG Evidence, p. 21.
123 Exhibit B9-10, BCUC IR 5.1 and 5.1.1.
124 Exhibit B9-9, PNG Evidence, p. 18.
125 Exhibit B9-9, PNG Evidence, p. 18.
126 Exhibit B9-9, PNG Evidence, p. 18.
127 Exhibit B9-9, PNG Evidence, p. 19.
128 Exhibit B9-9, PNG Evidence, pp. 14, 19.
129 Exhibit B9-9, PNG Evidence, pp. 12, 25.
130 Exhibit B9-9, PNG Evidence, p. 12, Exhibit B9-10, BCUC IR 5.1 and 5.1.1.

growth and a declining trend in ongoing gas usage.[131] PNG(NE) Tumbler Ridge expects to dedicate 97 percent of its capital expenditures to system betterment from 2025 to 2034. Given that PNG(NE) Tumbler Ridge relies on a single customer for most of its energy demand, cost recovery is riskier due to concentrated counterparty risk.[132] PNG concludes that its operating risk is higher than the Benchmark Utility and has increased since 2014.[133]

In conclusion, PNG submits its regulatory risk, which includes political / energy transition risk, is higher for all PNG divisions than the Benchmark Utility and has increased since 2014.[134]

3.2.3 PNG(NE) Fort St. John / Dawson Creek

As shown in Table 6 above and in contrast to its proposal for PNG-West and PNG(NE) Tumbler Ridge, PNG's proposal for PNG(NE) Fort St. John / Dawson Creek would maintain the currently approved equity premium of 2.5 pps, while increasing the ROE premium from 50 bps to 80 bps to reflect the heightened business risks faced by PNG(NE) Fort St. John / Dawson Creek relative to the Benchmark Utility and since 2014.[135] PNG submits that the proposed gradual increase for PNG-West's and PNG(NE) Tumbler Ridge's capital structures is not required for PNG(NE) Fort St. John / Dawson Creek because its capital premium over the Benchmark Utility was not as significant (i.e. 2.5 pps for the latter versus 8.0 pps for the former).[136]

PNG(NE) notes that in the BCUC's decision on the PNG(NE) 2023 to 2024 Revenue Requirements Application, the BCUC indicated that it has concerns about PNG(NE) adding a new natural gas pipeline as a long-term supply alternative to Dawson Creek due to potential declines in future demand related to federal and provincial government greenhouse gas emission reduction policies. PNG(NE) states that this demonstrates how new policies with respect to the energy transition impact regulatory risk faced by both the Benchmark Utility and PNG.[137] However, Brattle states that the impacts of political risks are greater for PNG's shareholders because they potentially exacerbate PNG's demand risk and competitive risk. Brattle elaborates that political risks will manifest in rising supply costs, competition for limited renewable natural gas supplies, increased competition from customers switching to alternative forms of energy, and heightened cost recovery risks. In conclusion, Brattle submits that the political risk for PNG(NE) Fort St. John / Dawson Creek is higher than the Benchmark Utility and has increased since 2014.[138]

PNG(NE) Fort St. John / Dawson Creek's system lies within the Treaty Eight First Nations territory, which is subject to an existing treaty with the Federal government.[139] PNG(NE) Fort St. John / Dawson Creek notes that permitting processes in respect of infrastructure on the Treaty Eight First Nations territories are evolving which provides uncertainty that may manifest in perceived increased investor risk. [140] Therefore, PNG concludes that

[131] Exhibit B9-9, PNG Evidence, p. 25.
[132] Exhibit B9-9, Brattle Evidence for PNG, p. 39, Exhibit 9-10, BCUC IR 3.1.
[133] Exhibit B9-9, PNG Evidence, p. 25, Exhibit B9-10, BCUC IR 5.1 and 5.1.1.
[134] Exhibit B9-9, PNG Evidence, p. 29, Exhibit B9-10, BCUC IR 5.1 and 5.1.1.
[135] Exhibit B9-9, PNG Evidence, p. 33, Exhibit B9-12, BCOAPO IR 23.2, PNG Final Argument, p. 27, Exhibit B9-10, BCUC IR 5.1.
[136] Exhibit B9-12, BCOAPO IR 23.2, PNG Final Argument, p. 27.
[137] Exhibit B9-9, PNG Evidence, p. 29.
[138] Exhibit B9-9, PNG Evidence, pp. 13, 29, Brattle Evidence for PNG, p. 51.
[139] Exhibit B9-9, PNG Evidence, p. 26.
[140] Exhibit B9-9, PNG Evidence, p. 26, Exhibit B9-14, RCIA IR 24.6.

PNG(NE) Fort St. John / Dawson Creek faces higher Indigenous rights and engagement risk than the Benchmark Utility and that this risk has increased since 2014.[141]

In PNG's view, the Benchmark Utility faces the same challenges with respect to competitive risk and while FEI's rates are comparable to those of PNG(NE) Fort St. John / Dawson Creek, the impacts may be higher to PNG due to its smaller size.[142] As a result, PNG submits that its competitive risk is higher than the Benchmark Utility and has increased since 2014.[143]

With respect to demand/market risk, PNG notes that PNG(NE) Fort St. John / Dawson Creek has more consistent customer demand with generally less variable throughput on its system as compared to PNG-West. However, PNG(NE) Fort St. John / Dawson Creek has experienced declines in total throughput since 2019 mainly driven by its residential and small commercial volumes. While not as high as PNG-West, PNG submits that the PNG(NE) Fort St. John / Dawson Creek division faces a higher level of demand/market risk relative to the Benchmark Utility, exacerbated by the small size of this division.[144] Thus, PNG concludes that PNG(NE) Fort St. John / Dawson Creek's demand/market risk is higher than it was in 2014.[145]

Since 2014, PNG has had to decommission the Rolla Lateral pipe that provided a secondary source of supply to Dawson Creek. As a result, PNG states that PNG(NE) is at higher risk with respect to its supply to Dawson Creek today than it was in 2014.[146] PNG further states that it is facing increased gas supply issues in Fort St. John and Dawson Creek due to its reliance on single suppliers, some of which have started to terminate service as a result of increasing integrity requirements.[147] PNG(NE)'s risk of gas supply interruptions has increased since 2014 due to the execution of integrity work upstream by its supplier. PNG(NE) is currently looking at alternatives for gas supply in this region going forward to address the integrity issues while protecting customer supply.[148] However, with the negative perception of investment in new gas supply infrastructure in BC, PNG does not have confidence that it could obtain approval for such an investment in redundant infrastructure.[149] Accordingly, PNG considers PNG(NE) Fort St. John / Dawson Creek's supply risk to be higher than that of the Benchmark Utility and higher than in 2014.[150]

As noted earlier, PNG(NE)'s systems require significant investment due to their age and overall integrity condition. PNG states that in the absence of an alternative supply arrangement for Dawson Creek, ongoing supply from the Enbridge system through the Penn West and Sunrise pipeline segments will result in significant increases in annual integrity maintenance work. PNG submits that the costs associated with these increased operating challenges and requirements impact PNG's ratepayers to a greater extent than the Benchmark Utility because PNG has fewer customers to recover costs from. Further, from an investor perspective, PNG submits that increased rates that erode the price competitiveness of PNG's gas service as compared to electricity add to

[141] Exhibit B9-9, PNG Evidence, p. 26, Exhibit B9-10, BCUC IR 5.1 and 5.1.1.
[142] Exhibit B9-9, PNG Evidence, p. 21, PNG Final Argument, p. 14.
[143] Exhibit B9-9, PNG Evidence, p. 23.
[144] Exhibit B9-9, PNG Evidence, pp. 17–18.
[145] Exhibit B9-10, BCUC IR 5.1 and 5.1.1.
[146] Exhibit B9-14, RCIA IR 9.2.
[147] Exhibit B9-9, PNG Evidence, pp. 10–12.
[148] Exhibit B9-9, PNG Evidence, p. 25, Exhibit B9-14, RCIA IR 9.2, Exhibit B9-10, BCUC IR 1.7.
[149] Exhibit B9-9, PNG Evidence, p. 10.
[150] Exhibit B9-9, PNG Evidence, p. 12, Exhibit B9-10, BCUC IR 5.1 and 5.1.1.

the "potential for decreasing demand and the compounding potential impact on rates" that can occur as fewer ratepayers remain to pay system operating costs.[151] For these reasons, PNG concludes that its operating risk is higher than the Benchmark Utility and has increased since 2014.[152]
In conclusion, PNG submits that its regulatory risk is higher for all PNG divisions than the Benchmark Utility and has increased since 2014.[153]

Positions of Parties

Interveners provided various submissions on the overall business risk assessment of PNG, with proposed equity premiums of 1.0 percent to 2.5 percent for PNG(NE) Fort St. John / Dawson Creek and with respect to PNG-West and PNG(NE) Tumbler Ridge, a proposed 5.0 percent on the part of all interveners.[154]

BCOAPO submits that it is reasonable to find that the business risks for the PNG divisions has increased since 2014 and that the overall relative business risk has increased more than the Benchmark Utility's since 2014, but to a lesser extent than put forward by PNG.[155] BCOAPO raises no issues with PNG's proposed deemed equity components for PNG-West, PNG(NE) Tumbler Ridge and PNG(NE) Fort St. John / Dawson Creek, assuming they are accompanied by appropriate allowed ROE values.[156] BCOAPO recommends a deemed equity component of 50.0 percent for PNG-West and PNG(NE) Tumbler Ridge accompanied by a 10.90 percent allowed ROE, and a deemed equity component of 47.5 percent for PNG(NE) Fort St. John / Dawson Creek accompanied by a 10.15 percent allowed ROE.[157] In reply, PNG upholds Brattle's approach of considering PNG's business risks holistically and the conclusion that PNG's relative overall business risk is higher than it was in 2014, noting that many risk factors are exacerbated in PNG due to its relatively smaller size, more concentrated customer base, and more geographically remote service territory.[158]

The CEC recommends a common deemed equity component and ROE premium for the three PNG divisions by weighting the BCUC's determinations for each division to improve regulatory efficiency.[159] In reply, PNG submits that this approach would not be appropriate due to the lack of evidence as to how a weighted average would be calculated, as well as the fact that PNG currently operates three separate service areas which all have separate revenue requirements, operational characteristics, delivery rates and regulatory accounting records. Accordingly, PNG submits that each division has its own risks, and a common deemed equity component and allowed ROE would introduce unnecessary complexity for PNG.[160]

The CEC submits that while PNG does have higher risk than FEI, the evidence does not necessarily point to a widening of the gap between PNG and the Benchmark Utility. For the PNG-West and PNG(NE) Tumbler Ridge divisions, the CEC considers the weighted ROE proposed by PNG (made up of a 50.0 percent deemed equity component and 11.00 percent allowed ROE) to be reasonable as it understands that the proposed change in

[151] Exhibit B9-9, PNG Evidence, p. 25, PNG Final Argument, p. 17.
[152] Exhibit B9-9, PNG Evidence, p. 25, Exhibit B9-10, BCUC IR 5.1 and 5.1.1.
[153] Exhibit B9-9, PNG Evidence, p. 29, Exhibit B9-10, BCUC IR 5.1 and 5.1.1.
[154] The CEC Final Argument, pp. 28–29, BCOAPO Final Argument, p. 23, RCIA Final Argument, p. 63.
[155] BCOAPO Final Argument, pp. 22, 27.
[156] BCOAPO Final Argument, p. 23.
[157] BCOAPO Final Argument, pp. 22–23, 27.
[158] PNG Reply Argument, p. 4.
[159] The CEC Final Argument, p. 27.
[160] PNG Reply Argument, pp. 25–26.

PNG reflects approximately the same risk relative to FEI as has been previously determined in 2014.[161] In reply, PNG notes that the CEC did not identify what the perceived gaps in evidence were. However, PNG submits that the CEC's approach to compare PNG's proposed overall cost of capital recommendations to the overall cost of capital determined by the BCUC in 2014 is a simplified, yet consistent, theory to Brattle's evidence for PNG.[162]

For the PNG(NE) Fort St. John / Dawson Creek division, the CEC submits that there is insufficient evidence to support an increase in the total risk for this division relative to the Benchmark Utility. The CEC recommends a 47.5 percent equity component and 10.15 percent allowed ROE to preserve the existing premium relationship between the utility and the Benchmark Utility.[163] In reply, PNG notes that the CEC did not provide evidence to support its assertion that the risk relative to the Benchmark Utility had not increased. PNG submits that it has provided ample evidence to show that PNG(NE) Fort St. John / Dawson Creek's overall business risk as compared to the Benchmark Utility have remained as high or are higher, as supported by the Brattle Evidence which concludes that all business risks are higher relative to the Benchmark Utility and higher than they were in 2014.[164]

RCIA submits that PNG-West's and PNG(NE) Tumbler Ridge's overall risk spreads relative to the Benchmark Utility since 2014 have decreased or remained the same.[165] RCIA submits that PNG's risks related to the energy transition are lower than FEI's due to fewer negative perceptions related to the fossil fuel industry in the colder climate of its service areas and the lack of restrictions imposed by municipalities on gas service in PNG's service areas.[166] In RICA's view, PNG has not provided any evidence to demonstrate its operations have greater exposure to Indigenous rights and engagement risk than FEI or since 2014.[167] RCIA notes that to the extent PNG's risks related to energy transition and Indigenous rights have changed relative to 2014, any necessary adjustment would already be captured by the Benchmark Utility's deemed equity component from Stage 1. RCIA recommends an equity component of 50.0 percent and an allowed ROE of 10.15 percent for PNG-West and PNG(NE) Tumbler Ridge and submits that this appropriately compensates the relative riskiness of PNG-West and PNG(NE) Tumbler Ridge versus PNG(NE) Fort St. John / Dawson Creek, as well as PNG's relative energy transition risk as compared to the Benchmark Utility.[168]

In reply, PNG submits that RCIA's positions are not supported by evidence and appear to be designed to mitigate impacts to ratepayers and may not properly consider the appropriate return that investors might require in order to accept the level of business risk facing small gas utilities in BC today.[169] PNG does not believe there is any evidence to support RCIA's position that the energy transition risk is lower for PNG than the Benchmark Utility. PNG notes that its service areas are not excluded from government climate policies and its customers are affected by the provincial carbon tax, which could drive customers to seek lower-carbon alternative fuels to

[161] The CEC Final Argument, p. 28.
[162] PNG Reply Argument, p. 22.
[163] The CEC Final Argument, p. 29.
[164] PNG Reply Argument, p. 23.
[165] RCIA Final Argument, p. 40.
[166] RCIA Final Argument, pp. 36, 41.
[167] RCIA Final Argument, p. 33.
[168] RCIA Final Argument, pp. 41, 63.
[169] PNG Reply Argument, p. 26.

reduce their heating bills.[170] PNG also submits that RCIA has not provided a fulsome analysis to support its conclusion on Indigenous rights and engagement risk.[171]

For the PNG(NE) Fort St. John / Dawson Creek division, RCIA submits that the risk spread to the Benchmark Utility since 2014 has remained the same, with the exception of energy transition risk which is lower than the Benchmark Utility.[172] RCIA recommends a deemed equity component of 46.0 percent and an allowed ROE of 9.90 percent for PNG(NE) Fort St. John / Dawson Creek and submits that this appropriately compensates the relative riskiness of PNG(NE) Fort St. John / Dawson Creek versus PNG-West and PNG(NE) Tumbler Ridge, as well as PNG's relative energy transition risk as compared to the Benchmark Utility.[173] In reply, PNG submits that RCIA has not substantiated the driver for a determination that PNG is less risky today relative to the Benchmark Utility.[174]

Panel Determination

The Panel agrees with Brattle's approach to consider business risks holistically as opposed to considering each business risk on its own, which is also consistent with the Panel's approach set out in Section 3.1. We begin our analysis by reviewing two risks that we view to be common for the three PNG divisions, and then go on to assess each division on its own.

As PNG and the Benchmark Utility are both natural gas utilities in BC, the Panel considers the impacts of the energy transition will apply to both utilities similarly with the only difference being PNG's relatively smaller size. However, Stage 2 utilities have already been compensated for any business risks related to their small size relative to the Benchmark Utility via the allowed ROE size adjustment established in Section 3.1 and thus risks related to size should not be reflected again in their deemed equity component.

Furthermore, the Panel is not convinced by PNG that energy transition risk has grown since Stage 1 to such an extent as would warrant a higher risk premium relative to the Benchmark Utility. At the same time, however, the Panel is equally unpersuaded by RCIA's position that PNG's risks related to the energy transition are lower than the Benchmark Utility's due to fewer negative perceptions related to the fossil fuel industry in the colder climate of PNG's service areas and the lack of restrictions imposed by municipalities on gas service in PNG's service areas. Energy transition risk is a common risk that all gas utilities currently face, wherever they are located within BC, and are not confined to specific service areas.

The Panel views that any change since 2014 in Indigenous rights and engagement risk for PNG as a gas utility operating in BC has already been captured in the Benchmark Utility's deemed equity component increase in Stage 1. The Panel agrees with Brattle's conclusion that PNG(NE) Tumbler Ridge faces similar Indigenous rights and engagement risk as the Benchmark Utility. However, the Panel is not persuaded by PNG-West's and PNG(NE) Fort St. John / Dawson Creek's position that their Indigenous rights and engagement risks are higher than those of the Benchmark Utility.

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[170] PNG Reply Argument, pp. 37–38.
[171] PNG Reply Argument, p. 36.
[172] RCIA Final Argument, pp. 40–41.
[173] RCIA Final Argument, pp. 41, 63.
[174] PNG Reply Argument, p. 40.

The Panel finds that PNG-West's overall business risk when compared against the Benchmark Utility has not materially changed since its last cost of capital proceeding in 2014. In addition to the energy transition risk and Indigenous rights and engagement risk discussed above for all PNG divisions, the Panel makes the following observations specific to PNG-West.

Firstly, PNG-West states that its assets are in mountainous areas subject to the highest geohazard risks in North America and the costs associated with these increased operating challenges impact PNG's ratepayers in a greater way than the Benchmark Utility. However, PNG has provided no evidence to indicate that these increased costs have affected or are likely to affect PNG-West's ability to recover these costs and earn a fair return in the future.

Secondly, PNG-West notes that its single access point for supply and its aging and under-utilized infrastructure are generally the same as in the past, but states that volatile natural gas prices along with the political push for gas utilities to move towards using higher-priced renewable natural gas also creates new supply risks for PNG. The Panel notes that both PNG and the Benchmark Utility experience volatile natural gas prices and these costs flow-through to be recovered from the commodity charges of each utility. Further, the Panel notes that the political shift has already been considered when setting the deemed equity component for the Benchmark Utility and the Panel considers the associated business risks of PNG are not materially different from those of the Benchmark Utility.

The Panel acknowledges that PNG-West has higher business risks than FEI as the BCUC concluded in 2014, but the Panel does not find that the gap between the two utilities has widened since then. The Panel views that many of the factors that PNG-West cites to justify as higher risks now were also present in 2014, and while this suggests a higher allowed return continues to be warranted, that allowed return should not be greater than the amount of increased return established in 2014.

The Panel finds that PNG(NE) Tumbler Ridge's overall business risk when compared against the Benchmark Utility has not materially changed since its last cost of capital proceeding in 2014. The Panel finds that all other business risks discussed by PNG(NE) Tumbler Ridge existed in 2014 and can be assessed at a similar level in comparison to the Benchmark Utility as they were in 2014. For example, PNG(NE) Tumbler Ridge continues to rely on a single industrial transportation customer, CNRL, for demand as well as being supplied solely through CNRL wells as it did in 2014. PNG(NE) Tumbler Ridge states that it expects increased annual system betterment spending from 2025 to 2034 and that the reliance on CNRL for most of its demand results in higher cost recovery risk. However, PNG(NE) Tumbler Ridge has not presented evidence to indicate that there is uncertainty associated with the recovery of these expenditures and PNG(NE) Tumbler Ridge's ability to earn a fair return in the future as a result.

The Panel finds that PNG(NE) Fort St. John / Dawson Creek's overall business risk when compared against the Benchmark Utility has not materially changed since its last cost of capital proceeding in 2014. The Panel finds that all other business risks discussed by PNG(NE) Fort St. John / Dawson Creek existed in 2014 and can be assessed at a similar level in comparison to the Benchmark Utility as they were in 2014. For example, PNG(NE) Fort St. John / Dawson Creek states that it has more consistent customer demand with generally less variable throughput on its system as compared to PNG-West. In line with the Panel's determination above with respect to PNG-West's demand/market risk, the Panel is not persuaded that PNG(NE) Fort St. John / Dawson Creek's risk is higher than the Benchmark Utility. PNG(NE) also states that its systems require significant investment as a result of their age and overall integrity condition and that these costs impact its ratepayers to a greater extent than the Benchmark Utility. However, the evidence does not indicate that these expenditures have affected or are likely to affect PNG(NE)'s opportunity to earn a fair return in the future.

With respect to the CEC's recommendation to adopt a single set of risk premiums for the PNG divisions to improve regulatory efficiency, the Panel considers it not appropriate to take this approach because the CEC has not provided any justification for this proposal. Further, the Panel views that there are inherent differences in risks between the three PNG divisions as discussed above, which may require separate deemed equity components and equity risk premiums to meet the Fair Return Standard.

The Panel now applies the above qualitative business risk assessment to the quantitative setting of the deemed equity component and allowed ROE, which in combination result in the weighted ROE or allowed return. Given the Panel's earlier finding that the three PNG divisions have not experienced any material change in overall business risk relative to the Benchmark Utility since 2014, the Panel has considered the deemed equity component that would be required to arrive at a weighted ROE that would maintain the overall allowed return differential between PNG and the Benchmark Utility as set in 2014.

As discussed in Section 3.1, we have determined that a 75 bps ROE premium is appropriate to reflect the small size premium. We have applied the same ROE premium here for the PNG utilities, which results in an allowed ROE of 10.40 percent.

Pursuant to the above methodology of maintaining the overall allowed return differential between PNG and the Benchmark Utility and given that the Panel has set the allowed ROE at 10.40 percent for the PNG utilities, the Panel has calculated the corresponding equity premium (i.e. deemed equity component) that would maintain the weighted ROE spreads between PNG and the Benchmark Utility. **The Panel sets a 7.0 pps equity premium, resulting in a 52.0 percent deemed equity component for PNG-West and PNG(NE) Tumbler Ridge, and a 1.0 pps equity premium, resulting in a 46.0 percent deemed equity component for PNG(NE) Fort St. John / Dawson Creek.**

Table 7 below provides a comparison of the currently approved versus previously approved cost of capital for the three PNG divisions. The table lays out PNG's cost of capital, beginning with the Benchmark Utility's cost of capital plus the approved equity and ROE premiums for each of the PNG divisions, to arrive at the cost of capital for each PNG division.

Table 7: Comparison of Previously and Currently Approved Cost of Capital for PNG

	Previously Approved[175]			Currently Approved		
	Deemed Equity Component	Allowed ROE	Weighted ROE	Deemed Equity Component	Allowed ROE	Weighted ROE
Benchmark Utility's cost of capital (for comparison)	38.5%	8.75%	3.37%	45.0%	9.65%	4.34%
PNG-West's premium	8.0 pps	75 bps	105 bps	7.0 pps	75 bps	107 bps
PNG-West's resulting cost of capital	46.5%	9.50%	4.42%	52.0%	10.40%	5.41%
PNG(NE) Tumbler Ridge's premium	8.0 pps	75 bps	105 bps	7.0 pps	75 bps	107 bps
PNG(NE) Tumbler Ridge's resulting cost of capital	46.5%	9.50%	4.42%	52.0%	10.40%	5.41%
PNG(NE) Fort St. John / Dawson Creek's premium	2.5 pps	50 bps	42 bps	1.0 pps	75 bps	44 bps
PNG(NE) Fort St. John / Dawson Creek's resulting cost of capital	41.0%	9.25%	3.79%	46.0%	10.40%	4.78%

As shown in Table 7 above, the currently approved cost of capital for each PNG division maintains the differential between each division's weighted ROE and the Benchmark Utility's weighted ROE from the previously approved amounts.[176] This appropriately reflects the Panel's determinations above, that the PNG divisions' overall business risk relative to the Benchmark Utility has not changed materially since 2014.

Beyond the risk matrix, the Panel notes that Brattle identified other considerations when developing its recommendations for PNG's deemed equity components, including a comparison to PNG's parent company with a deemed equity component of 48.7 percent and the average deemed equity component for US natural gas utilities, which was 54.45 percent in 2023. The BCUC has previously stated that to meet the Fair Return Standard, a utility must be assessed based on the Standalone Principle.[177] Therefore, the Panel finds Brattle's comparison to PNG's parent company as not relevant in determining the appropriate deemed equity component for the three PNG divisions. Further, the Panel notes that the GCOC Stage 1 Decision already considered a comparison to US gas utilities when determining the Benchmark Utility's deemed equity component in Stage 1.

In the 2014 GCOC Stage 2 Decision, the BCUC stressed the importance of ensuring that PNG's business risk assessment remain contemporary and its cost of capital aligned with such assessment. Accordingly, the BCUC directed PNG to include an updated business risk assessment in all future revenue requirements applications.[178]

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[175] 2016 FEI COC Decision, Directives 1 and 2; GCOC Stage 1 Decision, p. 3; 2014 GCOC Stage 2 Decision, p. 113.
[176] The Panel notes an increase in PNG-West and PNG(NE) Tumbler Ridge's weighted ROE of 2 bps (calculated as 107 bps less 105 bps) and an increase in PNG(NE) Fort St. John / Dawson Creek's weighted ROE of 2 bps (calculated as 44 bps less 42 bps) which reflects minor rounding in the weighted ROE spread from the historical amounts for ease of implementation.
[177] GCOC Stage 1 Decision, p. 6.
[178] 2014 GCOC Stage 2 Decision, p. 114.

The Panel has considered the need for this continued reporting and finds that the most appropriate forum for reviewing business risk assessments is as part of the BCUC's periodic reviews of cost of capital for utilities, considering that the BCUC does not adjust cost of capital in revenue requirements applications. **Therefore, the Panel rescinds the BCUC directive made in the 2014 GCOC Stage 2 Decision requiring PNG to file an updated business risk assessment in all future revenue requirements applications.**

3.3 Thermal Energy System Utilities

Four providers of TES services participated in Stage 2: Corix, Creative Energy, RDE and FAES.[179] These rate-regulated TES utilities typically include a central thermal energy generating facility that supplies heating or cooling to multiple residential and commercial buildings via an underground distribution piping system. Such systems are often designed to meet increasing demand as new customer buildings connect to the system. Notably, while FAES participated in Stage 2, it does not have any rate-regulated TES utilities that are directly affected by the outcome of Stage 2. The Panel discusses each of the affected TES utilities in turn below. A separate discussion addresses the TES Default, which includes FAES's submissions on the topic.

3.3.1 Corix

Corix provides evidence in Stage 2 regarding its three rate-regulated TES utilities in BC: (i) Corix Burnaby Mountain DE Limited Partnership, otherwise known as Burnaby Mountain District Energy Utility (BMDEU), (ii) Corix UBCDE Limited Partnership, known as Neighbourhood District Energy System at the University of British Columbia (UBC NDES), and (iii) Corix Dockside Green DE Limited Partnership, known as Dockside Green Energy (DGE).[180] These entities are collectively referred to as the Corix Utilities and individually as Corix Utility.

While each Corix Utility is individually assessed in the subsequent sections with respect to its specific risk profiles, this section provides general information applicable to the Corix Utilities, including the approach to business risk assessment, the overarching risks, and the recommendations for the equity premium and ROE premium for each utility.

As previously noted, Corix engaged Brattle to prepare expert evidence on its behalf in Stage 2. Brattle considered five elements of business risk in its evidence for the BMDEU: (i) supply risk; (ii) demand / market risk; (iii) competitive risk; (iv) operating risk (which were split into operating risk and Indigenous rights and engagement risk); and (v) regulatory risk (which also considered political risk). Brattle states that the BCUC's risk factors are broadly consistent with the five noted risk categories.[181]

Brattle concludes the Corix Utilities are generally exposed to similar risk factors as the Benchmark Utility, but to a greater extent due to their smaller size, concentrated customer base, and significant uncertainty around cost recovery within their rate structure.[182] Brattle also observes an increase in risks for both the Benchmark Utility and Corix Utilities since 2014 largely driven by emerging factors such as the provincial and federal decarbonization policies.[183]

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[179] FAES made submissions but does not have any rate-regulated TES projects impacted by Stage 2.
[180] Exhibit B6-9, Corix Evidence, p. 1.
[181] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 6–7.
[182] Exhibit B6-9-1, Brattle Evidence for Corix, p. 52.
[183] Exhibit B6-9-1, Brattle Evidence for Corix, p. 69.

Based on its comparative business risk analysis (detailed in the utility specific subsections below), Brattle recommends that the Corix Utilities should maintain or increase their overall rate of return relative to the Benchmark Utility.[184] Brattle also recommends that the ROE and equity premiums should be at least as great as those granted in the 2014 GCOC Stage 2 Decision.[185] Specifically, Brattle recommends retaining the 75 bps ROE premium for BMDEU and UBC NDES and a 100 bps ROE premium for DGE. Combined with a minimum deemed equity component of 47.0 percent for all three utilities, this approach would ensure the overall cost of capital premium is maintained.[186] Corix highlights that Brattle's calculations do not rely on the relative size premium estimates from the CRSP Decile Studies.[187] However, the CRSP size premium studies indicate a significant realized ROE differential of 153 bps between small and large utilities, which Corix states should be accounted for in its cost of capital. Corix states that this differential justifies a larger deemed equity component than proposed by Brattle, suggesting a 4.0 pps equity premium (i.e. 49.0 percent equity component) as a reasonable level based on the evidence presented.[188]

Table 8 summarizes the Corix Utilities' previously approved and currently proposed cost of capital.

Table 8: Previously Approved and Currently Proposed Cost of Capital for the Corix Utilities

	Previously Approved[189]			Currently Proposed[190]		
	Equity Premium (i.e. Deemed Equity Component)	ROE Premium (i.e. Allowed ROE)	Weighted ROE	Equity Premium (i.e. Deemed Equity Component)	ROE Premium (i.e. Allowed ROE)	Weighted ROE
BMDEU	4.0 pps (42.5%)	75 bps (9.50%)	4.04%	4.0 pps (49.0%)	75 bps (10.40%)	5.10%
UBC NDES	4.0 pps (42.5%)	75 bps (9.50%)	4.04%	4.0 pps (49.0%)	75 bps (10.40%)	5.10%
DGE	4.0 pps (42.5%)	100 bps (9.75%)	4.14%	4.0 pps (49.0%)	100 bps (10.65%)	5.22%

With Brattle's analysis of business risk and the associated recommendations for the Corix Utilities in mind, the following subsections provide additional background on each utility and review their specific business risks. Following are the position of the parties and the Panel determination.

Corix BMDEU

BMDEU is a district energy system (DES) that provides thermal heating and domestic hot water to Simon Fraser University (SFU) and the UniverCity residential neighbourhood located adjacent to the SFU campus. Initially, the

[184] Exhibit B6-9-1, Brattle Evidence for Corix, p. 61.
[185] Exhibit B6-9-1, Brattle Evidence for Corix, p. 69.
[186] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 61 69; Exhibit B6-12, BCUC IR 6.3.
[187] Exhibit B6-9, Corix Evidence, p. 7; Exhibit B6-12, BCUC IR 6.5.
[188] Exhibit B6-9, Corix Evidence, p. 7.
[189] 2014 GCOC Stage 2 Decision, pp. 127-128; Corix BMDEU 2020–2023 Revenue Requirements and Rates Application (RRRA), Decision and Order G-279-21 (BMDEU 2020–2023 RRRA Decision), p. 34; Order G-84-15.
[190] Exhibit B6-9, Corix Evidence, pp. 6–7; Corix Final Argument, Table 1, p. 18.

project served only the UniverCity neighbourhood, operating through temporary energy centers powered by natural gas boilers. SFU became a customer of BMDEU in 2020.[191]

In 2020, BMDEU placed a new central energy plant in service to serve most of SFU's Burnaby campus and approximately half of the UniverCity community. This facility produces thermal energy from biomass, a low-carbon energy source, sourced from locally available wood waste. The central energy plant also uses natural gas service from FEI to operate backup or peaking thermal energy for UniverCity; however, SFU does not obtain backup or peaking services from BMDEU.[192]

As of the end of 2023, BMDEU serves approximately 18 customers including approximately 19 residential buildings at UniverCity (totalling 2.3 million square feet) and 5 million square feet across SFU's Burnaby campus. In 2023, BMDEU delivered approximately 190,000 gigajoules of energy to its customers generating approximately $6.2 million in revenues.[193]

BMDEU's current cost of capital was established in the 2014 GCOC Stage 2 Decision. As shown in Table 8 above, the BCUC determined a deemed equity component at 42.5 percent (4.0 pps above the Benchmark Utility) and an allowed ROE of 9.50 percent (75 bps above the Benchmark Utility) at that time.[194] The BCUC made these determinations based on BMDEU's risk profile when it operated a temporary natural gas boiler facility.[195] In BMDEU's 2020 to 2023 Revenue Requirements Application, which included rate proposals reflecting the costs associated with the biomass central energy plant that commenced service in October 2020, the BCUC approved a deemed equity component of 42.5 percent and an allowed ROE of 9.50 percent consistent with the 2014 GCOC Stage 2 Decision.[196]

In this proceeding, Corix is proposing to maintain both the equity premium and ROE premium at the same levels as previously approved.[197] As shown in Table 8 above, this results in a deemed equity component of 49.0 percent and an allowed ROE of 10.40 percent.[198]

Corix provides a business risk assessment of BMDEU relative to the Benchmark Utility and to its 2014 profile to support its proposed equity and ROE premiums. Corix states that relative to the Benchmark Utility, BMDEU faces lower political risk, similar Indigenous rights and engagement risk, and higher levels of supply, demand and market, competitive, operating, and regulatory risks. Overall, Corix considers that BMDEU carries greater overall business risk than the Benchmark Utility.[199] Corix's assessment of BMDEU's changes in risks since 2014 concludes that operating risk remains similar, Indigenous rights and engagement risk has slightly increased, while supply, demand, competitive and regulatory risks have also risen, with political risk showing a significant increase.[200]

[191] Exhibit B6-9-1, Brattle Evidence for Corix, p. 16.
[192] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 16–17.
[193] Exhibit B6-9-1, Brattle Evidence for Corix, p. 17.
[194] 2014 GCOC Stage 2 Decision, p. 128.
[195] 2014 GCOC Stage 2 Decision, p. 127.
[196] BMDEU 2020–2023 RRRA Decision, p. 34.
[197] Exhibit B6-9, Corix Evidence, pp. 6–7; Corix Final Argument, Table 1, p. 18.
[198] Exhibit B6-9, Corix Evidence, pp. 6–7; Corix Final Argument, Table 1, p. 18.
[199] Exhibit B6-9-1, Brattle Evidence for Corix, Figure 15, p. 51.
[200] Exhibit B6-12, BCUC IR 1.5.

Brattle identified elevated supply risks for BMDEU relative to both the Benchmark Utility and to BMDEU's 2014 assessment. This is primarily due to its reliance on a single biomass supplier for the majority of its thermal energy production, which introduces counterparty and performance risks that are unique compared to utilities like FEI that source natural gas from a diverse set of suppliers in a liquid commodity market.[201] While wood waste is readily available in the Lower Mainland, it is a niche product compared to natural gas.[202] Additionally, Brattle points out that BMDEU's limited on-site storage capacity for biomass fuel reduces its ability to respond effectively to supply disruptions.[203] Brattle adds that contractual obligations with SFU require BMDEU to supply biomass exclusively, while the Benchmark Utility has the flexibility to substitute renewable natural gas or conventional natural gas. Brattle also notes the cost associated with biomass ash disposal have fluctuated significantly from 2021 to 2023.[204] Additionally, Brattle highlights natural gas supply risks associated with BMDEU's peaking and back-up plan, which services a relatively small customer base in UniverCity. Despite Corix forecasting that only 13 precent of energy demand will be met by natural gas by 2028, BMDEU is vulnerable to natural gas supply disruptions and rising costs, particularly as FEI incorporates higher-cost renewable natural gas to comply with decarbonization policies.[205]

Brattle further assesses BMDEU's demand and market risk as higher than the Benchmark Utility and also higher than it was in 2014.[206] BMDEU operates with a concentrated customer base, primary dependent on SFU, which constitutes approximately 48 percent of its energy sales and 36 percent of its total revenue. The potential loss of this key customer would significantly impact BMDEU's financial stability.[207] Additionally, customer growth is contingent upon the development of new buildings within its service area.[208] Once a project reaches full build-out, opportunities for adding new customers become limited.[209] Brattle notes that the expected completion of the UniverCity project has been delayed from 2019 to 2027, complicating future growth prospects.[210]

Brattle states that competitive risk for BMDEU is also greater than the Benchmark Utility and what it was in 2014.[211] BMDEU's infrastructure serves a limited number of customers, such as residential strata corporations, small commercial entities, or large anchor customers (e.g. university, hospital, hotel).[212] However, the switching risk for existing customers is relatively low for a DES compared to the Benchmark Utility.[213] While the sunk costs of connection associated with connection impose a barrier to switching that mitigates near-term competitive risk, BMDEU faces significant competitive challenges with respect to growth and expansion.[214]

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[201] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 23–34; Exhibit B6-12, BCUC IR 1.5 and 2.1.
[202] Exhibit B6-12, BCUC IR 2.2.
[203] Exhibit B6-9-1, Brattle Evidence for Corix, p. 24.
[204] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 24-25.
[205] Exhibit B6-9-1, Brattle Evidence for Corix, p. 25.
[206] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 29, 32; Exhibit B6-12, BCUC IR 1.5.
[207] Exhibit B6-9-1, Brattle Evidence for Corix, p. 30.
[208] Exhibit B6-9-1, Brattle Evidence for Corix, p. 28.
[209] Exhibit B6-9-1, Brattle Evidence for Corix, p. 28.; Exhibit B6-12, BCUC IR 2.4.
[210] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 30–31.
[211] Exhibit B6-9-1, Brattle Evidence for Corix, p. 36; Exhibit B6-12, BCUC IR 1.5.
[212] Exhibit B6-9-1, Brattle Evidence for Corix, p. 35.
[213] Exhibit B6-9-1, Brattle Evidence for Corix, p. 35.
[214] Exhibit B6-9-1, Brattle Evidence for Corix, p. 36.

Although Brattle recognizes BMDEU as a low-carbon utility given its use of biomass, it highlights higher operating risks relative to the Benchmark Utility due to its small size.[215] This risk has also risen since 2014.[216] BMDEU has not achieved full build-out, and the capital-intensive growth process results in these costs being distributed across a smaller customer base, leading to higher operating leverage reflected in a greater ratio of fixed costs to operating margins.[217] The smaller scale of BMDEU also limits its ability to achieve economies of scale compared to larger utilities like FEI.[218]

Brattle assesses BMDEU's regulatory risk as higher than the Benchmark Utility and higher than what it was in 2014.[219] BMDEU's regulatory risk arises from delays in recovering its revenue deficiency for the UniverCity development, which is attributed to a combination of higher-than-expected operating and capital costs and a slower-than-expected pace of development and customer connections.[220] The BMDEU UniverCity revenue deficiency deferral account was initially expected to be fully recovered by 2031, but this has been delayed to 2036 due to higher-than-expected operating and capital costs, as well as a slower pace of development and customer connections.[221] Brattle adds that any future costs exceeding the latest forecast will increase the risk of further delays in the anticipated elimination of the deficit.[222] Brattle notes that this prolonged recovery period poses significant regulatory risk for BMDEU, particularly given the unpredictability in development schedules, customer growth and the utility's small size.[223] Corix also emphasizes that the additional regulatory requirements and restrictions for new connections applicable for rate-regulated TES utilities compared to the Benchmark Utility should be considered in the risk profile and the cost of equity for district energy utilities.[224]

In contrast, Brattle considers BMDEU to experience comparatively lower political and transition risks relative to other utilities, particularly DGE and UBC NDES, although these risks have risen since 2014. This is primarily due to BMDEU's utilization of biomass for the majority of its thermal production, aligning with BC's decarbonization objectives. Although BMDEU relies on natural gas for backup and peaking generation, its core operations are largely insulated from the higher transition risks associated with the shift towards low-carbon technologies.[225]

Corix UBC NDES

The UBC NDES is a partnership between Corix and UBC to provide thermal heating and domestic hot water to select UBC residential buildings. Under this arrangement, Corix is responsible for the financing, design, construction, ownership, and operation of the system. The partnership, established in 2013, aligns with UBC's efforts to reduce greenhouse gas emissions from its residential buildings. UBC is currently evaluating potential new residential building developments on campus that would be served by UBC NDES. These additional developments will increase demand, supporting the construction of a permanent central energy plant, which is targeted to source 60 percent of its energy from alternative and renewable sources. One possibility under

[215] Exhibit B6-9-1, Brattle Evidence for Corix, p. 39.
[216] Exhibit B6-12, BCUC IR 1.5.
[217] Exhibit B6-9-1, Brattle Evidence for Corix, p. 39.
[218] Exhibit B6-9-1, Brattle Evidence for Corix, p. 39.
[219] Exhibit B6-9-1, Brattle Evidence for Corix, Figure 15, p. 51; Exhibit B6-12, BCUC IR 1.5.
[220] Exhibit B6-9-1, Brattle Evidence for Corix, p. 46.
[221] Exhibit B6-9-1, Brattle Evidence for Corix, p. 46.
[222] Exhibit B6-9-1, Brattle Evidence for Corix, p. 46.
[223] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 46–47.
[224]Exhibit B6-12, BCUC IR 2.5.
[225] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 47 and 49.

consideration is the use of waste heat energy from TRIUMF, Canada's national laboratory for particle and nuclear physics, located on UBC's south campus.[226] The UBC NDES was constructed after the 2014 GCOC Stage 2 Decision.[227]

In the decision to the final rate application for Phase 1 of the UBC NDES in 2015, the BCUC set a deemed equity component of 42.5 percent (4.00 pps above the Benchmark Utility) and allowed ROE of 9.50 percent (75 bps above the Benchmark Utility) for UBC NDES, consistent with the minimum TES Default.[228] As shown in Table 8 above, in the current proceeding Corix is proposing to maintain the equity and ROE premiums from the 2014 decision for UBC NDES.

Corix presents a business risk assessment of UBC NDES in comparison to the Benchmark Utility to justify its proposed equity and ROE premiums. Relative to the Benchmark Utility, Corix states that UBC NDES has lower supply risk, similar Indigenous rights and engagement risk, and higher levels of demand and market, competitive, operating, regulatory, and political risks. Overall, Corix concludes that UBC NDES carries a greater overall business risk than the Benchmark Utility.[229] These risks are discussed in further detail below.

UBC NDES is reliant solely on FEI for its natural gas supply and therefore Brattle states that it faces similar natural gas supply risks to the Benchmark Utility. UBC NDES is equally vulnerable to increasing supply costs as FEI incorporates renewable natural gas to comply with decarbonization mandates.[230] UBC NDES, along with DGE, faces greater energy price uncertainty compared to BMDEU due to its reliance on natural gas and potential volatility in FEI's natural gas commodity charge.[231]

Demand and market risks for UBC NDES are considered higher than for BMDEU, with Brattle noting these risks exceed those of the Benchmark Utility.[232] Property development risks contribute to this uncertainty since the timing of new connections and project completions are not guaranteed.[233] For example, the UBC development project was initially scheduled for completion in 2023 and is now projected for 2029.[234] Corix notes that while district energy systems like UBC NDES expand within the original Certificate of Public Convenience and Necessity project area, growth beyond this remains uncertain.[235] This contrasts with the Benchmark Utility which benefits from more stable customer growth due to its large, diversified customer base, providing more consistent investment opportunities for shareholders.[236]

Corix submits that UBC NDES also faces higher competitive risks compared to the Benchmark Utility. While it benefits from sunk costs associated with existing customer connections, UBC NDES faces significant competitive risks related to growth and expansion. Brattle notes that the rapid shift toward decarbonizing fuel sources poses challenges for smaller utilities like UBC NDES, which are already facing operating losses. Brattle highlights that

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226 Exhibit B6-9-1, Brattle Evidence for Corix, p. 19.
227 Exhibit B6-9-1, Brattle Evidence for Corix, p. 20.
228 Order G-84-15.
229 Exhibit B6-9-1, Brattle Evidence for Corix, Figure 15, p. 51.
230 Exhibit B6-9-1, Brattle Evidence for Corix, p. 25.
231 Exhibit B6-12, BCUC IR 2.1.
232 Exhibit B6-9-1, Brattle Evidence for Corix, pp. 31, 32.
233 Exhibit B6-9-1, Brattle Evidence for Corix, p. 30.
234 Exhibit B6-9-1, Brattle Evidence for Corix, p. 31.
235 Exhibit B6-12, BCUC IR 2.4.
236 Exhibit B6-9-1, Brattle Evidence for Corix, pp. 31–32.

smaller utilities with confined customer bases face greater difficulties in incorporating low-carbon technologies due to the significant capital investments required.[237] Brattle also notes that UBC NDES's reliance on natural gas exposes it to risks associated with meeting stringent decarbonization requirements. The cost of transitioning to low-carbon technologies, combined with potential switching costs for existing customers, adds to the utility's challenges. This dynamic is similar for both UBC NDES and DGE, which face barriers to switching due to sunk costs, but continue to face growth-related competitive risk.[238]

Brattle finds that operational risks for UBC NDES stem from its smaller size, limiting its ability to achieve economies of scale ranking it higher than the Benchmark Utility. UBC NDES is still in the build-out phase, spreading the costs associated with the capital-intensive growth process across a small customer base, resulting in higher operating leverage, reflected in a greater ratio of fixed costs to operational margin. This contrasts with larger utilities like the Benchmark Utility, which benefit from economies of scale and more predictable operating margins.[239]

Similar to BMDEU, Brattle notes that the UBC NDES faces heightened regulatory risk compared to the Benchmark Utility, largely due to slower-than-anticipated customer integration and higher-than-expected capital expenditures.[240] As of the end of 2023, the revenue deficiency deferral account for the UBC NDES had grown to approximately $6.0 million, up from $5.4 million the previous year.[241] Brattle notes that the challenges are compounded by the slower-than-expected pace of customer connections with full build-out anticipated for completion in 2029.[242] Coupled with higher-than-forecast capital expenditures, these delays mean that rates will need to increase to reduce and eliminate the growing long-term revenue deficiency.[243] Corix has also emphasized that regulatory requirements and restrictions on new connections for rate-regulated TES services should be factored into the risk profile and cost of capital for district energy utilities.[244]

Political risks for UBC NDES have escalated relative to the Benchmark Utility in recent years due to federal and provincial decarbonization goals.[245] As a DES relying on natural gas for thermal energy, UBC NDES is exposed to significant political risk given the increasing need for capital investment to adopt low-carbon technologies. These investments would be distributed among a relatively small customer base, complicating the financial outlook of the utility.[246] Additionally, UBC NDES faces rising supply costs as FEI incorporates higher levels of renewable natural gas into its supply.[247] Corix notes that while UBC NDES could purchase renewable natural gas from FEI, renewable natural gas is relatively expensive and is not considered a viable long-term solution for reducing emissions.[248] UBC NDES is currently in the feasibility stage for transitioning to low-carbon generation

[237] Exhibit B6-9-1, Brattle Evidence for Corix, p. 36.
[238] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 35–36.
[239] Exhibit B6-9-1, Brattle Evidence for Corix, Figure 15, pp. 39, 51.
[240] Exhibit B6-9-1, Brattle Evidence for Corix, p. 46.
[241] Exhibit B6-9-1, Brattle Evidence for Corix, p. 46.
[242] Exhibit B6-9-1, Brattle Evidence for Corix, p. 46.
[243] Exhibit B6-9-1, Brattle Evidence for Corix, p. 46.
[244] Exhibit B6-12, BCUC IR 2.5.
[245] Exhibit B6-9-1, Brattle Evidence for Corix, Figure 15, pp. 47, 50, 51.
[246] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 48, 50.
[247] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 48, 49, 50.
[248] Exhibit B6-12, BCUC IR 3.3.

technologies, with plans to begin the transition in 2027, subject to customer agreements and regulatory approval. Full transition is expected by 2030, if not sooner.[249]

Corix DGE

Dockside Green is a 15-acre sustainable community in Victoria designed to Leadership in Energy and Environmental Design Platinum standards. DGE operates a 2-megawatt distributed energy system providing space heating and hot water to approximately 130,000 square metres of floor space at full build-out. The system is powered by three gas-fired condensing boilers, which replaced older, less efficient units in 2021.[250] DGE has grown alongside the community since the first phase of the development in 2008 when the DES was placed into service. Corix acquired full ownership of DGE in 2018. While the community is still under development, it is projected to be fully built out by 2031. Once completed, Dockside Green is expected to be a largely self-sufficient, sustainable community where waste from one area provides fuels or inputs for another. DGE is actively evaluating low-carbon energy technologies to replace the gas-fired boilers and decarbonize the DES.[251]

DGE's cost of capital was last assessed in the 2014 GCOC Stage 2 Decision. In its decision the BCUC's summarized the risk assessments for DGE, which at that time was intended to provide service through a plant incorporating a biomass gasification system and a supplementary natural gas boiler. The BCUC noted that DGE was significantly under-earning its allowed return on investment due to lack of build-out and that the new biomass gasification technology presented higher risks than the Benchmark Utility.[252] Acknowledging these challenges, the BCUC opted to maintain the previously awarded 100 bps ROE premium. As shown in Table 8 above, the 2014 GCOC Stage 2 decision determined a deemed equity component of 42.5 percent (4.0 pps above the Benchmark Utility) and an allowed ROE of 9.75 percent (100 bps above the Benchmark Utility) for DGE.[253]

In this proceeding, Corix is proposing to maintain the previously approved equity and ROE premiums. As shown in Table 8 above, this results in a 49.0 deemed equity component and a 10.65 percent allowed ROE.[254] Corix provides a business risk assessment of DGE relative to the Benchmark Utility and to its 2014 profile, to support its proposed equity and ROE premium. Corix states that relative to the Benchmark Utility, DGE faces lower supply risk, similar Indigenous rights and engagement risk, and higher levels of demand and market, competitive, operating, regulatory, and political risk. Overall, Corix considers that the DGE carries greater overall business risk than the Benchmark Utility.[255] Corix's assessment of DGE changes in risks since 2014 concludes that operating risk remains similar, Indigenous rights and engagement risk has slightly increased, while supply, demand, competitive, and regulatory risk have also risen, with political risk showing a significant increase.[256]

While DGE's supply risk remains lower than the Benchmark Utility, Brattle notes it has increased since 2014.[257] Brattle notes that DGE is entirely dependent on natural gas from FEI to meet its thermal energy demand making it vulnerable to the same supply risks as the Benchmark Utility. Additionally, Brattle notes the incorporation of

[249] Exhibit B6-12, BCUC IR 3.1.1.
[250] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 17–18.
[251] Exhibit B6-9-1, Brattle Evidence for Corix, p. 18.
[252] 2014 GCOC Stage 2 Decision, p. 125-126.
[253] 2014 GCOC Stage 2 Decision, pp. 126–127.
[254] Exhibit B6-9, Corix Evidence, pp. 6–7; Corix Final Argument, Table 1, p. 18.
[255] Exhibit B6-9-1, Brattle Evidence for Corix, Figure 15, p. 51.
[256] Exhibit B6-12, BCUC IR 1.5.
[257] Exhibit B6-9-1, Brattle Evidence for Corix, Figure 15, p. 51; Exhibit B6-12, BCUC IR 1.5.

renewable natural gas into FEI's supply introduces the potential for rising supply costs that may impact DGE's operations.[258] Corix further states that both UBC NDES and DGE are subject to greater energy price uncertainty compared to BMDEU, primarily due to their reliance on natural gas and the potential for fluctuations in natural gas pricing.[259]

Demand and market risks also present challenges for DGE ranking higher than the Benchmark Utility and showing an increase since 2014.[260] Brattle highlights that similar to BMDEU and UBC NDES, DGE's demand risk is considered greater than the Benchmark Utility,[261] due to the lengthy and costly process for securing new connections and competition with other energy providers to attract potential customers.[262] The build-out of DGE was originally expected to be completed by 2014 but has been delayed to 2031, which complicates the outlook for customer growth.[263] Unlike larger utilities which benefit from steady customer growth and a diversified customer base which provides attractive opportunities for shareholders, DGE's smaller localized system faces the potential for variable or stagnant growth in any given year.[264]

Brattle notes that DGE's competitive risk is also higher than the Benchmark Utility and has increased since 2014.[265] The reliance on natural gas and the increasing pressures to meet decarbonization requirements create significant challenges. Brattle highlights that transitioning to low-carbon energy technologies requires significant investment, which is particularly difficult for smaller utilities like DGE with a limited customer base.[266] Similar to BMDEU and UBC NDES, while existing customers may be less likely to switch given the sunk costs of connection, growth and expansion remain uncertain and the high cost of decarbonization presents further competitive risk.[267]

For DGE, similar to both BMDEU and UBC NDES, regulatory risk is higher than the Benchmark Utility and has risen since 2014.[268] DGE's regulatory risk is driven by a growing deficit in the revenue deficiency deferral account following depletion of a $1 million starting surplus inherited from the previous owner at the time of Corix's acquisition in 2018. Brattle indicates that this starting surplus was fully depleted by the end of 2022, with a deficit balance expected to begin in 2023.[269] Despite contributions from the former owners, Corix emphasizes that DGE remains in a challenging financial position.[270] Corix further highlights that additional regulatory requirements and restrictions for new connections applicable for rate-regulated TES should be a factor into the risk profile and the cost of capital for district energy utilities.[271]

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[258] Exhibit B6-9-1, Brattle Evidence for Corix, p. 25.
[259] Exhibit B6-12, BCUC IR 2.1.
[260] Exhibit B6-9-1, Brattle Evidence for Corix, Figure 15, p. 51; Exhibit B6-12, BCUC IR 1.5.
[261] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 29, 30 and 32.
[262] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 28-30.
[263] Exhibit B6-9-1, Brattle Evidence for Corix, p. 31; Exhibit B6-12, BCUC IR 2.4; Exhibit B6-13, BCOAPO IR 5.2.
[264] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 31-32.
[265] Exhibit B6-9-1, Brattle Evidence for Corix, Figure 15, p. 51; Exhibit B6-12, BCUC IR 1.5.
[266] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 31, 35-36.
[267] Exhibit B6-9-1, Brattle Evidence for Corix, p. 36.
[268] Exhibit B6-9-1, Brattle Evidence for Corix, Figure 15, p. 47, 51; Exhibit B6-12, BCUC IR 1.5.
[269] Exhibit B6-9-1, Brattle Evidence for Corix, p. 46.
[270] Exhibit B6-13, BCOCPO IR 5.2.1.
[271] Exhibit B6-12, BCUC IR 2.5.

Brattle also identifies political risk as a key concern for DGE, particularly as decarbonization initiatives increasingly shape the energy landscape. Brattle states that this risk is higher than the Benchmark Utility and has increased for the DGE since 2014.[272] DGE's reliance on natural gas exposes it to significant transition risks, particularly as government initiatives push for low-carbon energy solutions.[273] Brattle suggests that transitioning to blended renewable natural gas may not be sufficient to meet local greenhouse gas reduction targets, which could require further investments in decarbonization efforts.[274] While Corix notes that DGE can directly purchase renewable natural gas from FEI, this option is relatively expensive and not a sustainable long-term solution for reducing emissions. Additionally, certain jurisdictions, such as the City of Victoria, prohibit the use of renewable natural gas to meet the Zero Carbon Step Code. Consequently, Corix is exploring other permanent solutions including geothermal and sewer/waste heat recovery as substitutes for renewable natural gas.[275] Similar to UBC NDES, DGE is currently in the feasibility and concept stages for transition to low-carbon generation technologies, with a complete transition anticipated by 2030.[276]

Positions of the Parties

Interveners submitted a range of proposals regarding the overall business risk assessment of the Corix Utilities. For BMDEU, their recommendations range from an equity discount of 2.5 pps to an equity premium of 3.0 pps. For UBC NDES and DGE, their recommendations range from an equity discount of 1.0 pps to an equity premium of 4.0 pps. They also recommended ROE premiums between 50 bps and 100 bps for the Corix Utilities.[277]

The CEC emphasizes that the increased risk from the energy transition affecting the Benchmark Utility is not equally applicable to the Corix Utilities. The CEC does not find Corix's proposal for a 49.0 percent equity component to be persuasive. Instead, the CEC prefers a minimum of 47.0 percent equity component and suggests that an equity component of 48.0 percent should be considered. Additionally, the CEC submits the ROE premium should be uniform across all TES utilities, unless there is a compelling reason to do otherwise, and proposes a 50 bps premium, reflecting the increased risk to the Benchmark Utility from the energy transition that is not equally applicable to the TESs.[278] In reply, Corix submits that Brattle's recommended 47 percent equity component is based on minimum threshold parameters. Corix also highlights that DGE experienced financial losses in the millions, suffered from poor cash flow, and faced weak earnings demonstrating significantly higher business risk compared to the Benchmark Utility.[279] Furthermore, Corix contends that the CEC's proposal for a 50 bps ROE premium fails to adequately reflect the increased business risks faced by the Corix Utilities relative to the Benchmark Utility.[280]

BCOAPO agrees that BMDEU's supply risks are generally higher than the Benchmark Utility's but argues that Corix overstates these risks. BMDEU's use of biomass reduces exposure to natural gas price volatility and potential alternative suppliers mitigate some risk. BCOAPO also notes BMDEU's demand/market risk is lower

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[272] Exhibit B6-9-1, Brattle Evidence for Corix, Figure 15, p. 51; Exhibit B6-12, BCUC IR 1.5.
[273] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 47 and 50.
[274] Exhibit B6-9-1, Brattle Evidence for Corix, pp. 48-49.
[275] Exhibit B6-12, BCUC IR 3.3.
[276] Exhibit B6-12, BCUC IR 3.1.
[277] The CEC Final Argument, p. 33; BCOAPO Final Argument, pp. 67-69; RCIA Final Argument, Table 12, p. 53; SFU Final Argument, pp. 3–4, 24–25.
[278] The CEC Final Argument, pp. 32-33.
[279] Corix Reply Argument, p. 44.
[280] Corix Reply Argument, p. 59.

than that of utilities primarily using natural gas, like UBC NDES and DGE, due to reduced natural gas reliance but remains higher than that of the Benchmark Utility. While BCOAPO recognizes that BMDEU's competitive risk is higher due to size, its low-carbon profile helps mitigate the change in this risk since 2014. BCOAPO agrees that BMDEU's operating risks are higher than the Benchmark Utility's because of its smaller size and associated challenges with build-out.[281] Overall, BCOAPO agrees BMDEU faces higher business risk than the Benchmark Utility, but the risk differential has decreased since 2014. BCOAPO considers that a 49.0 percent equity component is too high when combined with an allowed ROE of 10.40 percent for BCOAPO and submits that the appropriate equity component is 47.0 percent.[282] In reply, Corix asserts that the BMDEU faces significant challenges related to its revenue deficiency deferral account, which must be recovered from UniverCity customers. Corix adds that the BMDEU carries higher operational risks. Its small size and limited customer base, combined with its reliance on regulatory mechanisms such as levelized rates, creates additional risk factors that are not present for the Benchmark Utility.[283] Corix contends that BCOAPO's recommendation for a 47.0 percent deemed equity component does not adequately capture the existing business risks.[284]

BCOAPO concurs that UBC NDES faces higher business risks than the Benchmark Utility. BCOAPO considers that demand and market risk are also higher due to greenhouse gas reduction target pressures but the difference between UBC NDES and the Benchmark Utility remains similar to 2014. BCOAPO agrees that competitive and operating risks remain higher than the Benchmark Utility, though the differences have not changed significantly since 2014. BCOAPO acknowledges that regulatory and political risks are amplified by UBC NDES' smaller size due to local municipal bylaws for greenhouse gas emission reductions requiring additional investments. BCOAPO believes that the overall business risk profile for UBC NDES is higher than that of the Benchmark Utility but maintains that the risk differential between UBC NDES and the Benchmark Utility has not changed materially since 2014.[285] BCOAPO adds that arguably an equity component of 48.0 percent would maintain the existing differential between the weighted ROE for the Benchmark Utility and UBC NDES.[286] In reply, Corix concurs with BCOAPO's claim that UBC NDES' business risks relative to the Benchmark Utility have not materially changed since last assessed and agrees that a 49 percent deemed equity component is reasonable.[287]

BCOAPO concurs that DGE faces higher risks compared to the Benchmark Utility. It submits demand and market risks are higher for DGE due to its reliance on natural gas and concentrated customer base. Competitive risks mirror those of UBC NDES, with expansion challenges and adapting to lower-carbon solutions. BCOAPO further submits that DGE faces challenges with operating leverage, making it more susceptible to additional capital requirements for future build-out. BCOAPO concurs with Brattle that DGE experiences higher political risks compared to the Benchmark Utility given local government policies for GHG reductions, particularly the City of Victoria's prohibition on using renewable natural gas to meet its Zero Carbon Step Code.[288] However, BCOAPO maintains that the risk profile for DGE relative to the Benchmark Utility has not changed materially since 2014. BCOAPO considers Corix's recommended deemed equity component and allowed ROE to be reasonable, but at the same time notes that a deemed equity component of 48.0 percent would maintain the existing differential

[281] BCOAPO Final Argument, pp. 61–64.
[282] BCOAPO Final Argument, pp. 67 and 69.
[283] Corix Reply Argument, p. 47 and 49.
[284] Corix Reply Argument, p. 49.
[285] BCOAPO Final Argument, pp. 62–64.
[286] BCOAPO Final Argument, p. 69.
[287] Corix Reply Argument, p. 49.
[288] BCOAPO Final Argument, pp. 62–64 and 66.

between the weighted ROE for the Benchmark Utility and DGE.[289] In reply, Corix agrees with BCOAPO's assessment that DGE's risk profile relative to the Benchmark Utility remains unchanged since 2014 and concurs that a 49.0 percent deemed equity component is reasonable.[290]

RCIA submits that Corix's proposal lacks adequate evidentiary support. It recommends an equity discount of 1.0 pps accompanied by an ROE premium of 50 bps for all three Corix Utilities.[291] While RCIA acknowledges that the Corix Utilities face higher risk than the Benchmark Utility, it argues that the risk differential has narrowed since 2014.[292] RCIA notes that BMDEU has already transitioned away from direct use of fossil fuels, resulting in lower energy transition risk compared to the Benchmark Utility.[293] In contrast, UBC NDES has not yet transitioned away from fossil fuels, positioning its political risk is more closely to that of DGE. Additionally, RCIA submits that BMDEU, UBC NDES and DGE face reduced risks related to Indigenous rights and engagement due to their limited geographic footprint.[294]

In reply, Corix disagrees with RCIA's recommendation to assign a deemed equity component for BMDEU, UBC NDES, and DGE that is 1.0 pps lower than the Benchmark Utility. Corix notes that RCIA overlooks several pieces of evidence supporting a higher deemed equity component, while also conflating financial risk with business risk in its analysis.[295] Furthermore, Corix submits that RCIA's claim that the risk spread has narrowed since 2014 due to more rapid increases in risks for the Benchmark Utility compared to the Corix Utilities is insufficiently supported.[296] Corix adds that RCIA's assertion that the Corix Utilities face less energy transition risk is similarly lacking in justification or evidentiary support.[297] Corix emphasizes that RCIA has failed to consider material key facts demonstrating the higher business risks faced by district energy utilities.[298] These include the financial realities unique to small TES utilities such as unfavorable cash flow, a small customer base, and development risks associated with customer additions, which necessitate a higher cost of capital to maintain financial integrity and attract capital investment.[299]

SFU, a customer group of BMDEU, contends that there has been no material change in the overall business risk faced by BMDEU, for which it previously received approval for a deemed equity component of 42.5 percent. SFU further argues that the rationale supporting the BCUC's approval of a deemed equity component increase for FEI in Stage 1 does not apply to BMDEU. Therefore, SFU submits that there is no basis for approving the proposed increase in BMDEU's deemed equity component. SFU submits that an increase in BMDEU's allowed ROE should be limited to the extent that it aligns with the increases in the Benchmark Utility's allowed ROE due to market conditions, rather than any increase linked to business risks for FEI.[300]

[289] BCOAPO Final Argument, p. 69.
[290] Corix Reply Argument, p. 49.
[291] RCIA Final Argument, pp. 53.
[292] RCIA Final Argument, p. 54.
[293] RCIA Final Argument, pp. 54–55.
[294] RCIA Final Argument, pp. 55–56.
[295] Corix Reply Argument, p. 46.
[296] Corix Reply Argument, pp. 46-47.
[297] Corix Reply Argument, p. 47.
[298] Corix Reply Argument, p. 48.
[299] Corix Reply Argument, p. 47.
[300] SFU Final Argument, pp. 3–4 and 24–25.

Panel Determination

The BCUC established BMDEU's and DGE's current cost of capital in 2014, while BMDEU's cost of capital was last set during its 2020 to 2023 revenue requirement application once the biomass central energy plant entered service. Since their last cost of capital assessments, each Corix Utility has advanced operationally. BMDEU has transitioned to biomass as a primary energy source, notwithstanding its cost of capital remained unchanged after this transition in 2020. BMDEU has gained operational experience with its biomass energy center and Corix expects full build-out of the UniverCity development by 2027. DGE, having moved away from biomass gasification, upgraded its natural gas boilers to more efficient models in 2021, with full build-out projected by 2033. During this time, the Panel views that DGE has evolved into a mature utility. UBC NDES has also gained operational experience and is progressing toward full build-out, anticipated for 2029.

With respect to Corix's supporting evidence in this proceeding, the Panel accepts Brattle's holistic approach to assessing business risks, which aligns with the Panel's established framework in Section 3.1, and was applied for the review of PNG. Furthermore, the Panel recognizes that the Corix Utilities share several key characteristics that contribute to similar risk profiles in the broader context within their regulatory environment. For example, all three utilities are greenfield developments, operate with levelized rate structures over a long period, are smaller than the Benchmark Utility, rely on long-term infrastructure investments, depend on customer growth within dedicated service areas, and face customer building connection delays.

The Panel finds that with DGE's operational maturity, its build-out challenges have stabilized and its technology risks have diminished and it now has a comparable risk profile to that of the BMDEU and UBC NDES. Although DGE's completion date is the furthest out in 2031, the Panel recognizes that building connection delays exist across all three projects. With approximately ten years of operations since the utilities were last assessed, we find that DGE is not materially different than BMDEU and UBC NDES. Therefore, we determine that DGE's allowed return now should be similar to that for BMDEU and UBC NDES.

BMDEU, which operates a biomass energy plant for UniverCity and SFU customers, also relies on natural gas for backup and peaking demands for its UniverCity customers, making it somewhat exposed to energy transition risks. Despite its reliance on biomass, the Panel does not consider BMDEU's overall risk to be significantly lower than that of UBC and DGE. While biomass aligns with provincial energy policies, BMDEU continues to share several risks with the other two utilities, including greenfield development challenges, build-out delays, dependence on customer growth, and a limited customer base. Therefore, the Panel does not consider BMDEU's overall risk profile to be lower than UBC NDES and DGE.

The Panel concludes that the BMDEU, UBC NDES and DGE utilities should be treated similarly regarding equity and ROE premiums, as no unique risks justify differentiated allowed returns among them. While there are some differences (e.g. maturity, timelines for build-out, fuel type) they do not warrant disparate treatment. Given their comparable risk profiles, a uniform methodology for establishing the equity premium for all three Corix Utilities is warranted.

Additionally, the Panel considers that the Corix Utilities exhibit an overall higher risk profile relative to the Benchmark Utility due to challenges in build-out, including risks associated with recovery of revenue deficiencies under their levelized rate structure, and a limited customer base. However, the Panel assesses that this higher risk profile has not changed significantly since each of the Corix Utilities' respective most recent cost of capital review. Although the Panel considers that the risk profile of DGE has improved, this reduction now brings DGE in line with the risk profile and corresponding cost of capital of BMDEU and UBC NDES. Therefore, the previously approved 4.0 pps equity premium continues to be appropriate for the Corix Utilities. **The Panel sets a 4.0 pps equity premium, resulting in a 49.0 deemed equity component for Corix BMDEU, UBC NDES, and DGE.**

As outlined in Section 3.1, the Panel has determined that a 75 bps ROE premium is appropriate to account for the small size premium. This ROE premium will be applied to all Corix Utilities – BMDEU, UBC NDES, and DGE – resulting in an allowed ROE of 10.40 percent. Given the Panel's findings on DGE's risks and its approach of reflecting business risks solely in the equity premium, the Panel does not view that any further adjustments to DGE's allowed ROE are required.

Table 9 below provides a comparison of the currently approved versus previously approved cost of capital for the Corix Utilities. The table lays out the Corix Utilities' cost of capital beginning with the Benchmark Utility's cost of capital plus the approved equity and ROE premiums for the Corix Utilities to arrive at the Corix Utilities' cost of capital.

Table 9: Comparison of Previously and Currently Approved Cost of Capital for the Corix Utilities

	Previously Approved[301]			Currently Approved		
	Deemed Equity Component	Allowed ROE	Weighted ROE	Deemed Equity Component	Allowed ROE	Weighted ROE
Benchmark Utility's cost of capital (for comparison)	38.5%	8.75%	3.37%	45.0%	9.65%	4.34%
BMDEU's premium	4.0 pps	75 bps	0.67 bps	4.0 pps	75 bps	0.76 bps
BMDEU's resulting cost of capital	42.5%	9.50%	4.04%	49.0%	10.40%	5.10%
UBC NDES's premium	4.0 pps	75 bps	0.67 bps	4.0 pps	75 bps	0.76 bps
UBC NDES's resulting cost of capital	42.5%	9.50%	4.04%	49.0%	10.40%	5.10%
DGE's premium	4.0 pps	100 bps	0.77 bps	4.0 pps	75 bps	0.76 bps
DGE's resulting cost of capital	42.5%	9.75%	4.14%	49.0%	10.40%	5.10%

As shown in Table 9 above, the currently approved cost of capital for BMDEU and UBC NDES generally preserves the differential in weighted ROE relative to the Benchmark Utility, with a modest increase of approximately 9 bps.[302] Similarly, the currently approved cost of capital for DGE largely maintains the existing differential, decreasing by only 1 bps,[303] even as the relative ROE premium has been reduced from 100 bps to 75 bps. The

[301] 2014 GCOC Stage 2 Decision, pp. 127-128; 2016 FEI COC Decision, Directives 1 and 2; GCOC Stage 1 Decision, pp. 3; BMDEU 2020–2023 RRRA Decision, p. 34; Order G-84-15.
[302] Calculated as: 76 bps less 67 bps.
[303] Calculated as: 76 bps less 77 bps.

Panel considers these reductions to be acceptable, as the focus of the Panel's determination is not on maintaining absolute spreads, but rather on preserving the relative risk-return relationship between the Benchmark Utility and BMDEU and UCB NDES, and by extension to DGE. This appropriately reflects the Panel's overall finding on the Corix Utilities' business risk relative to the Benchmark Utility in this decision.

3.3.2 Creative Energy

Creative Energy provided submissions in Stage 2 for two groups of entities: (i) small district energy systems (Small DES), and (ii) the Core Steam System (Core TES).[304] The Core TES is discussed separately from the Small DES projects due to the distinct nature of these systems, which are detailed in their respective sections below.

Creative Energy Small DES

The Creative Energy Small DES group includes three TES projects: (i) South Downtown Heating TES (SODO Heating TES); (ii) South Downtown District Cooling System (SODO DCS); and (iii) Creative Energy Mount Pleasant Limited Partnership (CEMP), known as Mount Pleasant District Cooling System (Mount Pleasant DCS).[305]

The SODO Heating TES commenced providing heat and hot water services to the Vancouver House Development in November 2019, while the SODO DCS started offering cooling services to the same development in November 2020. The Vancouver House Development consists of four buildings: a mixed-use building, a residential tower, and two commercial-use buildings.[306] In approximately October 2021, the SODO Heating TES also began serving a fifth building, a residential tower, nearby.[307] In the initial rates decision for the SODO Heating TES and SODO DCS, the BCUC approved a deemed equity component of 42.5 percent (i.e. an equity premium of 4.0 pps) and an ROE premium of 75 bps above the Benchmark Utility (i.e. an allowed return of 9.50 percent). As part of the decision, the BCUC noted this approach was consistent with other rate-regulated TES utilities that share similar risk profiles, with no evidence presented to warrant a different approach.[308]

The Mount Pleasant DCS began providing cooling services for the Main Alley Development located at Main Street and East Fifth Avenue in Vancouver in February 2021. Upon full build-out, the system will serve five buildings: four commercial/light industrial-use buildings and one residential building. The Mount Pleasant DCS is being constructed in four phases, with completion and service to all five buildings in 2029.[309] In the initial rates decision, the BCUC approved CEMP's proposed deemed equity component of 42.5 percent (i.e. an equity premium of 4.0 pps) with an ROE premium of 75 bps over the Benchmark Utility (i.e. an allowed return of 9.50 percent). As was the case with the SODO Heating TES, the BCUC noted this approach was consistent with other

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304 Exhibit B7-8, Creative Energy Evidence, Figure 1, pp. 4–5.
305 Exhibit B7-8, Creative Energy Evidence, Figure 1, p. 5; Exhibit B7-9, BCUC IR 1.1.
306 Creative Energy Application for Heating Rates for the Heating Thermal Energy System and Cooling Rates for the District Cooling System at the Vancouver House Development, Decision and Order G-222-21 dated July 22, 2021 (SODO Heating TES and DCS Rates Decision), pp. 1, 3 and 4.
307 SODO Heating TES and DCS Rates Decision, p. 64.
308 SODO Heating TES and DCS Rates Decision, p. 28.
309 CEMP Rates for the Mount Pleasant DCS Decision accompanying Order G-265-24 dated October 21, 2024 (CEMP Mount Pleasant DCS 2024–2026 Rates Decision), p. 1; CEMP Application for Rates for the Mount Pleasant DCS, Decision and Order G-242-22 dated August 22, 2022 (2022 CEMP Mount Pleasant DCS Rates Decision), p. 1.

rate-regulated TES utilities with similar risk profiles, and no evidence was provided to justify an alternative approach.[310]

Creative Energy did not operate any Small DES projects in 2014 and these projects were not included in the 2014 Stage 2 GCOC Decision.[311] The SODO DCS and Mount Pleasant DCS are 90 to 100 percent electrified and comply fully with the emissions reductions targets set by the City of Vancouver and Clean BC.[312] In contrast, the SODO Heating TES relies on natural gas as a primary energy source and due to its temporary energy center set up, it does not have flexibility to be electrified.[313]

In this proceeding, Creative Energy is proposing to maintain the existing 4.0 pps equity premium and 75 bps ROE premium which results in a deemed equity component of 49.0 percent and an allowed ROE of 10.40 percent for its Small DES projects.[314] Creative Energy supports this proposal with an evaluation of the business risks faced by the Small DES projects, market, competitive, operational, and supply risks. Table 10 summarizes the Small DES projects' previously approved and currently proposed cost of capital values.

Table 10: Previously Approved and Currently Proposed Cost of Capital for the Small DES Projects

	Previously Approved[315]			Currently Proposed[316]		
	Equity Premium (i.e. Deemed Equity Component)	ROE Premium (i.e. Allowed ROE)	Weighted ROE	Equity Premium (i.e. Deemed Equity Component)	ROE Premium (i.e. Allowed ROE)	Weighted ROE
SODO Heating TES	4.0 pps (42.5%)	75 bps (9.50%)	4.04%	4.0 pps (49.0%)	75 bps (10.40%)	5.10%
SODO DCS	4.0 pps (42.5%)	75 bps (9.50%)	4.04%	4.0 pps (49.0%)	75 bps (10.40%)	5.10%
Mount Pleasant DCS	4.0 pps (42.5%)	75 bps (9.50%)	4.04%	4.0 pps (49.0%)	75 bps (10.40%)	5.10%

Creative Energy has evaluated its business risks using a qualitative approach rather than separately attributing risks to the equity premium or ROE premium.[317] Creative Energy provides a business risk assessment of the Small DES projects relative to the Benchmark Utility to support its proposed deemed equity component and allowed ROE using the same risk matrix from Stage 1 and discussed in Section 3.1 of this decision. Creative Energy states that the Small DES projects have lower risk than the Benchmark Utility in areas of political risk, Indigenous right and engagement risk, and energy price risk. However, risks related to business profile, energy supply, economic conditions, demand and market conditions, operating conditions, and regulatory factors are considered higher

310 2022 CEMP Mount Pleasant DCS Rates Decision, p. 27.
311 Exhibit B7-10, BCOAPO IR 9.1.
312 Exhibit B7-12, RCIA 6.1.
313 Exhibit B7-9, BCUC IR 5.1 and 5.2; Exhibit B7-10, BCOAPO IR 3.1.
314 Exhibit B7-8, Creative Energy Evidence, pp. 8, 13, 14; Creative Energy Final Argument, p. 4.
315 SODO Heating TES and DCS Rates Decision, p. 28; 2022 CEMP Mount Pleasant DCS Rates Decision, p. 27.
316 Exhibit B7-8, Creative Energy Evidence, pp. 8, 13, 14; Creative Energy Final Argument, p. 4.
317 Exhibit B7-9, BCUC IR 1.2 and 1.2.1.

for the Small DES projects compared to the Benchmark Utility. Overall Creative Energy concludes that the Small DES projects carry greater overall business risk than the Benchmark Utility.[318]

Creative Energy highlights several new challenges that have emerged since the 2014 GCOC Stage 2 Decision, including rising interest rates, the impact of the COVID-19 pandemic, softening commercial real estate markets, delayed condo presales and new decarbonization mandates. These factors have resulted in project delays, increased costs and overall volatility for Creative Energy's Small DES projects, contributing to increased business risks.[319]

Creative Energy highlights that its Small DES projects face overall business risks due to lower commercial occupancy, which has caused developers to pause or postpone mixed-use developments. These delays directly impact the utility's ability to implement its systems and deploy capital. Compounding this issue is elevated interest rates, which have rendered many previously viable developments unfeasible in the current macroeconomic environment, further hindering Creative Energy's ability to build new TESs.[320]
Despite long term contracts, Creative Energy notes that financial risks remain elevated relative to the Benchmark Utility. The smaller scale of Creative Energy's Small DES projects results in higher overall business and financial risk compared to the Benchmark Utility. Creative Energy adds that these projects are more vulnerable to community development and construction risks, macroeconomic trends, and a small, less diverse customer base. Additionally, with limited access to capital, Creative Energy notes that investors must be compensated with higher deemed equity components and allowed ROEs to account for these elevated risks.[321]
Creative Energy also identifies significant financial risk in the event of customer default, as the Small DES projects typically serve only one or a few customers. Even with long-term service contracts, Creative Energy notes the concentrated customer base means that a default could disproportionately impact the utility's revenue.[322]

Creative Energy also considers the availability of qualified contractors for project development to be limited, with competition for resources within a constrained market increasing project costs and delays.[323] Creative Energy must assume greater responsibility for procurement and project delivery, responsibilities traditionally borne by engineers or contractors.[324] Creative Energy believes these additional risks, combined with regulatory demands, have created a new baseline of higher costs and risks for constructing projects. Accordingly, Creative Energy considers construction risk for its Small DES to be higher than the Benchmark Utility.[325]

Creative Energy views energy supply risks for its Small DES projects to be higher than those faced by the Benchmark Utility, given the shift toward low-carbon technologies such as heat pumps and electric boilers, which increase competition for electrical supply.[326] As electrification efforts grow, Creative energy expects this

[318] Exhibit B7-8, Creative Energy Evidence, Table 2, p. 14.
[319] Exhibit B7-12, RCIA IR 5.1.
[320] Exhibit B7-9, BCUC IR 4.3.
[321] Exhibit B7-8, Creative Energy Evidence, p. 13.
[322] Exhibit B7-8, Creative Energy Evidence, p. 15; Exhibit B7-9, BCUC IR 4.7 and 4.10.
[323] Exhibit B7-8, Creative Energy Evidence, p. 14.
[324] Exhibit B7-9, BCUC IR 4.1.
[325] Exhibit B7-9, BCUC IR 4.1.1.
[326] Exhibit B7-9, BCUC IR 5.3.

risk to increase, presenting ongoing challenges in securing low-carbon energy resources.[327] However, compared to the Benchmark Utility, Creative Energy believes it faces lower political risks, as its Small DES projects, apart from the SODO Heating TES, are low-carbon and meet the requirements of CleanBC and City of Vancouver bylaws.[328] Despite this, Creative Energy's qualitative assessment concludes that the overall business risk for its Small DES projects remains higher than that of the Benchmark Utility.[329]

Positions of Parties

The CEC does not accept that the risk for the Small DES projects has increased at the same rate as the Benchmark Utility's, especially given the significant impact of the energy transition on the Benchmark Utility. While Creative Energy's Small DES projects continue to face certain challenges compared to the Benchmark Utility, primarily due to their smaller size, the CEC argues that the energy transition has actually benefited Creative Energy, as its Small DES projects offer a solution for decarbonization. The CEC asserts that the energy transition has reduced the Small DES projects' risk relative to the Benchmark Utility.[330] As a result, the CEC recommends a deemed equity component of 49.0 percent (i.e. an equity premium of 4.0 pps) and a 50 bps ROE premium (i.e. an allowed ROE of 10.15 percent) for the Small DES projects.[331]

In reply, Creative Energy emphasizes that its Small DES projects face increased risks, relative to the Benchmark Utility, related to community development, construction, macroeconomic trends, a smaller, less diverse customer base and less access to capital. Creative Energy maintains that these factors justify a 49.0 percent equity component and a 50 bps ROE premium.[332]

BCOAPO challenges Creative Energy's claim that the Small DES projects have a higher risk profile than the Benchmark Utility and questions the need to maintain the previously approved premiums. BCOAPO points out that two of the Small DES projects (the Mount Pleasant DCS and SODO DCS) are entirely electric, while the SODO Heating TES relies exclusively on natural gas, a material difference that Creative Energy's risk analysis does not adequately address.[333] BCOAPO agrees with Creative Energy that its Small DES projects face lower political risk than the Benchmark Utility. It acknowledges that the SODO Heating TES operates a temporary energy centre with no plans for long-term use of the current natural gas-fired boilers, and the SODO DCS and Mount Pleasant DCS comply with City of Vancouver and CleanBC emission targets, thus mitigating the political risk typically associated with TES utilities using natural gas. Based on these factors, BCOAPO argues that maintaining the previously approved equity premium and ROE premium is not justified. Instead, it recommends reducing the deemed equity component for the SODO DCS and Mount Pleasant DCS to no more than 47.0 percent (i.e. an equity premium of 2.0 pps), paired with an allowed ROE of 10.4 percent (i.e. an ROE premium of 75 bps) to reflect their electric source.[334] For the SODO Heating TES, BCOAPO recommends a deemed equity component of

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[327] Exhibit B7-8, Creative Energy Evidence, p. 14; Exhibit B7-1, The CEC IR 9.2.
[328] Exhibit B7-8, Creative Energy Evidence, p. 15; Exhibit B7-9, BCUC IR 5.3.
[329] Exhibit B7-9, BCUC IR 5.3.
[330] The CEC Final Argument, p. 35.
[331] The CEC Final Argument, p. 36.
[332] Creative Energy Reply, pp. 6, 8–9.
[333] BCOAPO Final Argument, pp. 57.
[334] BCOAPO Final Argument, p. 58.

48.0 percent (i.e. an equity premium of 3.0 pps) and an allowed ROE of 10.4 percent (i.e. an ROE premium of 75 bps) to reflect its natural gas source.[335]

In reply to BCOAPO, Creative Energy submits that BCOAPO overlooks the interconnected risks that all three systems face.[336] These include higher risks associated with community development and construction, greater exposure to macroeconomic trends, a smaller, less diverse customer base, and less access to capital. Creative Energy adds that these factors contribute to the overall risk profile of the Small DES projects, underscoring the need of its proposed equity and ROE premium. [337]

RCIA acknowledges that a 75 bps ROE premium for the Small DES projects may be acceptable. However, RCIA also contends that Creative Energy's proposed ROE premium of 75 bps and equity premium of 4.0 pps are not sufficiently justified by the evidence provided. RCIA recommends reducing the ROE premium to 50 bps and proposes an equity discount of 1.5 percent. This would result in a deemed equity component of 43.5 percent and an allowed ROE of 10.15 percent.[338]

In reply to RCIA, Creative Energy contends that RCIA's recommendations lack supporting evidence, both qualitative and quantitative, and should therefore be rejected. Creative Energy highlights inconsistencies in RCIA's stance, noting that while RCIA initially recommended a premium for the Small DES, it later argued in its final argument that Creative Energy's evidence was insufficient to justify a premium. Additionally, Creative Energy points out that RCIA acknowledges that small TES utilities, which include the Small DES projects, generally have a higher risk profile than the Benchmark Utility.[339]

Panel Determination

The Panel notes that Creative Energy's Small DES projects were assigned an ROE premium of 75 bps and equity premium of 4.0 pps when they were last assessed. This determination aligned with the approach used for other rate-regulated TES projects with similar risk profiles, as no evidence provided at the time justified an alternative approach.

In this proceeding, the Panel has reviewed whether the business risk profile for each of the Small DES projects has materially changed since their last review. While the Panel acknowledges that macroeconomic and industry-specific pressures such as competition for skilled resources may have changed, these factors would apply equally to the Benchmark Utility. **Thus, the Panel does not consider these changes sufficient to substantiate an increase in the overall risk profile for the Small DES projects compared to the Benchmark Utility.**

The Panel acknowledges that while heating and cooling energy systems have certain operational differences, these do not materially impact the overall business risk profile of these systems. Both heating and cooling systems within Creative Energy's Small DES projects share a degree of capital intensity, reliance on a limited customer base, and exposure to macroeconomic conditions. These similarities result in comparable sensitivities

[335] BCOAPO Final Argument, p. 59.
[336] Creative Energy Reply, pp. 10–11.
[337] Creative Energy Reply, p. 6.
[338] RCIA Final Argument, Table 8 and Table 10, pp. 44, 48, 49–50.
[339] Creative Energy Reply, pp. 6–7.

to business risk, customer attrition, and access to capital, which the Panel views as dominant in shaping the risk profile of the Small DES projects.

In addition, the Panel notes that energy transition policies have introduced new considerations. Although these policies may have a more direct impact on the SODO Heating TES due to its reliance on natural gas use, this distinction does not substantively increase the risk for the SODO Heating TES relative to the Mount Pleasant DCS and SODO DCS, which rely on electricity. Equally, the Panel does not consider that the Mount Pleasant DCS and SODO DCS that use electricity as an energy source should be awarded a lower allowed return than the SODO Heating TES due only to its difference in energy source.

The Panel considers that the inherent differences between heating and cooling systems within the Small DES projects are not significant enough to merit a differentiated approach when considering overall business risks. Each Small DES project shares underlying risk characteristics that are more consequential to the overall risk profile, primarily limited customer bases, constraints on access to capital, and heightened susceptibility to economic volatility. The Panel acknowledges that while some systems rely on different energy sources, the limited scale and concentrated customer base contribute to comparable business risks across all of Creative Energy's Small DES projects. Accordingly, the Panel considers these projects to face the same level of risk relative to the Benchmark Utility, justifying the continued application of the previously assessed equity premium without project-specific differentiation.

The Panel finds that the relative risk differential between Creative Energy's Small DES projects and the Benchmark Utility remains unchanged. The Panel therefore sees no material basis to differentiate the allowed returns among the Small DES projects. Accordingly, **the Panel approves the continuation of a 4.0 pps equity premium, resulting in a deemed equity component of 49.0 percent for the three Creative Energy Small DES projects**.

As discussed in Section 3.1, the Panel have determined that a 75 bps ROE premium is appropriate to reflect the small size premium. We have applied the same ROE premium here for the Core TES, which results in an allowed ROE of 10.40 percent.

Table 11 below provides a comparison of the currently approved versus previously approved cost of capital for the Small DES. The table lays out the Small DES's cost of capital beginning with the Benchmark Utility's cost of capital plus the approved equity and ROE premiums for the Small DES to arrive at the Small DES's cost of capital.

Table 11: Comparison of Previously and Currently Approved Cost of Capital for the Small DES

	Previously Approved[340]			Currently Approved		
	Deemed Equity Component	Allowed ROE	Weighted ROE	Deemed Equity Component	Allowed ROE	Weighted ROE
Benchmark Utility's cost of capital (for comparison)	38.5%	8.75%	3.37%	45.0%	9.65%	4.34%
SODO Heating's premium	4.0 pps	75 bps	0.67 bps	4.0 pps	75 bps	0.76 bps

[340] 2016 FEI COC Decision, Directives 1 and 2; GCOC Stage 1 Decision, p. 3; SODO Heating TES and DCS Rates Decision, p. 28; 2022 CEMP Mount Pleasant DCS Rates Decision, p. 27.

SODO Heating's resulting cost of capital	42.5%	9.50%	4.04%	49.0%	10.40%	5.10%
SODO DCS's premium	4.0 pps	75 bps	0.67 bps	4.0 pps	75 bps	0.76 bps
SODO DCS's resulting cost of capital	42.5%	9.50%	4.04%	49.0%	10.40%	5.10%
Mount Pleasant DCS's premium	4.0 pps	75 bps	0.67 bps	4.0 pps	75 bps	0.76 bps
Mount Pleasant DCS's resulting cost of capital	42.5%	9.50%	4.04%	49.0%	10.40%	5.10%

As shown in Table 11 above, the currently approved cost of capital for the Small DES generally preserves the differential between their and the Benchmark Utility's weighted ROE from the previously approved values with an immaterial increase of approximately 9 bps.[341] This appropriately reflects the Panel's overall finding on the Small DES's business risk relative to the Benchmark Utility in this decision.

Creative Energy Core TES

The Core TES consists of a centralized natural gas boiler plant located at 720 Beatty Street (Core Steam Plant) connected to an underground network of steam distribution piping that supplies thermal energy to more than 200 buildings in downtown Vancouver. This system also extends to a hot water distribution network in Northeast False Creek, providing thermal energy to four buildings in the area through steam generation from the Core Steam Plant. Currently, the Core Steam Plant relies entirely on natural gas.[342]

The BCUC last reviewed the cost of capital for the Core TES in the 2014 GCOC Stage 2 Decision, in which it approved a deemed equity component of 42.5 percent (i.e. an equity premium of 4.0 pps) and an ROE premium of 75 bps above the Benchmark Utility (i.e. an allowed ROE of 9.50 percent) for the Core TES. This decision reflected the competitive environment in which the Core TES operated at the time. Without mandatory customer connection contracts, Creative Energy faced direct competition from BC Hydro and FEI, making customer retention challenging and elevating the system's business risk. The decision also acknowledged the Core TES's transition towards cleaner energy sources and anticipated growing interest from government bodies in alternative energy systems, potentially driving new policies, incentives and greater competition within the market.[343]

In this proceeding, Creative Energy is proposing a deemed equity component of 49.0 percent (i.e. an equity premium of 4.0 pps) and an ROE premium of 125 bps above the Benchmark Utility (i.e. an allowed ROE of 10.90 percent) for its Core TES.[344] This maintains the existing equity premium of 4.0 pps, but increases ROE premium by 50 bps from the 2014 GCOC Stage 2 Decision.[345] Creative Energy supports this proposal with an evaluation of the business risks faced by the Core TES, including supply, demand and market, political, and operational risks. Table 12 summarizes the Small DES projects' previously approved and currently proposed cost of capital.

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[341] Calculated as: 76 bps less 67 bps.
[342] Exhibit B7-8, p. 9; Creative Energy Application for Rates for the Core Steam and Northeast False Creek Systems, Decision and Order G-345-22A dated November 29, 2022, p. 1.
[343] 2014 GCOC Stage 2 Decision, pp. 131–132.
[344] Exhibit B7-8, Creative Energy Evidence, pp. 8, 13–14; Creative Energy Final Argument, p. 4.
[345] Exhibit B7-8, Creative Energy Evidence, pp. 8, 13–14; Creative Energy Final Argument, p. 4.

Table 12: Previously Approved and Currently Proposed Cost of Capital for the Core TES

	Previously Approved[346]			Currently Proposed[347]		
	Equity Premium (i.e. Deemed Equity Component)	ROE Premium (i.e. Allowed ROE)	Weighted ROE	Equity Premium (i.e. Deemed Equity Component)	ROE Premium (i.e. Allowed ROE)	Weighted ROE
Core TES	4.0 pps (42.5%)	75 bps (9.50%)	4.04%	4.0 pps (49.0%)	125 bps (10.90%)	5.34%

In its submissions for the Core TES in this proceeding, Creative Energy did not separate the impact of business risks on the deemed equity component or allowed ROE given their interrelationship.[348] Instead, Creative Energy completed a qualitative assessment of overall business risks, noting that increased risks could be reflected in either the equity premium or the ROE premium.[349]

Creative Energy provides a business risk assessment of the Small DES projects relative to the Benchmark Utility to support its proposed deemed equity component and allowed ROE using the same risk matrix from Stage 1 and discussed in Section 3.1 of this decision.[350] Creative Energy specifies that the Core TES has lower risk than the Benchmark Utility concerning Indigenous right and engagement risk, with similar risk levels for energy supply and energy price risk. However, risks associated with business profile, demand and market conditions, and operating conditions are considered higher for the Core TES compared to the Benchmark Utility, with political and regulatory risk assessed as significantly higher. Overall, Creative Energy concludes that the Core TES carries "significantly higher" overall business risk than the Benchmark Utility.[351]

Creative Energy notes that since 2014, its business risks have grown due to the energy transition and increasing customer demand risks. Accelerating government decarbonization policies have further heightened political, regulatory and therefore overall business risks relative to the Benchmark Utility.[352]

While the Core TES is well-established, it requires substantial investment in both its generation and distribution to support the transition to a low-carbon product, ensure future reliability, and replace aging equipment.[353] Unlike other utilities, the Core TES operates entirely within the City of Vancouver, where it faces stringent decarbonization policies and heightened business risks, particularly in customer retention and forecast revenues.[354]

Creative Energy highlights that the pace of the energy transition presents significantly greater risk to its Core TES than to its other rate-regulated projects and the Benchmark Utility.[355] As an early adopter of energy transition

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[346] 2014 GCOC Stage 2 Decision, p. 132.
[347] Exhibit B7-8, Creative Energy Evidence, pp. 8, 13–14; Creative Energy Final Argument, p. 4.
[348] Exhibit B7-9, BCUC IR 1.2.
[349] Exhibit B7-9, BCUC IR 1.2.1.
[350] Exhibit B7-8, Creative Energy Evidence, Table 1, p. 10.
[351] Exhibit B7-8, Creative Energy Evidence, Table 1, p. 10.
[352] Exhibit B7-8, p. 8.
[353] Exhibit B7-8, Creative Energy Evidence, p. 9.
[354] Exhibit B7-8, Creative Energy Evidence, p. 9.
[355] Exhibit B7-8, Creative Energy Evidence, p. 10; Exhibit B7-9, BCUC IR 3.3.

policies, the City of Vancouver is expected to implement increasingly stringent greenhouse gas intensity and efficiency standards in the coming years. This situation not only exacerbates the risk of load attrition but also threatens the long-term viability of the Core TES.[356] Creative Energy believes that customer growth and retention will only be feasible by providing a low-carbon thermal energy product that meets both provincial and City of Vancouver emission regulations. In September 2022, Creative Energy received BCUC approval for a Certificate of Public Convenience and Necessity to add two electric boilers to the Core Steam Plant and plans to further increase the number of electric boilers, along with implementing hot water conversion in order to meet these emissions regulations.[357] Currently, Creative Energy manages fuel costs and curtailment risks through a gas contract with FEI. However, the utility will need to explore low-carbon alternatives, which will require new agreements and significant investments.[358] Creative Energy adds that it faces substantial regulatory and business risks as it seeks to decarbonize the Core TES.[359]

Creative Energy highlights that demand and market risk for the Core TES are elevated due to the absence of mandatory connection zoning, which allows customers to opt for competing options or develop their own systems. It further notes that the Core TES's limited service area, unlike the Benchmark Utility's broader reach, increases risk due to geographic constraints, as lengthy piping connections are not always economically viable.[360] Additionally, rising competition in Vancouver, along with advancements in independent heating technologies, has reduced reliance on the Core TES.[361] After the pandemic, demand for steam energy has declined, driven by rising costs, corporate environmental, social, and governance commitments, and greater climate change awareness.[362] Many customers, free from contract obligations, can disconnect with just six months' notice, emphasizing the need for a low-carbon offering to meet both provincial and City of Vancouver regulations.[363]

Creative Energy considers that rising inflationary pressures and elevated interest rates have heightened economic risks for the Core TES, particularly given its limited service area and constrained geography.[364] While Creative Energy addresses inflationary impacts through the revenue requirements process, customers may respond by reducing consumption or disconnecting from the system. Creative Energy highlights that this could lead to further rate increases as costs are spread over a lower load forecast in the future.[365]

Creative Energy faces challenges maintaining quality service without significant investments due to its small size.[366] Creative Energy notes that the resilience of the Core TES relies on its information technology services, including operational technology and cybersecurity. Due to historical underinvestment, significant investments are needed to support operations.[367] Creative Energy has also recently initiated its smart metering program.[368]

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[356] Exhibit B7-8, Creative Energy Evidence, pp. 10–11; Exhibit B7-9, BCUC IR 2.5, 3.3, 3.6.
[357] Exhibit B7-9, BCUC IR 2.5 and 3.3; Order C-5-22.
[358] Exhibit B7-8, Creative Energy Evidence, p. 12.
[359] Exhibit B7-9, BCUC IR 2.5, 3.9.
[360] Exhibit B7-9, BCUC IR 2.3, 2.6, 2.8 and 2.9.1.
[361] Exhibit B7-8, Creative Energy Evidence, p. 9.
[362] Exhibit B7-8, Creative Energy Evidence, p. 10; Exhibit B7-9, BCUC IR 2.5.
[363] Exhibit B7-8, Creative Energy Evidence, p. 10; Exhibit B7-9, BCUC IR 2.5.
[364] Exhibit B7-8, Creative Energy Evidence, p. 12.
[365] Exhibit B7-9, BCUC IR 2.1.
[366] Exhibit B7-8, Creative Energy Evidence, p. 12.
[367] Exhibit B7-8, Creative Energy Evidence, pp. 12–13.
[368] Exhibit B7-8, Creative Energy Evidence, p. 13.

These investments are typically addressed through revenue requirement applications, with any unrecovered costs impacting shareholders and the utility's financial stability.[369]

Positions of Parties

The CEC does not agree that the Core TES faces significantly higher risks than the Benchmark Utility, noting that the Benchmark Utility also encounters substantial risks related to the energy transition and other factors. The CEC contends that the Benchmark Utility bears greater risks compared to the Core TES and argues that Creative Energy's decarbonization efforts do not justify its proposed ROE premium. However, the CEC agrees that the small size of the Core TES warrants a premium in the deemed equity component. The CEC recommends maintaining the 49.0 percent deemed equity component (i.e. an equity premium of 4.0 pps) but lowering the ROE premium to 50 bps (i.e. an allowed ROE of 10.15 percent).[370]

In reply to the CEC, Creative Energy highlights the significantly higher political and regulatory risks it faces due to its sole operation within the City of Vancouver and the rapid pace of the energy transition. Creative Energy emphasizes that, unlike the Benchmark Utility, the Core TES must contend with the lack of mandatory connections, and elevated customer attrition risks that impact retention.[371]

BCOAPO challenges Creative Energy's assessment of increased business risk and the requested adjustments to the cost of capital. BCOAPO highlights that Core TES customers are not the only ones facing inflationary pressures, noting that FEI and its customers are subject to the same economic conditions.[372] It argues that the differential between FEI and the TES Default already recognizes the higher risks for smaller geographically constrained systems like Creative Energy's Core TES.[373] In terms of political risks, BCOAPO acknowledges Creative Energy's concerns about the energy transition and the City of Vancouver's restrictive bylaws on natural gas. However, Creative Energy has already implemented mitigation strategies, such as adding electric boilers. BCOAPO also addresses the demand and market conditions and submits that post-pandemic changes in occupancy and consumption patterns, along with competing offerings, relate to economic conditions already discussed.[374] BCOAPO considers the proposed 125 bps ROE premium to be "excessive". Instead, BCOAPO recommends maintaining the 4.0 pps equity premium (i.e. a deemed equity component of 49.0 percent) and increasing the ROE premium to only 100 bps (i.e. an allowed ROE of 10.65 percent).[375]

In reply to BCOAPO, Creative Energy emphasizes that the Core TES faces significantly higher risks compared to the Benchmark Utility. It highlights the necessity for infrastructure investments to address aging infrastructure and ensure compliance with the City of Vancouver's energy transition policies. Additionally, the Core TES faces significant regulatory, construction, and development challenges associated with upgrading the Core TES infrastructure. Creative Energy disagrees with BCOAPO's recommendations, noting that BCOAPO has not

[369] Exhibit B7-9, BCUC IR 2.4.
[370] The CEC Final Argument, p. 31.
[371] Creative Energy Reply, pp. 8–9.
[372] BCOAPO Final Argument, p. 54.
[373] BCOAPO Final Argument, p. 56.
[374] BCOAPO Final Argument, p. 55.
[375] BCOAPO Final Argument, p. 57.

provided evidence to justify its proposed figures and asserts that the recommendations should reflect the actual risks faced by the Core TES.[376]

RCIA submits that Creative Energy's proposed equity premium of 4.0 pps and ROE premium of 125 bps relative to the Benchmark Utility are not supported by the evidence. Instead, RCIA recommends an equity premium of 1.0 pps (i.e. a deemed equity component of 46.0 percent) and an ROE premium of 75 bps (i.e. an allowed ROE of 10.40 percent). While small TES utilities generally have a higher risk profile than the Benchmark Utility, RCIA argues that the Core TES is not exceptional amongst small TES utilities.[377]

In reply to RCIA, Creative Energy submits that RCIA's recommendations should be dismissed, as they lack support.[378] Creative Energy also highlights inconsistencies, noting that RCIA initially recommended a premium for the Core TES but later claimed Creative Energy's evidence was insufficient to support it.[379] Furthermore, Creative Energy emphasizes that the Core TES is geographically constrained to the City of Vancouver and subject to stringent GHG regulations.[380]

Panel Determination

The Panel finds that the business risks associated with the Core TES are higher relative to the Benchmark Utility and have increased since the last assessment in 2014. The Panel recognizes that the transition to decarbonization is rapidly evolving, and operating within the city of Vancouver subjects the Core TES to stringent decarbonization requirements imposed by both provincial and municipal regulations. This requires Creative Energy to adapt its infrastructure and service offerings to remain competitive and compliant to decarbonization requirements. The pace of this transition places substantial pressure on the utility, and although it has been granted a Certificate of Public Convenience and Necessity for its Core Steam Plant Decarbonization project in 2022,[381] the complexities of constructing and placing into operation such projects present significant challenges. The complexities involved in implementing this project coupled with the current government policy timelines intensify the operational and regulatory challenges contributing to an increase in business risks faced by the Core TES since its last assessment in 2014.

Additionally, the Panel notes that customers of the Core TES are not bound by long-term contractual obligations, allowing them to disconnect from services at their discretion. While this risk of customer attrition was also present in 2014, it has increased in today's rapidly evolving energy transition landscape where Core TES customers have viable low-carbon energy alternatives. Customers may perceive they can better manage energy transition requirements independently, and choose to disconnect services from Creative Energy, compounding the risk of customer attrition for the Core TES. As the customer base diminishes, remaining customers could face increased rates, potentially leading to a detrimental cycle for the Core TES, further underscoring the heightened business risks for the Core TES since its last assessment in 2014.

[376] Creative Energy Reply, p. 10.
[377] RCIA Final Argument, pp. 48 and 50.
[378] Creative Energy Reply, p. 6.
[379] Creative Energy Reply, pp. 6–7.
[380] Creative Energy Reply, p. 7.
[381] Order C-5-22.

Given these heightened risks associated with the energy transition and customer attrition, the Panel recognizes that these factors necessitate additional consideration in assessing the fair return for Creative Energy to ensure the financial integrity and capital attraction of the Core TES. Notwithstanding our assessment that Creative Energy's Core TES faces heightened risks, we maintain that these business risks should not be incorporated into the ROE premium. As discussed in Section 3.1, we have determined that a 75 bps ROE premium is appropriate to reflect the small size premium. We have applied the same ROE premium here for the Core TES to reflect size, which results in an allowed ROE of 10.4 percent. Consistent with our approach, we view that increased business risks should be captured only within the equity premium and should not also be reflected in the utility's allowed ROE.

The Panel sets a 6.0 pps equity premium, resulting in a 51.0 percent deemed equity component for the Core TES. This amount approximates Creative Energy's proposed weighted ROE of 5.34 percent[382] while maintaining the allowed ROE of 10.40 precent as previously set. A 51.0 percent deemed equity component places the Core TES above other TES utilities but below PNG-West and PNG(NE) Tumbler Ridge, which is reasonable given the Core TES's risks relative to those PNG utilities.

Table 13 below provides a comparison of the currently approved versus previously approved cost of capital for the Core TES. The table also sets out the Core TES's cost of capital beginning with the Benchmark Utility's cost of capital plus the approved equity and ROE premiums for the Core TES to arrive at the Core TES's cost of capital.

Table 13: Comparison of Previously and Currently Approved Cost of Capital for Core TES

	Previously Approved[383]			Currently Approved		
	Deemed Equity Component	Allowed ROE	Weighted ROE	Deemed Equity Component	Allowed ROE	Weighted ROE
Benchmark Utility's cost of capital (for comparison)	38.5%	8.75%	3.37%	45.0%	9.65%	4.34%
Core TES's premium	4.0 pps	75 bps	67 bps	6.0 pps	75 bps	96 bps
Core TES's resulting cost of capital	42.5%	9.50%	4.04%	51.0%	10.40%	5.30%

As shown in Table 13 above, the currently approved cost of capital for the Core TES increases the differential between its and the Benchmark Utility's weighted ROE from the previously approved values by 29 bps.[384] This appropriately reflects the Panel's overall finding on the Core TES's business risk relative to the Benchmark Utility in this decision.

3.3.3 River District Energy

RDE is a limited partnership formed in February 2011 under the laws of BC for the purpose of developing, owning, and operating a district energy utility system located in the River District community in southeast

382 Calculated as: 49.0 multiplied by 10.90.
383 2016 FEI COC Decision, Directives 1 and 2; 2014 GCOC Stage 2 Decision, p. 132.
384 Calculated as: 96 bps less 67 bps.

Vancouver. The general partner of RDE is River District Energy Ltd., a wholly owned subsidiary of Wesgroup Properties Limited Partnership.[385] RDE operates a 128-acre master-planned community which is expected to reach full build-out by the mid-2040s. RDE currently provides space heating and domestic hot water to 20 customer buildings with residential and retail uses with a total connected floor area of 3.1 million square feet. RDE will continue to expand its customer base to 55 buildings, increasing its total connected floor area to approximately 9.3 million square feet at full build-out.[386]

RDE is currently investing approximately $30 million in the construction of its new, permanent community energy centre, which will approximately triple RDE's rate base over a three-year period.[387] The new community energy centre will use thermal energy produced from waste heat generated at Metro Vancouver's waste-to-energy facility in Burnaby, BC. The thermal energy will be purchased by RDE from Metro Vancouver Regional District (MVRD) under a long-term thermal energy sale and purchase agreement between MVRD and RDE dated December 2021. MVRD will deliver the thermal energy to RDE at the new community energy centre in the form of hot water through a closed-loop pipeline delivery system.[388]

The existing cost of capital for RDE was determined as part of the 2014 GCOC Stage 2 Decision. The BCUC set RDE's deemed equity component at 42.5 percent (i.e. an equity premium of 4.0 pps) and its ROE premium at 75 bps above the Benchmark Utility (i.e. an allowed ROE of 9.50 percent), which was consistent with the TES minimum default at the time.[389]

In this proceeding, RDE is proposing a deemed equity component and allowed ROE that reflect the same risk premiums over the Benchmark Utility of 4.0 pps and 75 basis points, respectively, established by the BCUC in the 2014 GCOC Stage 2 Decision.[390] This results in a deemed equity component of 49.0 percent and an allowed ROE of 10.40 percent. Table 14 summarizes RDE's previously approved and currently proposed cost of capital.

Table 14: Previously Approved and Currently Proposed Cost of Capital for RDE

	Previously Approved[391]			Currently Proposed[392]		
	Equity Premium (i.e. Deemed Equity Component)	ROE Premium (i.e. Allowed ROE)	Weighted ROE	Equity Premium (i.e. Deemed Equity Component)	ROE Premium (i.e. Allowed ROE)	Weighted ROE
RDE	4.0 pps (42.5%)	75 bps (9.50%)	4.04%	4.0 pps (49.0%)	75 bps (10.40%)	5.10%

RDE provides a business risk assessment comparing small TES utilities to the Benchmark Utility, including an assessment of the changes in small TES utilities' business risks since its last cost of capital proceeding in 2014. RDE presents its business risks assessment consistent with the business risk categories used in Stage 1 and

[385] RDE Application for a Certificate of Public Convenience and Necessity dated June 30, 2022, p. 6.
[386] Exhibit B8-5, RDE Evidence, p. 4.
[387] Exhibit B8-5, RDE Evidence, p. 10.
[388] RDE Application for a Certificate of Public Convenience and Necessity dated June 30, 2022, p. 1.
[389] 2014 GCOC Stage 2 Decision, p. 134.
[390] Exhibit B8-5, RDE Evidence, p. 17.
[391] 2014 GCOC Stage 2 Decision, p. 134.
[392] Exhibit B8-5, RDE Evidence, p. 17.

referenced in Section 3.1 of this decision.[393] RDE states that small TES utilities' risk is similar to FEI for economic conditions risk, political risk, and Indigenous rights and engagement risk. RDE states that small TES utilities' risk is higher than FEI for the following risks: business profile, energy price, demand/market, energy supply, operating, and regulatory.[394] When comparing the risks of small TESs against 2014, RDE submits all risks are higher with the exception of business profile risk which is similar to what it was in 2014.[395]

RDE submits, regarding risks specific to RDE, that its political risk is higher than in 2014 and is higher than the Benchmark Utility.[396] RDE explains that it is required to adhere to the City of Vancouver's low-carbon energy system requirements, which RDE does through its connection to the waste-to-energy facility. However, there is a risk that the City of Vancouver may alter its position on the waste-to-energy facility, no longer deeming the waste heat from mass burn of municipal solid waste to be low-carbon and therefore not compliant with the low-carbon energy system requirements. RDE's exposure to regulatory risk specific to the City of Vancouver is significant because changes to the regulatory regime, which RDE cannot influence, could have significant negative consequences for RDE. Further, RDE elaborates that its connection to a single source of low-carbon energy for its baseload service at MVRD's waste-to-energy facility exposes RDE to incremental regional and municipal government regulatory and political risks not faced by other TES utilities.[397] RDE submits that the inherent uncertainty in the energy transition and lack of a clear pathway through the transition gives rise to political risk for small TES utilities. RDE explains that although the public policy response is strengthening, climate-related public policy remains "highly contentious and uncertain."[398]

RDE states that its demand/market risk is higher than in 2014 and higher than the Benchmark Utility. There is uncertainty in RDE's demand growth materializing since future connections are contingent upon broader market conditions for real estate development, whereas the Benchmark Utility would never experience such rapid growth nor growth predicated on future growth spanning decades.[399]

On the other hand, RDE submits that the differential between FEI's energy supply risk and RDE's supply risk has decreased compared to the differential in 2014 because of RDE entering into a thermal energy sale and purchase agreement with MVRD.[400] RDE submits that its business profile risk is similar to what it was in 2014, since the increase in demand from the higher connected floor area approximately balances the reduction in demand which resulted from the introduction of the Zero Emissions Building Plan.[401]

[393] Exhibit B8-5, RDE Evidence, p. 3.
[394] Exhibit B8-5, RDE Evidence, Table 1, p. 4.
[395] Exhibit B8-5, RDE Evidence, Table 1, p. 4.
[396] Exhibit B8-5, RDE Evidence, p. 6.
[397] Exhibit B8-5, RDE Evidence, p. 17.
[398] Exhibit B8-5, RDE Evidence, p. 7.
[399] Exhibit B8-5, RDE Evidence, p. 10.
[400] Exhibit B8-8, BCOAPO IR 7.2.
[401] Exhibit B8-8, BCOAPO IR 1.1.

Positions of Parties

Interveners provided various submissions on the overall business risk assessment of RDE, with recommended values ranging from an equity discount of -1.0 pps to an equity premium of 4.0 pps, and a recommended ROE premium of 50 bps to 75 bps.[402]

BCOAPO states that the community energy centre represents a significant expansion to meet RDE's projected growth. RDE's reliance on developer activity for this growth increases its demand/market risk, but RDE is insulated from competition in supplying new developments when they occur.[403] BCOAPO submits that RDE's unique characteristics have altered its business risks such that they are now less than those of a TES Default (i.e. a TES relying on natural gas). Therefore, BCOAPO recommends a deemed equity component of 47.0 percent and an allowed ROE of 10.40 percent.[404] RDE did not specifically address BCOAPO's final argument in its reply.

The CEC submits that a deemed equity component of 49.0 percent and an allowed ROE of 10.15 percent would be appropriate for RDE.[405] The CEC does not elaborate on the proposed return for RDE, but makes the same proposed deemed equity component and allowed ROE for the TES Default and explains that TES in general do not have the same risk profile as FEI due to its gas supply business and related greenhouse gas emissions.[406] RCIA submits that RDE's energy transition risks are not as high as FEI's, and that a long-term contract with a historically stable supplier does not constitute elevated risk to the extent that RDE claims.[407] RCIA recommends an equity discount of -1.0 pps, resulting in a deemed equity component of 44.0 percent, and an ROE premium of 75 bps, resulting in an allowed ROE of 10.40 percent.[408]

In reply to RCIA and the CEC, RDE submits that both parties' arguments reduce RDE's energy transition risk solely to the risk associated with the carbon intensity of the utility's energy source without considering the significant uncertainty that remains even with low-carbon sources of energy. RDE submits that uncertainty in the timing in cost recovery, nature of government policy (specifically carbon pricing and building greenhouse gas emissions requirements), and the pathway to be followed in the energy transition do not inherently result in RDE being exposed to a lower overall energy transition risk than FEI. RDE submits that its energy transition risks may be different to FEI's but are, in these early stages of the energy transition, no less material.[409]

Panel Determination

The Panel finds that RDE's overall business risk continues to be higher than the Benchmark Utility, but the risk differential has not materially changed since its last cost of capital proceeding in 2014. The Panel agrees with RDE that it faces higher political risk than the Benchmark Utility due to its connection to MVRD's waste-to-energy facility, higher demand/market risk due to its construction of the new community energy centre, but lower energy supply risk from entering into a thermal energy sale and purchase agreement with MVRD since 2014. The Panel also recognizes that RDE is in the process of tripling its rate base, which involves development,

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402 BCOAPO Final Argument, p. 53; CEC Final Argument, p. 34; RCIA Final Argument, p. 51.
403 BCOAPO Final Argument, p. 53.
404 BCOAPO Final Argument, p. 53.
405 The CEC Final Argument, p. 34.
406 The CEC Final Argument, p. 18.
407 RCIA Final Argument, pp. 51–52.
408 RCIA Final Argument, p. 51.
409 RDE Reply Argument, p. 2.

construction and operating risks not faced by the Benchmark Utility with its mature and established gas distribution system. With regards to energy transition, the Panel observes that the current government policies around energy transition are not exclusively applicable to gas utilities and may impact all utilities in different ways. Since policies around energy transition are relatively new, the Panel recognizes that there are risks faced by all utilities from the uncertainty with newly implemented and evolving government policies.

On balance, the Panel finds RDE's risks to be equally higher than the Benchmark Utility as they were in 2014, which warrants maintaining the previously approved equity premium. **The Panel sets a 4.0 pps equity premium, resulting in a 49.00 percent deemed equity component for RDE.**

As discussed in Section 3.1, we have determined that a 75 bps ROE premium is appropriate to reflect the small size premium. We have applied the same ROE premium here for RDE, which results in an allowed ROE of 10.40 percent.

Table 15 below provides a comparison of the currently approved versus previously approved cost of capital for RDE. The table lays out RDE's cost of capital beginning with the Benchmark Utility's cost of capital plus the approved equity and ROE premiums for RDE to arrive at RDE's cost of capital.

Table 15: Comparison of Previously and Currently Approved Cost of Capital for RDE

	Previously Approved[410]			Currently Approved		
	Deemed Equity Component	Allowed ROE	Weighted ROE	Deemed Equity Component	Allowed ROE	Weighted ROE
Benchmark Utility's cost of capital (for comparison)	38.5%	8.75%	3.37%	45.0%	9.65%	4.34%
RDE's premium	4.0 pps	75 bps	67 bps	4.0 pps	75 bps	76 bps
RDE's resulting cost of capital	42.5%	9.50%	4.04%	49.0%	10.40%	5.10%

As shown in Table 15 above, the currently approved cost of capital for RDE generally preserves the differential between its and the Benchmark Utility's weighted ROE from the previously approved values with an immaterial change of approximately 9 bps.[411] This appropriately reflects the Panel's overall finding on RDE's business risk relative to the Benchmark Utility in this decision.

3.3.4 TES Default

In the 2014 GCOC Stage 2 Decision, the BCUC found that TES projects "are more similar than different" and, for regulatory efficiency, established a minimum TES Default structure.[412] The BCUC established the TES Default cost of capital as an equity premium of 4.0 pps, resulting in a deemed equity component of 42.5 percent, and an ROE premium of 75 bps, resulting in an allowed ROE of 9.50 percent for the minimum TES Default.[413] This TES Default was subsequently, but not automatically, adopted as the cost of capital for certain TES projects that began providing service after the 2014 GCOC Stage 2 Decision. Some of those TES projects have been previously discussed in this decision. As a result of the BCUC's TES Regulatory Framework Guidelines[414], the determinations from the 2014 GCOC Stage 2 Decision related to the TES Default only apply to the utilities identified as Stream B, or rate-regulated, TES utilities.[415]

In the 2014 GCOC Stage 2 Decision,[416] the BCUC also accepted the validity of the eight TES-specific risk factors put forward by Ms. McShane, the FAES's cost of capital expert at the time, which reflect the higher business risk of TES projects relative to the Benchmark Utility:

1. Their greenfield characteristics, including the lack of an established customer base;
2. Reliance on non-traditional rate structures to make the projects competitive and provide an opportunity to recover the related investment;

[410] 2016 FEI COC Decision, Directives 1 and 2; GCOC Stage 1 Decision, pp. 3; 2014 GCOC Stage 2 Decision, p. 134.
[411] Calculated as: 76 bps less 67 bps.
[412] 2014 GCOC Stage 2 Decision, p. 27.
[413] 2014 GCOC Stage 2 Decision, p. 124.
[414] Thermal Energy Systems Framework Revisions to the Thermal Energy Systems Regulatory Framework Guidelines, Order G-27-15 dated March 2, 2015.
[415] 2014 GCOC Stage 2 Decision, p. 116.
[416] 2014 GCOC Stage 2 Decision, p. 123.

3. Small size of individual TES projects, e.g. fewer customers to recover the costs of the assets constructed and operated to serve them;
4. Reliance on more complex systems to provide thermal energy service;
5. Competition to provide thermal energy services from conventional sources of energy;
6. Competition to provide thermal energy services from other TES providers;
7. The relatively high upfront capital costs that must be recovered only from thermal energy customers; and
8. Higher counterparty risk due to reliance on one or a limited number of counterparties for revenue.[417]

During this proceeding, the Panel requested that all public utilities and registered interveners provide submissions on certain questions related to the establishment of a TES Default. The Panel discusses each of these questions in turn below.[418] Before doing so, the Panel must address a threshold issue regarding FAES's role in this proceeding related to the TES Default.

The Role of FAES in Stage 2

FAES currently has two non-exempt projects that are subject to sections 59 to 61 of the UCA, the TELUS Garden TES project and the Delta School District TES project. By virtue of the terms of both projects' negotiated service agreements, FAES is only indirectly impacted by the Benchmark Utility's cost of capital.[419] While none of FAES's TES projects will be directly affected by the outcome of Stage 2, FAES states it nonetheless has an interest in the outcome of this proceeding because FAES has non-exempt TES projects that make use of the deemed equity component, allowed ROE, and interest rates that are subject to review and approval by the BCUC herein. Moreover, FAES submits that a TES Default for rate-regulated TES utilities is nonetheless useful as a reference point in the negotiation of rates for projects that are exempt from rate regulation.[420]

Positions of Parties

RDE and Corix raised issues with the relevance of FAES's evidence.

RDE believes that FAES's contracts are not explicitly bound by the BCUC's decision on Stage 2 and were freely negotiated to include references to the regulated aspects of rate setting. RDE submits that a contractual choice by a utility that will not be directly impacted by Stage 2 has no bearing on the business and financial risks for true rate-regulated TES utilities.[421]

Corix states that FAES has 54 TES projects, but only the Delta School District TES was identified as a rate-regulated TES utility. However, Corix notes that the Delta School District TES is actually a number of discrete TES sites that each have a separate TES but are treated as one utility for regulatory purposes. Therefore, Corix submits that little weight should be placed on FAES's evidence and arguments since FAES is not as well

[417] 2014 GCOC Stage 2 Decision, p. 119.
[418] Order G-172-24 dated June 24, 2024, Appendix B.
[419] Exhibit B3-7, FAES Evidence, p. 4.
[420] Exhibit B3-7, FAES Evidence, pp. 2–3.
[421] RDE Final Argument, p. 3.

positioned as the other Stage 2 TES utilities such as Corix, Creative Energy, and RDE to comment on the needs of a typical Stream B TES.[422]

In reply, FAES submits it is well-qualified to provide evidence on the TES Default because it has the history and the required knowledge to comment on all types of TES utilities, including district TESs. FAES keenly understands the heightened risks associated with rate-regulated TES utilities from being a minority equity investor in DGE which experienced a write down and which Corix cites as an example of the investor risks associated with district TESs, as well as from receiving approval for the Kelowna district energy system that did not proceed. FAES remains a participant in the rate-regulated TES utilities market and has a strong interest in having a TES Default in place that can be adopted by new projects. Lastly, FAES notes that the BCUC has previously recognized that rate-regulated TES utilities share common characteristics and can be characterized as "more similar than different" in the 2014 GCOC Stage 2 Decision. FAES's evidence highlights those common characteristics and explains that some of the features cited by other utilities are not inherent in all non-exempt TES utilities. [423]

Panel Discussion

FAES is a utility eligible to participate in this proceeding, and the Panel sees value in considering contributions from all informed and/or impacted parties in making its determination. Therefore, the Panel will consider FAES's evidence along with that of the other parties when making its determinations regarding the TES Default despite FAES's rates for its TELUS Garden TES project and Delta School District TES project not being directly impacted by the Panel's determinations on the cost of capital for a TES Default.

Need for a TES Default

All four TES service providers in Stage 2 (Corix, Creative Energy, RDE, and FAES) agree there should be a TES Default for regulatory efficiency.[424] With regards to the eight risk factors accepted by the BCUC in 2014, FAES submits that these risk factors continue to characterize the TES utilities' risk profiles.[425]

Except for SFU, all interveners agree that a TES Default should be established.[426] SFU states it supports regulatory efficiency; however, it is unclear whether a TES Default offers regulatory efficiency since each TES would still need to compare itself to that Benchmark Utility in order to adopt the cost of capital for the TES Default.[427]

Panel Determination

The Panel determines that establishing a TES Default is warranted. Based on the Panel's review of the participating TES utilities in this proceeding, the Panel finds that rate-regulated TES utilities continue to face unique and higher business risks, with the eight TES-specific risk factors accepted by the BCUC in the 2014 GCOC Stage 2 Decision continuing to be reflective of the TES utilities reviewed in the current proceeding. The Panel

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[422] Corix Final Argument, pp. 11–12.
[423] FAES Reply Argument, pp. 10–11.
[424] Corix Final Argument, p. 10; Creative Energy Final Argument, p. 6; RDE Final Argument, p. 4; FAES Final Argument, p. 4.
[425] Exhibit B3-7, FAES Evidence, p. 23.
[426] The CEC Final Argument, p. 2; BCOAPO Final Argument, p. 47; RCIA Final Argument, p. 57.
[427] SFU Final Argument, p. 23.

views that establishing a TES Default will continue to reduce regulatory burden on small utilities and therefore promotes regulatory efficiency.

"Minimum TES Default" versus "TES Default"

Among TES service providers, Corix and RDE support establishing a TES Default for a TES with average risk, whereas FAES and Creative Energy support a minimum TES Default that represents the floor.[428]

Corix opposes a minimum TES Default because the appropriate cost of equity above such a minimum default would have to be addressed in each rate-regulated TES utility's future rate applications, which would be duplicative and expensive. Corix submits that this proceeding should directly address the cost of equity for a typical rate-regulated TES utility, which would apply to the three Corix district energy systems, in addition to Creative Energy's and RDE's rate-regulated TES utilities.[429]

RDE echoes Corix's concern with a minimum TES Default, and states that a minimum could not be considered representative of a typical TES provider and would increase the regulatory burden because typical TES providers would need to justify why they should have a deemed equity component and allowed ROE higher than the minimum.[430]

FAES supports a minimum default that is determined with reference to risk factors that are inherent in all rate-regulated TES utilities. It would be up to individual utilities to make the case that project-specific characteristics necessitate a higher return to meet the Fair Return Standard.[431] FAES clarifies that the minimum default does not represent a floor where the return can never be lower, for example, the return could be lower in the case of a customer complaint.[432] FAES elaborates in its reply argument that the adjectives "typical" and "average" are unhelpful in the context of setting a default to the extent that one equates those terms with all of the characteristics of the existing RDE, Creative Energy and Corix projects. [433] The business risk analyses provided by Corix, RDE and Creative Energy have highlighted risks that are not inherent in all rate-regulated TES utilities– notably, the risk associated with building out a TES in advance of demand, challenges associated with securing a low-carbon fuel supply, and municipality-specific political risk. The next projects may not share those characteristics.[434] FAES states that it has a strong interest in having a default cost of capital in place that will have broader application.[435]

Creative Energy supports a minimum TES Default approach to provide shareholders with certainty around the minimum return that can be earned on a rate-regulated project, which would aid in investment decisions. This approach considers whether the risk is higher or lower than a default risk, recognizing different profiles of rate-regulated projects while maintaining regulatory efficiency by avoiding the need to adjudicate every project application.[436]

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[428] Corix Final Argument, p. 10; RDE Final Argument, p. 4; FAES Final Argument, p. 4; Creative Energy Final Argument, p. 6.
[429] Corix Final Argument, p. 11.
[430] RDE Final Argument, p. 4.
[431] FAES Final Argument, p. 4.
[432] FAES Final Argument, p. 4.
[433] FAES Reply Argument, p. 7.
[434] FAES Reply Argument, p. 7.
[435] FAES Reply Argument, p. 7.
[436] Creative Energy Final Argument, p. 6.

Among interveners, BCOAPO, RCIA, and the CEC support the BCUC establishing a TES Default based on the risk of a typical TES.[437] BCOAPO submits that if a minimum TES Default were established, most TES utilities would find it necessary to apply for a cost of capital with a higher level of risk, negating much of the efficiency of establishing a TES Default.[438] The CEC recommends avoiding a minimum TES Default because of the risks to customers of over-compensating the utilities and creating incentives to pursue individual increases over the minimum for differences between TES utilities for which there should not be additional compensation, thereby creating unnecessary regulatory process, inefficiencies, and costs.[439]

SFU supports establishing a minimum TES Default which reflects the TES utility with the lowest risk but does not otherwise elaborate on its position.[440]

Panel Determination

The Panel determines that establishing a TES Default that is reflective of the typical TES is warranted. We find that this approach would result in the most certainty for future TES planning purposes and increased regulatory efficiency for future TES utilities that wish to adopt the TES Default. The Panel expects the TES Default would reflect the risk profile of a typical TES and therefore also reflect a fair return for such a typical TES. The Panel concurs with the CEC that establishing a minimum TES Default that represents a floor could overcompensate a future TES that may be less risky than the typical TES. The appropriate return for each future TES should be reflective of the future TES's risk and operational environment, which could be higher or lower than the TES Default. The Panel agrees with FAES that the TES Default should have broad application, which can be achieved with setting a TES Default for a typical TES along with other guidance on implementation to be discussed below. The Panel clarifies that the term "typical" does not equate with all of the characteristics of the existing RDE, Creative Energy and Corix projects as FAES suggests. Rather, the typical TES refers to one that faces a combination of the eight risk factors commonly faced by TES utilities as the BCUC determined in the 2014 GCOC Stage 2 Decision and as outlined above.

Determination of the TES Default

All TES utilities participating in Stage 2 proposed the TES Default to be the same as their proposal for their own system, with the exception of Creative Energy's Core TES. Table 16 below summarizes the various proposals they put forward for the cost of capital for the TES Default . Please see Sections 3.3.1 through 3.3.3 for a detailed discussion on each TES utility's proposal.

[437] BCOAPO Final Argument, p. 49; RCIA Final Argument, p. 57, the CEC Final Argument, pp. 17–18.
[438] BCOAPO Final Argument, p. 49.
[439] The CEC Final Argument, p. 2.
[440] SFU Final Argument, p. 23.

Table 16: Summary of Equity and ROE Premium for the TES Default Proposed by TES Service Providers and Interveners[441]

	Party	Equity premium or discount against the Benchmark (Deemed equity component)	ROE premium or discount against the Benchmark (Allowed ROE)
TES service providers	Corix	4.0 pps premium (49.0%)	75 bps premium (10.40%)
	Creative Energy	4.0 pps premium (49.0%)	75 bps premium (10.40%)
	RDE	4.0 pps premium (49.0%)	75 bps premium (10.40%)
	FAES	1.5 pps discount (43.5%)	50 bps premium (10.15%)
Intervener	BCOAPO	4.0 pps premium (49.0%)	75 bps premium (10.4%)
	RCIA	-1.0 pps discount (44.0%)	50 bps premium (10.15%)
	The CEC	4.0 pps premium (49.0%)	50 bps premium (10.15%)
	SFU	Use BMDEU or FBC as the Default	Use BMDEU or FBC as the Default

While none of FAES's TES projects will be directly affected by the outcome of this decision, FAES provided evidence on the TES Default as previously discussed. As shown in Table 16 above, FAES is proposing an equity discount of 1.50 pps and an ROE premium of 50 bps for the TES Default.[442] FAES states that its proposed deemed equity component is 1.0 pp higher than the currently approved deemed equity component for the TES Default in order to reflect the BCUC's new approach regarding financial flexibility as determined in Stage 1. This effectively replaces the historical premium in TES projects' approved deemed equity component with a -1.5 percent equity discount. FAES states that this change recognizes that the risk differential between TES projects and FEI has narrowed and that the small size risk premium is compensated through the ROE.[443] Under FAES's proposal, the weighted ROE differential between the Benchmark Utility and FAES's proposed TES Default would decrease to reflect the narrowing of the risk differential between TES utilities and FEI, mainly due to the more pronounced impact of the energy transition on FEI's business.[444]

In reply to Creative Energy's, Corix's, and RDE's proposals for the TES Default, FAES submits that the key considerations in their respective risk analyses include the risk associated with building out a TES system in advance of demand, challenges associated with securing a low-carbon fuel supply, and municipality specific political risk. In contrast, FAES's proposed cost of capital for the TES Default does not account for such features since its proposal only reflects the eight features that make rate-regulated TES "more similar than different" as the BCUC determined in the 2014 GCOC Stage 2 Decision.[445]

BCOAPO agrees that a deemed equity component of 49.0 percent and an allowed ROE of 10.40 percent for the TES Default is reasonable assuming the TES Default is facing the same political and social pressures as FEI with respect to the energy transition.[446]

[441] FAES Final Argument, p. 5; Corix Final Argument, p. 17; RDE Final Argument, p. 3; Creative Energy Final Argument, p. 6; SFU Final Argument, p. 23; RCIA Final Argument, p. 59; BCOAPO Final Argument, p. 50; The CEC Final Argument, p. 2.
[442] Exhibit B3-7, FAES Evidence, pp. 5–6.
[443] Exhibit B3-7, FAES Evidence, p. 6
[444] Exhibit B3-8, BCUC IR 9.3.
[445] FAES Final Argument, pp. 11–12.
[446] BCOAPO Final Argument, p. 50.

The CEC recommends the TES Default's deemed equity component be set at 49.0 percent and the allowed ROE at 10.15 percent. The CEC explains that the Benchmark Utility has a well-recognized risk profile regarding its gas supply business and related greenhouse gas emissions. The existential risks faced by the Benchmark Utility do not equally apply to the TES utilities since the latter offer a mitigating solution to the issues with gas supply and greenhouse gas emissions.[447]

SFU submits the TES Default should be the TES utility with the lowest risk. Since BMDEU made the switch to a low-carbon technology, it could be considered the low-risk TES utility for setting the TES Default.[448] SFU also submits that there could be merit in using FBC as the TES Default going forward given that TES and electric utilities generally do not face the same energy transition and decarbonization risks faced by natural gas utilities. TES utilities may indeed face lower risks from an energy transition perspective given their ability to integrate multiple low-carbon energy sources to manage their loads.[449]

Panel Determination

The Panel finds a 4.0 pps equity premium resulting in a 49.0 percent deemed equity component and a 75 bps ROE premium resulting in an allowed ROE of 10.40 percent to be the appropriate return for the TES Default.

The Panel previously determined that a 4.0 pps equity premium (i.e. a 49.0 percent deemed equity component) was appropriate for all Stage 2 TES utilities, with the exception of Creative Energy's Core TES. While Stage 2 TES utilities all have different inherent operational characteristics (e.g. energy source, location, stage of build-out, etc.), and received the 4.0 pps equity premium for different combinations of risk factors (e.g. supply risk, demand/market risk, political risk), the Panel found this equity premium to appropriately compensate them all under the Fair Return Standard. The Panel views that the typical TES continues to have greater business risk than the Benchmark Utility. Accordingly, the Panel finds that this 4.0 pps equity premium is also appropriate to compensate a typical TES when setting the TES Default.

The Panel reiterates that the deemed equity component for the TES Default reflects the typical TES which faces a combination of the eight risk factors commonly faced by TESs as outlined above. Should a rate-regulated TES project possess risk characteristics that overall are higher or lower than those implicit in the TES Default, the project proponent can bring forward the related evidence and make its case for a different return.

We have already determined that the 75 bps ROE premium to reflect small size, as discussed in Section 3.1 of this decision, applies to all Stage 2 TES utilities. We find that it equally applies to the TES Default.

Application of the TES Default

FAES, Creative Energy and RDE support automatic adoption of the TES Default for regulatory certainty for TES providers that have TESs under consideration or are in the planning, design, or construction stages. [450]

Corix does not consider it appropriate for a future rate-regulated TES to automatically adopt the TES Default on the basis that a new TES may be materially different than the TES Default and thus its cost of capital should be

[447] The CEC Final Argument, p. 18.
[448] SFU Final Argument, p. 23.
[449] SFU Final Argument, p. 23.
[450] FAES Final Argument, p. 5; Creative Energy Final Argument, p. 7; RDE Final Argument, p. 5.

awarded based on its own merits and consistent with the Standalone Principle. Corix proposes that the TES Default should be set as a starting point for the cost of capital, with the onus on a future rate-regulated TES to justify its deemed equity component and allowed ROE in its rate application. Corix states the volume of information required by the future TES to justify its equity component and equity risk premium would be informed by how similar or different the future TES is to the TES Default.[451]

All Stage 2 TES utilities consider any future rate-regulated TES that begins providing service after the conclusion of Stage 2 should be able to request, with justification, a different equity component and equity risk premium to the TES Default.[452]

Amongst the interveners, RCIA and the CEC support the automatic adoption of the TES Default, whereas BCOAPO does not. RCIA submits that automatic adoption would promote regulatory efficiency by reducing the need for case-by-case determinations and provide certainty, creating a level playing field for new entrants. It could also encourage increased TES development by simplifying the regulatory process for new utilities.[453] The CEC submits that automatic adoption of the TES Default would result in further regulatory efficiency.[454] The CEC expects that the comparative risks and financing should not be significantly out of line with the typical TES in order to be competitive as a new TES provider.[455]

BCOAPO submits that depending on how similar or different a future rate-regulated TES is relative to a TES Default, a future rate-regulated TES should have to justify why its deemed equity component should be the same, higher, or lower than the TES Default. The same should apply regarding its equity risk premium. BCOAPO would expect the effort involved in justifying the use of the TES default would be less than that required to justify the use of different values.[456]

RCIA and BCOAPO consider that future TESs should be able to request a different return than that of the TES Default.[457] RCIA submits this provision would recognize that some TES projects may face unique risks or challenges that warrant different treatment. It would maintain flexibility in the regulatory framework to address specific circumstances and place the onus on the utility to provide compelling evidence for any deviation from the TES Default, thus protecting consumer interests.[458] BCOAPO submits that TES utilities with unique business risks should be able to do this to ensure a fair return under the Fair Return Standard.[459] The CEC disagrees and submits that future TES should not be able to access a process for claiming greater risk adjustments because the TES utilities should not be starting off in significantly riskier situations than the base industry.[460]

SFU did not comment on how the TES Default ought to apply to future TES utilities.

[451] Corix Final Argument, p. 21.
[452]Corix Final Argument, p. 20; Creative Energy Final Argument, p. 7; RDE Final Argument, p. 5; FAES Final Argument, p. 6.
[453] RCIA Final Argument, p. 59.
[454] The CEC Final Argument, p. 19.
[455] The CEC Final Argument, pp. 18–19.
[456] BCOAPO Final Argument, p. 51.
[457] RCIA Final Argument p. 59; BCOAPO Final Argument, p. 51.
[458] RCIA Final Argument, p. 59.
[459] BCOAPO Final Argument, p. 51.
[460] The CEC Final Argument, p. 3.

Panel Determination

The Panel finds the TES Default should not be automatically applied and that each future TES should have the opportunity to justify its proposed equity premium (i.e. deemed equity component) and ROE premium (i.e. allowed ROE), which could be the TES Default or higher or lower than the TES Default based on its business risks and circumstances at the time of its regulatory filing. Due to the unknown operational circumstance and business environment that future TESs will face, the Panel finds that some regulatory oversight to confirm whether a future TES should receive the TES Default, or some other return, is warranted in order to ensure future TES utilities receive an opportunity to earn a return consistent with the Fair Return Standard. The Panel clarifies that since the cost of capital for the TES Default has already been established in this proceeding, the regulatory process to justify the deemed equity component and allowed ROE for future TES utilities is intended to be simply a check against the approved TES Default.

The Panel further confirms that a brief risk analysis is necessary for future TES utilities to adopt the TES Default, but a comprehensive risk analysis as was done in this proceeding would not be needed. The Panel views that this appropriately balances regulatory effectiveness and efficiency.

3.4 Electric Utilities

Three electric utilities participated in Stage 2. Boralex and Nelson Hydro participated fully while KPL participated in a limited capacity.[461] The Panel discusses each electric utility's submissions in turn below, followed by the Panel determinations.

3.4.1 Boralex

Boralex owns and operates hydroelectric generation, transmission and distribution facilities in Ocean Falls on the central coast of BC. These facilities supply electricity to BC Hydro, which in turn serves customers in the communities of Bella Bella and Shearwater within a non-integrated area. Boralex also supplies electricity to approximately 100 retail customers and two industrial customers, Mowi Canada West Inc. and Ocean Falls Blockchain Corp.[462]

Boralex's rates for service to BC Hydro, retail, and industrial customers have historically been exempted from the application of a majority of the provisions of the UCA. However, in 2019, the energy purchase agreement between Boralex and BC Hydro expired and the parties were unable to agree to new terms. As a result, in 2019, Boralex filed its first rates application with the BCUC related to its rates for service to BC Hydro only. Boralex's rates for service to retail and industrial customers remain exempt.[463] Boralex's annual sales of electricity to BC Hydro are approximately $3 million or 13,000 megawatt hours.[464]

In October 2020, the BCUC determined Boralex's rate design, cost of service allocation, and cost of capital as they relate to Boralex's service to BC Hydro.[465] The BCUC set Boralex's deemed equity component at 46.5

[461] Exhibit B5-3, KPL Response to BCUC IR No. 1.
[462] Exhibit C3-2, Boralex Evidence, p. 1.
[463] Exhibit C3-2, Boralex Evidence, p. 1.
[464] Boralex 2023 to 2027 Rates for Service to BC Hydro, Exhibit B-1, Tables 22, 23, and 24, pp. 29–30.
[465] Exhibit C3-2, Boralex Evidence, pp. 1–2; Boralex Application for Rates and Terms and Conditions for Service to BC Hydro, Decision and Order G-270-20 dated October 27, 2020 (Boralex 2019–2022 Rates to BC Hydro Decision).

percent (i.e. 8.00 pps above the Benchmark Utility) and its ROE premium at 75 bps above the Benchmark Utility (i.e. an allowed ROE of 9.50 percent) based on an overall risk assessment of Boralex as higher, but not significantly higher, than the Benchmark Utility.[466] The BCUC found that Boralex's remote and isolated location and relatively small size increased its risk profile relative to the Benchmark Utility but were offset by its clean hydroelectric facilities and stable revenue from BC Hydro, decreasing its risk profile relative to the Benchmark Utility.[467] The BCUC also compared Boralex to Corix BMDEU and PNG(NE) Tumbler Ridge in order to assess the deemed equity component and equity risk premium.[468]

In this proceeding, Boralex is proposing a deemed equity component of 50.0 percent (i.e. 5.0 pps above the Benchmark Utility) and an ROE premium of 75 bps above the Benchmark Utility (i.e. an allowed ROE of 10.40 percent).[469] This proposal would reduce the equity premium from the currently approved 8.0 pps to 5.0 pps, while maintaining the ROE premium. Boralex believes that this smaller equity premium reflects the increase in its risks since its last cost of capital proceeding in 2020, while also recognizing a greater increase in the Benchmark Utility's risks due to energy transition as discussed in Stage 1.[470]

Table 17 summarizes Boralex's previously approved and currently proposed cost of capital.

Table 17: Previously Approved and Currently Proposed Cost of Capital for Boralex

	Previously Approved[471]			Currently Proposed[472]		
	Equity Premium (i.e. Deemed Equity Component)	ROE Premium (i.e. Allowed ROE)	Weighted ROE	Equity Premium (i.e. Deemed Equity Component)	ROE Premium (i.e. Allowed ROE)	Weighted ROE
Boralex	8.0 pps (46.5%)	75 bps (9.50%)	4.42%	5.0 pps (50.0%)	75 bps (10.40%)	5.20%

Boralex provides a business risk assessment comparing itself to the Benchmark Utility, including an assessment of the changes in its own business risks since its last cost of capital review in 2020. Boralex also uses FBC as an additional data point for its proposed deemed equity component and allowed ROE given that they are both electric utilities operating in BC.[473]

Boralex uses a 15-factor risk matrix, which is discussed further below, consistent with its last cost of capital proceeding in 2020, and also maps its 15 factors to the risk matrix used in Stage 1.[474] Boralex states that its risk is lower than FEI for fuel risk (including cost and availability) and provincial climate change and energy policies. Boralex's risk is similar to FEI's for the following risks: technology risk, Indigenous rights and engagement risk, rate design, and competitive challengers. Boralex states that its risk is higher than FEI's for the following risks:

466 Boralex 2019–2022 Rates to BC Hydro Decision, p. 49.
467 Exhibit C3-2, Boralex Evidence, pp. 3–4; Boralex 2019–2022 Rates to BC Hydro Decision, pp. 48–50.
468 Exhibit C3-2, Boralex Evidence, p. 4; Boralex 2019–2022 Rates to BC Hydro Decision, p. 49.
469 Exhibit C3-2, Boralex Evidence, p. 14.
470 Exhibit C3-2, Boralex Evidence, p. 14.
471 Boralex 2019–2022 Rates to BC Hydro Decision, p. 49.
472 Exhibit C3-2, Boralex Evidence, p. 14.
473 Exhibit C3-2, Boralex Evidence, p. 6; Exhibit C3-4, BCOAPO IR 3.1, 5.1, Schedule A, Tables 2 and 3.
474 Exhibit C3-2, Boralex Evidence, p. 6; Exhibit C3-4, BCOAPO IR 2.1, Schedule A, Table 1.

system performance risk, customer base (including diversity, certainty, growth), default risk of customer, load forecast uncertainty, utility size, future construction cost risk, operating cost risk, regulatory uncertainty, and business development risk.[475]

Boralex acknowledges that as an electric utility it does not face the same energy transition risks as the Benchmark Utility as a natural gas utility.[476] However, Boralex differentiates the impact of the energy transition on itself and FBC as both electric utilities. FBC has the opportunity to capitalize on energy transition by attracting existing and potential new natural gas customers in its service territory that choose electricity over natural gas, as well as through new load opportunities such as electric vehicle charging. In contrast, there is no natural gas service in Boralex's service territory and therefore Boralex does not have this same opportunity.[477]

Of the risks that Boralex classifies as "higher", it further classifies four of these risks as "significantly higher" than the Benchmark Utility. Boralex views that its customer base and customer default risk is significantly higher than the Benchmark Utility because its customer base is very small with low diversity and slow growth. Approximately 12 percent of Boralex's gross forecast revenue requirement comes from its two industrial customers, both of which have more uncertainty now than in 2020.[478] In 2023, the share of total revenue from Boralex's retail customers was approximately three percent.[479] However, Boralex does acknowledge that Boralex's industrial loads are forecast to remain stable at average historical levels.[480]

Boralex views that its rate structure and load forecast uncertainty risks are significantly higher than the Benchmark Utility because it retains all load forecasting risk under the energy charge rate structure with BC Hydro and with regards to its retail and industrial customers.[481] However, Boralex also states that the BC Hydro load is expected to remain relatively stable over the 2024 to 2027 period, adjusted for the planned outages associated with the completion of Boralex's penstock rehabilitation project.[482]

Boralex views that its system performance risk is significantly higher than the Benchmark Utility because Boralex generates, transmits, and distributes electricity in a remote and isolated location with dam and generating facilities that are more than 100 years old and a single, non-redundant 45 kilometre transmission line over difficult and hard to access terrain.[483] Boralex is forecasting to spend a total of $19 million for planned capital projects from 2023 to 2027 which include a variety of capital projects to address the deteriorated condition of specific assets and the completion of Boralex's penstock rehabilitation project.[484]

Lastly, Boralex views that its operating cost risk is significantly higher than the Benchmark Utility because its facilities are located in an isolated and remote location with an "extremely harsh" operating environment. There is no road access to the facilities and water access is the only reliable year-round access. The transmission line

[475] Exhibit C3-2, Boralex Evidence, pp. 6–11.
[476] Exhibit C3-2, Boralex Evidence, p. 11.
[477] Exhibit C3-5, The CEC IR 5.1.
[478] Exhibit C3-2, Boralex Evidence, pp. 11–12.
[479] Exhibit C3-6, RCIA IR 1.1.
[480] Exhibit C3-3, BCUC IR 3.1, 3.2, 3.3.
[481] Exhibit C3-2, Boralex Evidence, pp. 12–13.
[482] Exhibit C3-3, BCUC IR 3.1.
[483] Exhibit C3-2, Boralex Evidence, p. 13.
[484] Exhibit C3-3, BCUC IR 2.3.

can only be accessed by water, on foot, or by helicopter. Boralex states that this imposes much higher operating cost risks to operate, maintain, and respond to emergencies in its operating environment than in FEI's relatively more urban service areas. Boralex also states that it is also more difficult to recruit, train, and retain qualified operating personnel who are willing to work in its remote location.[485]

Overall, Boralex believes that it still faces "significantly higher" business risks compared to the Benchmark Utility and that its business risks have also increased since its last cost of capital review in 2020.[486] Boralex states that the increases in its own business risks since 2020 are majorly driven by the increase in risk associated with Boralex's two industrial customers in Ocean Falls and the increase in Boralex's test period to five years as opposed to the previous three-year term. Boralex does not believe that any risks have decreased compared to those in 2020.[487]

By reference to FBC, Boralex's proposed deemed equity component would represent a spread of 9 pps (i.e. 50.0 percent for Boralex compared to 41.0 percent for FBC), which is marginally higher than the prior spread of 6.5 pps (i.e. 46.5 percent for Boralex compared to 40.0 percent for FBC). Boralex believes that this spread is necessary to reflect its significantly higher overall risks compared to FBC, including the increase in Boralex's risks since 2020 due to the increased risk and uncertainty associated with its industrial load and longer test period.[488]

Positions of Parties

Interveners provided various submissions on the overall business risk assessment of Boralex, with recommended equity premiums of 0.0 pps to 4.0 pps and recommended ROE premiums of 50 bps to 75 bps.[489]

The CEC agrees that a lower equity premium is appropriate given Boralex's risk changes do not exceed FEI's existential risk changes discussed in Stage 1. The CEC recommends a deemed equity component of 49.0 percent and a 10.40 percent allowed ROE for Boralex as a small operation with some significant risks.[490] In reply, Boralex states that it has amply demonstrated that its proposed equity premium of 5.0 pps is necessary to reflect its higher overall business risks compared to the Benchmark Utility and 2020.[491]

BCOAPO submits that Boralex's business risk is less than or similar to FEI's in the majority of the business areas considered.[492] BCOAPO states that Boralex's proposal reduces the difference between the weighted ROEs of Boralex and FEI by less than 20 percent which does not go far enough in recognizing the reduction in the relative business risk faced by the respective utilities. In BCOAPO's view, it would be reasonable to reduce this differential by close to 50 percent. BCOAPO accepts that maintaining the 75 bps ROE premium from 2020 is reasonable and submits that it is the equity premium that should be reduced. As a result, BCOAPO recommends a 47.0 percent deemed equity component for Boralex.[493] In reply, Boralex disagrees with BCOAPO's risk

485 Exhibit C3-2, Boralex Evidence, p. 13.
486 Exhibit C3-2, Boralex Evidence, p. 14.
487 Exhibit C3-4, BCOAPO IR 3.1.1.
488 Exhibit C3-2, Boralex Evidence, p. 14.
489 The CEC Final Argument, p. 32; BCOAPO Final Argument, p. 34; RCIA Final Argument, p. 8.
490 The CEC Final Argument, p. 32.
491 Boralex Reply Argument, p. 1.
492 BCOAPO Final Argument, p. 33.
493 BCOAPO Final Argument, pp. 34, 35.

categorizations and states that the recommended 47.0 percent equity premium does not adequately reflect Boralex's significantly higher overall business risks compared to the Benchmark Utility.[494]

RCIA submits that Boralex's risks remain largely unchanged relative to the last applicable decision. While there have been some minor changes in circumstances, RCIA states that, on balance, the changes net out or are mitigated by regulatory conventions.[495] RCIA considers that other than its smaller relative size and more remote service territory, the risks facing Boralex are more in line with those of FBC than FEI. RCIA states that energy transition risk is considerably less for electric utilities, so Boralex's energy transition risk is likely more similar to FBC's than FEI's. Taking relative size into account, as well as associated limitations on customer growth, market opportunities, and Boralex's more remote location, RCIA submits that an equity premium relative to FBC of 4.0 pps is reasonable (i.e. a deemed equity component of 45.0 percent), as well as an ROE premium of 50 bps (i.e. an allowed ROE of 10.15 percent). Stated in relation to FEI, RCIA proposes no equity premium, which it submits would reflect the relevant risk spread due to energy transition, while also balancing the impact of a negative equity adjustment on investor expectations.[496]

In reply, Boralex disagrees with RCIA's comparison to FBC and outlines the following factors that differentiate Boralex from FBC: Boralex operates in a truly remote and isolated location on the central coast with no road access and an "extremely harsh" physical environment; while both FBC and Boralex are smaller than FEI, Boralex is "significantly smaller" than FBC in terms of facilities, customer base and revenue; Boralex clarifies that it does not have the same opportunities for new load under electrification during the energy transition that FBC may have (e.g. there are no electric vehicle load opportunities in Boralex's service area); and Boralex's customer base is "vastly smaller and less diversified" than FBC's customer base.[497]

Panel Determination

The Panel agrees with Boralex's overall business risk assessment that its risks remain higher than the Benchmark Utility, but that the gap has narrowed since 2020. The Panel does not agree with Boralex's categorization of its own change in risks since 2020 as being "significantly higher".[498] Rather, the Panel views that Boralex's risk profile is similar now to what it was in 2020. While Boralex's business risks remain similar to 2020, certain business risks of the Benchmark Utility were found to be significantly higher in Stage 1, and therefore the gap between the two utilities is now smaller than it was in 2020. Accordingly, the Panel views that Boralex's overall business risk when compared against the Benchmark Utility has decreased since its last cost of capital proceeding in 2020.

Boralex still faces higher overall business risks than the Benchmark Utility given the unique characteristics of its operations including its remote location, limited customer diversity, and aging infrastructure. Any increased risks in Indigenous rights and engagement have already been reflected in the Benchmark Utility's deemed equity component and therefore should not constitute a further equity premium for Boralex at this time. The Panel agrees with Boralex and interveners that the energy transition has a more pervasive impact on the Benchmark Utility than it does on Boralex as an electric utility. However, Boralex's last cost of capital determination was in

[494] Boralex Reply Argument, pp. 2–5.
[495] RCIA Final Argument, p. 14.
[496] RCIA Final Argument, p. 8.
[497] Boralex Reply Argument, pp. 5–6.
[498] Exhibit C3-2, Boralex Evidence, p. 14.

2020 and already reflects some of those energy transition influences including the "clean hydroelectric facilities" noted as an offsetting factor to higher risks at that time.[499] Overall, the Panel finds that Boralex's overall risk assessment is higher, but not significantly higher, than that of the Benchmark Utility at this time.
The Panel views that many of the above cited factors also justify a higher business risk for Boralex when compared to FBC. Additionally, Boralex has less opportunity for load growth either from new customer additions or increased usage via electric vehicle charging arising from the energy transition than FBC given the unique characteristics of its operating environment. This further justifies a determination of higher business risk for Boralex than FBC.

The Panel views that Boralex's proposed equity premium reasonably reflects the change in business risk between Boralex and the Benchmark Utility since 2020. The proposed equity premium also reflects the difference in risks between Boralex and FBC as an additional data point to consider. The Panel notes that the most recent prior cost of capital decision for Boralex used PNG(NE) Tumbler Ridge as a reference point.[500] However, while the remote nature of the two utilities remains the same, there is a marked difference in how energy transition impacts an electric utility like Boralex versus a natural gas utility like PNG(NE) Tumbler Ridge. Thus, the Panel views that a reasonable deemed equity component for Boralex is one that is higher than the Benchmark Utility's 45 percent, but not as high as PNG(NE) Tumbler Ridge's 52 percent. **Accordingly, the Panel sets a 5.0 percent equity premium, resulting in a 50.0 percent deemed equity component for Boralex.**

As discussed in Section 3.1, we have determined that a 75 bps ROE premium is appropriate to reflect the small size premium. We have applied the same ROE premium here for Boralex, which results in an allowed ROE of 10.40 percent.

Table 18 below provides a comparison of the currently approved versus previously approved cost of capital for Boralex. The table lays out Boralex's cost of capital beginning with the Benchmark Utility's cost of capital plus the approved equity and ROE premiums for Boralex to arrive at Boralex's cost of capital.

Table 18: Comparison of Previously and Currently Approved Cost of Capital for Boralex

	Previously Approved[501]			Currently Approved		
	Deemed Equity Component	Allowed ROE	Weighted ROE	Deemed Equity Component	Allowed ROE	Weighted ROE
Benchmark Utility's cost of capital (for comparison)	38.5%	8.75%	3.37%	45.0%	9.65%	4.34%
Boralex's premium	8.0 pps	75 bps	105 bps	5.0 pps	75 bps	86 bps
Boralex's resulting cost of capital	46.5%	9.50%	4.42%	50.0%	10.40%	5.20%

[499] Exhibit C3-2, Boralex Evidence, pp. 3–4; Boralex 2019–2022 Rates to BC Hydro Decision, p. 48.
[500] Exhibit C3-2, Boralex Evidence, p. 4; Boralex 2019–2022 Rates to BC Hydro Decision, p. 49.
[501] 2016 FEI COC Decision, Directives 1 and 2; GCOC Stage 1 Decision, p. 3; Boralex 2019–2022 Rates to BC Hydro Decision, p. 49.

As shown in Table 18 above, the currently approved cost of capital for Boralex decreases the differential between its and the Benchmark Utility's weighted ROE from the previously approved amounts by 19 bps.[502] This appropriately reflects the Panel's overall finding on Boralex's business risk relative to the Benchmark Utility.

3.4.2 Nelson Hydro

Nelson Hydro is owned and operated by the City of Nelson and serves customers within its municipal boundaries (Urban), as well as rural customers outside the City of Nelson's boundaries (Rural).[503] Municipalities providing utility services within their own boundaries are excluded from the definition of a public utility under the UCA,[504] and therefore the BCUC's review of Nelson Hydro's evidence in this proceeding pertains solely to the setting of the cost of capital for Nelson Hydro's Rural service area. Nelson Hydro's Rural service area has approximately 4,500 residential customers and 350 commercial customers with total annual sales of electricity of approximately $9 million or 68,000 megawatt hours.[505]

Prior to 2022, Nelson Hydro calculated its revenue requirements based on its forecast costs for the entire utility, resulting in the same rates for the Urban and Rural service areas. In 2020, however, Nelson Hydro filed a cost of service and rate design (COSA and RD) application with the BCUC, in which it proposed a rate differential between Urban and Rural customers.[506] As part of this COSA and RD application, Nelson Hydro proposed a cost of capital for Rural operations supported by a business risk analysis performed by InterGroup Consultants. The InterGroup Consultants report was dated March 2020 and was completed for Nelson Hydro on a consolidated basis (i.e. Rural and Urban) as well as with financial information prior to the implementation of changes associated with the proposed COSA and RD.[507]

In July 2022, the BCUC issued its decision on Nelson Hydro's COSA and RD application (Nelson Hydro 2022 COSA and RD Decision), directing Nelson Hydro to use the modified COSA and RD in its subsequent revenue requirements applications.[508] For Nelson Hydro's cost of capital, the BCUC found that Nelson Hydro had greater risk than the Benchmark Utility due to its size, geographic and service area, customer profile, delivery rates, and security of supply.[509] The BCUC compared Nelson Hydro to Boralex as another small electric utility that also owns its generation resources.[510] The BCUC set Nelson Hydro's Rural deemed equity component at 50.0 percent (i.e. 11.50 percent points above the Benchmark Utility) and its equity risk premium at 50 bps above the Benchmark Utility (i.e. an allowed ROE of 9.25 percent) due to (i) its higher risk profile than the Benchmark Utility and (ii) the BCUC's finding that Nelson Hydro could theoretically achieve an actual debt level equivalent to the deemed equity component (i.e. 50.0 percent).[511]

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[502] Calculated as: 86 bps less 105 bps.
[503] Nelson Hydro 2024 Revenue Requirements, Order G-170-24 with decision dated June 21, 2024, p. 1.
[504] Nelson Hydro 2024 Revenue Requirements, Order G-170-24 with decision dated June 21, 2024, p. 1.
[505] Nelson Hydro 2024 Revenue Requirements, Exhibit B-3 (Evidentiary Update), Attachment "Updated-Appendix7-1.xlsx", Tab "Other supporting".
[506] Nelson Hydro Cost of Service Analysis and Rate Design proceeding, Exhibit B-1.
[507] Exhibit A2-42 (BCUC Staff Submission of Nelson Hydro's InterGroup Report dated March 4, 2020); Nelson Hydro Cost of Service Analysis and Rate Design proceeding, Exhibit B-1, Appendix 6-1 "Nelson Hydro Appropriate Level of ROE Document (March 2020)".
[508] Nelson Hydro Cost of Service Analysis and Rate Design, Decision and Order G-196-22 dated July 19, 2022 (Nelson Hydro 2022 COSA and RD Decision), pp. 60, 76–78, 83.
[509] Nelson Hydro 2022 COSA and RD Decision, pp. 75–79.
[510] Nelson Hydro 2022 COSA and RD Decision, pp. 75–79.
[511] Nelson Hydro 2022 COSA and RD Decision, pp. 75–79.

In December 2022, Nelson Hydro filed for reconsideration of certain components of the Nelson Hydro 2022 COSA and RD Decision, including the directives regarding Nelson Hydro's deemed capital structure.[512] In its reconsideration application, Nelson Hydro submitted that it would not be able to achieve an actual debt level equivalent to the deemed equity component, which was one of the reasons cited by the BCUC when setting the deemed equity component at 50.0 percent.[513] On November 15, 2023, the BCUC issued its decision on Nelson Hydro's reconsideration application (Nelson Hydro 2023 Reconsideration Decision), denying the reconsideration application and upholding the cost of capital from the Nelson Hydro 2022 COSA and RD Decision in 2023. The BCUC found that the risk profile was sufficient reason to maintain the cost of capital determination from the Nelson Hydro 2022 COSA and RD Decision.[514] In the Nelson Hydro 2023 Reconsideration Decision, the BCUC stated:[515]

> Using a deemed capital structure is a common practice among utility regulators in Canada. When setting a rate under the UCA, the BCUC must consider whether the rate is insufficient to yield fair and reasonable compensation for the services provided by the utility. A utility must be given <u>an opportunity</u> to earn a fair and reasonable return, but this <u>does not guarantee that it will actually earn such return</u>. The [BCUC] considers that so long as the return, as determined in the [Nelson Hydro 2022 COSA and RD] Decision, is commensurate to the risks faced by Nelson Hydro as compared to the Benchmark Utility, Nelson Hydro's Rural rate should be sufficient to yield a fair and reasonable compensation. The [BCUC] considers that how Nelson Hydro decides to actually finance itself, albeit subject to certain municipal restrictions, is a decision for the utility and the City. Other utilities in British Columbia, such as small utilities, may choose to finance their business with no actual debt because it is not practical or heavily constrained. Whatever mechanism Nelson Hydro chooses, Rural ratepayers should not bear the burden of the City of Nelson's borrowing restrictions by way of an increase to the equity component beyond what is already fairly compensated via the risk assessment.

Nelson Hydro views that this proceeding provides the forum to update the approach for assessing Nelson Hydro's opportunity to earn a fair return on its invested capital as previously determined by the BCUC.[516] In this proceeding, Nelson Hydro is proposing two alternate methodologies that result in either a 74 percent or 87 percent deemed equity component (i.e. a 29 percent or 42 percent equity premium to the Benchmark Utility).[517] Both of the alternate approaches are predicated on Nelson Hydro's submission that its Rural operations should not be able to benefit from the debt financing that is available to Nelson Hydro as a municipal utility, but rather that debt financing is only available for use by its Urban operations.[518] The Municipal Finance Authority (MFA) supports Nelson Hydro's stance in a letter filed in this proceeding (MFA Letter).[519] The MFA Letter states that if a city-owned utility provides electricity outside of the city, the MFA has to be particularly careful that lending

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[512] Nelson Hydro Reconsideration and Variance of Order G-196-22, Exhibit B-1, p. 4.
[513] Nelson Hydro Reconsideration and Variance of Order G-196-22, Exhibit B-1, pp. 14–15.
[514] Nelson Hydro Reconsideration and Variance of BCUC Order G-196-22, Decision and Order G-311-23 dated November 15, 2023 (Nelson Hydro 2023 Reconsideration Decision), pp. 26–27.
[515] Nelson Hydro 2023 Reconsideration Decision, p. 27.
[516] Exhibit B4-6, Nelson Hydro Evidence, p. 3-6.
[517] Exhibit B4-6, Nelson Hydro Evidence, p. 3-11.
[518] Exhibit B4-6, Nelson Hydro Evidence, p. 3-10.
[519] Exhibit B4-6, Nelson Hydro Evidence, Appendix 1: Letter from the Municipal Finance Authority (MFA Letter).

(with its associated low rate) may be effectively providing a subsidy to non-residents of the city.[520] Nelson Hydro emphasizes its stance that it does not have "peers" on which to base a peer comparison analysis given the unique nature of its municipal ownership.[521]

Table 19 summarizes Nelson Hydro's previously approved and currently proposed cost of capital.

Table 19: Previously Approved and Currently Proposed Cost of Capital for Nelson Hydro

	Previously Approved[522]			Currently Proposed[523]		
	Equity Premium (i.e. Deemed Equity Component)	ROE Premium (i.e. Allowed ROE)	Weighted ROE	Equity Premium (i.e. Deemed Equity Component)	ROE Premium (i.e. Allowed ROE)	Weighted ROE
Nelson Hydro	5.0 pps (50.0%)	50 bps (9.25%)	4.63%	29 pps (74.0%)	50 bps (10.15%)	7.51%

Nelson Hydro's two alternate methodologies are as follows:

1. The standalone approach: An approach whereby Nelson Hydro's Rural cost of capital would be determined independent of the unique nature of its municipal ownership. Rural operations would not have access to favourably priced MFA debt, would require a 1.2 minimum debt to service coverage ratio (DSCR),[524] and would not benefit from the municipal ownership's non-taxable status and so would be taxable, which would increase the cost of equity.[525] Nelson Hydro submits that this approach results in a deemed equity component of 74 percent and is Nelson Hydro's recommended approach.[526]

2. The look-through approach: An approach whereby the benefits and limitations of Nelson Hydro's municipal ownership are reflected in the Rural operations' cost of capital. This would include reflecting the favourable rates of MFA debt in Rural operations, but also acknowledging the restraints that MFA debt entails such as the MFA debt being 9 to 18 percent of capital funding. This approach would also acknowledge that Rural operations could utilize capital that is exempt from taxes.[527] Nelson Hydro submits that this approach results in a deemed equity component of 87 percent.[528]

Nelson Hydro states that ad-hoc selective application of these two approaches can lead to outcomes that do not yield a fair return to the utility owner and do not reflect the risks inherent in Nelson Hydro's capital.[529]

[520] MFA Letter, p. 1.
[521] Exhibit B4-6, Nelson Hydro Evidence, p. 3-6; Exhibit B4-8, BCUC IR 4.1, 4.2.
[522] Nelson Hydro 2022 COSA and RD Decision, pp. 75–79.
[523] Exhibit B4-6, Nelson Hydro Evidence, p. 4-21.
[524] Exhibit B4-6, Nelson Hydro Evidence, p. 3-10. The debt service coverage ratio (DSCR) is calculated as: free operating cash flow divided by the sum of annual total principal and interest.
[525] Exhibit B4-6, Nelson Hydro Evidence, p. 3-14.
[526] Exhibit B4-6, Nelson Hydro Evidence, p. 3-16.
[527] Exhibit B4-6, Nelson Hydro Evidence, p. 3-16.
[528] Exhibit B4-6, Nelson Hydro Evidence, p. 3-11.
[529] Exhibit B4-6, Nelson Hydro Evidence, p. 4-22.

Nelson Hydro accepts the previously determined 50 bps ROE premium, so long as it is applied to a "reasonable percentage of rate base being financed by equity" (e.g. 74 percent or more, depending on the approach).[530]

Positions of Parties

Interveners generally do not support Nelson Hydro's proposed alternative methodologies to determine its deemed equity component in this proceeding. Instead, they recommend equity premiums ranging from 0.0 pps to 5.0 pps and a consistent 50 bps ROE premium.[531]

The CEC supports Nelson Hydro's request to be assessed on a standalone basis whereby the Rural cost of capital is considered independent of the unique nature of the utility's ownership. The CEC submits that Nelson Hydro has lower risk than FEI because it is an electric utility and because of the range of options available to it for managing its rates and financings due to its municipal ownership. The CEC recommends a deemed equity component of 49.0 percent and an allowed ROE of 10.15 percent to reflect a "more normal" equity premium than Nelson Hydro's proposed look-through approach.[532] In reply, Nelson Hydro states that the CEC provides no rationale for its recommended deemed equity component.[533]

BCOAPO notes that Nelson Hydro's approach is fundamentally different from what the BCUC has previously directed.[534] BCOAPO submits that Nelson Hydro has incorrectly interpreted when and how the Fair Return Standard and the accompanying Standalone Principle are to be applied. BCOAPO states that these interpretations seem to have led Nelson Hydro to set the requirements for raising debt as if its Rural operations were an entirely separate utility, not as a regulated part of a larger utility operation in terms of its ability to re-pay the loan as well as the cost of debt. BCOAPO does not agree that it is appropriate for Nelson Hydro to use figures that purport to bifurcate its Rural and Urban operations in this manner.[535] BCOAPO submits that an equity ratio of no more than 50.0 percent and an allowed ROE of 10.15 percent are more than sufficient to allow Nelson Hydro to attract capital using the Standalone Principle.[536] In reply, Nelson Hydro reiterates its inability to draw on debt from municipal operations for Rural utility service as explained in the MFA Letter.[537]

RCIA states that while Nelson Hydro's evidence in this proceeding largely focuses on alternative methods for determining its cost of capital, these approaches are at odds with the methodology adopted by the BCUC. In RCIA's submission, these matters were addressed in the Nelson Hydro 2022 COSA and RD Decision and the Nelson Hydro 2023 Reconsideration Decision. In terms of Nelson Hydro's proposed deemed equity component and allowed ROE, RCIA submits that an increase of the magnitude sought by Nelson Hydro is not justified in terms of its relative risk and would place an undue burden on ratepayers.[538]

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[530] Exhibit B4-6, Nelson Hydro Evidence, p. 4-21.
[531] The CEC Final Argument, pp. 10–11; BCOAPO Final Argument, p. 41; RCIA Final Argument, pp. 8–9.
[532] The CEC Final Argument, pp. 10–11.
[533] Nelson Hydro Reply Argument, p. 3-13.
[534] BCOAPO Final Argument, pp. 35–36.
[535] BCOAPO Final Argument, p. 38.
[536] BCOAPO Final Argument, p. 41.
[537] Nelson Hydro Reply Argument, pp. 2-5 to 2-6.
[538] RCIA Final Argument, p. 9.

RCIA states that other than its smaller relative size, the risks facing Nelson Hydro are more in line with those of FBC than FEI. RCIA states that energy transition risk is considerably less for electric utilities compared to FEI. Taking relative size into account, as well as associated limitations on customer growth, and market opportunities, RCIA submits an equity premium relative to FBC of 4.0 percent is reasonable (i.e. a deemed equity component of 45.0 percent), as well as an ROE premium of 50 bps (i.e. an allowed ROE of 10.15 percent). Stated in relation to FEI, RCIA proposes no equity premium, which it states should reflect the relevant risk spread due to energy transition, while also balancing the impact of a negative equity adjustment on investor expectations.[539] RCIA submits that if a downward adjustment from the current 50.0 percent deemed equity component is not considered to be achievable at this point, then the current 50.0 percent should be considered the outermost limit.[540] RCIA submits that Nelson Hydro has not demonstrated whether its overall risk profile has changed substantively since the last applicable decision.[541]

In reply, Nelson Hydro reiterates its stance that it does not have "peers" with which to do a business risk comparison and emphasizes the importance of the MFA Letter supporting Nelson Hydro's proposed alternate methodologies.[542]

Panel Determination

Nelson Hydro's arguments regarding its borrowing constraints were extensively reviewed in the Nelson Hydro 2022 COSA and RD Decision and the Nelson Hydro 2023 Reconsideration Decision. In this proceeding, Nelson Hydro adds to that argument by providing its two alternate methodologies and the MFA Letter. The Panel agrees with the BCUC's findings in the above referenced decisions in regards to setting Nelson Hydro's deemed equity component, and in particular the passage from the Nelson Hydro 2023 Reconsideration Decision cited above. The Panel acknowledges that Nelson Hydro considers the MFA Letter to constitute new evidence to support its position in this proceeding, but the Panel finds that "how Nelson Hydro decides to actually finance itself, albeit subject to certain municipal restrictions, is a decision for the utility and the City."[543] That decision, however, is not determinative of the Panel's establishment of Nelson Hydro's cost of capital in accordance with the Fair Return Standard and the Standalone Principle.

The Panel is not persuaded that Nelson Hydro has provided evidence in this proceeding that warrants a change from the most recent business risk analysis reviewed in the Nelson Hydro 2022 COSA and RD Decision, nor the currently approved deemed equity component. **Accordingly, the Panel finds that Nelson Hydro's overall business risk has not changed since its last cost of capital proceeding in 2022. The Panel sets a 5.0 pps equity premium, resulting in a 50.0 percent deemed equity component for Nelson Hydro.**

As for the allowed ROE, the Panel considers that the 75 bps ROE premium is applicable to Nelson Hydro to reflect the small size premium discussed in Section 3.1 of this decision. This results in a higher ROE premium from the previously approved 50 bps. We find that this increase in ROE premium for Nelson Hydro is fair and reasonable for the reasons we articulated when setting the 75 bps ROE premium for size. The Panel also clarifies that Nelson Hydro will adopt the 75 bps ROE premium on an after-tax basis like all other Stage 2 utilities.

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[539] RCIA Final Argument, p. 8.
[540] RCIA Final Argument, p. 9.
[541] RCIA Final Argument, p. 11.
[542] Nelson Hydro Reply Argument, pp. 2-2 to 2-5.
[543] Nelson Hydro 2023 Reconsideration Decision, p. 27.

Table 20 below provides a comparison of the currently approved versus previously approved cost of capital for Nelson Hydro. The table lays out Nelson Hydro's cost of capital beginning with the Benchmark Utility's cost of capital plus the approved equity and ROE premiums for Nelson Hydro to arrive at Nelson Hydro's cost of capital.

Table 20: Comparison of Previously and Currently Approved Cost of Capital for Nelson Hydro

	Previously Approved[544]			Currently Approved		
	Deemed Equity Component	Allowed ROE	Weighted ROE	Deemed Equity Component	Allowed ROE	Weighted ROE
Benchmark Utility's cost of capital (for comparison)	38.5%	8.75%	3.37%	45.0%	9.65%	4.34%
Nelson Hydro's premium	11.5 pps	50 bps	126 bps	5.0 pps	75 bps	86 bps
Nelson Hydro's resulting cost of capital	50.0%	9.25%	4.63%	50.0%	10.40%	5.20%

As shown in Table 20 above, the currently approved cost of capital for Nelson Hydro decreases the differential between its and the Benchmark Utility's weighted ROE from the previously approved amounts by 40 bps.[545] This appropriately reflects the Panel's overall finding regarding the lack of change in Nelson Hydro's business risk relative to the Benchmark Utility since Nelson Hydro's last cost of capital review in 2022, which means no ensuing change in Nelson Hydro's deemed equity component. At the same time, however, the Benchmark Utility's business risk has changed significantly from its last cost of capital review in 2016, such that the gap in weighted ROE between the Benchmark Utility and Nelson Hydro has decreased as result of the impact of the GCOC Stage 1 Decision on the Benchmark Utility's weighted ROE. In other words, the decrease in the weighted ROE differential is appropriate to reflect a similar narrowing of the gap between Nelson Hydro and the Benchmark Utility since the GCOC Stage 1 Decision, as discussed for Boralex above.

3.4.3 Kyuquot Power Ltd.

KPL is an electric utility that procures electricity from BC Hydro to serve the community of Kyuquot, BC. The utility operates a 14.4 kilovolt single phase distribution line in the area extending from BC Hydro's electrical grid at Oclucje to Kyuquot. KPL is a wholly owned subsidiary of Synex Energy Resources Ltd., which is a wholly owned subsidiary of its parent company, Synex Renewable Energy Corporation (formerly, Synex International Inc.). Since June 2006, KPL has supplied electricity to customers including the Ka:yu:'k't'h'/Che:k'tles7et'h' First Nations, the Village of Houpsitas, and others, primarily in Fair Harbour, Chamiss Bay and Kyuquot.[546] KPL's annual sales of electricity are approximately $0.5 million or 1,700 megawatt hours.[547]

KPL's cost of capital was first set in 2006 at a 40.0 percent deemed equity component (i.e. 1.5 pps above the Benchmark Utility) and a 75 bps ROE premium above the Benchmark Utility (i.e. an allowed ROE of 9.50 percent). Based on KPL's small customer base and its major capital investment to set up its single phase distribution line, the BCUC recognized that KPL was in the higher risk category of utilities in BC. The BCUC set this cost of capital in 2006 considering the business and investment risks of KPL in comparison to other regulated

[544] 2016 FEI COC Decision, Directives 1 and 2; GCOC Stage 1 Decision, pp. 3; Nelson Hydro 2022 COSA and RD Decision, pp. 75–79.
[545] Calculated as: 86 bps less 126 bps.
[546] KPL 2024 Revenue Requirements, Decision and Order G-53-24 dated February 29, 2024 (KPL 2024 RRA Decision), p. 1.
[547] KPL 2024 RRA Decision, Table 1, pp. 5, 15, Exhibit B-1-2, Appendix 2, PDF p. 14.

utilities in BC, which generally had not been awarded a deemed equity component greater than 40.0 percent or an ROE premium greater than 75 bps at that time. [548] KPL's last cost of capital review was completed in 2014 and re-affirmed in 2021, in which the BCUC maintained the original 40.0 percent deemed equity component and 75 bps ROE premium.[549]

In its 2024 revenue requirements proceeding, KPL noted that due to its very small size and financial cost/benefits, it would not participate in Stage 2.[550] However, in the decision on the KPL 2024 Revenue Requirements proceeding, the BCUC found that KPL's current cost of capital will remain in effect on an interim basis pending the BCUC's final decision on Stage 2. The BCUC also stated that Stage 2 will "determine the cost of capital for most public utilities in BC, including KPL."[551]

While KPL did not submit evidence in Stage 2, it did respond to BCUC Information Request No. 1. KPL submits that it is most comparable to Nelson Hydro as they are both small electric utilities that purchase electricity from larger utilities under tariff conditions, and they are both unable to secure third-party debt.[552] Therefore, KPL states that it would expect a similar deemed equity component and ROE premium to Nelson Hydro in Stage 2.[553] KPL also states that it should have the highest deemed equity component and ROE premium across Stages 1 and 2 due to its small size, rugged terrain, and reliance on one customer for over 50 percent of its revenues.[554] Lastly, KPL confirms that it "would accept the [Stage 2 deemed equity component and ROE premium] decisions of the BCUC, unless patently unreasonable."[555]

Positions of Parties

BCOAPO was the only intervener to comment on KPL in its submissions. BCOAPO "urg[es] this Panel to recognize the state of the evidence in this matter is insufficient to justify any finding setting KPL's equity thickness and its ROE and to decline to do so until such a time as KPL provides the necessary evidence upon which the [BCUC] might rely when making its decision."[556]

Panel Determination

While there is limited information for KPL in comparison to other Stage 2 utilities in this proceeding, we acknowledge KPL's reasoning for limiting its participation based on the costs of participating being uneconomical due to its small size. Waiting until such a time that KPL provides further evidence on this matter would require a separate proceeding. We find that such additional process would not be regulatorily efficient and would be cost prohibitive for a small utility like KPL. Despite the limited information, the Panel finds that KPL's business risks can be reasonably assessed as similar to the other two electric utilities in Stage 2 operating in remote service

[548] Kyuquot Electric 2005 Tariff & Rates, Order G-11-06 with Reasons for Decision dated February 2, 2006, Appendix A, p. 3.
[549] KPL Application for Amendments to Revenue Requirements along with Certain Rate Matters, Order G-158-14 dated October 9, 2014, p. 3; KPL Revenue Requirements Application, Order G-213-21 dated July 12, 2021, pp. 10, 11, 14.
[550] KPL 2024 RRA Decision, p. 13.
[551] KPL 2024 RRA Decision, pp. 13, 14.
[552] Exhibit B5-3, BCUC IR 1.2.
[553] Exhibit B5-3, BCUC IR 1.4.1.
[554] Exhibit B5-3, BCUC IR 1.1.3.
[555] Exhibit B5-3, BCUC IR 1.4.
[556] BCOAPO Final Argument, p. 42.

areas (i.e. Boralex and Nelson Hydro). **Accordingly, the Panel sets a 5.0 pps equity premium, resulting in a 50.0 percent deemed equity component for KPL.**
As discussed in Section 3.1, we have determined that a 75 bps ROE premium is appropriate to reflect size. We have applied the same ROE premium here for KPL, which results in an allowed ROE of 10.40 percent.

Table 21 below provides a comparison of the currently approved versus previously approved cost of capital for KPL. The table lays out KPL's cost of capital beginning with the Benchmark Utility's cost of capital plus the approved equity and ROE premiums for KPL to arrive at KPL's cost of capital.

Table 21: Comparison of Previously and Currently Approved Cost of Capital for KPL

	Previously Approved[557]			Currently Approved		
	Deemed Equity Component	Allowed ROE	Weighted ROE	Deemed Equity Component	Allowed ROE	Weighted ROE
Benchmark Utility's cost of capital (for comparison)	38.5%	8.75%	3.37%	45.0%	9.65%	4.34%
KPL's premium	1.5 pps	75 bps	43 bps	5.0 pps	75 bps	86 bps
KPL's resulting cost of capital	40.0%	9.50%	3.80%	50.0%	10.40%	5.20%

As shown in Table 21 above, the currently approved cost of capital for KPL increases the differential between its and the Benchmark Utility's weighted ROE from the previously approved amounts by 43 bps.[558] This appropriately reflects the Panel's overall finding on KPL as similar to the other two Stage 2 electric utilities operating in remote service areas (i.e. Boralex and Nelson Hydro) and the lack of change in KPL's cost of capital since 2006.

4.0 Deemed Interest Rate

The capital structure of a utility is comprised of two components: an equity component and a debt component. Section 3.0 of this decision addressed the deemed equity component and allowed return on equity for the Stage 2 utilities. In this section, the Panel will address the deemed interest rate to be applied to the debt component for those Stage 2 utilities that require a deemed interest rate. The Fair Return Standard includes both a fair return on invested equity in the form of allowed ROE and a fair return on invested debt in the form of deemed interest; hence, the importance of determining the deemed interest rate in this proceeding.

In the 2013 GCOC Stage 1 Decision, the BCUC reaffirmed two principles as it relates to debt. First, deemed debt is appropriate for small utilities in cases where raising debt is not practical or not possible.[559] Second, deemed debt rates and durations should reflect the particular circumstances of each utility. Accordingly, the BCUC

[557] 2016 FEI COC Decision, Directives 1 and 2; GCOC Stage 1 Decision, pp. 3; KPL Revenue Requirements Application, Order G-213-21 dated July 12, 2021, pp. 10, 11, 14.
[558] Calculated as: 86 bps less 43 bps.
[559] 2013 GCOC Stage 1 Decision, p. 105.

determined that the cost of deemed debt for each utility should be addressed on a case-by-case basis.[560] In the 2013 GCOC Stage 1 Decision, the BCUC recommended a methodology as a guideline for setting the deemed debt rate on a go-forward basis when reviewing each utility's cost of deemed long-term debt.[561]

Throughout this proceeding, the Panel canvassed several matters related to deemed interest rate[562] including: the circumstance where a deemed interest rate is required, the determination and implementation of the deemed interest rate methodology, and the appropriateness of an automatic adjustment mechanism (AAM). The Panel will address each of these matters in turn below.

Corix, RDE, FAES, and Nelson Hydro provided evidence and submissions on the deemed interest rate.[563] PNG and Creative Energy did not comment because they do not require a deemed interest rate. PNG obtains an annual private rating report from Morningstar DBRS which is used by lenders to establish market rates for debt issuances by PNG.[564] Creative Energy seeks recovery of its interest costs based on actual or forecasted interest rates it prudently incurs or expects to incur.[565]

4.1 The Circumstances Requiring a Deemed Interest Rate

Corix, RDE, and FAES submit that a deemed interest rate is required when the utility does not have access to third-party debt.[566] FAES submits that unlike the cost of equity, the cost of issued debt is typically based on actual interest rates that can be objectively observed and determined. However, it may be inefficient or uneconomical for a small utility to issue debt on a standalone basis. In these circumstances, the utility may access the debt market through non-arm's length transactions with its parent company where the parent company issues the debt, and the utility subsidiary enters into an arrangement with the parent for a specific portion of that debt issue. In these situations, the actual interest rate may not be objectively observable and, therefore, a deemed cost of debt may be warranted.[567] FAES states that a deemed interest rate methodology is a transparent, efficient, and consistent manner of determining the interest expense to be passed along to ratepayers in the case of FAES's TES projects and can enhance regulatory efficiency and reduce the administrative burden on small TES projects.[568]

Positions of Parties

RCIA supports a single deemed interest rate methodology for establishing a deemed interest rate for a utility in situations where a utility does not have any debt or is incapable of engaging in arms-length transactions.[569] RCIA submits this methodology would lead to greater efficiency and less uncertainty in the regulatory process,

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[560] 2013 GCOC Stage 1 Decision, p. 105.
[561] 2013 GCOC Stage 1 Decision, p. 110.
[562] Previously referred to as "cost of deemed debt" in the 2013 GCOC Stage 1 Decision.
[563] Exhibit B6-9, Corix Evidence, Section 4; Exhibit B6-9-2, Corix MPA Evidence Submission, Written Evidence of Morrison Park Advisors Inc. (Corix MPA Evidence Submission); Exhibit B8-7, BCUC IR 11.1; Exhibit B3-7, FAES Evidence, Section 5; Exhibit B4-6, Nelson Hydro Evidence, Appendix 1, Appendix 2.
[564] PNG Final Argument, p. 32.
[565] Exhibit B7-8, Creative Energy Evidence, p. 3.
[566] Exhibit B3-7, FAES Evidence, p. 15; Exhibit B8-7, BCUC IR 11.1; Exhibit B6-9, Corix Evidence, p. 8.
[567] Exhibit B3-7, FAES Evidence, p. 15.
[568] Exhibit B3-7, FAES Evidence, pp. 15, 17.
[569] RCIA Final Argument, p. 64.

reduced regulatory burden, and allow for a more direct and clearer comparison of deemed costs of debt across different utilities.[570]

The CEC opposes the establishment of a deemed interest rate.[571] The CEC states that the regulatory process of establishing a deemed interest rate would be unnecessarily complex and lead to opportunities for some public utilities with financing advantages to make unwarranted gains over and above standard cost of service recovery.[572]

In reply to the CEC, Corix submits that the Standalone Principle would require a deemed interest rate methodology that would be applicable to those utilities with no third-party debt.[573] The CEC did not respond to such a situation.[574] Corix further submits that the existing deemed interest rate methodology yields significantly lower absolute interest rates than KPL's and Creative Energy's actual cost of debt that have been approved by the BCUC and flowed through to customers. Corix goes on to state that it is a fallacy to conclude that a deemed interest rate methodology favours the shareholder over the customers.[575]

Panel Determination

As already noted, the Fair Return Standard applies to both the deemed equity component and the deemed debt component of a utility's capital structure. Therefore, **the Panel finds that establishing a deemed interest rate continues to be warranted when a utility does not have third-party debt. The Panel further finds that a deemed interest rate serves as an effective mechanism for setting the appropriate cost of debt in determining a utility's fair return when there is no observable debt or where the utility does not incur actual financing costs.** A deemed interest rate methodology serves as a proxy that reflects the debt rate a utility may be able to obtain on its own rather than relying on its parent company, and thus, satisfies the Standalone Principle. Having a deemed interest rate also conforms with the Fair Return Standard because the utility's investors are afforded an opportunity to earn a fair return on the debt component of their invested capital at market rates.

4.2 The Determination of the Deemed Interest Rate

In the 2013 GCOC Stage 1 Decision, the BCUC recommended the use of the following methodology as a guideline for setting the deemed debt rate on a go-forward basis:[576]

> **Step 1**: Assign a credit rating on a stand-alone basis, and then obtain indicative quotes from investment dealers or banks based on the credit rating of a comparable proxy issuer. Using proxy companies that are engaged in the power sector or energy infrastructure can help to minimize subjectivity […] A reasonable deemed stand-alone rating for a small regulated utility appears to be in the range of BBB to BBB(low), with the deemed debt cost set on this basis.
>
> **Step 2**: Determine a Government of Canada (GoC) bond yield reflecting the proposed term of debt that could be either the 10-year or 30-year bond as the benchmark, or an interpolation of

570 RCIA Final Argument, pp. 60, 64.
571 The CEC Final Argument, p. 3.
572 The CEC Final Argument, p. 3.
573 Corix Reply Argument, p. 27.
574 Corix Reply Argument, p. 26.
575 Corix Reply Argument, p. 27.
576 2013 GCOC Stage 1 Decision, pp. 107–108, 110.

the two. The selected benchmark should reflect the long-term nature of utility assets, contractual terms and available debt terms.

Step 3: Determine the credit spread of a comparable corporate proxy issuer in similar industries or lines of business (e.g., regulated utility, power generation, energy infrastructure) at the same term to maturity as that selected as the benchmark GoC bond.

In this proceeding, Corix, RDE, FAES, and Nelson Hydro each have their own preferred methodology, but they all include: (i) reference to the GoC long-term bond, (ii) a premium to reflect the lower credit rating of small utilities, and (iii) issuance costs.[577]

Nelson Hydro and Corix engaged Morrison Park Advisors (MPA) to provide expert support in this proceeding to review and comment on the issue of the choice of a deemed interest rate to be applied to small utilities in BC that are owned by a larger entity.[578] MPA makes three key recommendations in its report which are discussed in more depth below:

- Refer to yields associated with non-investment Grade issuers at the level of BB+ or BB as there does not appear to be evidence that small utilities in Canada with rate bases under $50 million would qualify for an investment Grade credit rating. [579]
- Include a 50 bps adder to compensate for the relative size of transaction costs for small utilities.[580] MPA states that given the prevalence of 10-year loans for small utilities and the high costs associated with loan sizes that are common at this level (i.e. anywhere between $5 million and $20 million), it believes that a properly amortized transaction cost expectation would be 50 bps per year.[581]
- Since the debt products typically used by small utilities require the repayment of principal during the term of the borrowing, unlike the interest-only debt products available to larger utilities, MPA suggests compensating small utilities for this additional burden either through 1) modifying the deemed debt component assumed for small utilities or 2) including a further adder in the deemed interest rate. [582]

Regarding its recommendation relating to Canadian small utilities which are non-investment grade, MPA states that many of the analyses in credit rating methodology can result in a shift of credit rating conclusions due to, among others, small utilities' lack of liquidity, lack of diversity of revenue sources (and risk of customer loss), lack of depth of resources to withstand economic shocks, and lack of portfolio diversification.[583] MPA states that absent actually retaining the services of a ratings agency to systematically review a basket of small utilities in BC, it is difficult to support the conclusion that two or three notches of discount against FEI's credit rating (i.e. from A- to BBB+, or from A- to BBB or BBB-) is the correct assumption to make for the purposes of setting deemed interest rates.[584]

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[577] Exhibit B6-9, Corix Evidence, p. 13; Exhibit B8-7, BCUC IR 11.1; Exhibit B3-7, FAES Evidence, pp. 16–18; Exhibit B4-6, Nelson Hydro Evidence, Appendix 1 – Letter from the MFA, PDF p. 31.
[578] Exhibit B6-9-2, Corix MPA Evidence Submission, cover letter, p. 3; Exhibit B4-6, Nelson Hydro Evidence, Appendix 2 – Report from MPA, p. 3
[579] Exhibit B6-9-2, Corix MPA Evidence Submission, p. 3.
[580] Exhibit B6-9-2, Corix MPA Evidence Submission, p. 3.
[581] Exhibit B6-9-2, Corix MPA Evidence Submission, p. 20.
[582] Exhibit B6-9-2, Corix MPA Evidence Submission, p. 3.
[583] Exhibit B6-9-2, Corix MPA Evidence Submission, p. 16.
[584] Exhibit B6-9-2, Corix MPA Evidence Submission, pp. 17–18.

MPA analyzes the average yield spreads between the bonds of utilities and GoC bonds. MPA's analysis includes four Canadian utilities that currently have a BBB- issuer rating from S&P Global Ratings with bonds that have maturity dates approximately 5 or 10 years in the future. MPA also analyzes two Canadian utilities (each of which also has a similarly rated subsidiary) that currently have ratings of either BB+ or BB- with bonds that mature in approximately five years. MPA clarifies that BB utilities do not have any bonds currently trading that are approximately 10 years away from maturity, so a 10-year analysis was not possible. MPA notes that given the relatively small number of bonds that were examined, the statistical error range for the calculated averages would be large. Normally, spread analysis is conducted for much larger populations of bonds. However, MPA focused exclusively on Canadian utility bonds, rather than examining a larger population of BBB-, BB+ and BB- bonds from companies in other industry sectors. Table 22 below provides a summary of MPA's analysis calculated for the January 1, 2024 to March 31, 2024 period.

Table 22: Selected Canadian Utility Bond Yield Spreads[585]

	Spread to GoC		
	5 year	10 year	Difference
BBB-	163	197	34
BB+ or BB-	255	N/A	
Difference	92		

MPA also calculates the difference in spread to be 152 bps for 5-year bonds using data as of October 2022, rather than the 92 bps as was calculated for the January 1, 2024 to March 31, 2024 period as shown in Table 22 above. Therefore, MPA states that the 92 bps non-investment grade premium recommended in its report may be considered a "floor" for this value, based on conditions in the relatively recent past.[586]

Corix states that the key task in setting a deemed interest rate for a standalone TES utility is to estimate a lender's offered interest rate for the standalone risk of the TES utility. Corix proposes that the deemed interest rate should be based on the sum of:[587]

1. GoC 10-year bond yields based on the average of the last trailing 12 months;
2. The corporate credit spreads on the GoC 10-year bonds for BBB and BBB(low) rated utilities based on the average of the last trailing 12 months;
3. Non-investment grade lending premium of 92 bps; and
4. A deemed issuance fee of 50 bps.

Corix explains that its proposal to include a non-investment grade lending premium of 92 bps and the deemed issuance fee of 50 bps is based on MPA's evidence. [588] Corix states that applying the methodology outlined above, the GoC 10-year bond yields would be updated along with the observed BBB to BBB(low) utility corporate credit spreads. The non-investment grade lending premium and the issuance fee would be fixed and

[585] Exhibit B6-9-2, Corix MPA Evidence Submission, Table 3, p. 18.
[586] Exhibit B4-10, BCOAPO IR 8.3.
[587] Exhibit B6-9, Corix Evidence, p. 12.
[588] Exhibit B6-9, Corix Evidence, p. 13.

can be updated in the next GCOC proceeding.[589] Corix calculates that this methodology results in a deemed interest rate of 6.91 percent.[590] RDE supports Corix's proposed deemed interest rate methodology.[591]

FAES believes there is no compelling reason to deviate from the BCUC's previously approved approach to determining the deemed cost of debt for a small TES project.[592] Considering the small size and lack of diversity of TES projects, the BBB/BBB(low) rating continues to remain appropriate and ensures that the deemed interest rate reflects the risk profile of FAES and not that of its parent company.[593] FAES further states that continuing to rely on the 10-year rates remains appropriate, as some banks are not always able to provide longer tenure debt indicative spreads for all comparable utilities due to market factors.[594]

FAES raised concerns that MPA's recommendation to change the deemed credit rating from BBB to BBB(low) to BB+ to BB, which is a non-investment grade rating, is impractical and could have adverse business implications.[595] FAES elaborates that gathering the information on the cost of debt of non-investment grade entities required "painstaking research" on the part of MPA and left a considerable margin of error. FAES states that it would theoretically be possible to compare against non-utility sectors, but other sectors do not typically issue debt for longer terms (i.e. 10 to 30 years) like utilities do.[596] Moreover, counterparties are generally very reluctant to transact with non-investment grade entities.[597]

FAES does agree, however, with MPA's recommendation to increase the transaction costs adder to 50 bps. FAES notes that this would be consistent with the issuance fee that other FortisBC entities currently pay for new bond financing with 16-year terms or longer with typical bonds issued by FEI or FBC being 10 to 30 years.[598]

While Nelson Hydro filed the report by MPA as part of its evidence similar to Corix, it ultimately recommends the approach set out in the MFA Letter, which is to take the then-current 30-year Canada bond yield and add 325 basis points.[599] The 325 bps is calculated from three components: 160 bps for the 30-year average utility versus GoC curve, a 160 bps private placement premium, and 5 bps for issuance costs.[600]

Positions of Parties

BCOAPO is the only intervener that commented on the specifics of the deemed interest rate methodology. BCOAPO submits that while the methodology should specify the components to be considered, it should not include specific values. In BCOAPO's view, there are sufficient differences between the various utilities that it would be impractical to establish a common premium to be applied to all non-investment grade utilities (e.g. those rated less than BBB/BBB(low)). As a result, BCOAPO does not support the approach set out by Corix where

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589 Exhibit B6-9, Corix Evidence, p. 13.
590 Exhibit B6-9, Corix Evidence, p. 13.
591 Exhibit B8-7, BCUC IR 11.1.
592 Exhibit B3-7, FAES Evidence, p. 16.
593 Exhibit B3-7, FAES Evidence, p. 17.
594 Exhibit B3-7, FAES Evidence, p. 18.
595 Exhibit B3-8, BCUC IR 10.1.
596 Exhibit B3-8, BCUC IR 10.1.
597 Exhibit B3-8, BCUC IR 10.1.
598 Exhibit B3-8, BCUC IR 10.2.
599 Exhibit B4-8, BCUC IR 6.7.
600 Exhibit B4-6, Nelson Hydro Evidence, Appendix 1 – MFA Letter, PDF p. 31.

the non-investment grade premium is set at a fixed 92 bps amount in this proceeding and held constant until the next GCOC proceeding.[601]

BCOAPO also submits that rather than using the average spread as calculated by MPA or the private placement premium provided in Nelson Hydro's evidence, BCOAPO supports either:

1. Retaining the BCUC's current approach and permitting utilities to make their case if they believe a higher deemed debt rate is appropriate; or
2. Retaining the current approach but including provision for a nominal premium (e.g. no more than 50 bps) for additional borrowing costs for non-investment grade utilities while permitting utilities to make their case if they believe a higher deemed debt rate is appropriate.[602]

BCOAPO's concern is that utilities are unlikely to apply for and provide evidence to support a deemed cost of debt rate that is less than what would be derived using the recommended methodology. Thus, without other parties or the BCUC itself providing contrary evidence, there would be no basis to justify a lower deemed cost of debt. BCOAPO submits that its approach would likely negate the need for such evidence and the utility would only be required to provide additional evidence when it believed a higher deemed cost of debt was warranted and sufficiently material to justify providing the evidence to support it.[603]

Panel Determination

The Panel determines that the deemed interest rate methodology should be based on the sum of:

1. **GoC 10-year bond yields based on the average of the last trailing 12 months;**
2. **The corporate credit spreads on the GoC 10-year bonds for BBB and BBB(low) rated utilities based on the average of the last trailing 12 months;**
3. **Non-investment grade lending premium of 92 bps; and**
4. **A deemed issuance fee of 50 bps.**

The Panel finds that tracking utility corporate credit spreads on the GoC 10-year bonds for BBB and BBB(low) rated utilities based on the average of the last trailing 12 months is consistent with what was approved in the 2013 GCOC Stage 1 Decision and was uncontroversial in this proceeding. The Panel views GoC 10-year bond yields and Corporate credit spreads on the GoC 10-year bonds for BBB and BBB(low) rated utilities track regularly updated market information, ensuring that the deemed interest rate determined by the methodology appropriately reflects market rates at the time the methodology is applied, and therefore continues to be an important component of the deemed interest rate methodology.

Two additional issues arose regarding the deemed interest rate methodology: (i) whether small utilities are considered non-investment grade, and (ii) whether an additional premium to account for deemed issuance fees is appropriate. These two issues are addressed below.

[601] BCOAPO Final Argument, p. 76.
[602] BCOAPO Final Argument, p. 76.
[603] BCOAPO Final Argument, pp. 76–77.

Regarding whether small utilities are considered non-investment grade, the Panel is persuaded by MPA's evidence that small utilities in Canada with rate bases under $50 million are unlikely to qualify for an investment grade credit rating. The Panel is further persuaded that those Stage 2 utilities that would use the deemed interest rate methodology would receive a borrowing cost consistent with a non-investment grade entity rated at BB+ or BB- for the purpose of setting their deemed interest rate based on the risk assessment for each utility as reviewed earlier in this decision. Regarding FAES's submission that a non-investment grade rating could have adverse business implications as counterparties are generally very reluctant to transact with non-investment grade entities, the Panel clarifies it has not conducted a formal credit rating exercise for each Stage 2 utility and is not making a finding that they are non-investment grade in terms of financial health.

The proposed premium to account for additional borrowing costs for non-investment grade utilities ranges from 50 bps as proposed by BCOAPO to 92 bps as proposed by Corix, with MPA's additional analysis using October 2022 data resulting in 152 bps. **The Panel finds 92 bps as the appropriate non-investment grade lending premium on the basis of the expert evidence which is supported by market data and analysis.** The Panel notes FAES's concern that setting a non-investment grade rating is impractical, as the information on the cost of debt of non-investment grade entities is not readily available. Given the lack of market data on non-investment grade credit spreads, however, the Panel views that it is regulatorily efficient to establish a fixed premium using available analysis in this proceeding to avoid the need for each utility to quantify a proposed non-investment grade premium on a case-by-case basis in future rates proceedings.

Regarding the deemed issuance fee, the Panel is persuaded by MPA's analysis that a 50 bps deemed issuance fee would be consistent with the issuance fee that can reasonably be assumed to apply if these small utilities were to issue debt on a standalone basis. The 50 bps deemed issuance fee is further supported by FAES's confirmation that it is consistent with the issuance fee that other FortisBC entities currently pay for new bond financing with 16-year terms or longer, with typical bonds issued by FEI or FBC being 10 to 30 years. **Accordingly, the Panel finds that a 50 bps deemed issuance fee within the deemed interest rate methodology is appropriate.**

4.3 Implementation of the Deemed Interest Rate Methodology

This section examines three other questions related to the deemed interest rate methodology that are included in the scope of Stage 2:

1. Is an AAM warranted for the deemed interest rate?[604]
2. Should the deemed interest rate methodology be standardized or adaptable for different circumstances and evidence?[605]
3. What should the effective date be for the deemed interest rate?[606]

[604] Order G-6-24 dated January 11, 2024, Appendix B.
[605] Order G-172-24 dated June 24, 2024, Appendix B.
[606] Order G-6-24 dated January 11, 2024, Appendix B.

4.3.1 Automatic Adjustment Mechanism for the Deemed Interest Rate

In the 2013 GCOC Stage 1 Decision, the BCUC stated that because the deemed long-term debt by definition is set for a fixed term, the BCUC found that adjustments will not be necessary during the term of the loan. The only reason for a re-opener would be the situation where a small utility actually issues new debt, or there is a measurable change in market conditions or actual debt cost. The impact of the rate change could be considered in a subsequent revenue requirement review.[607] In this proceeding, the Panel sought input on having an AAM in place for the deemed interest rate. Corix, RDE, FAES and Nelson Hydro are the only parties that provided submissions on this topic.

Corix and RDE state they are unable to comment on an AAM, as there is a lack of details on how an AAM would be formulated.[608] Nelson Hydro is not in favour of an AAM. [609] FAES is the only party that supports an AAM in principle. [610]

FAES submits that, consistent with the 2013 GCOC Stage 1 Decision, the cost of debt rates and duration should reflect the particular circumstances of the utility, and that a more flexible approach is preferable.[611] Generally speaking, fixing the interest rate set by the formula for periods longer than one year is preferred since it would provide more rate stability for customers and is more consistent with the definition of the long-term debt.[612] FAES further submits that the ability to periodically update the relevant deemed interest rate via an interest rate AAM would result in improved regulatory and administrative efficiency. This enables utilities to plan ahead for these adjustments and effectively communicate these changes to their customers.[613]

Nelson Hydro is not in favour of an AAM for deemed long-term debt. Nelson Hydro prefers an approach that crystallizes notional bullet[614] borrowing for a long period (e.g. 20 to 30 years) and maintains the relevant characteristics of that notional debt throughout. When necessary to add a new notional borrowing, that can be built into the next rate proceeding.[615]

Positions of Parties

The CEC submits that a deemed interest rate is not warranted. However, if the BCUC chooses to develop a deemed interest rate, the CEC recommends that it should be available with periodic updates as required in order to remain current.[616] No other interveners provided comments on implementation matters for the deemed interest rate methodology.

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[607] 2013 GCOC Stage 1 Decision, p. 110.
[608] Exhibit B6-9, Corix Evidence, p. 14; Exhibit B8-7, BCUC IR 10.1.
[609] Exhibit B4-8, BCUC IR 6.7.
[610] Exhibit B3-7, FAES Evidence, p. 18.
[611] Exhibit B3-7, FAES Evidence, p. 18.
[612] Exhibit B3-7, FAES Evidence, pp. 18–19.
[613] Exhibit B3-7, FAES Evidence, p. 19.
[614] Exhibit B4-6, Nelson Hydro Evidence, p. 3-16; Exhibit B4-8, BCUC IR 5.2. Nelson Hydro explains "bullet debt" refers to debt where there was no routine principal repayment required from cash flow. Nelson Hydro states the maximum debt Nelson Hydro could sustain would be lower with amortizing debt compared to bullet debt.
[615] Exhibit B4-8, BCUC IR 6.7.
[616] The CEC Final Argument, p. 21.

Panel Determination

The Panel finds that the deemed interest rate methodology, as determined above, sufficiently accounts for changes in the market in the absence of an AAM by tracking the GoC 10-year bond yields and the BBB to BBB(low) utility corporate credit spreads, which would be updated based on the latest market information available at the time the deemed interest rate methodology is applied. Given a deemed interest rate methodology has already been established, the Panel considers little regulatory efficiency and simplicity can be gained from the adoption of an AAM. For utilities that file revenue requirements applications with the BCUC on a regular interval, the Panel expects the deemed interest rate would be reviewed regularly as part of the revenue requirements application process to ensure the deemed interest rate continues to meet the Fair Return Standard.

For utilities that do not file rate applications on a regular basis, if market conditions change significantly to the extent that the approved deemed interest rate no longer meets the Fair Return Standard, the BCUC may review the deemed interest rate as part of a regulatory filing to assess any changes that may be required to reflect new circumstances. Accordingly, we decline to establish an AAM in favour of periodic regulatory reviews to set the deemed interest rate, which we consider to be a better, more thorough and transparent forum for ensuring that a utility's cost of debt meets the Fair Return Standard than reliance on a formula which may or may not accurately reflect all relevant factors. Having so determined, we see no need to deal with the specifics of any potential AAM formula and its possible application in this proceeding.

4.3.2 Flexibility to Apply Different Deemed Interest Rate Methodologies

In the 2013 GCOC Stage 1 Decision, the BCUC stated that to allow flexibility, utilities will have an option to apply for a rate adjustment if there is a measurable change in market conditions or in actual debt costs.[617]

In this proceeding, the Panel sought comment from parties on whether the BCUC should establish a single deemed interest rate methodology to apply to all public utilities that use a deemed interest rate or whether different public utilities should be able to apply for different deemed interest rate methodologies based on their specific circumstances and evidence.[618] Corix, RDE and Boralex are the only parties that provided their positions on this matter, as further described below.

Corix submits that Stage 2 should set the general framework on how to calculate the deemed interest rate, but it is the utility's individual rate hearing that would decide the resulting deemed interest rate amount. In that utility's rate hearing, the utility should be permitted to propose a departure from the general framework if warranted by its own circumstances. Corix expects that the onus would be on the utility to provide sufficient justification to support any departure from the methodology.[619]

RDE supports a "single methodology" for setting deemed interest rates for different classes of utilities to align with how different types of utilities have been considered in Stage 2 and reflect their unique financing considerations.[620]

[617] 2013 GCOC Stage 1 Decision, p. 110.
[618] Order G-172-24 dated June 24, 2024, Appendix B.
[619] Exhibit B6-9, Corix Evidence, p. 8.
[620] RDE Final Argument, p. 5.

Consistent with the TES Default, RDE submits that TES utilities should be able to request a deviation from the single deemed interest rate methodology, providing justification for the difference in approach. This flexibility would allow TES utilities to reflect their specific circumstances and financing needs should the single methodology not provide a fair return for the shareholder(s) or adversely affect customer rates. TES utilities will need to weigh the effort required to justify the deviation to the BCUC against the potential benefits to shareholders and ratepayers.[621]

Boralex does not believe that the BCUC should establish a single deemed interest rate methodology to apply to all public utilities that use a deemed interest rate. The appropriate deemed interest rate applicable to each utility depends on the utility's operations and business risks, capital structure, and other financial metrics. Accordingly, Boralex believes that different public utilities should be able to apply different deemed interest rate methodologies based on their specific circumstances and evidence, such as a part of a utility's rate application.[622]

SFU sees merit in simplifying the calculation of the deemed interest rate, but states that it is "difficult and unfair" to use a single deemed interest rate if utilities have different levels of equity and financial leverage.[623] SFU believes that in principle, long-term assets should be financed with long-term financing. Accordingly, assets should be deemed to be financed at the prevailing deemed interest rate for longer terms (e.g. 10-year terms) and refinanced at the end of the term, except in unusual market conditions. SFU states that this would be similar to how a utility with actual third-party debt would be financed.[624]

Panel Determination

Consistent with the Panel's finding regarding the TES Default earlier in this decision, **the Panel finds that utilities should be free to apply for different deemed interest rate methodologies based on their specific circumstances.** These alternate methodologies could result in a deemed interest rate that is higher or lower than the resulting deemed interest rate based on the methodology established in this proceeding, but the review of such an alternate methodology would be subject to assessment by a future BCUC panel.

As a result and given the lack of evidence to suggest different classes of utilities would incur significantly different borrowing costs, all else equal, the Panel finds RDE's suggestion to establish a different deemed interest rate methodology for different classes of utilities is not warranted.

4.3.3 Effective Date of the Deemed Interest Rate Methodology

Corix, RDE, and FAES all submit that the effective date for the deemed interest rate methodology should be the same as the deemed equity component and allowed ROE.[625] No other parties made specific submissions on this matter.

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621 RDE Final Argument, p. 5.
622 Boralex Final Argument, pp. 10–11.
623 SFU Final Argument, p. 23.
624 SFU Final Argument, p. 24.
625 Exhibit B6-9, Corix Evidence, p. 14; Exhibit B8-7, BCUC IR 11.1; Exhibit B3-7, FAES Evidence, p. 19.

Corix submits that for those ongoing rate applications that are under interim rates subject to this Stage 2 decision, those rate applications should be allowed to apply the deemed interest rate methodology based on the outcome of this decision.[626] For utilities that do not have ongoing rate applications with interim rates in place subject to this decision, Corix submits that the effective date could be set to be the 1st of the month following the issuance of this decision, subject to any relevant compliance filings that need to be submitted to BCUC for review and acceptance/approval.[627] RDE concurs with Corix's position.[628]

FAES submits that the effective date for the deemed interest rate should be consistent with the effective date for other components of the cost of capital and rates for a particular TES project.[629] Nevertheless, FAES believes that the effective date for this Stage 2 decision should be left up to each utility to determine according to their specific circumstances in order to maintain the same cadence as has been utilized for each utility's past rate adjustments.[630]

Panel Determination

The Panel determines that the deemed interest rate methodology established above is effective January 1, 2024, for those utilities that use a deemed interest rate in setting their cost of debt. The Panel expects that each Stage 2 utility that uses the deemed interest rate methodology and wishes to adopt the currently approved methodology, effective January 1, 2024, will do so in accordance with the implementation processes as outlined in Section 5.1 of this decision. Any application received after January 31, 2025, to use the deemed interest rate determined in this decision will be applied on a go-forward basis. No action is required for those Stage 2 utilities or other utilities in BC that do not currently use the deemed interest rate methodology.

5.0 Other Matters

In this last section, the Panel discusses three remaining matters: implementation of this decision on the rates for Stage 2 utilities, the process for review of items in scope after the completion of Stage 2, and confidentiality of certain exhibits within Stage 2.

5.1 Implementation of Stage 2 Decision

As part of the GCOC Stage 1 Decision, the BCUC established interim rates, effective January 1, 2024, on a refundable or recoverable basis, for all other utilities, except FBC, that used the Benchmark Utility at the time of that order to set their cost of capital pending the BCUC's final decision on Stage 2.[631] As part of Stage 2 of this proceeding, utilities provided their preferred implementation approaches for the outcome of the Stage 2 decision on their respective rates in 2024 and beyond. In June 2024, the BCUC also invited letters of comment from public utilities that did not actively participate in Stage 2 to indicate their preferred implementation

[626] Exhibit B6-9, Corix Evidence, p. 14.
[627] Exhibit B6-9, Corix Evidence, p. 14.
[628] Exhibit B8-7, BCUC IR 11.1.
[629] Exhibit B3-7, FAES Evidence, p. 19.
[630] Exhibit B3-7, FAES Evidence, p. 19.
[631] GCOC Stage 1 Decision, p. 142.

approach, as the outcome of Stage 2 may impact their business.[632] The BCUC did not receive any letters of comment by the deadline.

For all of its divisions, PNG is currently providing service under the rates approved on an interim and recoverable or refundable basis from January 1, 2024 to December 31, 2024, pending the outcome of this Stage 2 decision.[633] PNG's preferred approach to implementing changes to the cost of capital elements that may arise from this proceeding would be to capture the net impact arising from the Stage 2 decision on 2024 rates in deferral accounts that would attract interest at the division's respective short-term interest rate. The disposition of the deferred amounts would then be addressed in the respective division's next revenue requirements application. PNG submits that this is the most appropriate solution for implementing the Stage 2 decision, as it will ensure that the impacts of changes are recovered or refunded across all customer rate classes; it is the most efficient, as it avoids the administrative and cost burden of rebilling or refunding customers for 2024 impacts; and it is consistent with past cost of capital proceedings.[634]

Corix provides its preferred implementation for each of its impacted utilities as follows:

- Corix BMDEU has an on-going rates proceeding to review its rates for 2024 and 2025, effective March 1, 2024 and January 1, 2025, respectively, which are for SFU and UniverCity customers.[635]
    - For BMDEU - SFU, any cost of capital changes effective January 1, 2024, should be incorporated into rates since SFU does not have a long-term deferral account. Corix states that this could be done through a compliance filing to its 2024 to 2025 revenue requirements and rates proceeding.[636]
    - For BMDEU - UniverCity, the impact of cost of capital changes, effective January 1, 2024, could be incorporated into rates in a similar manner to SFU. However, Corix prefers that the impact to UniverCity customers be captured in the existing Revenue Deficiency Deferral Account until the cost of capital forecast can be updated in the next revenue requirement and rates application. Corix anticipates that the next revenue requirement and rates application for BMDEU will be submitted in Q4 of 2025 and would include 2026 as a test year. Therefore, only two years' worth of impact (2024 and 2025) would be captured in the Revenue Deficiency Deferral Account.[637]
- For UBC NDES and DGE, Corix notes that while they do not have active rates proceedings, the impact of cost of capital changes, effective January 1, 2024, should be captured in the existing Revenue Deficiency Deferral Accounts until such time that a revenue requirement and rates application can be filed.[638]

Creative Energy states that its preference is to preserve interim rates for 2024 for ease of administration and to allow for timely completion of the processes for determining the revenue requirements for the Core TES and

[632] Exhibit A-45, Letter dated June 24, 2024.
[633] PNG 2023–2024 Revenue Requirements Application for the PNG-West Division, Decision and Order G-339-23 dated December 11, 2023, p. 35; PNG(NE) 2023–2024 Revenue Requirements Application for the Fort St. John/Dawson Creek and Tumbler Ridge Divisions, Decision and Order G-19-24 dated January 22, 2024, p. 29.
[634] Exhibit B9-10, BCUC IR 10.1.
[635] Corix BMDEU 2024-2025 Revenue Requirements and Rates, Exhibit B-1, Cover Letter, p. 1.
[636] Exhibit B6-12, BCUC IR 9.1.
[637] Exhibit B6-12, BCUC IR 9.1.
[638] Exhibit B6-12, BCUC IR 9.1.

rates for the Mount Pleasant DCS. Creative Energy states that rates for the SODO DCS have been approved through 2025[639] and it plans to submit a rates application for the SODO Heating TES.[640]

Creative Energy's Core TES is currently providing service under the rates approved on an interim and recoverable or refundable basis for January 1, 2024 to December 31, 2024 pending the outcome of this Stage 2 decision.[641] In October 2024, the BCUC issued its decision in Creative Energy's Core TES 2024 Revenue Requirements proceeding. The BCUC directed Creative Energy to establish a Revenue Variance Deferral Account for the Core TES to record the variance between the original interim rate and the interim thermal energy service rate as updated, pursuant to the decision in Creative Energy's Core TES 2024 Revenue Requirements proceeding. The BCUC also directed Creative Energy to file a final compliance filing for the Core TES following the BCUC's final decision on Stage 2 of this GCOC proceeding, in accordance with this decision, that includes updated financial schedules and amended tariff pages.[642]

The Mount Pleasant DCS is currently providing service under the capacity charge approved on an interim and recoverable or refundable basis for January 1, 2024 to December 31, 2026, pending the outcome of this Stage 2 decision.[643] In October 2024, the BCUC issued its decision on the CEMP Rates for the Mount Pleasant DCS proceeding (CEMP Mount Pleasant DCS 2024–2026 Rates Decision). The BCUC directed CEMP to establish a Revenue Variance Deferral Account for the Mount Pleasant DCS to record the difference between revenue collected under the 2024 capacity charge approved on an interim basis by Order G-350-23 and the 2024 capacity charge resulting from the directives and determinations in the CEMP Mount Pleasant DCS 2024–2026 Rates Decision. The BCUC also directed CEMP to file a proposal to address the refund or recovery of any amounts related to the variance between interim and permanent rates for the Mount Pleasant DCS within 30 days of the final decision on Stage 2 of this GCOC proceeding, or as otherwise directed by the BCUC, once permanent rates are established.[644]

RDE is currently providing energy under the rates approved on an interim and recoverable or refundable basis for January 1, 2024 to December 31, 2025, pending the outcome of this Stage 2 decision.[645] RDE wishes to see the changes resulting from Stage 2 implemented in small TES utilities' next revenue requirement applications, with an effective date of January 1, 2024. Should utilities not have a revenue requirement application in progress, RDE states that they should be afforded the opportunity to reflect in an existing revenue deficiency deferral account the difference in rates between their existing rate and that which would result from the Stage 2 decision.[646]

Boralex is currently providing service to BC Hydro under the rates approved on an interim and recoverable or refundable basis for January 1, 2024 to December 31, 2027, pending the outcome of this Stage 2 decision.[647]

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[639] SODO Heating TES and DCS Rates Decision.
[640] Exhibit B7-9, BCUC IR 8.1.
[641] Creative Energy 2024 Revenue Requirements for the Core Thermal Energy System, Decision G-272-24 dated October 24, 2024, p. 31.
[642] Creative Energy 2024 Revenue Requirements for the Core Thermal Energy System, Decision G-272-24 dated October 24, 2024, pp. 31–32.
[643] CEMP Mount Pleasant DCS 2024–2026 Rates Decision, pp. 4, 15.
[644] CEMP Mount Pleasant DCS 2024–2026 Rates Decision, pp. 15–16.
[645] River District Energy Limited Partnership 2024 to 2025 Interim Rates, Order G-94-24 dated March 27, 2024, Directive 1.
[646] Exhibit B8-7, BCUC IR 12.1.
[647] Boralex 2023 to 2027 Rates for Service to BC Hydro, Decision and Order G-351-23 dated December 14, 2023, pp. 11, 13.

Boralex proposes to submit a compliance filing with the BCUC to reflect any changes in its revenue requirement and rates for service to BC Hydro for 2024 to 2027 as a result of the Stage 2 decision. Any difference between Boralex's interim and final approved rates between January 1, 2024 and the date of approval of the final approved rates would then be recovered or refunded to BC Hydro through a subsequent one-time adjustment to Boralex's next invoice to BC Hydro. Boralex prefers this approach to implement changes to its cost of capital resulting from this proceeding because it is administratively simple and consistent with past practice.[648]
Nelson Hydro is currently providing service to Rural customers under the rates approved on an interim and recoverable or refundable basis for January 1, 2024 to December 21, 2024, pending the outcome of this Stage 2 decision.[649] Nelson Hydro states that in its 2024 revenue requirement proceeding it proposed a revenue variance deferral account for any variances in interim and permanent rates that flow from the utility's rate applications in 2024 and 2025. Nelson Hydro's preferred approach to implementing the outcome of the Stage 2 decision is to use this deferral account, as it allows time to communicate the changes and their impact to ratepayers, reduces the administrative burden of adjusting rates mid-year, and improves overall rate implementation efficiency by combining it with any changes resulting from Nelson Hydro's 2024 revenue requirement proceeding.[650] In June 2024, the BCUC issued its decision on Nelson Hydro's 2024 revenue requirement proceeding. The BCUC approved Nelson Hydro's request to expand the scope of the 2023 Revenue Variance Deferral Account, which it must rename as Revenue Variance Deferral Account, to record the revenue difference between interim and permanent rates that flow from the 2024 revenue requirement, as well as future revenue requirements upon request from Nelson Hydro and approval by the BCUC. [651] In October 2024, Nelson Hydro filed its 2025 revenue requirement application.[652]

KPL is currently providing service under the rates approved on an interim and recoverable or refundable basis for January 1, 2024 to December 31, 2024, pending the outcome of this Stage 2 decision.[653] KPL did not indicate a preferred implementation approach for the impact of the Stage 2 decision on its current interim 2024 rates.[654] However, in April 2024, the BCUC directed KPL to apply for a revised deemed interest on notional debt or permanent rates within 45 days of the date of the Stage 2 decision.[655]

Positions of Parties

Interveners did not comment on implementation of the allowed return in their submissions.

Panel Determination

The Panel reviews the following two issues regarding implementation of the allowed returns:

[648] Exhibit C3-3, BCUC IR 7.1.
[649] Nelson Hydro 2024 Revenue Requirements, Decision accompanying Order G-170-24 dated June 21, 2024, p. 13.
[650] Exhibit B4-8, BCUC IR 7.1.
[651] Nelson Hydro 2024 Revenue Requirements, Decision accompanying Order G-170-24 dated June 21, 2024, p. 11.
[652] Nelson Hydro 2025 Revenue Requirement, Exhibit B-1.
[653] KPL 2024 RRA Decision, p. 22.
[654] Exhibit B5-3, BCUC IR 1.4.1, 1.4.2, 1.2.
[655] KPL Request to Vary 2024 Revenue Requirements Order G-53-24 Directive 4 Scope and Filing Date, Order G-121-24 dated April 25, 2024, p. 2.

1. The manner by which Stage 2 utilities will be eligible to collect the variance between permanent rates and interim rates arising from this Stage 2 decision from January 1, 2024 to the date of implementation of this decision; and
2. The timing of when utilities are able to change their rates to a level that appropriately reflects their allowed return as determined in this decision.

In making its determinations on implementation for each of the Stage 2 utilities, the Panel considered several factors. They include ease of understanding and regulatory efficiency for all parties, ease of implementation for utilities based on their preferred implementation approaches as discussed above, financing costs and intergenerational equity considerations for any deferral mechanisms used, and recognition of the various points of rates cycles that Stage 2 utilities may be at currently. For example, some Stage 2 utilities have ongoing rates proceedings, some had recently completed rates proceedings for one or multiple test years, some have upcoming rates applications in the near term, and others have no set schedule for rates applications.

Given the different circumstances among the various Stage 2 utilities, the Panel does not view that a standard implementation for all Stage 2 utilities is feasible. Instead, the Panel will review the appropriate implementation approach for each Stage 2 utility respectively below. While the Panel will establish various deferral accounts below, the ultimate disposition of those accounts will best be determined by a future BCUC proceeding that reviews the rates impacted by those deferral accounts.

For all three PNG divisions, the Panel approves the previously approved interim 2024 rates[656] as permanent. Each PNG division is directed to establish a new GCOC Variance Deferral Account, attracting PNG's weighted average cost of capital (WACC), to record the variance between the previously approved interim 2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision. The GCOC Variance Deferral Account will also capture the difference between any 2025 interim rates before and after incorporation of the new cost of capital under this decision. **The amounts to be added to the GCOC Variance Deferral Account and their disposition are to be addressed in PNG's next rates applications, which are expected to be filed before the end of 2024. If PNG does not have ongoing rate applications before the end of 2024, then PNG is directed to file a compliance filing by January 31, 2025, to implement the Stage 2 decision. As applicable, revised tariff pages should be filed with the BCUC by January 31, 2025.**

For Corix BMDEU - SFU, the Panel views that the proposed one-time bill adjustment to account for the variance related to GCOC impacts is reasonable given the nature of its service to SFU and its lack of deferral accounts to record such items. The Panel views that the establishment of a new deferral account to record the variance for GCOC impacts is not warranted at this time because such deferral will incur carrying costs, and SFU did not oppose a one-time bill adjustment. We also consider that Corix should charge SFU at a rate which reflects the new cost of capital under this decision in a timely basis to avoid any further adjustments in the future. Therefore, **Corix BMDEU is directed to file a compliance filing with the BCUC by January 31, 2025, that calculates (i) the impact of this one-time bill adjustment to SFU and (ii) the updated proposed permanent rates after the incorporation of the new cost of capital under this decision for the remaining test period for which Corix BMDEU currently has interim approval (i.e. until December 31, 2025).[657] As Corix BMDEU's**

[656] PNG 2023–2024 Revenue Requirements Application for the PNG-West Division, Decision and Order G-339-23 dated December 11, 2023, p. 35; PNG(NE) 2023–2024 Revenue Requirements Application for the Fort St. John/Dawson Creek and Tumbler Ridge Divisions, Decision and Order G-19-24 dated January 22, 2024, p. 29.
[657] Corix BMDEU 2024–2025 Revenue Requirements and Rates, Order G-76-24 dated March 19, 2024, Directive 1, p. 2.

revenue requirements and rates proceeding is ongoing, this Panel expects that 2024 and 2025 permanent rates will be addressed in that decision. As applicable, revised tariff pages should be filed with the BCUC by January 31, 2025.

For Corix BMDEU - UniverCity, Corix is directed to establish a new GCOC Variance Deferral Account, attracting Corix's WACC, to record the variance between the previously approved interim 2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision for its service to UniverCity. For clarity, the GCOC Variance Deferral Account is separate from the existing Revenue Deficiency Deferral Account for UniverCity customers, as this arrangement will provide flexibility for the utility and collection from ratepayers. The GCOC Variance Deferral Account will capture the difference between any 2025 interim rates before and after incorporation of the new cost of capital under this decision for its service to UniverCity. **The amounts to be added to the GCOC Variance Deferral Account and their disposition are to be addressed in a compliance filing to be filed with the BCUC by January 31, 2025. This compliance filing would incorporate adjustments to rates reflecting the allowed return approved for UniverCity for 2024 and 2025. As Corix BMDEU's revenue requirements and rates proceeding is ongoing, this Panel expects that 2024 and 2025 permanent rates will be addressed in that decision. As applicable, revised tariff pages should be filed with the BCUC by January 31, 2025.**

For Corix UBC NDES and DGE, the Panel approves the previously established interim 2024 rates[658] as permanent. Corix is directed to establish a new GCOC Variance Deferral Account for each utility, attracting Corix's WACC, to record the variance between the previously established interim 2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision. For clarity, the GCOC Variance Deferral Accounts are separate from the existing Revenue Deficiency Deferral Accounts for UBC NDES and DGE, as these arrangements will provide flexibility for the utility and collection from ratepayers. The GCOC Variance Deferral Accounts will also capture the difference between any 2025 interim rates before and after incorporation of the new cost of capital under this decision. **The amounts to be added to the GCOC Variance Deferral Accounts and their disposition are to be addressed the earlier of (i) these Corix Utilities' next rates applications or (ii) a compliance filing to be filed with the BCUC by January 31, 2025. This filing should also include revised permanent rates that reflect the new cost of capital under this decision for UBC NDES's and DGE's rates for 2025 and beyond. As applicable, revised tariff pages are to be filed with the BCUC by January 31, 2025.**

For Creative Energy's Core TES, the Panel approves the previously approved interim 2024 rates[659] as permanent. Creative Energy is directed to establish a new GCOC Variance Deferral Account for the Core TES, attracting the Core TES's WACC, to record the variance between the previously approved interim 2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision. For clarity, the new GCOC Variance Deferral Account is separate from the Core TES's Revenue Variance Deferral Account, as this arrangement will provide flexibility for the utility and collection from ratepayers. The GCOC Variance Deferral Account will also capture the difference between any 2025 interim rates before and after incorporation of the new cost of capital for Creative Energy's Core TES under this decision. **The amounts to be**

[658] While Corix UBC NDES and DGE did not have any active rates proceedings during the course of Stage 2, the GCOC Stage 1 Decision made rates interim effective January 1, 2024, pending the outcome of Stage 2 for any utilities in BC that use the Benchmark Utility. This applies to Corix UBC NDES and DGE.
[659] Creative Energy 2024 Revenue Requirements for the Core Thermal Energy System, Decision G-272-24 dated October 24, 2024, p. 31.

added to the GCOC Variance Deferral Account and their disposition are to be addressed in Creative Energy's next rates application for the Core TES, which is expected to be filed by December 31, 2024. If Creative Energy does not have an ongoing rate application for the Core TES before the end of 2024, then Creative Energy is directed to file a compliance filing for the Core TES by January 31, 2025, to implement the Stage 2 decision. As applicable, Creative Energy should file revised tariff pages for the Core TES with the BCUC by January 31, 2025.

For CEMP's Mount Pleasant DCS, the Panel approves the previously approved interim 2024 rates[660] as permanent. CEMP is directed to establish a new GCOC Variance Deferral Account for the Mount Pleasant DCS, attracting the Mount Pleasant DCS's WACC, to record the variance between the previous interim 2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision. For clarity, the new GCOC Variance Deferral Account is separate from the Mount Pleasant DCS's Revenue Variance Deferral Account, as this arrangement will provide flexibility for the utility and collection from ratepayers. The GCOC Variance Deferral Account will also capture the difference between any 2025 interim rates before and after incorporation of the new cost of capital under this decision. **The amounts to be added to the GCOC Variance Deferral Account and their disposition are to be addressed in a compliance filing to be filed with the BCUC by January 31, 2025. This compliance filing should also include revised permanent rates that reflect the new cost of capital under this decision for 2025 and 2026.[661] As applicable, revised tariff pages are to be filed with the BCUC by January 31, 2025.**

For Creative Energy's SODO Heating TES, the Panel approves the previously established interim 2024 rates[662] as permanent. Creative Energy is directed to establish a new GCOC Variance Deferral Account for the SODO Heating TES, attracting the SODO Heating TES's WACC, to record the variance between the previously established interim 2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision. The GCOC Variance Deferral Account will also capture the difference between any 2025 interim rates before and after incorporation of the new cost of capital under this decision. **The amounts to be added to the GCOC Variance Deferral Account and their disposition are to be addressed in the sooner of (i) its next rates application or (ii) a compliance filing to be filed with the BCUC by January 31, 2025. This filing should also include revised permanent rates that reflect the new cost of capital under this decision for the SODO Heating TES's rates for 2025 and beyond. As applicable, revised tariff pages should be filed with the BCUC by January 31, 2025.**

For Creative Energy's SODO DCS, the Panel approves the previously established interim 2024 rates[663] as permanent. Creative Energy is directed to establish a new GCOC Variance Deferral Account for the SODO DCS, attracting the SODO DCS's WACC, to record the variance between the previous interim 2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision. The GCOC Variance Deferral Account will also capture the difference between any 2025 interim rates before and after incorporation of the new cost of capital under this decision. **The amounts to be added to the GCOC Variance Deferral Account and their disposition are to be addressed in a compliance filing to be filed with the BCUC by**

[660] CEMP Mount Pleasant DCS 2024–2026 Rates Decision, pp. 4, 15.
[661] CEMP Mount Pleasant DCS 2024–2026 Rates Decision, pp. 4, 15.
[662] While Creative Energy SODO Heating TES did not have any active rates proceedings during the course of Stage 2, the GCOC Stage 1 Decision made rates interim effective January 1, 2024, pending the outcome of Stage 2 for any utilities in BC that use the Benchmark Utility. This applies to Creative Energy SODO Heating TES.
[663] SODO Heating TES and DCS Rates Decision.

January 31, 2025. This compliance filing should also include revised permanent rates that reflect the new cost of capital under this decision for 2025. As applicable, revised tariff pages should be filed with the BCUC by January 31, 2025.

For RDE, the Panel approves the previously approved interim 2024 and 2025 rates[664] as permanent. RDE is directed to establish a new GCOC Variance Deferral Account, attracting RDE's WACC, to record the variance between the previous interim 2024 and 2025 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision. The amounts to be added to the GCOC Variance Deferral Account and their disposition are to be addressed in a compliance filing to be filed with the BCUC by January 31, 2025. This compliance filing must also address when RDE will change the rate level for 2026 and beyond to reflect the new cost of capital under this decision. While the Panel has made 2024 and 2025 rates permanent in this decision, RDE may propose another process in its compliance filing that would adjust its 2025 rates sooner if RDE views that such process would be more appropriate based on its circumstances. **As applicable, revised tariff pages are to be filed with the BCUC by January 31, 2025.**

For Boralex, the Panel views that the proposed one-time bill adjustment is reasonable given the nature of its service to BC Hydro and its consistency with historical treatment of such adjustments that make this a more understandable approach for its sole rate-regulated customer, BC Hydro. The Panel directs Boralex to file a compliance filing with the BCUC by no later than January 31, 2025, that calculates (i) the impact of this one-time bill adjustment to BC Hydro and (ii) the updated proposed permanent rates after the incorporation of the new cost of capital under this decision for the remaining test period for which Boralex currently has interim approval (i.e. until December 31, 2027). This compliance filing should also include revised permanent rates that reflect the new cost of capital under this decision for the remainder of Boralex's current test period (i.e. until December 31, 2027). **As applicable, revised tariff pages are to be filed with the BCUC by January 31, 2025.**

For Nelson Hydro, the Panel approves the previously approved interim 2024 rates[665] as permanent. The Panel notes that in the BCUC's decision on Nelson Hydro's 2024 revenue requirement proceeding, it did not explicitly approve the use of the Revenue Variance Deferral Account for purposes of 2025 rates, as that proceeding was for the 2024 revenue requirements. **Nelson Hydro is directed to establish a new GCOC Variance Deferral Account, attracting Nelson Hydro's WACC, to record the variance between the previous interim 2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision.** The GCOC Variance Deferral Account will also capture the difference between any 2025 interim rates before and after incorporation of the new cost of capital under this decision. **The amounts to be added to the GCOC Variance Deferral Account and their disposition are to be addressed as an evidentiary update to Nelson Hydro's current 2025 revenue requirement proceeding.[666] As applicable, revised tariff pages are to be filed with the BCUC by January 31, 2025.**

For KPL, the Panel directs KPL to include a proposal for implementing its new cost of capital, effective January 1, 2024, under this decision into rates as part of its currently directed application for a revised deemed

[664] River District Energy Limited Partnership 2024 to 2025 Interim Rates, Order G-94-24 dated March 27, 2024, Directive 1.
[665] Nelson Hydro 2024 Revenue Requirements, Decision accompanying Order G-170-24 dated June 21, 2024, p. 13.
[666] Nelson Hydro 2025 Revenue Requirement, Exhibit B-1.

interest on notional debt or permanent rates as per Order G-121-24.[667] The Panel considers that the 45-day deadline from the date of this decision as per Order G-121-24 should now be extended to January 31, 2025, because there are other additional components in the compliance filing and doing so would make this timeline consistent with other Stage 2 utilities' deadlines in this decision. Therefore, **the Panel varies Directive 1 from Order G-121-24 such that KPL is directed to apply to the BCUC for a revised deemed interest on notional debt or permanent rates by January 31, 2025. This application must (i) calculate the impact on 2024 rates from incorporating the new cost of capital, effective January 1, 2024 under this decision, (ii) request permanent approval of 2024 interim rates,[668] and (iii) include specifics of any proposed deferral account to capture the difference (i.e. mechanism and timeline for recovery, financing costs, etc.).** The Panel clarifies that permanent 2024 rates for KPL, including revised tariff pages as applicable, will be established following review of that application.

For any other utilities in BC that have interim rates in place pending this Stage 2 decision[669] but have not actively participated in the GCOC proceeding, they should file an application for permanent rates with the BCUC as applicable by no later than January 31, 2025. If the BCUC receives no such application by January 31, 2025, or unless the BCUC directs otherwise, any rate adjustments will be assessed on a go-forward basis (i.e. no retroactive adjustments to reflect the impact of this decision will be allowed).

5.2 Process After Stage 2

In January 2024, the Panel set the scope after completion of Stage 2 to include:[670]

1. Deferral account financing costs; and
2. Any other items as the BCUC may direct.

The Panel noted that deferral account or regulatory account (both referred to as regulatory account) financing costs constitute a discrete issue that does not affect all utilities and therefore should be addressed after the conclusion of Stage 2.[671]

Panel Determination

The Panel finds that no new items are required for inclusion in the scope of the next phase of this GCOC proceeding. Therefore, the scope after completion of Stage 2 will consist only of regulatory account financing costs as the BCUC has already determined. The Panel considers that this is a discrete issue such that the Stage 1 and Stage 2 evidentiary records do not need to be rolled over nor do the intervening parties, although all parties will be able to participate should they choose to do so. The Panel views that this will essentially be a "Stage 3" to the GCOC proceeding. **Stage 3 will commence on a date with regulatory process to be determined by the BCUC.**

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[667] KPL Request to Vary 2024 Revenue Requirements Order G-53-24 Directive 4 Scope and Filing Date, Order G-121-24 dated April 25, 2024, p. 2.
[668] KPL 2024 RRA Decision, p. 22.
[669] GCOC Stage 1 Decision, p. 142.
[670] Order G-6-24 with Reasons for Decision dated January 11, 2024, Appendix B.
[671] Order G-6-24 with Reasons for Decision dated January 11, 2024, Appendix C, p. 13.

Given the limited scope of Stage 3, unless otherwise ordered by the BCUC, the Panel considers that the outcome of Stage 3 should be applied on a go-forward basis from the date of the final decision of Stage 3 of this GCOC proceeding or at a future date as may be determined by the BCUC. For clarity, the Panel anticipates that no interim rates or effective date that precedes the date of the final decision in Stage 3 should be required.

5.3 Confidentiality

PNG was the only party that filed confidential materials in Stage 2. In response to RCIA's IR No. 1, PNG filed two confidential exhibits[672] containing private ratings reports that were issued in confidence by Morningstar DBRS to PNG for limited distribution and credit review purposes only. PNG stated that it is prohibited from disclosing this information to the public and requested that the BCUC treat the private ratings reports as confidential within and after the conclusion of Stage 2 of the GCOC proceeding pursuant to Section 18 of the BCUC's Rules of Practice and Procedure.[673]

Panel Determination

The Panel acknowledges the restrictions on distribution of the two private ratings reports issued in confidence by Morningstar DBRS to PNG. **Therefore, unless otherwise ordered by the BCUC, the Panel grants PNG's request to keep Exhibits B9-14-1 and B9-14-2 confidential.**

DATED at the City of Vancouver, in the Province of British Columbia, this 29th day of November 2024.

Electronically signed by Anna Fung

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A. K. Fung, KC
Panel Chair/Commissioner

Electronically signed by Karen Keilty

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K. A. Keilty
Commissioner

Electronically signed by Tom Loski

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T. A. Loski
Commissioner

[672] Exhibit B9-14-1 and B9-14-2.
[673] Exhibit B9-14, RCIA IRs 1.2 and 1.3.

British Columbia Utilities Commission
Generic Cost of Capital Stage 2

LIST OF TERMS AND ACRONYMS

Term/Acronym	Description
2013 GCOC Stage 1 Decision	BCUC 2013 GCOC proceeding (Stage 1), Decision and Order G-75-13 dated May 10, 2013
2014 GCOC Stage 2 Decision	BCUC 2013 GCOC Proceeding (Stage 2), Decision and Order G-47-14 dated March 25, 2014
2016 FEI GCOC Decision	FortisBC Energy Inc. Application for its Common Equity Component and Return on Equity for 2016 [FEI 2016 Cost of Capital (COC)], Decision and Order G-129-16 dated August 10, 2016
2022 CEMP Mount Pleasant DCS Rates Decision	Creative Energy Mount Pleasant Limited Partnership Application for Rates for the Mount Pleasant District Cooling System, Decision and Order G-242-22 dated August 22, 2022
AAM	Automatic adjustment mechanism
AMPC	Association of Major Power Customers of BC
BC	British Columbia
BC Hydro	British Columbia Hydro and Power Authority
BCOAPO	British Columbia Old Age Pensioners' Organization et al.
BCUC	British Columbia Utilities Commission
Benchmark Utility	FortisBC Energy Inc. (FEI) has been established as the benchmark utility against which other utilities that currently use the Benchmark Utility set their own cost of capital.
BMDEU	Corix Burnaby Mountain District Energy Utility
BMDEU 2020–2023 RRRA Decision	Corix Multi-Utility Services Inc. Burnaby Mountain District Energy Utility 2020-2023 Revenue Requirements and Rates Application, Decision and Order G-279-21 dated September 24, 2021
Boralex	Boralex Ocean Falls Limited Partnership
Boralex 2019–2022 Rates to BC Hydro Decision	Boralex Application for Approval of Rates and Terms and Conditions for Service to British Columbia Hydro, Decision and Order G-270-20 dated October 27, 2020
bps	Basis points
Brattle	The Brattle Group
CAPM	Capital pricing asset model
CEMP	Creative Energy Mount Pleasant Limited Partnership, also known as Mount Pleasant District Cooling System (Mount Pleasant DCS).
CEMP Mount Pleasant DCS 2024–2026 Rates Decision	CEMP Rates for the Mount Pleasant District Cooling System, Decision accompanying Order G-265-24 dated October 21, 2024

Term/Acronym	Description
CNRL	Canadian Natural Resources Ltd.
Core Steam Plant	A centralized natural gas boiler plant located at 720 Beatty Street that is part of Creative Energy's Core Thermal Energy System.
Core TES	Creative Energy's Core Steam System
Corix	Corix (CA) DE Services Limited Partnership, formerly known as Corix Mult-Utility Services Inc.
Corix MPA Evidence Submission	Written Evidence of Morrison Park Advisors Inc. submitted by Corix as Exhibit B6-9-2 in Stage 2.
Corix Utilities	Collectively, (i) Corix Burnaby Mountain DE Limited Partnership, otherwise known as Burnaby Mountain District Energy Utility; (ii) Corix UBCDE Limited Partnership, known as Neighbourhood District Energy System at the University of British Columbia; and (iii) Corix Dockside Green DE Limited Partnership, known as Dockside Green Energy
COSA and RD	Cost of service and rate design
Creative Energy	Creative Energy Vancouver Platforms Inc.
CRSP	Center for Research in Security Prices
COC	Cost of capital
DCS	District cooling system
DES	District energy system
DGE	Corix Dockside Green DE Limited Partnership, known as Dockside Green Energy
DSCR	Debt to service coverage ratio
FAES	FortisBC Alternative Energy Service Inc.
FBC	FortisBC Inc.
FEI	FortisBC Energy Inc.
FEI 2016 Cost of Capital	FortisBC Energy Inc. Application for its Common Equity Component and Return on Equity for 2016
FortisBC	Collectively, FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC)
GCOC	Generic cost of capital
GCOC Stage 1 Decision	BCUC GCOC (Stage 1) proceeding, Decision and Order G-236-23 dated September 5, 2023
GHG	Greenhouse gas
GoC	Government of Canada
IR	Information request(s)
KPL	Kyuquot Power Ltd.
KPL 2024 RRA Decision	KPL 2024 Revenue Requirements, Decision and Order G-53-24 dated February 29, 2024
MFA	Municipal Finance Authority

Term/Acronym	Description
MFA Letter	Letter from the Municipal Finance Authority filed as evidence by Nelson Hydro in Stage 2 as part of Exhibit B4-6
Mount Pleasant DCS	Mount Pleasant District Cooling System
MPA	Morrison Park Advisors Inc.
MVRD	Metro Vancouver Regional District
Nelson Hydro 2022 COSA and RD Decision	Nelson Hydro Cost of Service Analysis and Rate Design, Decision and Order G-196-22 dated July 19, 2022
Nelson Hydro 2023 Reconsideration Decision	Nelson Hydro Reconsideration and Variance of BCUC Order G-196-22, Decision and Order G-311-23 dated November 15, 2023
PNG	Collectively, Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. and all their divisions
PNG(NE)	Pacific Northern Gas (N.E.) Ltd.
PNG-West	Western division of Pacific Northern Gas Ltd.
pps	Percentage points
RCIA	Residential Consumer Intervener Association
RDE	River District Energy
ROE	Return on equity
RRRA	Revenue Requirements and Rates Application
Rural	Area outside the City of Nelson’s municipal boundaries
SFU	Simon Fraser University
Small DES	Small district energy system(s), a group of Creative Energy thermal energy system projects that includes the South Downtown Heating Thermal Energy System, South Downtown District Cooling System, and Creative Energy Mount Pleasant Limited Partnership.
SODO DCS	Creative Energy’s South Downtown District Cooling System
SODO Heating TES	Creative Energy’s South Downtown Heating Thermal Energy System
SODO Heating TES and DCS Rates Decision	Creative Energy Application for Heating Rates for the Heating Thermal Energy System and Cooling Rates for the District Cooling System at the Vancouver House Development, Decision and Order G-222-21 dated July 22, 2021
Stage 1	First stage of this current GCOC proceeding
Stage 2	Second stage of this current GCOC proceeding
TES	Thermal energy system
TES Default	The default equity component and default allowed return on equity premium for rate-regulated thermal energy systems
the CEC	Commercial Energy Consumer Association of British Columbia

Term/Acronym	Description
UBC	University of British Columbia
UBC NDES	Corix UBCDE Limited Partnership, known as Neighbourhood District Energy System at the University of British Columbia
UCA	*Utilities Commission Act*
Urban	Area within the City of Nelson's municipal boundaries
US	United States
WACC	Weighted average cost of capital

British Columbia Utilities Commission
Generic Cost of Capital Stage 2

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-32	Letter dated September 5, 2023 – BCUC Order G-237-23 establishing a regulatory timetable for Stage 2 of the British Columbia Utilities Commission (BCUC) Generic Cost of Capital (GCOC) proceeding
A-33	Letter dated September 20, 2023 – BCUC amending the Panel for the review of the application
A-34	Letter dated January 11, 2024 – BCUC Order G-6-24 establishing a further regulatory timetable and amended scope for Stage 2 of the BCUC GCOC proceeding with Reasons for Decision
A-35	Letter dated May 2, 2024 – BCUC Information Request No. 1 to Boralex LP
A-36	Letter dated May 2, 2024 – BCUC Information Request No. 1 to Corix
A-37	Letter dated May 2, 2024 – BCUC Information Request No. 1 to Creative Energy
A-38	Letter dated May 2, 2024 – BCUC Information Request No. 1 to FAES
A-39	Letter dated May 2, 2024 – BCUC Information Request No. 1 to KPL
A-40	Letter dated May 2, 2024 – BCUC Information Request No. 1 to Nelson Hydro
A-41	Letter dated May 2, 2024 – BCUC Information Request No. 1 to PNG
A-42	Letter dated May 2, 2024 – BCUC Information Request No. 1 to RDE
A-43	Letter dated May 28, 2024 – BCUC Order G-150-24 amending the regulatory timetable
A-44	Letter dated June 24, 2024 – BCUC Order G-172-24 amending the regulatory timetable
A-45	Letter dated June 24, 2024– Amended timetable and letter of comment deadline reminder
A-46	Letter dated August 6, 2024 – BCUC Order G-209-24 amending the regulatory timetable
A-47	Letter dated August 12, 2024 – BCUC Order G-213-24 amending the regulatory timetable

Exhibit No.	Description
COMMISSION STAFF DOCUMENTS	
A2-42	Letter dated May 2, 2024 – BCUC Staff submission: InterGroup Consultants analysis Nelson Hydro - Appropriate Level of ROE dated March 2020
APPLICANT DOCUMENTS	
B1-55	**FORTISBC ENERGY INC. (FEI) and FORTISBC INC. (FBC) (collectively FORTISBC) –** Letter dated December 4, 2023 – FortisBC submitting reply submission on benchmark and scope modification
B3-5	**FORTISBC ALTERNATIVE ENERGY SERVICE INC. (FAES) –** Letter dated November 14, 2023 – FAES submitting comments on benchmark and scope modification
B3-6	Letter dated December 4, 2023 – FAES submitting reply submission on benchmark and scope modification
B3-7	Letter dated April 4, 2024 – FAES submission of evidence
B3-8	Letter dated June 5, 2024 – FAES submitting response to BCUC Information Request No. 1
B3-9	Letter dated June 5, 2024 – FAES submitting response to CEC Information Request No. 1
B3-10	Letter dated June 5, 2024 – FAES submitting response to Corix Information Request No. 1
B3-11	Letter dated June 5, 2024 – FAES submitting response to RCIA Information Request No. 1
B3-12	Letter dated June 5, 2024 – FAES submitting response to BCOAPO Information Request No. 1
B4-5	**NELSON HYDRO** – Letter dated November 14, 2023 – Nelson Hydro submitting comments on benchmark and scope modification
B4-6	Letter dated April 4, 2024 – Nelson Hydro submission of evidence
B4-7	Letter dated May 9, 2024 – Nelson Hydro submitting Information Request No. 1 on Evidence to PNG
B4-8	Letter dated June 5, 2024 – Nelson Hydro submitting response to BCUC Information Request No. 1

Exhibit No.	**Description**
B4-9	Letter dated June 5, 2024 – Nelson Hydro submitting response to RCIA Information Request No. 1
B4-10	Letter dated June 5, 2024 – Nelson Hydro submitting response to BCOAPO Information Request No. 1
B5-3	**KYUQUOT POWER LTD. (KPL) –** Letter dated May 29, 2024 submitting responses to BCUC Information Request No. 1
B6-7	**CORX MULTI-UTILITY SERVICES INC. (CORIX) –** Letter dated November 14, 2023 – Corix submitting comments on benchmark and scope modification
B6-8	Letter dated December 4, 2023 – Corix submitting reply submission on benchmark and scope modification
B6-9	Letter dated April 4, 2024 – Corix submission of evidence
B6-10	Letter dated May 9, 2024 – Corix submitting Information Request No. 1 on Evidence to FAES
B6-11	Letter dated May 27, 2024 – Corix submitting extension request to file Information Request No. 1 response
B6-12	Letter dated June 5, 2024 – Corix submitting response to BCUC Information Request No. 1
B6-13	Letter dated June 5, 2024 – Corix submitting response to BCOAPO Information Request No. 1
B6-14	Letter dated June 5, 2024 – Corix submitting response to CEC Information Request No. 1
B6-15	Letter dated June 5, 2024 – Corix submitting response to RCIA Information Request No. 1
B6-16	Letter dated June 5, 2024 – Corix submitting response to SFU Information Request No. 1
B7-7	**CREATIVE ENERGY VANCOUVER PLATFORMS INC. (CREATIVE ENERGY) –** Letter dated November 14, 2023 – Creative Energy submitting comments on benchmark and scope modification
B7-8	Letter dated April 4, 2024 – Creative Energy submission of evidence
B7-9	Letter dated June 4, 2024 – Creative Energy submitting response to BCUC Information Request No. 1
B7-10	Letter dated June 4, 2024 – Creative Energy submitting response to BCOAPO Information Request No. 1

Exhibit No.	Description
B7-11	Letter dated June 4, 2024 – Creative Energy submitting response to CEC Information Request No. 1
B7-12	Letter dated June 4, 2024 – Creative Energy submitting response to RCIA Information Request No. 1
B8-3	**RIVER DISTRICT ENERGY (RDE) –** Letter dated November 14, 2023 – RDE submitting comments on benchmark and scope modification
B8-4	Letter dated December 4, 2023 – RDE submitting reply submission on benchmark and scope modification
B8-5	Letter dated April 4, 2024 – RDE submission of evidence
B8-6	Letter dated May 27, 2024 – RDE submitting support for Corix extension request to file Information Request No. 1 responses
B8-7	Letter dated June 5, 2024 – RDE submitting response to BCUC Information Request No. 1
B8-8	Letter dated June 5, 2024 – RDE submitting response to BCOAPO Information Request No. 1
B8-9	Letter dated June 5, 2024 – RDE submitting response to CEC Information Request No. 1
B8-10	Letter dated June 5, 2024 – RDE submitting response to RCIA Information Request No. 1
B9-8	**PACIFIC NORTHERN GAS LTD. (PNG) AND PACIFIC NORTHERN GAS (N.E.) LTD. (PNGNE) (COLLECTIVELY PNG)** – Letter dated November 14, 2023 – PNG submitting comments on benchmark and scope modification
B9-9	Letter dated April 4, 2024 – PNG submission of evidence
B9-10	Letter dated June 5, 2024 – PNG submitting response to BCUC Information Request No. 1
B9-11	Letter dated June 5, 2024 – PNG submitting response to Nelson Hydro Information Request No. 1
B9-12	Letter dated June 5, 2024 – PNG submitting response to BCOAPO Information Request No. 1
B9-13	Letter dated June 5, 2024 – PNG submitting response to CEC Information Request No. 1
B9-14	Letter dated June 5, 2024 – PNG submitting response to RCIA Information Request No. 1

Exhibit No.	Description
B9-14-1	**CONFIDENTIAL** - Letter dated June 5, 2024 – PNG submitting response to RCIA Information Request No. 1 confidential Attachment 1
B9-14-2	**CONFIDENTIAL** - Letter dated June 5, 2024 – PNG submitting response to RCIA Information Request No. 1 confidential Attachment 2

INTERVENER DOCUMENTS

C1-14	**RESIDENTIAL CONSUMER INTERVENER ASSOCIATION (RCIA) –** Letter dated November 14, 2023 - RCIA submitting comments on benchmark and scope modification
C1-15	Letter dated December 4, 2023 – RCIA submitting reply submission on benchmark and scope modification
C1-16	Letter dated May 9, 2024 – RCIA submitting Information Request No. 1 on Evidence to RDE
C1-17	Letter dated May 9, 2024 – RCIA submitting Information Request No. 1 on Evidence to Creative Energy
C1-18	Letter dated May 9, 2024 – RCIA submitting Information Request No. 1 on Evidence to Boralex
C1-19	Letter dated May 9, 2024 – RCIA submitting Information Request No. 1 on Evidence to FAES
C1-20	Letter dated May 9, 2024 – RCIA submitting Information Request No. 1 on Evidence to Nelson Hydro
C1-21	Letter dated May 9, 2024 – RCIA submitting Information Request No. 1 on Evidence to PNG
C1-22	Letter dated May 9, 2024 – RCIA submitting Information Request No. 1 on Evidence to Corix
C1-23	Letter dated June 24, 2024 – RCIA submitting Confidentiality Declaration and Undertaking Form
C3-2	**BORALEX OCEAN FALLS LIMITED PARTNERSHIP (BORALEX LP)** – Letter dated April 4, 2024 submission of evidence
C3-3	Letter dated May 30, 2024 – Boralex LP submitting responses to BCUC Information Request No. 1

Exhibit No.	Description
C3-4	Letter dated May 30, 2024 – Boralex LP submitting responses to BCOAPO Information Request No. 1
C3-5	Letter dated May 30, 2024 – Boralex LP submitting responses to CEC Information Request No. 1
C3-6	Letter dated May 30, 2024 – Boralex LP submitting responses to RCIA Information Request No. 1
C4-3	**ASSOCIATION OF MAJOR POWER CUSTOMERS OF BC (AMPC) –** Letter dated November 14, 2023 - AMPC submitting comments on benchmark and scope modification
C6-18	**COMMERCIAL ENERGY CONSUMER ASSOCIATION OF BRITISH COLUMBIA (CEC) –** Letter dated November 14, 2023 – CEC submitting comments on benchmark and scope modification
C6-19	Letter dated December 4, 2023 – CEC submitting reply submission on benchmark and scope modification
C6-20	Letter dated May 9, 2024 – CEC submitting Information Request No. 1 on Evidence to FAES
C6-21	Letter dated May 9, 2024 – CEC submitting Information Request No. 1 on Evidence to PNG
C6-22	Letter dated May 9, 2024 – CEC submitting Information Request No. 1 on Evidence to Boralex
C6-23	Letter dated May 9, 2024 – CEC submitting Information Request No. 1 on Evidence to Corix
C6-24	Letter dated May 9, 2024 – CEC submitting Information Request No. 1 on Evidence to Creative Energy
C6-25	Letter dated May 9, 2024 – CEC submitting Information Request No. 1 on Evidence to RDE
C7-12	**BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION, ACTIVE SUPPORT AGAINST POVERTY, DISABILITY ALLIANCE BC, COUNCIL OF SENIOR CITIZENS' ORGANIZATION OF BC, TENANTS RESOURCE AND ADVISORY CENTRE, AND TOGETHER AGAINST POVERTY SOCIETY (BCOAPO) –** Letter dated November 14, 2023 - BCOAPO submitting comments on benchmark and scope modification
C7-13	Letter dated December 4, 2023 – BCOAPO submitting reply submission on benchmark and scope modification
C7-14	Letter dated May 9, 2024 – BCOAPO submitting Information Request No. 1 on Evidence to PNG

Exhibit No.	Description
C7-15	Letter dated May 9, 2024 – BCOAPO submitting Information Request No. 1 on Evidence to Corix
C7-16	Letter dated May 9, 2024 – BCOAPO submitting Information Request No. 1 on Evidence to RDE
C7-17	Letter dated May 9, 2024 – BCOAPO submitting Information Request No. 1 on Evidence to Creative Energy
C7-18	Letter dated May 9, 2024 – BCOAPO submitting Information Request No. 1 on Evidence to FAES
C7-19	Letter dated May 9, 2024 – BCOAPO submitting Information Request No. 1 on Evidence to Boralex
C7-20	Letter dated May 9, 2024 – BCOAPO submitting Information Request No. 1 on Evidence to Nelson Hydro
C7-21	Letter dated August 2, 2024 – BCOAPO submitting extension request for filing Final Argument
C8-3	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BC HYDRO) –** Letter dated November 14, 2023 – BC Hydro submitting comments on benchmark and scope modification
C10-1	**SIMON FRASER UNIVERSITY (SFU) –** Letter dated April 15, 2024 submitting request to intervene by Joyce Chong
C10-2	Letter dated May 6, 2023 – SFU submitting Information Request No. 1 on Corix Evidence

British Columbia Utilities Commission
Generic Cost of Capital Stage 2

SUMMARY OF DETERMINATIONS AND DIRECTIVES

This summary is provided for the convenience of readers. In the event of any difference between the determinations and directives in this summary and those in the body of the decision, the wording in the decision shall prevail.

Determination/Directive	Page
The Panel finds that business risk should only affect the deemed equity component in Stage 2 and that the equity premium can wholly reflect the difference in each Stage 2 utility's business risks relative to those of the Benchmark Utility.	8
Following from the Panel's findings on the equity premium approach above, the Panel finds that business risk is not a primary driver of the ROE premium. Rather, consistent with BCUC's approach in Stage 1, the Panel finds that the ROE premium in Stage 2 should be based on sound financial theory and empirical evidence that would have resulted in a different allowed ROE from the 9.65 percent determined for the Benchmark Utility in Stage 1.	13
Accordingly, the Panel finds that a size premium is warranted within the CAPM output for Stage 2 utilities' allowed ROE and that such size premium should be the same for all Stage 2 utilities.	14
The Panel determines that the ROE premium for all Stage 2 utilities will be 75 bps to reflect size relative to the Benchmark Utility.	15
The Panel finds that PNG-West's overall business risk when compared against the Benchmark Utility has not materially changed since its last cost of capital proceeding in 2014.	26
The Panel finds that PNG(NE) Tumbler Ridge's overall business risk when compared against the Benchmark Utility has not materially changed since its last cost of capital proceeding in 2014.	27
The Panel finds that PNG(NE) Fort St. John / Dawson Creek's overall business risk when compared against the Benchmark Utility has not materially changed since its last cost of capital proceeding in 2014.	27
The Panel sets a 7.0 pps equity premium, resulting in a 52.0 percent deemed equity component for PNG-West and PNG(NE) Tumbler Ridge, and a 1.0 pps equity premium, resulting in a 46.0 percent deemed equity component for PNG(NE) Fort St. John / Dawson Creek.	28
The Panel rescinds the BCUC directive made in the 2014 GCOC Stage 2 Decision requiring PNG to file an updated business risk assessment in all future revenue requirements applications.	30

Determination/Directive	Page
The Panel finds that with DGE's operational maturity, its build-out challenges have stabilized and its technology risks have diminished and it now has a comparable risk profile to that of the BMDEU and UBC NDES.	42
The Panel concludes that the BMDEU, UBC NDES and DGE utilities should be treated similarly regarding equity and ROE premiums, as no unique risks justify differentiated allowed returns among them.	42
The Panel sets a 4.0 pps equity premium, resulting in a 49.0 deemed equity component for Corix BMDEU, UBC NDES, and DGE.	42
Thus, the Panel does not consider these changes sufficient to substantiate an increase in the overall risk profile for the Small DES projects compared to the Benchmark Utility.	48
The Panel approves the continuation of a 4.0 pps equity premium, resulting in a deemed equity component of 49.0 percent for the three Creative Energy Small DES projects.	49
The Panel finds that the business risks associated with the Core TES are higher relative to the Benchmark Utility and have increased since the last assessment in 2014.	54
The Panel sets a 6.0 pps equity premium, resulting in a 51.0 percent deemed equity component for the Core TES.	54
The Panel finds that RDE's overall business risk continues to be higher than the Benchmark Utility, but the risk differential has not materially changed since its last cost of capital proceeding in 2014.	58
The Panel sets a 4.0 pps equity premium, resulting in a 49.00 percent deemed equity component for RDE.	58
The Panel determines that establishing a TES Default is warranted.	61
The Panel determines that establishing a TES Default that is reflective of the typical TES is warranted.	63
The Panel finds a 4.0 pps equity premium resulting in a 49.0 percent deemed equity component and a 75 bps ROE premium resulting in an allowed ROE of 10.40 percent to be the appropriate return for the TES Default.	65

Determination/Directive	Page
The Panel finds the TES Default should not be automatically applied and that each future TES should have the opportunity to justify its proposed equity premium (i.e. deemed equity component) and ROE premium (i.e. allowed ROE), which could be the TES Default or higher or lower than the TES Default based on its business risks and circumstances at the time of its regulatory filing.	67
The Panel agrees with Boralex's overall business risk assessment that its risks remain higher than the Benchmark Utility, but that the gap has narrowed since 2020.	71
The Panel sets a 5.0 percent equity premium, resulting in a 50.0 percent deemed equity component for Boralex.	72
The Panel finds that Nelson Hydro's overall business risk has not changed since its last cost of capital proceeding in 2022. The Panel sets a 5.0 pps equity premium, resulting in a 50.0 percent deemed equity component for Nelson Hydro.	77
Accordingly, the Panel sets a 5.0 pps equity premium, resulting in a 50.0 percent deemed equity component for KPL.	79
The Panel finds that establishing a deemed interest rate continues to be warranted when a utility does not have third-party debt. The Panel further finds that a deemed interest rate serves as an effective mechanism for setting the appropriate cost of debt in determining a utility's fair return when there is no observable debt or where the utility does not incur actual financing costs.	82
The Panel determines that the deemed interest rate methodology should be based on the sum of: 1. GoC 10-year bond yields based on the average of the last trailing 12 months; 2. The corporate credit spreads on the GoC 10-year bonds for BBB and BBB(low) rated utilities based on the average of the last trailing 12 months; 3. Non-investment grade lending premium of 92 bps; and 4. A deemed issuance fee of 50 bps.	86
The Panel finds 92 bps as the appropriate non-investment grade lending premium on the basis of the expert evidence which is supported by market data and analysis.	87
Accordingly, the Panel finds that a 50 bps deemed issuance fee within the deemed interest rate methodology is appropriate.	87

Determination/Directive	Page
The Panel finds that the deemed interest rate methodology, as determined above, sufficiently accounts for changes in the market in the absence of an AAM by tracking the GoC 10-year bond yields and the BBB to BBB(low) utility corporate credit spreads, which would be updated based on the latest market information available at the time the deemed interest rate methodology is applied.	88–89
The Panel finds that utilities should be free to apply for different deemed interest rate methodologies based on their specific circumstances.	90
The Panel determines that the deemed interest rate methodology established above is effective January 1, 2024, for those utilities that use a deemed interest rate in setting their cost of debt.	91
For all three PNG divisions, the Panel approves the previously approved interim 2024 rates as permanent. Each PNG division is directed to establish a new GCOC Variance Deferral Account, attracting PNG's weighted average cost of capital (WACC), to record the variance between the previously approved interim 2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision. […] The amounts to be added to the GCOC Variance Deferral Account and their disposition are to be addressed in PNG's next rates applications, which are expected to be filed before the end of 2024. If PNG does not have ongoing rate applications before the end of 2024, then PNG is directed to file a compliance filing by January 31, 2025, to implement the Stage 2 decision. As applicable, revised tariff pages should be filed with the BCUC by January 31, 2025.	95
For Corix BMDEU - SFU, the Panel views that the proposed one-time bill adjustment to account for the variance related to GCOC impacts is reasonable given the nature of its service to SFU and its lack of deferral accounts to record such items. […] Corix BMDEU is directed to file a compliance filing with the BCUC by January 31, 2025, that calculates (i) the impact of this one-time bill adjustment to SFU and (ii) the updated proposed permanent rates after the incorporation of the new cost of capital under this decision for the remaining test period for which Corix BMDEU currently has interim approval (i.e. until December 31, 2025). As Corix BMDEU's revenue requirements and rates proceeding is ongoing, this Panel expects that 2024 and 2025 permanent rates will be addressed in that decision. As applicable, revised tariff pages should be filed with the BCUC by January 31, 2025.	95

Determination/Directive	Page
For Corix BMDEU - UniverCity, Corix is directed to establish a new GCOC Variance Deferral Account, attracting Corix's WACC, to record the variance between the previously approved interim 2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision for its service to UniverCity. […] The amounts to be added to the GCOC Variance Deferral Account and their disposition are to be addressed in a compliance filing to be filed with the BCUC by January 31, 2025. This compliance filing would incorporate adjustments to rates reflecting the allowed return approved for UniverCity for 2024 and 2025. As Corix BMDEU's revenue requirements and rates proceeding is ongoing, this Panel expects that 2024 and 2025 permanent rates will be addressed in that decision. As applicable, revised tariff pages should be filed with the BCUC by January 31, 2025.	95–96
For Corix UBC NDES and DGE, the Panel approves the previously established interim 2024 rates as permanent. Corix is directed to establish a new GCOC Variance Deferral Account for each utility, attracting Corix's WACC, to record the variance between the previously established interim 2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision. […] The amounts to be added to the GCOC Variance Deferral Accounts and their disposition are to be addressed the earlier of (i) these Corix Utilities' next rates applications or (ii) a compliance filing to be filed with the BCUC by January 31, 2025. This filing should also include revised permanent rates that reflect the new cost of capital under this decision for UBC NDES's and DGE's rates for 2025 and beyond. As applicable, revised tariff pages are to be filed with the BCUC by January 31, 2025.	96
For Creative Energy's Core TES, the Panel approves the previously approved interim 2024 rates as permanent. Creative Energy is directed to establish a new GCOC Variance Deferral Account for the Core TES, attracting the Core TES's WACC, to record the variance between the previously approved interim 2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision. […] The amounts to be added to the GCOC Variance Deferral Account and their disposition are to be addressed in Creative Energy's next rates application for the Core TES, which is expected to be filed by December 31, 2024. If Creative Energy does not have an ongoing rate application for the Core TES before the end of 2024, then Creative Energy is directed to file a compliance filing for the Core TES by January 31, 2025, to implement the Stage 2 decision. As applicable, Creative Energy should file revised tariff pages for the Core TES with the BCUC by January 31, 2025.	96

Determination/Directive	Page
For CEMP's Mount Pleasant DCS, the Panel approves the previously approved interim 2024 rates as permanent. CEMP is directed to establish a new GCOC Variance Deferral Account for the Mount Pleasant DCS, attracting the Mount Pleasant DCS's WACC, to record the variance between the previous interim 2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision. […] The amounts to be added to the GCOC Variance Deferral Account and their disposition are to be addressed in a compliance filing to be filed with the BCUC by January 31, 2025. This compliance filing should also include revised permanent rates that reflect the new cost of capital under this decision for 2025 and 2026. As applicable, revised tariff pages are to be filed with the BCUC by January 31, 2025.	96–97
For Creative Energy's SODO Heating TES, the Panel approves the previously established interim 2024 rates as permanent. Creative Energy is directed to establish a new GCOC Variance Deferral Account for the SODO Heating TES, attracting the SODO Heating TES's WACC, to record the variance between the previously established interim 2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision. […] The amounts to be added to the GCOC Variance Deferral Account and their disposition are to be addressed in the sooner of (i) its next rates application or (ii) a compliance filing to be filed with the BCUC by January 31, 2025. This filing should also include revised permanent rates that reflect the new cost of capital under this decision for the SODO Heating TES's rates for 2025 and beyond. As applicable, revised tariff pages should be filed with the BCUC by January 31, 2025.	97
For Creative Energy's SODO DCS, the Panel approves the previously established interim 2024 rates as permanent. Creative Energy is directed to establish a new GCOC Variance Deferral Account for the SODO DCS, attracting the SODO DCS's WACC, to record the variance between the previous interim 2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision. […] The amounts to be added to the GCOC Variance Deferral Account and their disposition are to be addressed in a compliance filing to be filed with the BCUC by January 31, 2025. This compliance filing should also include revised permanent rates that reflect the new cost of capital under this decision for 2025. As applicable, revised tariff pages should be filed with the BCUC by January 31, 2025.	97

Determination/Directive	Page
For RDE, the Panel approves the previously approved interim 2024 and 2025 rates as permanent. RDE is directed to establish a new GCOC Variance Deferral Account, attracting RDE's WACC, to record the variance between the previous interim 2024 and 2025 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision. The amounts to be added to the GCOC Variance Deferral Account and their disposition are to be addressed in a compliance filing to be filed with the BCUC by January 31, 2025. This compliance filing must also address when RDE will change the rate level for 2026 and beyond to reflect the new cost of capital under this decision. […] As applicable, revised tariff pages are to be filed with the BCUC by January 31, 2025.	97–98
For Boralex, the Panel views that the proposed one-time bill adjustment is reasonable given the nature of its service to BC Hydro and its consistency with historical treatment of such adjustments that make this a more understandable approach for its sole rate-regulated customer, BC Hydro. The Panel directs Boralex to file a compliance filing with the BCUC by no later than January 31, 2025, that calculates (i) the impact of this one-time bill adjustment to BC Hydro and (ii) the updated proposed permanent rates after the incorporation of the new cost of capital under this decision for the remaining test period for which Boralex currently has interim approval (i.e. until December 31, 2027). […] As applicable, revised tariff pages are to be filed with the BCUC by January 31, 2025.	98
For Nelson Hydro, the Panel approves the previously approved interim 2024 rates as permanent. […] Nelson Hydro is directed to establish a new GCOC Variance Deferral Account, attracting Nelson Hydro's WACC, to record the variance between the previous interim 2024 rates and the rates that would reflect the new cost of capital, effective January 1, 2024, under this decision. […] The amounts to be added to the GCOC Variance Deferral Account and their disposition are to be addressed as an evidentiary update to Nelson Hydro's current 2025 revenue requirement proceeding. As applicable, revised tariff pages are to be filed with the BCUC by January 31, 2025.	98

Determination/Directive	Page
For KPL, the Panel directs KPL to include a proposal for implementing its new cost of capital, effective January 1, 2024, under this decision into rates as part of its currently directed application for a revised deemed interest on notional debt or permanent rates as per Order G-121-24.	98
The Panel varies Directive 1 from Order G-121-24 such that KPL is directed to apply to the BCUC for a revised deemed interest on notional debt or permanent rates by January 31, 2025. This application must (i) calculate the impact on 2024 rates from incorporating the new cost of capital, effective January 1, 2024 under this decision, (ii) request permanent approval of 2024 interim rates, and (iii) include specifics of any proposed deferral account to capture the difference (i.e. mechanism and timeline for recovery, financing costs, etc.).	98
The Panel finds that no new items are required for inclusion in the scope of the next phase of this GCOC proceeding. Therefore, the scope after completion of Stage 2 will consist only of regulatory account financing costs as the BCUC has already determined.	99
Stage 3 will commence on a date with regulatory process to be determined by the BCUC.	99
Therefore, unless otherwise ordered by the BCUC, the Panel grants PNG's request to keep Exhibits B9-14-1 and B9-14-2 confidential.	100